U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

SPECIAL PERMIT – Strain Based Design

SEP 9 2019

Special Permit Information:

Docket Number:	PHMSA-2017-0044
Requested By:	Alaska Gasline Development Corporation
Operator ID#:	40015
Original Date Requested:	April 14, 2017
Original Issuance Date:	September 9, 2019
Effective Date:	September 9, 2019
Code Sections:	49 CFR 192.103, 192.105, 192.317, and 192.620

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS),[1] grants this special permit to Alaska Gasline Development Corporation (AGDC), owner and operator of the Alaska LNG Pipeline.[2] This special permit waives compliance from 49 Code of Federal Regulations (CFR) 192.103, 192.105, 192.317, and 192.620 for the use of strain based design (SBD). This permit implements SBD conditions within the design, construction, operations, and maintenance procedures for the subject special permit segments within the 807-mile, 42-inch-diameter natural gas transmission pipeline, as described in this special permit.

[1] Throughout this special permit, the use of "PHMSA" or "PHMSA OPS" means the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety.

[2] As used in these draft conditions, the term Alaska LNG Pipeline refers to the approximately 807 miles of 42-inch natural gas transmission pipeline and not to any potential owners, operators, or entities associated with the Alaska LNG Pipeline. The Special Permit owner, operator, and applicant/permittee name is Alaska Gasline Development Corporation. Please note that this pipeline does not transport liquefied natural gas (LNG). It will supply natural gas to a LNG facility for further transportation as LNG.

I. Purpose and Need:

The Alaska LNG Pipeline is a proposed 42-inch-diameter natural gas transmission pipeline, approximately 807 miles in length, extending from the Alaska LNG's Gas Treatment Plant (GTP) on the North Slope of Alaska to the Liquefaction Facility on the shore of the Cook Inlet near Nikiski, Alaska, including an offshore pipeline section crossing Cook Inlet. The onshore 42-inch pipeline will be a buried pipeline except for short above-ground special design segments, such as aerial water crossings and aboveground fault crossings. The Alaska LNG Pipeline design has a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig).

AGDC requested a waiver of compliance with 49 CFR 192.103, 192.105, 192.317, and 192.620 for the use of SBD along the 42-inch diameter pipeline segments that traverse areas potentially subject to geotechnical hazards (geo-hazards). The geo-hazards of interest for the Alaska LNG Pipeline are frost heave from discontinuous permafrost and thaw settlement due to surface disturbance from construction. Thaw settlement may occur when ground temperatures rise as a result of the disturbance of the surface vegetative mat, causing the ice present in the soil to melt. The melting of previously permanently frozen (permafrost), ice-rich (i.e., contains ice more than the volume required to fill the pore space in an unfrozen state) soils results in soil consolidation or settlement, the magnitude of which is dependent on the type of soil. The amount of settlement divided by the initial thickness of the frozen soil layer is known as "thaw strain." Differing amounts of settlement along the pipeline's alignment may cause longitudinal bending in the pipe resulting in strains in excess of 0.5% (the pipe material's yield strength, which is defined at 0.5% strain), and thereby prompt the need to address thaw strain with the use of SBD, heavier-walled pipe, or an above-ground pipeline. Soils that are only seasonally frozen (the near-surface soil layers freeze during winter along the entire pipeline alignment) will likely not cause displacement of the bottom of the pipe ditch and thus will likely not affect pipe longitudinal bending.

Other geo-hazards such as fault displacement are not expected to be of concern due to the pipeline's design and construction approach (the active faults on the pipeline alignment will be crossed via an aboveground mode designed to allow for fault displacement).

Based on soil mapping and geotechnical borings along the Alaska LNG Pipeline route, AGDC has confirmed the presence of discontinuous permafrost in seven (7) segments between mile post (MP) 194 through MP 196, MP 227 through MP 230, MP 257 through MP 262, MP 270 through MP 276, MP 429 through MP 440, MP 541 through MP 544, and MP 559 through MP 563 (see Table 1 – Alaska LNG Pipeline - Mainline ***SBD Segments*** on page 48 of 59 and Table 2 – Class Location for the 42-inch Mainline on page 48 of 59) that could potentially result in thaw settlement causing longitudinal pipe strains in excess of 0.5%. Section 192.103 requires pipe to be "designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation." The SBD approach would account for external pressures and loads imposing strains on the pipeline in excess of 0.5% from soil consolidation and settlement using alternative strategies, mitigation, and conditions in lieu of a heavy-walled pipe. Regulatory requirements do not presently exist for the use of SBD. SBD includes factors and conditions to ensure the design and safety considerations described under 49 CFR 192.103, 192.105, 192.317, and 192.620 Because buried pipe in permafrost conditions would need to be exceptionally thick-walled to withstand the forces and strains due to thaw settlement, AGDC will design, construct, operate, and maintain the pipeline between MP 194 through MP 196, MP 227 through MP 230, MP 257 through MP 262, MP 270 through MP 276, MP 429 through MP 440, MP 541 through MP 544, and MP 559 through MP 563 using an SBD approach.

PHMSA and AGDC recognize that additional areas of permafrost that could potentially result in thaw settlement causing longitudinal pipe strains in excess of 0.5% may be identified at any point between MP 0 and MP 807 as project engineering and construction advances. If such areas are identified and cannot be addressed using the alternative engineering and construction techniques (such as horizontal direction drilling (HDD), heavier-walled pipe, or excavation of frozen material that is below the pipe), the change process established in Appendix B of this special permit may be utilized (AGDC would design, construct, operate, and maintain these additional areas using an SBD approach). The final environmental assessment for the pipeline and the Federal Energy Regulatory Commission (FERC) draft Environmental Impact Statement (EIS) for the Alaska LNG Project address the entire pipeline from MP 0 through MP 807 (defined as the ***SBD Segments Permit Area***).

II. Special Permit - SBD Segments and SBD Segments Permit Area:

State of Alaska

SBD Segments consist of the portions of the Alaska LNG Pipeline from MP 194 through MP 196, MP 227 through MP 230, MP 257 through MP 262, MP 270 through MP 276, MP 429 through MP 440, MP 541 through MP 544, and MP 559 through MP 563 (see Table 1 – Alaska LNG Pipeline - Mainline ***SBD Segments*** on page 48 of 59 and Table 2 – Class Location for the 42-inch Mainline on page 48 of 59). The ***SBD Segments*** are in Class 1 locations.

SBD Segments Permit Area[3] consists of the Alaska LNG Pipeline from MP 0 through MP 807 (see Figure 1 – Alaska LNG Pipeline Route on page 49 of 59).

Any changes to the ***SBD Segments*** during design and construction must be in accordance with the design change process in Appendix B and must be within the ***SBD Segments Permit Area*** which extends from MP 0 through MP 807. The conditions as set forth below (the ***SBD Conditions***) must be implemented for all ***SBD Segments.***

On the condition that AGDC complies with the terms and conditions set forth below, this special permit waives compliance with 49 CFR, 192.103, 192.105, 192.317, and 192.620 for the ***SBD Segments***. This special permit allows AGDC to continue to operate each Alaska LNG Pipeline ***SBD Segment*** at its current listed MAOP.

AGDC must apply SBD methodology to the design, construction, operation, and maintenance of certain pipeline segments (the ***SBD Segments***).

PHMSA grants this special permit for the Alaska LNG Pipeline ***SBD Segments and SBD Segments Permit Area*** based on the implementation of the below ***SBD Conditions***, ***Appendix A – Pipe***, and ***Appendix B – Design Change Process***. The Alaska LNG Pipeline special permit application, submittals, Federal Register notice, final environmental assessment, finding of no significant impact (FONSI), and special permit conditions can be read in their entirety in Docket No. PHMSA-2017-0044 in the Federal Docket Management System (FDMS) at:

---

[3] The ***SBD Segments Permit Area*** consists of the Alaska LNG Pipeline milepost areas reviewed in the project draft EIS.

www.regulations.gov.

III. Conditions:

PHMSA grants this special permit to AGDC subject to the following ***SBD Conditions***,[4] as presented under the following titles below:

- Overview – Conditions 1 through 3
- Design and Materials – Conditions 4 through 7
- Construction – Conditions 8 through 14
- Operations and Maintenance – Conditions 15 through 23
- Reporting and Certification – Conditions 24 through 26
- Nomenclature – Condition 27
- Proprietary Data – Condition 28
- Limitations
- Table 1: Alaska LNG Pipeline - Mainline SBD Segments
- Table 2: Class Locations for the 42-inch Mainline
- Table 3: Operational Constraints
- Table 4: Summary of Bending Strain Inline Inspection (ILI) Tool Performance
- Table 5: Pipeline Segment Strain Demand Monitoring
- Table 6: Data Integration Plan Information
- Figure 1: Alaska LNG Pipeline Route
- Appendix A – Pipe
- Appendix B – Design Change Process

AGDC and PHMSA agree that these ***SBD Conditions*** are necessary for the safe design, construction, and operation of the ***SBD Segments***.

[4] AGDC may propose changes to these ***SBD Conditions***, review dates, or timing by submitting a written request to PHMSA's Western Region Director or Project Designee. Any proposed changes to ***SBD Conditions*** by AGDC must maintain equivalent/acceptable levels of safety, as determined by PHMSA. PHMSA will determine whether substantive changes to ***SBD Conditions*** require a modification of the special permit or public notice. Changes to the ***SBD Conditions*** must receive "no objection" response letter from PHMSA prior to the changes being implemented.

Overview:

1) **Maximum Allowable Operating Pressure:** AGDC must operate the 42-inch diameter Alaska LNG Pipeline ***SBD Segments Permit Area*** at or below a MAOP of 2,075 psig. The ***SBD Segments*** must be designed for operation at a hoop stress of 72% of specified minimum yield strength (SMYS) or less, but allow for pressure build-up and overpressure protection in accordance with 49 CFR 192.605(b)(5) and 192.201(a)(2). AGDC must maintain compressor station discharge temperature and pressure records to confirm compliance with the compressor station discharge temperature limits presented in Table 3: Operational Constraints.

Table 3: Operational Constraints		
Description	**Discharge Pressure**	**Station Discharge Temperature[1, 2]**
Gas Treatment Plant Outlet	2025 psig	30 degrees Fahrenheit (°F) maximum
Compressor Station Discharge		
Continuous Permafrost	2050 psig	30°F maximum
Discontinuous Permafrost	2050 psig	45°F maximum
Non-Permafrost	2050 psig	80°F maximum

[1]Station discharge temperature requirements represent temperatures at the point where the mainline enters the ground. Unplanned excursions, due to cooling equipment malfunctions, of up to 10°F above the maximums are permissible for up to 24-hours in a 72-hour interval. and response of "no objection."
[2] AGDC may propose an alternative temperature excursion limits operational procedure that is supported by project-specific data, operational analysis, and environmental impact analysis to PHMSA. This procedure must receive a response of "no objection" from PHMSA's Western Region Director or Project Designee prior to implementation.

2) **Applicable Regulations:** The ***SBD Segments*** 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 (49 CFR 192.112,[5] 192.328, and 192.620). In addition to conforming to Part 192, the ***SBD Segments*** must also be designed, constructed, operated, and maintained in accordance with the ***SBD***

[5] Pending the approval of the Three Layer Polyethylene Coating special permit, the requirements of 49 CFR 192.112(f)(1) will be excluded.

Conditions. In the event of a conflict between these ***SBD Conditions*** and the applicable requirements under 49 CFR Part 192, the ***SBD Conditions*** shall control. This special permit waives compliance with 49 CFR, 192.103, 192.105, 192.317, and 192.620 for the ***SBD Segments*** where external pressures and loads may impose strains on the pipeline in excess of 0.5% from soil consolidation and settlement.

3) **Strain-Based Design Plan (*SBD Plan*):** AGDC must develop a ***SBD Plan*** that describes the SBD methodology that will be implemented. The ***SBD Plan*** shall address the life cycle of the ***SBD Segments,*** including design, materials, construction, and operations and maintenance (O&M). This ***SBD Plan*** will be submitted to PHMSA,[6] for review. The ***SBD Plan*** will consist of three Elements (Design and Materials, Construction, Operations and Maintenance) and must be developed for all line pipes, girth welds, and pipeline components subject to a longitudinal strain with a projected magnitude[7] greater than 0.5%. Through analysis and testing, the ***SBD plan*** must also examine the influence of adjacent pipes (including field bends) experiencing longitudinal strains greater than a magnitude of 0.5% on the integrity of hot bends, tees, valves, and other fittings. Also, the ***SBD plan*** must take into account that strain concentrations may occur at pipeline locations associated with transitions from thinner to thicker wall pipe (such as transition pups). The girth welds in these regions must be qualified and the destructive tests and documentation materials must be inspected by AGDC, for strength, toughness, flaws, and other properties to ensure their integrity is in accordance with Conditions 7, 8, and 9.

   a) The three (3) Elements of the final ***SBD Plan*** (Design and Materials, Construction, Operations and Maintenance) must be submitted to PHMSA in accordance with the following schedule:

---

6 Throughout these ***SBD Conditions,*** where documents must be submitted to PHMSA and no contact is named, AGDC must submit the project documents to the PHMSA Western Region Director or Project Designee. If the PHMSA Western Region Director is not the appropriate PHMSA contact, the PHMSA Western Region Director will notify AGDC of the PHMSA contact.

7 This projection will be performed by AGDC, as it is a necessary requirement to determine the ***SBD Segment*** mileposts. Only the ***SBD Segments*** identified within the Special Permit can utilize these ***SBD Conditions*** for continued operation beyond 0.5% axial strain. In accordance with Appendix B, AGDC must submit the locations of the mileposts for the ***SBD Segments*** to the PHMSA Western Region Director or Project Designee for this project and must receive a response of "no objection" prior to proceeding.

i) Element I: Design and material specifications and procedures for the ***SBD Plan*** must conform to Conditions 4 through 7 and must be submitted to PHMSA for review three (3) months prior to rolling steel for pipe. AGDC may submit design and material specification revisions one (1) month prior to rolling steel for pipe, if AGDC arranges for independent third-party review during the development of this Element.

ii) Element II: Construction specifications and procedures for SBD must conform to Conditions 8 through 14 and must be submitted to PHMSA for review three (3) months prior to beginning of pipeline construction. The AGDC may submit specifications revisions one (1) month prior to commencement of pipeline construction, if AGDC arranges for independent third-party review during the development of this Element.

iii) Element III: O&M specifications and procedures for SBD must conform to Conditions 15 through 23, and must be submitted to PHMSA for review three (3) months prior to placing the pipeline into natural gas service. AGDC may submit specification revisions one (1) month prior to placing the pipeline into natural gas service if AGDC arranges for independent third-party review during the development of this Element.

b) After placing the pipeline into natural gas service, AGDC must meet with PHMSA to review the ***SBD Plan*** for O&M (Conditions 15 through 23) each year for the first two (2) years after initial operation, and every second year thereafter,[8] or as otherwise required by the ***SBD Plan*** or requested by PHMSA. AGDC must review compliance with the ***SBD Plan*** in the annual AGDC Integrity Management Plan report submitted to PHMSA. This review must include compliance with Condition 24 and must contain the following:

1. A notation of any ***SBD Segments*** that exhibit longitudinal strains with magnitudes in excess of 0.5% ("high strains");

---

[8] AGDC may request a change in the frequency of these meetings regarding the ***SBD Plan*** for O&M from every second year up to every fourth year by letter to the PHMSA Western Region Director or Project Designee. AGDC can proceed with the change in the frequency of meetings if it does not receive a response from PHMSA within 60 days of its request being received by PHMSA.

2. A notation of all ongoing monitoring of ***SBD Segments*** that exhibit high strains;[9]
3. A plan for maintenance of ***SBD Segments*** that exhibit high strains, or ***SBD segments*** where high strains are anticipated; and
4. An analysis of the strain change in ***SBD Segments*** that exhibit high strains, or where high strains are anticipated, including estimation (based on all applicable factors, including geotechnical and operational data) of expected strain for the next annual cycle.

c) Each Element set out in Condition 3(a)(i) through (iii) of the ***SBD Plan*** must be reviewed and certified for compliance[10] with these Conditions by an independent third-party engineering expert/firm. The independent third-party engineering expert/firm must be retained by AGDC, in advance of AGDC's submittal to PHMSA for review.[11] The independent third-party engineering expert/firm must be approved by PHMSA. The role of the independent third-party engineering expert/firm is to ensure each Element of the ***SBD Plan*** is consistent with the applicable ***SBD Conditions***.

i) In advance of submittal of the final ***SBD Plan*** and Elements set out in Condition 3(a)(i) through (iii), AGDC, PHMSA, and AGDC's independent third-party engineering expert/firm must undertake joint technical review meetings to discuss the draft ***SBD Plan*** Elements and relay their respective comments. To the extent practicable, the joint technical review meetings must be scheduled at least 60 days prior to submittal of the final ***SBD Plan*** Elements). Prior to the joint technical review meeting, AGDC must submit the draft ***SBD Plan*** to PHMSA;

---

[9] Monitoring is required for all ***SBD Segment***s specified in this Special Permit.

[10] The term "certified for compliance" means that a technical analysis and/or testing has been conducted to demonstrate the factors listed in Condition 3(a)(i) through (iii) will not impact the integrity of tensile strain capacity (TSC) and compressive strain capacity (CSC).

[11] Upon a written request by AGDC, where PHMSA determines sections of the SBD Plan do not need to be reviewed by an independent third-party engineering expert/firm, the PHMSA Western Region Director or Project Designee may issue a response stating PHMSA has "no objection" to waiving review of these elements by an independent third-party expert/firm.

ii) PHMSA's comments and/or concerns must be resolved in joint technical meetings of AGDC, PHMSA, and the AGDC's independent third-party engineering expert/firm;

iii) This review process can be adjusted with the mutual consent of AGDC and PHMSA.

Design and Materials:

4) **Material Specifications:** AGDC's pipe material specifications for the ***SBD Segments*** must include the requirements in Appendix A.[12] AGDC's pipe material specifications must be consistent with the requirements in Conditions 5 and 6. These specifications must stipulate that the pipe is manufactured to achieve a sufficient level of strain capacity as discussed in Conditions 6 and 7 while accommodating variations in yield/tensile (Y/T) ratio, elongation, tensile strength in hoop and longitudinal directions, pipe chemical composition, fine-grain practice, and steel rolling and cooling practices. The material test and analysis results and any acceptable variations in these results must be technically considered in Conditions 6 and 7 and documented. Any material test reports required by AGDC's pipe material specifications and submitted to AGDC must also be made available to PHMSA upon request.

5) **Material Testing:** In conjunction with Conditions 6, 7, and 8, AGDC must implement a process to determine longitudinal-tensile and compressive strain capacity of pipe and girth welds, representing all reasonably anticipated operating and environmental conditions the ***SBD Segments*** will be subjected to during their lifecycle. The material testing process must explicitly account for all-parameters appropriate to the pipeline's design and operational life cycle, including but not limited to, pipe diameters, wall thicknesses, grades, girth weld flaws (type and size), and internal and external loading. The effects of corrosion and mechanical damage (such as dents and gouges) on the longitudinal tensile

[12] References to industry standards, such as the American Petroleum Institute (API) 5L, must be to the edition incorporated by reference in 49 CFR 192.7. In the event that there is a conflict between these conditions and a referenced standard, the more stringent conditions must be used. If industry standards are used that are not referenced in 49 CFR Part 192 and not expressly included in these ***SBD Conditions***, AGDC must obtain a response of "no objection" from the PHMSA Western Region Director or Project Designee for usage of the industry standard and edition.

and compressive strain capacity of pipe and girth welds must be addressed as part of the O&M requirements in Condition 16. The cyclic and static stresses from environmental loading (such as frost heave, ground thawing, and earthquake ground motions) and operational parameters (pressure, temperature, etc.) and static stresses (thermal expansion and the potential of upheaval buckling) must also be technically considered. The material testing process must include analyses which have been validated by testing, using appropriate finite element analysis, small-scale testing, medium-scale testing (e.g. curved wide plate testing), and/or full-scale testing, as appropriate. The need for medium-scale and large-scale testing must be dependent on the parameters being evaluated.

a) AGDC's Material Testing Program must include performance of tests to address the pipe material properties of Condition 4 and Appendix A. The variations of pipes and girth welds being tested and technically analyzed must represent those of expected production pipe, double jointing welds, field welds, tie-in welds, repair welds, and their variations, as provided in pipe specifications of Condition 4 and Appendix A. The tests and technical analysis must validate that the pipes have the necessary properties to achieve the tensile and compressive strain capacity under combined loadings for field installation, operations, and environmental conditions.

b) AGDC must conduct tests and analysis to address the appropriate range of material characteristics, including: chemical compositions, fine-grain practice, manufacturing variables, manufacturers, and girth welding procedures. The tests and analyses must include, as appropriate, finite element analysis, small-scale testing, medium-scale testing, and full-scale testing.

c) AGDC's Material Testing Program must address the following parameters, at a minimum:

   i) Source and type of pipes (e.g. U-ing, O-ing, and Expanding (UOE); J-ing, C-ing, and O-ing (JCOE); etc.), steel chemical composition, and rolling practice;

   ii) Range of mechanical properties, including continuous stress-strain curves, strength, strain hardening rate (e.g., Y/T ratio), and effects of strain aging;

   iii) Girth welding process (mainline welds, double joint welds, tie-in welds, repair welds, and welds to fittings);

iv) Girth weld mechanical properties (including strength, toughness, and ductility);
v) Girth weld high-low misalignment;
vi) Pipe material design conditions (e.g., diameter/wall thickness (D/t) ratio, design factor, and pipe wall thickness variations);
vii) Construction conditions (i.e., temperature during installation and construction backfill);
viii) Operational pressure;
ix) Operational temperature;
x) Girth weld flaw (flaw type, flaw location (i.e., surface-breaking),[13] flaw length, flaw depth, flaw height, weld metal versus heat affected zone (HAZ); and
xi) Wall thickness and pipe grade differences across the weld, if included as part of the design.

When appropriate, the conditions corresponding to the maximum, nominal, and minimum values of those parameters must be technically considered and tested.

d) Full-scale testing must be performed to validate the strain capacity at critical project operational conditions.[14] If full-scale testing of a critical condition is deemed not feasible, the validation of the strain capacity must be conducted through a combination of small-scale testing, medium-scale testing, or numerical analysis by qualified labs and technical analysts. AGDC must technically justify why the full-scale testing is unfeasible and submit an alternative plan to the PHMSA Western Region Director or Project Designee for review and must receive a response of "no objection" prior to proceeding.

[13] The impact of embedded flaws must be technically considered, including, but not limited to, re-characterizing embedded flaws as surface-breaking flaws. Testing embedded flaws is not required if it is technically demonstrated that they can be conservatively treated with the same acceptance criteria as surface flaws.

[14] Prior to submittal of the draft and final ***SBD Plan*** Elements, AGDC may conduct such material testing as it deems necessary for the development of the ***SBD Plan*** Elements. Prior to conducting such material testing, AGDC must coordinate and consult with PHMSA on such material testing. AGDC may incorporate the material testing and results into the draft and final ***SBD Plan*** Elements.

e) For tests for which standardized procedures sanctioned by standard-making organizations do not exist, or standardized procedures do not cover key elements affecting the outcome of the tests,[15] AGDC must develop test procedures for material test laboratories[16] to use throughout the project to obtain consistent results.

   i) The following test procedures must be technically considered:

      a. Tensile test of pipe hoop and longitudinal properties;
      b. Tensile test of all-weld metal;
      c. Charpy V-Notch Impact test of pipe;
      d. Charpy V-Notch Impact test of girth weld HAZ and weld metal; and
      e. Crack tip opening displacement (CTOD) test or single-edge notched bending (SENB) test of girth weld HAZ and weld metal.

   ii) The following test procedures must be evaluated unless AGDC can technically justify why a test procedure is not feasible:

      a. Single-edge notched tensile (SENT) test of girth weld HAZ and weld; and
      b. Full-scale test.

f) Each of the test procedures must include the following parameters, as appropriate for the type of test:

   i) Specimen removal from pipe or weld:

      a. Specimen orientation (longitudinal or hoop direction);
      b. Specimen position (e.g., o'clock around the circumference, thickness position);
      c. Method of removal, including the possible effects of cutting and machining heat on the materials being tested);

   ii) Specimen dimensions, including tolerance;

   iii) Specimen machining, including tolerance;

---

[15] For instance, tensile test of round bar specimens is covered by a number of standardized test procedures. However, those test procedures may not cover specimen extraction (e.g., specimen position relative to the pipe wall, specimen dimensions) from pipes and girth welds.

[16] Material test labs must have procedures for calibration and a quality program in place to ensure quality and repeatability of the test results.

iv) Placement of notch, including process of locating the notch with respect to the target fine-grain practice, notch front acuity;
v) Electrical discharge machining (EDM) notching of flaws;
vi) Instrumentation plan;
vii) Calibration of instruments;
viii) Calibration of test machine;
ix) Test temperature and uniformity of the test temperature throughout tests;
x) Loading procedure, including internal pressure if applicable;
xi) Data collection rate;
xii) Acquisition and storage of raw test data;
xiii) Data processing procedure and possible corrections to machine compliance, if applicable;
xiv) Post-processing of raw data;
xv) Data reporting, including raw data, processed data, fracture surfaces, if applicable;
xvi) Verification of test data;
xvii) Validity criteria of flaw dimensions, if applicable;
xviii) Validity criteria of test data, if applicable; and
xix) Verification of notch location, if applicable.

Parts of the test procedures may be referenced from published test standards. Parts of the test procedures not covered by such published test standards must be supplemented by the project test procedures. A document containing all test procedures must be provided to PHMSA prior to commencement of the test.

g) A fracture control plan must be developed to determine the fracture arrest for pipe from each unique combination of steel mill,[17] pipe diameter, wall thickness, and grade to meet 49 CFR 192.112(b).[18]

h) If mechanical crack arrestors are used to ensure fracture arrest, destructive tests must be used to determine the ability of all crack arrestor designs used to stop and arrest an operational pipe fracture as specified in 49 CFR 192.112(b). AGDC must justify the selection of an appropriate test matrix that is conservatively representative of pipeline conditions. The worst-case fracture propagation driving force (highest pressure, worst case gas composition) must be considered and the ability of the crack arrestor to function under these conditions must be demonstrated. However, it is not necessary to test all combinations of diameter and wall thickness. Tests on larger diameter, thinner wall pipe may be used to demonstrate the function of arrestors for heavier wall and smaller diameter pipe operated at the same design pressure.

6) **<u>Design Procedures</u>:** Based upon the findings from the AGDC Material Testing Program and analysis, as required in Condition 5, AGDC must develop and implement written material, design, construction, and O&M specifications and procedures in accordance with these ***SBD Conditions.*** The purpose of these steps is to prevent the strain demand for pipe and girth welds from exceeding the defined strain demand limits under operational conditions for the ***SBD Segments***. The construction and O&M specifications and procedures are to be included in Element II and Element III, respectively, of the ***SBD Plan***. Specifications and procedures must be based upon Condition 5 test and analysis results and engineering critical assessment as specified in Condition 7. The specifications and procedures must be refined as construction and operational history becomes more developed.

---

[17] A steel mill must use the same rolling parameters throughout the steel making process. If rolling parameters and steel compositions materially change during the manufacturing process, additional small-scale destructive tests must be conducted as if the steel was rolled by another manufacturer. AGDC has the option to submit to PHMSA documentation of why rolling parameters, steel composition, and manufacturer changes would not affect pipe fracture arrest; however, such changes must receive a response of "no objection" from PHMSA's Western Region Director or Project Designee prior to implementation.

[18] It is not necessary to consider the effects of strain on the fracture arrest behavior of pipe. Ground movements apply bending strains only to short lengths of pipe (in most cases less than a joint in length), and any fracture initiated within a strained region would be arrested by adjacent unstrained pipe or crack arrestors that meet the requirements of 49 CFR 192.112(b).

a) Tensile and compressive strain demand limits must be established as follows:

i) The tensile strain demand limit for the ***SBD segments*** must be the tensile strain capacity calculated using the procedures, predictive equations and models in accordance with Condition 7[19] divided by 1.667.[20]

ii) The compressive strain demand limit for the ***SBD segments*** must be the compressive strain capacity calculated using the procedures, predictive equations and models in accordance with Condition 7[21] divided by 1.25[22] in Class 1, 2, 3, and 4 locations. In Class 1 locations that (a) are not in the right-of-way for an aboveground pipeline; (b) are not in the right-of-way for a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway; or (c) contain less than two buildings within a potential impact circle, as defined in § 192.903, and that have human occupancy of less than 50 days in a 12-month period, a 1.11 factor may be used in-lieu of 1.25. AGDC can propose an alternate safety factor in Element I for independent third-party review and PHMSA Western Region Director or Project Designee review and "no objection" that is supported by project-specific data and analysis.

---

19 The procedures, predictive equations, and models described in Condition 7 may be reviewed and technically adjusted to incorporate the results of AGDC's Material Testing Program as described in Condition 5. A document detailing the review and technical adjustment process (including how any new models produce the same or better consistency and accuracy in predicting tensile strain capacity of the ***SBD segments***) must be submitted to an independent third-party engineering expert/firm for review and to PHMSA for a response of "no objection." If AGDC adjusts the predictive equations and models described in Condition 7 after obtaining a response of "no objection" from PHMSA, the review and technical adjustment process must be incorporated into the draft and final ***SBD Plan*** Elements.

20 An alternative, equivalent method of determining the tensile strain demand limit would be 0.60 times the tensile strain capacity in Condition 7.

21 The procedures, predictive equations, and models described in Condition 7 may be reviewed and technically adjusted to incorporate the results of AGDC's Material Testing Program as described in Condition 5. A document detailing the review and technical adjustment process (including how any new models produce the same or better consistency and accuracy in predicting tensile strain capacity of the ***SBD segments***) must be submitted to an independent third-party engineering expert/firm for review and to PHMSA for a response of "no objection." If AGDC adjusts the predictive equations and models described in Condition 7 after obtaining a response of "no objection" from PHMSA, the review and technical adjustment process must be incorporated into the draft and final ***SBD Plan Elements.***

22 An alternative equivalent method of determining the compressive strain demand limit would be 0.80 or 0.90 times the compressive strain capacity in Condition 7.

iii) The tensile and compressive strain demand limits for the ***SBD segments*** must not exceed 2%.

b) The strain demand for the ***SBD segments*** must be technically based upon, and technically account for:

   i) Field conditions – above ground, below ground, seismic, permafrost, soil loads, settlement, and/or movement along the pipeline;

   ii) Different operational pressures – maximum to minimum;

   iii) Pipe temperatures, which include contributions from both operational and environmental heat sources/sinks – maximum to minimum; and

   iv) Seasonal changes in operational and environmental conditions.

c) The strain capacity for the ***SBD segments*** must be technically based upon, and technically account for:

   i) Variations in pipe tensile properties, pipe diameter, wall thickness, ovality, and out-of-roundness;

   ii) Flaws in girth welds that account for welding procedures actually used, high-low misalignment, engineering critical assessment as specified in Condition 7, construction and operational loads, girth weld flaw sizes, girth weld variability, repair; and

   iii) Pipe strain aging and hardening effects on the pipe properties, including pipe strength, Y/T ratios, and pipe elongation from the pipe coating heating effects during external or internal coating applications.

7) **Engineering Critical Assessment:** AGDC must develop and implement engineering critical assessment (ECA) procedures and document ECA findings as follows:

   a) Part I - Tensile Strain Capacity[23]

      ECA procedures, predictive equations, and models for calculating tensile strain capacity in the ***SBD Segments*** during their life cycle must adequately address the following parameters:

      i) The operation of materials (pipes and girth welds) on the upper shelf[24] (i.e., having ductile behavior) of the brittle-ductile transition;

      ii) Combined loading effects from longitudinal stress, hoop stress, and environmental loads;

      iii) Geometric pipe parameters, including, but not limited to:

         a. Pipe geometry, including wall thickness;
         b. Girth weld high-low misalignment; and
         c. Type of joints, including pipe to pipe, pipe to bend, pipe to fitting, and pipe to valve.

      iv) Pipe material and girth weld property parameters that are necessary inputs to the model, including:

         a. Y/T ratio;
         b. Uniform strain;
         c. Weld strength mismatch at ultimate tensile strength (UTS);
         d. Flaw size (height and length);

---

[23] The procedures, predictive equations, and models described in Condition 7 may be reviewed and technically adjusted to incorporate the results of AGDC's Material Testing Program as described in Condition 5. A document detailing the review and technical adjustment process (including how any new models produce the same or better consistency and accuracy in predicting tensile strain capacity of the ***SBD segments***) must be submitted to an independent third-party engineering expert/firm for review and to PHMSA for a response of "no objection." If the AGDC adjusts the predictive equations and models described in Condition 7 after obtaining a response of "no objection" from PHMSA, the review and technical adjustment process must be incorporated into the draft and final ***SBD Plan*** Elements.

[24] The brittle-ductile transition behavior must be established by conducting one or more of the following tests: (1) Charpy V-Notch Impact Test, (2) Drop Weight Tear Test (DWTT), or (3) Full-Scale Test. The effects of specimen size and flaw-tip constraint conditions may be considered and accounted for in predicting materials' full-scale behavior. When ductile shear area can be determined, having 85% shear area may be viewed as achieving ductile behavior. If the ductile shear area cannot be determined, a full transition curve based on total energy must be used to determine the attainment of the ductile behavior.

e. Flaw location (weld metal or HAZ);

f. Flaw geometry (surface breaking, embedded, etc.);

g. HAZ hardening or softening;

h. Weld toughness properties for weld centerline and HAZ including CTOD, SENT resistance curves (R-Curves), Charpy transition curves, curved wide plate, or other tests with pre-approved qualified test procedures; and

i. Flaw interaction rules suitable for strain-based design.[25]

v) The predictive equations or models for tensile strain capacity must evaluate the possible failure modes and locations for tensile strain capacity including, but not limited to, crack initiation, ductile tearing, and plastic collapse in the pipe and weld and the possibility of brittle failure. The predictive equations must be validated by the tests specified in Condition 5.

a. AGDC may use the tensile strain capacity predictive equations in published references[26,27] subject to review and approval of the ***SBD Plan*** by the independent third-party expert/firm and PHMSA in accordance with Condition 3(b). AGDC must demonstrate that these equations account for physical parameters that affect tensile strain capacity, such as those specified in Conditions 7(a)(i) through 7(a)(iv).

b. If AGDC's project-specific predictive equations cannot meet Conditions

---

[25] Flaw interaction rules must cover all possible scenarios that can occur in the field, including but not limited to, interaction of stacked flaws at weld starts and stops and interaction of surface-breaking and embedded flaws. API 1104, Appendix A, provides examples of various possible scenarios. Flaw interaction rules for strain-based design conditions are not well developed. Methodology in the following references can be used as a guide to develop flaw interaction rules: (1) Wang, Y.-Y., Liu, M., Long, X., Stephens, M., Petersen, R., and Gordon, R., "Validation & Documentation of Tensile Strain Limit Design Models for Pipelines," PRCI Project ABD-1, US DOT Agreement DTPH56-06-T000014, Final report, August 2, 2011, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=200 and (2) a paper by Tang et. al. at ISOPE 2014-1-14-556. Flaw interaction rules must be submitted to PHMSA Western Region Director or Project Designee for review and must receive a "no objection" response prior to implementation.

[26] Tang, H, Panico, M, Fairchild, DP, Crapps, JM, Cheng, W (2014). "Strain Capacity Prediction of Strain-Based Design Pipelines" Proc. of 10th Int'l Pipeline Conf., Calgary, Alberta, Canada.

[27] Tang, H., Fairchild, D.P., Cheng, W., Kan, W., Cook, M.F., Macia, M.L., 2014, "Development of Surface Flaw Interaction Rules for Strain-based Design Pipelines", Proc. 24th Int'l Soc. Offshore and Polar Eng. Conf., Busan, S. Korea.

7(a)(i) through 7(a)(iv) above, no tensile strain capacity greater than those from the PHMSA/PRCI predictive equations[28] can be used in the design, construction, and O&M.

b) Part II – Compressive Strain Capacity[29]

The predictive equations or finite element analysis (FEA) models for calculating compressive strain capacity in the ***SBD Segments*** during their life cycle must adequately address the following parameters:

i) Pipe diameter;
ii) Pipe wall thickness;
iii) Pipe imperfections;
iv) Field cold bending and its impact on material properties;
v) Material grade;
vi) Material strain hardening rate (Y/T ratio);
vii) Internal pressure;
viii) All weld metal strength of girth weld;
ix) Girth weld misalignment;
x) Presence of girth weld; and
xi) Girth weld transitions between different wall thicknesses.

c) Part III – Interaction of hoop strain and longitudinal strain: in addition to technically considering the strain capacity which is measured in the pipe longitudinal direction in Part I and Part II above (Condition 7(a) and (b)), the interaction of hoop strain and seam weld must be technically considered.

---

[28] Wang, Y.-Y., Liu, M., and Song, Y., 2011, "Second Generation Models for Strain-Based Design," PRCI Project ABD-1, US DOT Agreement DTPH56-06-T000014, Final report, August 30, 2011, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=201.

[29] The procedures, predictive equations, and models described in Condition 7 may be reviewed and technically adjusted to incorporate the results of the AGDC Material Testing Program as described in Condition 5. A document detailing the review and technical adjustment process (including how any new models produce the same or better consistency and accuracy in predicting tensile strain capacity) must be submitted to an independent third-party engineering expert/firm for review and to PHMSA for "no objection" response prior to implementation. If AGDC adjusts the predictive equations and models described in Condition 7 after obtaining "no objection" from PHMSA, the review and technical adjustment process must be incorporated into the draft and final ***SBD Plan*** Elements.

Construction:

8) **Girth Welding Procedure Qualifications:** Girth welding procedures qualified to meet 49 CFR 192.225 requirements must address:

   a) Weld procedure tests:

      i) The preferred all-weld metal tensile tests are described in Appendix C of "Background of All-Weld Metal Tensile Test Protocol, Final Report 277-T-02." [30] However, this test specimen may not be suitable for all weld bevel geometries. The largest practical diameter round bar tensile specimen which fits inside the weld cross-section may be used as an alternative to the weld metal strip tensile specimen.[31] AGDC must submit its all weld metal testing procedure and justification as part of Element II. Plastically deforming the pipe segment (e.g. flattening) before removal of the tensile test specimen is not allowed;

      ii) Hardness test;

      iii) Weld tensile strength overmatch (minimum weld metal strength must ensure tensile strength overmatch); and

      iv) Weld metal/ HAZ fracture toughness tests, such as, where appropriate: Charpy V-Notch (CVN) Impact, CTOD, SENB, SENT, curved wide plate, and full scale tests. The tests must be conducted in groupings in accordance with the essential variable requirements of American Petroleum Institute (API) 1104 Annex A,[32, 33] including possible variations of welding

---

[30] Wang, Y-Y., Zhou, H., Liu, M., Tyson, B., Gianetto, J., Weeks, T., Richards, M., McColskey, J.D., Quintana, M., and Rajan, V.B. (December 20, 2011). *Background of All-Weld Metal Tensile Test Protocol.* Final Report 277-T-02. Retrieved from: http://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=225.

[31] As described in the referenced report, the all weld metal strip specimen is not considered suitable for testing of tie-ins with an open bevel. Furthermore, fewer labs capable of testing this specimen may be available. Tensile property data based on round bar specimens was used in the development and validation of the strain capacity models referenced in Footnote 25. Tensile property data based on round bar specimens has been observed to be suitable for predicting strain capacity.

[32] The API (September 2013) *Standard 1104: Welding of Pipelines and Related Facilities.* 21st edition, including errata 1 (April 2014), errata 2 (June 2014), errata 3 (July 2014), and addition 1 (July 2014) or the edition referenced in 49 CFR 192.7.

[33] AGDC must use the edition of API Standard 1104 that is incorporated by reference in 49 CFR 192.7

parameters such as heat input in field welding and material property variations resulting from all pipe sources including, but not limited to, chemical compositions and steel rolling temperatures, including their effects on yield and tensile strengths and elongations. Toughness tests must include initiation resistance and/or ductile tearing resistance, ductile-to-brittle transition temperature of the weld metal and heat affected zones.[34]

b) Weld high-low misalignment parameters must be defined and addressed in full-scale tests, finite element models, or a combination of the two methods.

c) Weld flaw acceptance criteria and nondestructive testing (NDT) criteria:

   i) Weld flaw acceptance criteria listing imperfection sizes, lengths, and depths, using automated ultrasonic testing (AUT) which includes sizing error allowance and flaw interaction rules;

   ii) The flaw acceptance criteria must be consistent with the requirements of weld strain capacity in the life cycle of the pipeline and Conditions 5, 6, and 7.

d) Procedures for repair welding must be developed in accordance with the requirements of API 1104[35] and the strain capacity during the entire life cycle of the ***SBD Segments***. The impact of repairs on material properties, such as tensile, toughness, and ductility, from repair thermal cycles must be technically considered. The post-repair properties must be used in evaluating the girth weld strain capacity if those properties are inferior to the properties of the original welds. For instance, possible toughness degradation in the HAZ of the repair weld in the original girth weld and base metal must be technically considered. Limits on repairs must be specified and technically justified.

e) Expanded Weld Procedure Qualification (WPQ) requirements for ***SBD Segments***:

---

[34] Temperatures for field joint coating are much lower than the temperatures experienced by the weld and HAZ during girth welding. Because these temperatures are lower, no effect of field joint coating temperatures on properties is expected. Additionally, the field joint coating thermal cycle has the potential to improve toughness by allowing the diffusion of hydrogen out of the girth welds.

[35] The API (September 2013), *Standard 1104: Welding of Pipelines and Related Facilities,* 21st edition, including errata 1 (April 2014), errata 2 (June 2014), errata 3 (July 2014), and addition 1 (July 2014) or the edition referenced in 49 CFR 192.7.

i) All SBD welding procedures (pipeline procedures, tie-in procedures, and repair procedures) must be subject to expanded WPQ testing over the range of welding parameters expected during construction to demonstrate procedure robustness and consistency;

ii) Mechanized weld procedures must be qualified and have tensile and toughness tests performed on both high heat input and low heat input welds;

iii) Manual weld procedures must be qualified over the full range of heat inputs anticipated during construction. During WPQ, the average voltage and current must be measured. The number of weld passes must also be recorded.

f) WPQ Consistency Program:

i) As part of WPQ, a Consistency Program must be conducted for all mechanized weld procedures in which a minimum of five (5) consecutive girth welds must be made to SBD ECA flaw acceptance criteria or workmanship criteria, whichever is more restrictive;

ii) The girth welds fabricated for the Consistency Program must be made with parameters within the qualified ranges.

g) Welder training:

i) Mechanized welding: every welder and/or pair of welders must be permitted a minimum of three (3) welds for training. Following training, the welder and/or pair of welders must make a test weld to SBD ECA flaw acceptance criteria or workmanship criteria, whichever is more restrictive.

ii) Manual Welding: every welder must be permitted a minimum of one (1) practice weld followed by a single test weld. The testing must include Non-Destructive Examination (NDE) or API Standard 1104 destructive tests. Re-tests must be permitted for nick break tests.

iii) Welder training (mechanized and manual welding) must be performed after a break of six (6) months or more from welding with project welding procedures.

9) **Construction Quality:**

a) The spacing between any two girth welds must not be smaller than 1 pipe diameter (1D) for pipeline welds and not be smaller than 1D for transition welds in bends.[36]

b) No welded sleeve or composite sleeve repair is permitted during new pipe construction.

c) A measurement and monitoring system must be developed and implemented to quantify the pipe ovality, out-of-roundness, and pipe wall thickness at the pipe mill. AGDC must document procedures for pipe handling, storage and transportation and visual inspection of pipe for transportation damage. Dimensions must be measured on any pipes suspected of being damaged or deformed. During each construction season, it must be verified on at least 10 pipes that the pipe still meets the dimensional requirements after being transported to the right-of-way.

d) Each girth weld must be inspected for misalignment to ensure that the maximum misalignment for each girth weld has not been exceeded. Inspection may be performed visually with the use of appropriate tools or with a measuring system that measures misalignment around the circumference. Procedures for remediating girth welds outside specified misalignment limits must be developed. Alternatively, if misalignment is greater than the maximum allowed, the weld must be cut out or the strain capacity of the pipe segment where the subject weld is located must be lowered based upon the measured misalignment using the ECA approach of Condition 7.

e) Longitudinal stress and strain during construction must be calculated based upon the anticipated pipe ditch installation procedure. Pipe lifting and lowering-in practices, ditch depths, lift heights, number of lift points, and spacing between lift points must be specified:

   i) Pipe lowering-in stress and strain analysis must consider the total transition length, defined as all pipe joints between the touch down point at the bottom of the trench and the touchdown point on the leading end of the pipe string.

[36] AGDC has the option of submitting to PHMSA a procedure for minimum pipe length for girth welding to take the place of this condition. This procedure must receive a response of "no objection" from PHMSA's Western Region Director or Project Designee prior to implementation.

Both vertical profile and horizontal offset from pipe support to the center of the ditch must be technically considered;

ii) Lifting practices must assure that the radius of curvature of the pipe during lifting will not overstress the pipe and girth welds.

10) **<u>Girth Weld Testing During Production Welding</u>:** AGDC must implement a program to confirm ongoing quality for application of SBD. The program, which must be addressed in Element II, must receive an independent third-party review and a response of "no objection" from PHMSA, in accordance with Condition 3(b). The program must include:

a) Increased quality assurance and/or quality control (QA/QC).

i) Production welding must be performed within the range of welding parameters of those qualified.

ii) A comprehensive QA/QC program must be established to record and monitor the welding parameters during production welding on a real-time basis to ensure that production welds are made within the welding parameter tolerances qualified during WPQ.

a. Any weld that is made outside the range of qualified parameters, such as those made outside the qualified heat input range (as measured by the electronic recording equipment), must be rejected and cut out.

b. Electronic measurement spikes, while not common, do occur; however, these anomalous spikes will not automatically trigger a cut out. The spikes must be evaluated on a case-by-case basis.

iii) QA/QC staff and independent inspectors must be trained and qualified prior to inspecting production welding.

b) Start-up weld consistency requirements prior to full production

i) Weld consistency at start-ups, including seasonal start-ups and shut downs due to high repair rates, must consider staggered production where weld quality is evaluated over a limited number of welds.

ii) If the weld repair rate is greater than 10% for a rolling average of 200 consecutive mainline welds, AGDC must perform a root cause analysis and take remedial action.

11) **<u>Girth Weld Identification</u>:** Each girth weld and pipe joint must be uniquely identified and traceable to:

a) Weld history records including, but not limited to:

   i) Weld procedure used;

   ii) Weld repair procedure used;

   iii) Weld identification;

   iv) Welder(s) name(s);

   v) Weld rod or wire; and

   vi) Date of weld;

b) Identification of weld procedure specification (WPS) and procedure qualification record (PQR);

c) NDT history including, but not limited to:

   i) NDT procedure used;

   ii) Weld/NDT identification;

   iii) Results of NDT;

   iv) NDT technician (Level II);

   v) NDT technician (Level III); and

   vi) Date of NDT;

d) Coatings and any other post-weld processes applied to the weld.

12) **<u>Deformation Tool</u>:** AGDC must run a high-resolution deformation tool through all ***SBD Segments*** not later than the end of pipeline start-up (see Condition 27, "Nomenclature") and remediate, as required, all expanded pipe in accordance with PHMSA's "Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength" dated September 10, 2009. [37]

13) **<u>Grounding and Cathodic Protection</u>:** Interference current protection and cathodic protection (CP) must be provided for all buried ***SBD Segments*** within one (1) year of

[37] PHMSA's Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength, dated September 10, 2009, can be retrieved from PHMSA's Pipeline Technical Resources website section on Low Strength Pipe: https://primis.phmsa.dot.gov/lowstrength/documents.htm.

installation of the pipeline in the ditch (including backfill) to meet 49 CFR 192.328(e), 192.620(d)(5) through (8) and Condition 19. Interference currents to be mitigated include:

a) Induced alternating current (AC) and fault current protection from overhead AC transmission lines;
b) Telluric currents (geomagnetic earth currents); and
c) All other sources of direct current (DC) earth currents.

During the commissioning of the CP systems and during the annual CP surveys, AGDC must test for the presence of interference currents and insufficient levels of CP along the buried pipeline. Should such conditions be detected, then AGDC must take remedial action within one (1) year of detection, whether through effective CP or some other means. The interference current protection and CP system may be temporary or permanent, but in all cases, one or more of the applicable criteria contained in Appendix D of Part 192 must be achieved and maintained. At a minimum, both the interference protection and CP systems must include provisions for testing and monitoring the performance of the systems including provisions for AC coupons and measuring polarized pipe-to-soil potentials.

14) **<u>Right-of-Way (ROW) Construction Monitoring Program</u>:** A ROW monitoring program must be developed and implemented for all pipeline ***SBD Segments*** during all construction phases based upon the progress of construction. The ROW construction monitoring program must include provisions for:

a) Periodic collection of soil and groundwater samples to test for chemical and electrical properties related to pipe corrosion, where technically applicable;
b) Quality assurance for bedding and backfill materials;
c) Quality assurance for main line pipe and girth weld coatings (above ground and below ground), including horizontal directional drill (HDD) coating quality; and
d) Where the pipeline is parallel to overhead AC transmission lines, AC pipe-to-soil potentials and AC current densities must be measured periodically and supplemental grounding provided, where necessary, to assure safe conditions.

Observed field conditions that can have an integrity impact on pipeline operations and integrity management plans must be documented during construction.

Operations and Maintenance:

15) **Conditions for Start of Service:** Conditions 4 through 14 above (except Condition 12) must be implemented prior to placing the pipeline in natural gas service. The implementation of Conditions 4 through 14 must be included in the AGDC O&M Procedures if they apply to O&M.

16) **O&M Procedures:** In addition to O&M procedures otherwise required by 49 CFR Part 192, the AGDC O&M procedures must technically consider all operating parameters that have an effect on the implementation or compliance with any of these ***SBD Conditions***, including, but not limited to, maximum and minimum pressures, pipe corrosion, gas and environmental temperatures, gas quality, and the following:

a) The effects of corrosion anomaly (defects) and mechanical damage, such as dents and gouges, on the strain capacity of the pipe and girth welds. A procedure to evaluate the effect of anomalies on tensile and compressive strain capacity must be developed and used as part of the O&M plan to assess pipeline integrity and fitness for service. The anomaly interaction criteria of a minimum of 6t, (with t being the pipe wall thickness), must be used for longitudinal and circumferential wall loss.[38]

b) Interaction of pipe anomaly and longitudinal strain. In addition to technically considering the strain capacity which is measured in the pipe longitudinal direction in Condition 7(a) and (b), the interaction of pipe anomalies and hoop strain must be technically considered.

i) The hoop strain limit must be maintained to a safe level when the interaction of hoop strain and longitudinal strain is technically considered in the presence of metal wall loss or other anomalies.

ii) Unless justified by research,[39] as provided in paragraph iii below, metal loss must be maintained below 20% of the pipe wall thickness (see Condition

[38] Other anomaly interaction criteria may be used if it is more conservative than the required criteria.

[39] PHMSA has a completed research project on the effects of anomaly wall loss under combined pipeline loadings. The project is titled "Strain-Based Design and Assessment of Segments of Pipelines with and without Fittings" and is being conducted by the Center for Reliable Energy Systems. The project web link is: https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=556. AGDC may need to conduct additional tests on the effects of anomalies on longitudinal strain capacity based on the findings of this project.

18), and pressure failure ratios maintained in accordance with Condition 23, when the longitudinal strain magnitude exceeds 0.5%.

iii) Anomalies exhibiting wall loss greater than 20% but not greater than 40% may be allowed in ***SBD Segments*** with longitudinal strains over 0.5% strain but must be evaluated with O&M procedures that are based upon:

a. A destructive test program;

b. Finite element analysis; or

c. A combination of the two methods, which validates the procedures.

AGDC must develop O&M procedures based upon the results of the AGDC Material Testing Program as described under Condition 5, and PHMSA research with anomalies simulating wall loss under combined longitudinal and hoop loadings.

c) Determination of the nature, growth parameters, and location of all strain demand events (e.g., frost heave, thaw settlement, seismic, geologic fault areas, soil liquefaction areas, or soil movement areas).

d) Determination of strain capacity and strain demand along the ***SBD Segments*** in accordance with design and material specifications and tests for key parameters (as determined in Conditions 5, 6 and 7) including, as appropriate:

i) Pipe wall thickness;

ii) Pipe tensile properties;

iii) Weld tensile properties;

iv) Weld hardness, including weld metal and HAZ;

v) Weld toughness;

vi) Pipe dimensional tolerance;

vii) Girth weld high-low misalignment;

viii) As-built girth weld NDT acceptance flaw size;

ix) Allowance for flaw growth if ductile tearing limit state is used in determining the tensile strain capacity;[40]

[40] The O&M plan must ensure that the flaw growth in the life cycle of the pipeline is less than the critical flaw growth in the ductile tearing limit state. It is necessary to demonstrate that the flaw growth can be accurately and consistently measured if the allowance for flaw growth were to be given.

x) Manufacturing, construction and operational inspection plan for ***SBD Segments;*** and

xi) O&M procedures and life cycle implementation plan for ***SBD Segments.***

e) Develop and implement strain demand monitoring systems including in-line inspection tools as specified in Condition 17, to verify the reliability and accuracy of these procedures. The strain demand monitoring systems must be technically justified for estimation of actual strain (tensile, compressive, and combined) demand levels. The strain demand from the monitoring systems must have the comparable level of accuracy and resolution as the strain capacity so the strain demand can be compared consistently to the strain demand limit. When strain demand magnitude greater than 0.5% is determined, the pipeline must be monitored or remediated in accordance with integrity remediation measures specified in Condition 17.

f) Develop and implement material properties surveillance procedures for any time-dependent degradation mechanisms found during material testing, construction, or on-going operations that may affect SBD.

17) **Monitoring and Determination of Pipeline Strain Demand:**

a) When locations of high strain are anticipated before a pipeline is put into service and/or discovered after a pipeline is put into service, strain demand monitoring processes or devices must be installed or implemented. The processes or devices must be installed or implemented, as applicable, either during construction (e.g., fiber optical cable) or during operation (inertial measurement unit (IMU), ground surveys, and aerial surveys). When the monitoring system is not directly on the pipeline, appropriate soil and pipe interaction models must be used to calculate the strains imposed on the pipe.

b) The resolution of the strain demand monitoring devices and processes must be consistent with that required to accurately determine strains up to the magnitude of the strain capacity as determined in Condition 7. Tool inaccuracy is addressed in Condition 17(g)(iii) and must be technically considered.

c) AGDC's strain demand monitoring procedures must take into account the limitations, accuracy, strain demand seasonal variability, and measurement intervals of the strain measurement. If monitoring devices have directional or accuracy limitations that cannot be offset through tolerances and safety factors in the procedures, multiple devices or processes for monitoring must be used. Unless the ILI is performed during the time of year when the peak strain is expected, the procedures must also account for potential seasonal variation in strain demand.

d) Data acquisition and analysis must be of a frequency to ensure the strain demand limit on the ***SBD segments*** is not exceeded before mitigation measures can be implemented. The frequency of monitoring may be adjusted based on the site-specific strain growth rate calculations with safety factors using procedures that have been reviewed by PHMSA's Western Region Director or Project Designee with "no objection." PHMSA may request an independent third-party review of the procedures and findings.

e) Whenever high strain conditions are identified, AGDC must evaluate the site-specific strain demand limit. For the strain demand limit evaluation, the site-specific data must include actual pipe geometry, stress-strain data, Y/T ratios, construction weld records, NDE results and other recorded data that affect the strain capacity as given in Condition 7. The appropriate safety factor, as given in Condition 6, must be applied to obtain the site-specific strain demand limit from the site-specific strain capacity. In lieu of site-specific data, the strain demand limit can be established based on the conservative values from the material, geometry, and weld records of the ***SBD Segment*** containing the identified high-strain condition.[41]

f) Whenever high strain conditions are identified, AGDC must evaluate the site-specific strain demand. For the strain demand evaluation, the site-specific geotechnical data must include burial depth, soil type and subsurface temperature information, water table height, and other recorded data that contribute to the evaluation and understanding of strain demand and growth of strain at this location. If site-specific geotechnical data is not available, conservative assumptions must be used to assess

[41] Procedures using conservative values must receive a response letter of "no objection" from PHMSA's Western Region Director or Project Designee prior to implementation.

future strain demand growth.[42] The site-specific strain demand model must be calibrated to the pipeline strain measured at the location of high strain.

g) The conditions for geospatial mapping are given below as an example of a strain demand monitoring method. The principles of mapping are applicable to other monitoring methods when appropriate.

   i) Geospatial Pipeline Mapping: Multi-dimensional geospatial pipeline mapping in-line inspection (Mapping ILI) tools must be run through all ***SBD Segments***. The Mapping ILI tools (e.g. IMU) must be capable of mapping the pipeline location based upon: plan, elevation, and distance. The Mapping ILI tools must be capable of mapping features such as: pipeline alignment, direction, and orientation of horizontal and vertical with respect to angle, radius, direction, and location. To ensure accurate usage of ECA and O&M procedures for SBD that are capable of identifying and locating high bending strain conditions associated with the strain demand in Condition 17, the Mapping ILI tool must be able to meet the performance parameters listed in Table 4: "Summary of Bending Strain ILI Tool Performance." Conditions that can cause additional stresses or strains on girth welds, but not measurable from geospatial mapping tools, must be technically considered in the weld integrity evaluation.

Table 4: Summary of Bending Strain ILI Tool Performance

	Bending strain[1]
Detection threshold Probability of Detection (POD) 90%	0.1% maximum
Accuracy	+/- 0.05%
Reporting threshold	0.125% strain

Notes:
1. All values given for 80% certainty.
2. For maximum reported strain values ≤ 2%.

[42] Procedures using conservative values must receive a response letter of "no objection" from PHMSA's Western Director or Project Designee prior to implementation.

ii) The Mapping ILI tool must be run not later than the end of pipeline start-up and once each calendar year not to exceed fifteen (15) months thereafter. Alternatively, the Mapping ILI schedule can be proposed in Element III by routing for review by both the independent third-party engineering expert/firm and PHMSA. An alternative schedule must receive a letter response of "no objection" from PHMSA prior to implementation.

iii) All Mapping ILI tool measurements must have a tool inaccuracy (tolerance) factor, as appropriate for the ILI tool, added to all strain demand calculations.

h) AGDC must report and remediate high strain conditions, as specified in Table 5: "Pipeline Segment Strain Demand Monitoring."[43] Alternatively, AGDC can propose a strain demand monitoring approach in Element III. The justification for any alternative strain demand monitoring approach must be sent to an independent third-party engineering/expert firm for review and to the PHMSA's Western Region Director or Project Designee for review and AGDC must receive a response of "no objection" prior to implementation.

[43] This table "Pipeline Segment Strain Demand Monitoring" assumes the strain demand limit is no less than 0.67%. If the strain demand limit is less than 0.67%, the ***SBD Plan*** must be reviewed jointly by AGDC, PHMSA, and independent third-party engineering experts. Monitoring levels must have a response of "no objection" from PHMSA Western Region Director or Project Designee.

Table 5: Pipeline Segment Strain Demand Monitoring		
Strain Demand Magnitude that Triggers Action		**Action Required**[44]
Level	***Strain Demand***	
1	Greater than 0.5% longitudinal strain and less than 75% of strain demand limit	Monitor
2	Equal to or greater than 75% of strain demand limit and less than 90% of strain demand limit[45]	Monitor. Develop site specific strain growth rate and corresponding remediation plan to ensure strain demand limit is not reached during the pipe's operational life. The remediation plan must be implemented within one (1) year of the date of discovery or prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.
3	Equal to or greater than 90% of strain demand limit	Report strain findings to the PHMSA Western Region Director or Project Designee within 5 days of discovery. Develop remediation plan and submit to PHMSA within 30 days of discovery. The remediation plan is to be implemented within one (1) year of the date of discovery, or 90 days prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.

18) **<u>Coating Disbondment and Cathodic Protection Current</u>:** Within an ***SBD Segment*** where ILI results indicate a wall loss greater than 20%[46] and the strain exceeds a magnitude of 0.5%, AGDC must take remedial action to address the condition of the coating system, the level of CP, and to mitigate the corrosion that has occurred. Within one (1) year of the ILI tool run and subsequent data analysis identifying the wall loss, AGDC must:

a) Remediate areas greater than 20% wall loss;[47] or

---

[44] AGDC must submit the Level 2 and 3 monitoring procedures and plans to PHMSA's Western Region Director or Project Designee and must receive a response of "no objection" from PHMSA. PHMSA may request an independent third-party engineering expert/firm review.

[45] The strain demand limit used in this table must have a safety factor as defined in Condition 6. Level 2 and 3 evaluations can be based upon the "site-specific strain demand limit" for the pipeline section.

[46] Anomalies greater than 20% wall loss and up to 40% wall loss may be allowed in ***SBD Segments*** with strains over 0.5% strain, but must be evaluated with O&M procedures that are based upon a destructive test program and finite element evaluation that validates the procedure.

[47] Anomalies greater than 20% wall loss and up to 40% wall loss may be allowed in ***SBD Segments*** with strains over 0.5% strain, but must be evaluated with O&M procedures that are based upon a destructive test program and finite element evaluation that validates the procedure.

b) Use technologies to demonstrate that adequate levels of CP are being afforded to the pipeline, and that coating degradation or disbondment is limited to the area in question. Further, an evaluation must be performed to ensure that the detected wall loss combined with the detected strain levels will not reduce the pipe hoop strength capacity below that required for pressure containment (see Condition 7).

19) **Interference Currents Control:** AGDC must address induced alternating current (AC) from parallel electric transmission lines, foreign or nearby pipelines, telluric currents, and other interference issues—such as direct current (DC) in the ***SBD Segments***—that may affect the pipeline. 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 one (1) year of the ***SBD Segment*** pipe being installed in the ditch (including backfill).

a) AGDC must take readings at each AC mitigation test coupon location once every calendar year throughout the life of the pipeline. AGDC must also take 24-hour recordings of AC interference voltages at 20% of the AC interference coupon test stations each calendar year. If there are any significant changes in the amount of electrical current flowing in any of the co-located high voltage AC power lines, such as from additional generation, a voltage up rating, additional lines, or new or enlarged substations, AGDC must perform an AC interference survey along the entire co-located pipeline right of way within twelve (12) months of such change. To determine if remediation measures are warranted, AGDC must evaluate interference areas where AC current discharge is greater than 20 amperes per meter squared with the most recent metal loss ILI tool results. AGDC must remediate any interference causing AC current discharge greater than 50 amperes per meter squared of pipe surface within twelve (12) months of the AC interference survey.

b) At least once every seven (7) calendar years not exceeding 84 months, AGDC must perform an engineering analysis on the effectiveness of AC, DC, telluric current, and other electrical interference mitigation measures. AGDC also must evaluate any AC interference causing AC current discharge greater than 20 amperes per meter squared of surface area. In evaluating such interference, AGDC must integrate AC and all other electrical interference data with the most recent metal loss ILI tool results to determine remediation measures.

c) Within twelve (12) months of the results of receiving the interference engineering analysis, AGDC must remediate any AC interference causing AC current discharge greater than 50 amperes per meter squared of surface area. 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 twelve (12) months of this evaluation.

d) Electrical interference mitigation and CP systems and equipment must comply with Condition 13.

20) **Data Integration:** AGDC must create a data integration plan to integrate and analyze data pertaining to the integrity of the ***SBD Segments***. The data integration plan must define the integrity management data elements required for integrity management of the ***SBD Segments***; strain capacity assessment; determination and forecast of strain demand; and monitoring and remediation.

a) The data integration plan must reflect the information in Table 6: "Data Integration Plan Information," as a minimum, in addition to the requirements in Table 1 of ASME B31.8S-2004;

b) Data integration must be outlined on pipeline route sheets (example: scale of 1 inch = 100 up to 500 feet on D (24"x36") or E (36"x42") size drawings or similar size drawings) or in an electronic geographic information system (GIS), with parallel sections for each integrity category and recent aerial photography or satellite imagery (recent photography, within 24 months of initial filing and every 7 years thereafter). Data integration must be capable of being updated on a continuing basis in accordance with 49 CFR Part 192;

Table 6: Data Integration Plan Information

Language from ASME B.318S – 2004, Table 1		SBD Condition Language
Category	***Data***	***Data Element***
Attribute Data	Material Properties	Line pipe mechanical properties on a per heat basis, to include: - Tensile: UTS, Uniform Elongation (UEl), Y/T; and - Compressive: full stress-strain curve Weld properties on a per WPS/PQR basis to include: - All weld metal UTS; and - Weld Metal Single Edge Notch Tension (WM SENT).
Construction	Depth of cover	Depth of cover surveys.
	Crossings/casings	Location of casings and highway/railroad crossings
Operational	Normal maximum and minimum operating pressures	MAOP, including normal, maximum, and minimum operating pressures. Operating temperatures based upon seasonal, through-put, and normal, maximum, and minimum operating pressures.
	Leak/failure history	Any in-service ruptures or leaks.
	CP system performance	Rectifier voltage and current outputs over the past 7 years; CP test point survey readings – past 7 years; AC and DC interference surveys; telluric current surveys.
	Other (not included in B31.8S)	High consequence areas (HCAs), including boundaries on aerial photography or satellite imagery.
		Class location, including boundaries on aerial photography or satellite imagery.
Inspection	Pressure tests	Hydrostatic test pressure including any known hydrostatic test failures or leaks.
	In-line inspections	ILI tool results including high resolution (HR) metal loss ILI tools, HR-deformation tools, coating disbondment tool and/or CP current measurement, and mapping ILI tool results.
	CP inspection	Close Interval Survey (CIS).
	Coating condition inspections (DC voltage gradient)	Pipe coating surveys and pipe coating and anomaly evaluations from pipe excavations.
	Other (not included in B31.8S)	Stress corrosion cracking (SCC) excavations and findings.
		Pipe exposures for any reason.
		Geotechnical locations where strain monitoring is on-going with periodic measurements.
		Each high strain location identified in accordance with Condition 17 (e).

21) **Treatment of SBD Segments as Covered Segments under 49 CFR 192, subpart O:**

Notwithstanding the definition of "covered segment," AGDC must incorporate the ***SBD***

Segments in its written integrity management program (IMP) and treat the ***SBD Segments*** as a covered segment in a high consequence area (HCA) in accordance with 49 CFR Part 192, Subpart O, except for the reporting requirements contained in 49 CFR 192.945.

a) AGDC must include the ***SBD Segments*** in its IMP baseline assessment plan in accordance with 49 CFR 192.905.

b) AGDC must perform ILI assessment along the entire length of the ***SBD Segments*** using ILI tools (high resolution metal loss, high resolution deformation and Mapping) not later than the end of pipeline start-up.

c) AGDC must perform ILI assessment using all ILI tools described in Condition 21(b) on a maximum seven (7) calendar-year interval. These ILI tools may be required to be run individually at more frequent intervals as needed in order to comply with all ***SBD Conditions***.

d) AGDC must perform a CP assessment by a protective coating assessment of buried pipe by DC voltage gradient or AC voltage gradient in accordance with 49 CFR § 192.620 along the entire length of the ***SBD Segments*** after pipe construction backfill but within nine (9) months of placing the CP system in operation.

e) AGDC must perform an External Corrosion Direct Assessment (ECDA) in accordance with 49 CFR 192.925, on a maximum seven (7) calendar-year interval to evaluate and remediate external pipe coating and CP operational performance.

22) **Analysis of ILI Tool Data and Discovery of Actionable Anomalies:** In addition to the assessment and repair requirements contained in 49 CFR Part 192, Subpart O, AGDC must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used. AGDC must demonstrate ILI tool tolerance accuracy for each ILI tool run by use of calibration excavations or pre-built calibrated pipe segments[48] and, for each tool run, unity plots that demonstrate ILI tool detection accuracy for depth and length within ±10% for 90% of the time. The unity plots must show: actual anomaly depth versus predicted ILI tool depth, as well as failure pressure/MAOP for actual anomaly dimensions versus ILI tool predicted failure

[48] Any pre-built calibrated pipe segments and procedures must receive a response of "no objection" from PHMSA's Western Region Director or Project Designee prior to implementation.

pressure/MAOP for ILI tool anomaly dimensions. The discovery date must be within 90 days of an ILI tool run for each type ILI tool (high-resolution geometry, high-resolution deformation or high-resolution metal loss), unless that period is impractical, [49] in which case the discovery date must be within 180 days of an ILI tool run. ILI tool evaluations for metal loss must use "6t x 6t" interaction or more conservative criteria for determining anomaly failure pressures and remediation response timing. [50]

23) **Remediation:** In addition to all assessment and repair requirements contained in 49 CFR Part 192, Subpart O, the following section provides requirements for excavation, investigation, and remediation of anomalies based on ILI tool data results in accordance with 49 CFR 192.485 and 192.933. Also, these requirements must incorporate the appropriate Class location design factors in the anomaly repair criteria[51] for the ***SBD Segments***.

Reassessment by ILI tool must reset the timing for anomalies not already investigated and/or repaired. AGDC must evaluate ILI tool metal loss data by using appropriate assessment analytical tools that incorporate the effects of longitudinal strain on the pressure containment capacity of the pipeline. Such tools may be developed by using three-dimensional finite element analysis with the full range material properties, anomaly dimensions, and interaction of multiple anomalies; the final analytical tool may be a finite element procedure for use in ECA. Established tools, such as ASME Standard B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines" (ASME B31G), the modified B31G (0.85dL) or R-STRENG,[52] may be used provided that (a) the effects of longitudinal strain are technically considered/implemented, and (b) the safety of the tool is

[49] Discovery dates that are more than 90-days due to impracticality must be reported to PHMSA and receive a response of "no objection" from the PHMSA Western Region Director or PHMSA Project Designee.

[50] ILI tool metal loss interaction criteria of "6t x 6t" is based upon a length or width measurement of six times the pipe wall thickness (t).

[51] Anomaly repair methods (such as steel or composite sleeves) must take into their impact on longitudinal strain capacity at that location.

[52] RSTRENG: John F Kiefner and Pat H Vieth, *A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe*, Contract PR-3-805, Prepared for the Pipeline Corrosion Supervisory Committee Pipeline Research Committee of Pipeline Research Council International, Inc. by Battelle Memorial Institute, December 22, 1989.

equivalent or greater than that established for assessing pipelines under traditional stress-based design (longitudinal strain magnitude less than 0.5%). The ILI tool results must address ILI tool tolerances, unity charts findings, and corrosion growth rates of anomalies.

a) Immediate response: Any anomaly within a ***SBD Segment*** that meets either (a) Failure Pressure Ratio (FPR)[53] equal to or less than 1.1 or (b) an anomaly depth equal to or greater than 60% wall thickness loss.
b) One-year response: Any anomaly within an ***SBD Segment*** in Class 1 location pipe that meets either (a) an FPR equal to or less than 1.39[54] or (b) an anomaly depth equal to or greater than 40% wall thickness loss.
c) Monitored response: Any anomaly within an ***SBD Segment*** with a Class 1 location pipe that meets both (a) an FPR greater than 1.39[55] and (b) an anomaly depth less than 40% and greater than 20% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account;
d) Anomaly Response for Class 2 and 3 locations: Anomaly response for Class 2 and 3 locations must use a FPR in Condition 23(b) and (c) of 1.67 for Class 2 locations and 2.0 for Class 3 locations.

If factors beyond AGDC's control prevent the completion of any evaluation or implementation of any remediation measure, or plan required under this Condition, or Conditions 17 through 22, within the time period specified, the completion of the evaluation or implementation of the remediation measure or plan must be completed as soon as practicable. A letter justifying the delay and providing the anticipated date that the evaluation will be completed or remediation measure or plan implemented must be submitted to the PHMSA Western Region Director or Project Designee no later than one (1) month prior to the end of the time period specified under the applicable Condition. Any extended evaluation or remediation schedule submitted to the PHMSA Western

[53] Failure Pressure Ratio (FPR) means the predicted failure pressure divided by MAOP.

[54] When the anomaly is in a Class 2 location, AGDC must use an FPR of 1.67. When the anomaly is in a Class 3 or Class 4 location, AGDC must use an FPR of 2.00.

[55] When the anomaly is in a Class 2 location, AGDC must use an FPR of 1.67. When the anomaly is in a Class 3 or Class 4 location, AGDC must use an FPR of 2.00.

Region Director or Project Designee and must receive a response of "no objection" from PHMSA.

Reporting and Certification:

24) **Reporting:** Within twelve (12) months following pipeline start-up and annually[56] thereafter (except as noted herein), AGDC must report the following to the PHMSA Western Region Director or Project Designee with copies to the Director, PHMSA Engineering and Research Division, and Director, PHMSA Standards and Rulemaking Division:[57]

a) The number of new residences, identified sites, or other structures intended for human occupancy and public gathering areas built within an ***SBD Segment's*** potential impact radius (PIR), as defined in 49 CFR 192.903;
b) Any integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year (such as strains over 0.5% and anomalies over 20% wall loss) in the ***SBD Segments***;
c) Any reportable incident or any leak reported on the DOT Annual Report in the ***SBD Segments***;
d) All repairs that occurred during the previous year in the ***SBD Segments***;
e) Any on-going damage prevention, corrosion, and longitudinal strain preventative initiatives affecting the ***SBD Segments*** and a discussion of the results of the initiatives;
f) Annual data integration information, as required in Condition 20 "Data Integration," for the ***SBD Segments***;
g) All actual strain demand conditions that exceed the 0.5% Level 1 strain demand limit specified in Condition 17 in the ***SBD Segments***;
h) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

---

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

[57] Upon notice to AGDC, PHMSA may update reporting contacts for Condition 24.

25) **<u>Extension of Special Permit Segments</u>**: At the request of AGDC, and in accordance with the procedures under Appendix B: Design Change Process, PHMSA may expand the original ***SBD Segments*** as defined in this permit to include new segments. PHMSA may also extend the length of the original ***SBD Segments*** up to the limits of the ***SBD Segments Permit Area***, as defined in the Alaska LNG Pipeline EIS.[58] To include new segments or extensions of the original ***SBD Segments***, AGDC must:

a) Provide notice to the PHMSA Western Region Director or Project Designee, PHMSA Standards and Rulemaking Division Director, and PHMSA Engineering and Research Division Director of a requested new ***SBD Segment*** or extension of an original ***SBD Segment.***[59] The request must include the location of the new ***SBD Segment*** or extension of the original ***SBD Segments***, and any anticipated remedial or pipe replacement actions, including survey stationing. All requests for a new ***SBD Segment*** or extension of the original ***SBD Segments*** must be approved by PHMSA in advance of their implementation and follow the Appendix B: Design Change Process, including data integration (see Condition 20), and provide information on any potential environmental impacts of the new ***SBD Segment*** or extensions of the original ***SBD Segments***;

b) Complete all inspections and remediation of the proposed ***SBD Segment*** extension to the extent required of the original the ***SBD Segments***; and

c) Comply with all the special permit conditions and limitations included herein to all new ***SBD Segments*** and/or extensions.

26) **<u>Certification</u>:**

a) An AGDC senior executive officer, vice president or higher, must certify the following in writing:

---

[58] A milepost update that does not alter the geographical location and extent of an ***SBD Segment*** covered under this special permit requires only notification to PHMSA. For example, route milepost changes may be caused by route alignment changes outside the boundaries of the ***SBD Segment*** that lengthen or shorten the overall route, resulting in renumbering the mile posts without altering the geographical extent or location of the ***SBD Segments*** covered under this special permit.

[59] For a new ***SBD Segment*** or extension within the ***SBD Segments Permit Area*** to be considered by PHMSA, AGDC must confer with PHMSA's Western Director or Project Designee to determine the need for any additional environmental review. AGDC must obtain a response of "no objection" from PHMSA prior to implementing the change.

i) The ***SBD Segments*** meet the ***SBD Conditions*** of this special permit; and

ii) The written manual of O&M procedures for the Alaska LNG Pipeline includes all applicable requirements in 49 CFR Part 192 and these ***SBD Conditions***.

b) AGDC must send the certifications required by this permit with completion date, compliance documentation summary, the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety, with copies to the PHMSA Western Region Director or Project Designee; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division.

c) AGDC must send the certifications within three (3) months of placing the pipeline into natural gas service. A copy of the certification must be placed by AGDC on the docket at www.regulations.gov at Docket No. PHMSA-2017-0044.

d) AGDC must provide a status update, including any proposed changes to the final ***SBD Plan*** (see Condition 3(a)) within six (6) months after placing the pipeline into natural gas service.

Nomenclature:

27) **Nomenclature:** Defines technical terms used for strain-based design throughout these ***SBD Conditions***.

a) Actionable anomaly: Anomalies that may exceed acceptable limits based on AGDC's anomaly and pipeline data analysis.

b) The Alaska LNG Pipeline: The mainline gas pipeline that extends from the Prudhoe Bay Gas Treatment Plant to the LNG Plant in Nikiski, Alaska.

c) Compressive strain capacity:[60] Compressive strain capacity (CSC) is the maximum longitudinal compressive strain when the pipe segment reaches its maximum bending moment under lateral bending or its maximum compressive load under compression.

d) Full-scale testing: A full-scale test involves a full-size pipe with no portions of the pipe circumference cut out. The test may be performed with or without internal pressure. The pipe can be loaded in longitudinal tension, longitudinal compression, lateral bending, or combination thereof.

e) High strain: Longitudinal strain with a magnitude greater than 0.5%.

f) Independent third-party engineering expert/firm: An engineering expert or firm that (a) is agreed upon by AGDC and PHMSA and (b) commits to submitting reports and other forms of communication simultaneously to AGDC and PHMSA.

g) Independent third-party review: A written technical review carried out by an independent third-party engineering expert/firm.

h) Medium-scale testing: A typical medium-scale test is a curved wide plate (CWP) test. The test specimen is a curved piece of pipe with a nominal gauge width of 200 mm (8 inch) to 450 mm (18 inch) and a nominal length of 4-5 times of the gauge width. The specimen usually has a girth weld in mid-length and is pulled in the longitudinal direction. A machined notch or fatigue-sharpened flaw is usually placed in the weld or heat-affected zone to simulate welding defects.

i) Natural gas service: The date on which gas product is first introduced into the pipeline.

j) 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. For the purposes of these ***SBD Conditions***, pipeline start-up is defined as a period of no more than one (1) calendar year after natural gas service.

---

[60] Reaching CSC generally does not lead to immediate loss of pressure containment if the pipe is restrained from further deformation. The consequence of exceeding CSC varies, depending on the mechanical properties of the pipe and welds, site-specific support conditions, and operational conditions of the pipeline. During the Alaska LNG Pipeline Material Testing Program, the CSC will be reviewed and an alternative evaluation may be proposed by AGDC. Any alternative definition of CSC must be reviewed with PHMSA for "no objection" response from PHMSA. Both immediate and long-term consequence of exceeding the CSC as defined must be evaluated and technically justified. Condition 23 has requirements for the assessment and remediation of dents and wrinkles in accordance with 49 CFR 192.933, subpart O.

k) Probability of detection: Probability of a change in strain being detected by the ILI-IMU tool.

l) Site-specific strain demand: Site-specific strain demand is the strain demand specific to a particular pipeline site within the ***SBD Segment***. Site-specific conditions contribute to the site-specific strain demand, including local operational parameters, local soil conditions, pipe material and geometric features, and pipe/soil interaction. The strain demand profile varies over the length of the strain feature and values can be established at distinct locations, e.g., pipe body and individual girth weld locations.

m) Site-specific strain demand limit: Site-specific strain demand limit is the strain demand limit specific to a particular pipeline site within the ***SBD Segment***. Site-specific conditions contribute to the site-specific strain demand limit, including material conditions and weld imperfections.

n) Small-scale testing: Typical small-scale testing includes uniaxial tension test, uniaxial compression test, single edge notched bending (SENB) test, single edge notched tensile (SENT) test, and Charpy V-notch (CVN) impact test. The dimensions of typical small-scale test specimens range from a few inches to tens of inches. The specimens are usually light enough that they can be handled without the use of lifting equipment.

o) Strain-based design: SBD is a pipeline design methodology with specific goals of providing safe and reliable service when such a pipeline is subjected to longitudinal strains with magnitudes greater than 0.5%. It does not replace design requirements based on the maximum hoop stress criteria of 49 CFR Part 192.

p) Strain capacity: Strain capacity is the longitudinal strain limit of a pipe and/or girth weld at the point of an incipient failure event, such as a leak or rupture with accompanying loss of pressure containment, loss of structural stability, or features that have long-term negative consequences.

q) Strain demand: Strain demand is the longitudinal strain imposed on a pipeline by its surrounding environment (e.g., frost heave, thaw settlement, seismic, geologic fault areas, soil liquefaction areas, or soil movement areas) as outlined in Condition 6(b).

r) Strain demand limit: Strain demand limit is a specific longitudinal strain demand value that cannot be exceeded. The strain demand limit must be less than the strain capacity. The difference between the strain capacity and strain demand limit is a part of the safety margin in a SBD approach (see Condition 6(a)). The strain demand limit must be established for the ***SBD Segments*** in accordance with Condition 6.

s) Technically considered: A documented engineering and operational technical review of all findings and plans.

t) Tensile strain capacity: Tensile strain capacity (TSC) is the maximum longitudinal tensile strain the pipe and/or girth weld can withstand without loss of pressure containment.

u) Tensile strength overmatch: The difference between the tensile strength of the girth weld and the pipe. For practical purposes, the tensile strength of the girth weld is measured in the hoop direction using all weld metal specimen, while the tensile strength of the pipe is measured in the axial direction.

v) Uniform strain: Uniform strain is the engineering strain corresponding to the ultimate tensile strength in an engineering stress vs. engineering strain plot.

Limitations:

This special permit is subject to the limitations set forth in 49 CFR 190.341 as well as the following limitations:

1) PHMSA has the sole authority to make all determinations on whether AGDC has complied with the specified conditions of this special permit. Failure to comply with any condition of this special permit may result in revocation of the permit.

2) Any work plans and associated schedules for the Alaska LNG Pipeline supporting this special permit are automatically incorporated into this special permit and are enforceable in the same manner.

3) Failure by AGDC to submit the certifications required by Condition 26 (Certifications) within the time frames specified may result in revocation of this special permit.

4) As provided in 49 CFR 190.341, PHMSA may issue an enforcement action for failure to comply with this special permit for the Alaska LNG Pipeline. 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.

5) If AGDC sells, merges, transfers, or otherwise disposes of all or part of the assets known as the Alaska LNG Pipeline, AGDC must provide PHMSA with written notice of the change within 30 days of 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 underlying the permit. Any notifications for this limitation must be sent to the PHMSA Associate Administrator for Pipeline Safety with copies to the Deputy Associate Administrator, PHMSA Field Operations; Deputy Associate Administrator, PHMSA Policy and Programs; PHMSA Western Region Director; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division.

AUTHORITY: 49 U.S.C. 60118 and 49 CFR 1.97.

Issued in Washington, DC on SEP 9 2019.

Alan K. Mayberry,

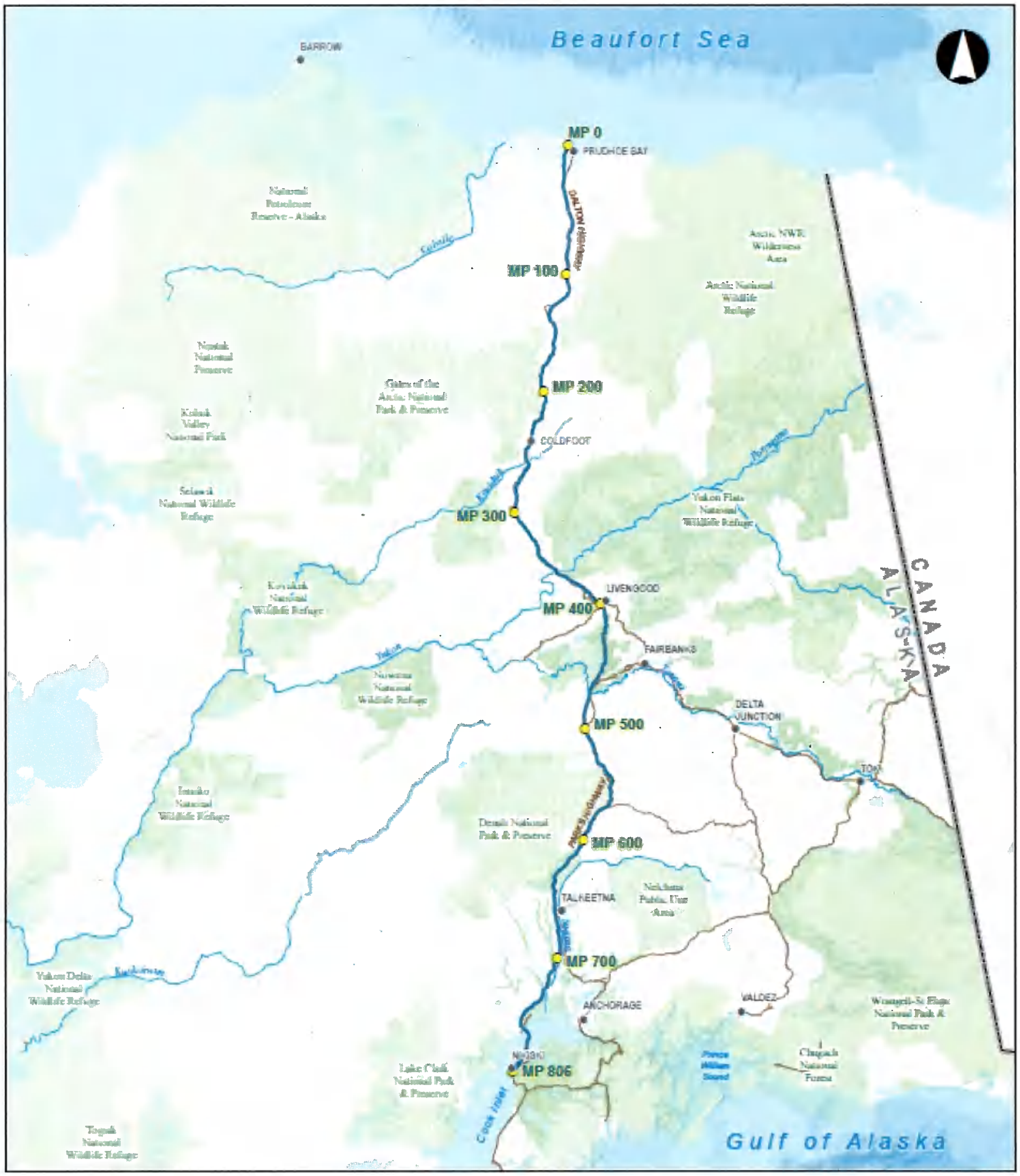
Associate Administrator for Pipeline Safety

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

TABLE 2: Class Locations for the 42-inch Mainline[61]		
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

[61] TABLE 11.7.2-1 (From FERC Resource Report No. 11).

Figure 1: Alaska LNG Pipeline Route



Appendix A - Pipe

AGDC must prepare: material specifications, including requirements for qualification and production tests, and an Inspection and Test Plan using Appendix A.[62]

The ***SBD Segments*** of the Alaska LNG Pipeline must be constructed of line pipe meeting the requirements of API 5L Grade X70 PSL 2.[63]

1) Materials Specifications for Pipe
    a. Hoop tensile properties must be established by testing round-bar specimens without flattening;
    b. Longitudinal tensile properties must be established by testing full thickness strap specimens without flattening. The gage length and width of the reduced section must comply with American Society for Testing and Materials (ASTM) A370, Section A.2.2.2 for longitudinal strip specimens for tubular products;
    c. For tensile tests for which a full stress strain curve is required, the stress-strain curve must be recorded at least until the ultimate tensile strength and uniform elongation is reached. The extensometer may be removed after the load begins to decrease;
    d. Requirements that apply after simulated coating (the aged condition) must be performed for five (5) minutes on test specimens aged at a temperature equal to the lesser of 250 degrees Celsius or the maximum temperature experienced during fusion bonded epoxy (FBE) coating;

---

[62] Appendix A is intended to ensure consistent material properties are used throughout the Alaska LNG Pipeline for material testing, strain capacity modeling, welding procedures, and strain demand limits. Any changes to the material specifications used on the Alaska LNG Pipeline ***SBD Segments*** that are not in accordance with this Appendix A must be submitted to PHMSA Western Region Director or Project Designee for review and approval. Appendix A changes are not intended as being a change that would subject the special permit to be publicly noticed.

[63] References to industry standards, such as the American Petroleum Institute (API) 5L, must be to the edition incorporated by reference in 49 CFR 192.7.

e. The minimum longitudinal tensile yield strength in the aged condition defined at 0.5 % engineering strain must be ≥ 90% of the SMYS in the hoop tension direction;[64]

f. For longitudinal specimens, the maximum yield strength to ultimate tensile strength (YS/UTS) ratio must be ≤ 0.90 (both before and after simulated coating);

g. Longitudinal compression tests must be conducted for information only and the longitudinal stress-strain curves in the "aged" condition must exhibit "round house" (continuous yielding) behavior, i.e., no Lüders plateau of more than 0.2% strain;

h. The longitudinal tensile stress-strain curves in the "aged" condition should ideally exhibit "round house" (continuous yielding) but if discontinuous yielding is exhibited the Lüders plateau elongation must be ≤ 0.5 %, i.e., the length of the plateau from initial yielding must be ≤ 0.5 %;

i. The longitudinal tension specimen must exhibit uniform strain (elongation at maximum load) of ≥ 6 %;

j. The maximum longitudinal tensile yield strength must not exceed SMYS + 20.3 kilopounds per square inch (ksi), which converts to 140 megapascals (MPa);

k. The maximum longitudinal UTS must not exceed SMYS + 35 ksi (240 MPa);

l. The drop weight tear test (DWTT) specimens taken 90 degrees from the weld must exhibit an average shear area ≥ 85 % at the lowest temperature under normal operations or Lowest Anticipated Service Temperature (LAST);

m. The Charpy energy for samples taken at mid thickness and 90 degrees from the weld must be specified at LAST. Shear area must be reported for information.

n. CTOD R curves must be reported for information only;

o. The pipe must be resistant to heat affected zone (HAZ) softening. The minimum HAZ hardness in the seam weld heat affected zone must be ≥ 160 H_v10;

p. The maximum tolerances on pipe diameter, ovality and wall thickness must be in accordance with American Petroleum Institute: "Specification for Line of Pipe"

[64] It is typical for UOE line pipe to exhibit strength anisotropy that results in the axial strength being less than hoop strength. This is beneficial for strain-based design since the weld metal overmatch, which is in the axial direction, will be greater.

(API 5L). The average wall thickness for the quantity of pipe on the purchase order must not be less than the specified wall thickness. The minus wall thickness tolerance at any location must be 0.8 mm (0.031 inches), except in localized areas where grinding is required to remove surface imperfections. Such localized areas must meet a minimum tolerance equal to 95% of specified wall thickness.

2) Manufacturing Procedure Qualification Test (MPQT)

The pipe manufacturer must produce a minimum of two heats to demonstrate compliance with the specification. A change in any of the essential variables listed in Table A-1 below require requalification. Alternatively, each time the actual value for the considered parameter is outside of the defined range, the plate is declared as "out of process plate" and will be individually mechanically tested to confirm compliance with specification requirements.

a) For longitudinal seam line pipe, one plate from each heat must be tested on each corner of the plate. For manufacture of helical seam line pipe, coils from each heat must be tested on both edges and at the extreme head and tail of the coil. The data developed during prequalification must be used to establish the appropriate test locations during production. As an option, testing of plate/coil may be performed after pipe forming to account for changes in pipe properties due to forming.

Table A-1: Line Pipe Manufacturing Essential Variables	
Essential Variables	**Parameters**
Chemistry	A change in chemistry outside the limits in Table A-2
Steelmaking Method	Electric Arc Furnace (EAF) or Basic Oxygen Furnace (BOF)
Refining Process	LMF and/or Vacuum Treatment
Casting	Ingot or continuous casting
Slab Reheating Temp	+/– 40 degrees Celsius (°C)
Slab Reheating Time.	Minimum reheating time
Rolling Practice	Air or Water Cooling; Thermo-Mechanical Control Process (TMCP)
Total Rolling Reduction	+ Unlimited, –15%
Finishing Reduction	+ Unlimited, –15%
Finish Rolling Temp.	+/– 45 degrees Fahrenheit (+/–25 degrees Celsius)
TMCP Water Start Temperature NOTE 1	+/– 63 degrees Fahrenheit (+/–35 degrees Celsius)
TMCP Water Stop Temperature NOTE 1	+/– 90 degrees Fahrenheit (+/–50 degrees Celsius)
TMCP Cooling Rate NOTE 2	+/– 25%
Plate Manufacturer	Any change in manufacturer or manufacturing location.
Change in the Pipe Making Process	From JCOE to UOE to Three Roll Bending or Spiral, etc.
Expansion Ratio	+/– 0.3%
Coating Temp.	+ 36°F (+ 20°C), - Unlimited

NOTE 1 Applicable only if accelerated cooling is used.

NOTE 2 Cooling rate is the average cooling rate between the water start temperature and the water finish temperature

Table A-2: Allowable Chemistry Variation	
Carbon	+0.02, –0.03%
Manganese	+/– 0.20%
Phosphorus	+0.010%, –no limit
Sulfur	+/– 0.005%
Silicon	+0.15%, –no limit
Copper	+/– 0.15%
Nickel	+0.50%, –0.15%
Chromium	+/– 0.10%
Molybdenum	+0.04%, –0.06%
Niobium	+/– 0.010%
Titanium	+/– 0.010%
Aluminum	+/– 0.025%
Vanadium	+/– 0.02%
Boron	+/– 0.0005% (+/–5 parts per million (ppm))
Nitrogen (total)	+0.0025%, –0.0045%(+25 ppm, –45 ppm)
Carbon Equivalent (CE - IIW)	+0.02, –0.03
CE - Pcm	+0.02, –0.03

b. Two (2) pipes from each heat must be tested for the items (i) through (ix) below. One (1) pipe from each heat must be tested for items (x) and (xi).[65]

   i. Chemical analysis;

   ii. Longitudinal and hoop tensile tests of pipe body in the as-received condition (provide full stress-strain curves) on three (3) specimens per pipe for each orientation must be tested;

   iii. Longitudinal tensile tests of pipe body in the aged condition (provide full stress-strain curves), on three (3) specimens per pipe must be tested. The sampling position for the strain ageing test specimen is the same as that of non-aged specimens;

   iv. Longitudinal compression tests of pipe body in the aged condition (provide full stress-strain curves) on three (3) specimens per pipe must be tested. The sampling position is the same as for longitudinal tensile test specimens;

[65] If API 5L requires additional testing, the more stringent requirements must apply.

v. Tensile Test of seam weld in the as-received condition, which must be performed on three (3) round bar specimens representing all pipe seam weld metal. Full stress-strain curves must be provided;

vi. Charpy impact test (pipe body, weld and HAZ), at the specified temperature;

vii. DWTT, at the specified temperature;

viii. Vickers Hardness traverse across seam weld;

ix. Guided bend test;

x. Metallography of pipe body;

xi. Visual inspection and dimensions;

xii. Nondestructive inspection;

xiii. Hydrostatic test—one (1) pipe from each heat must be tested hydrostatically at an applied hoop stress corresponding to 100% SMYS;

1. The pressure must be calculated using specified outside diameter and minimum wall thickness. For mills with an end-sealing ram that produces a compressive longitudinal stress, the applied hoop stress must correspond to 100% SMYS after provision for end loading per API 5L, Paragraph 10.2.6.6 are applied.
2. If the dimension of pipe fails to conform to the requirements of this specification after hydrostatic test, then two additional pipes from the same heat must be selected to perform the same hydrostatic test;

xiv. SENT tests or CTOD tests of pipe body to measure CTOD R curves; and

xv. For information only, Charpy transition curve of the pipe body in the aged condition. Complete fracture shear area percentage and Charpy absorbed energy transition curves for transverse Charpy impact tests must be provided. Tests must be performed on three specimens per test temperature at a minimum of five (5) test temperatures that cover the ductile to brittle transition temperature range.

3) Production Testing of Mechanical Properties

a. Tests and Requirements: The tests and requirements are shown in Table A-3;

b. Quality Assurance and Quality Control Surveillance (QA/QC): Manufacturing QA/QC of pipe production must be conducted in accordance with an Inspection and Test Plan approved by **AGDC**.

Table A-3: Test and Requirements

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

NOTE 1: For helical seam pipe the samples must be taken mid-way between the weld seam.
NOTE 2: A lot is defined as 100 pipes, or per heat, or as per API 5L, whichever is less.
NOTE 3: Testing frequency and test type must meet both Table A-3 and API 5L criteria.
NOTE 4: Location and orientation must comply with API 5L, if not specified otherwise.
NOTE 5: All references to API 5L require usage of the edition incorporated by reference version in 49 CFR 192.7.

Appendix B – Design Change Process

If required, AGDC must implement a Design Change Process (***DCP***) to address how the ***SBD Segments*** in the special permit will be extended or new ***SBD Segments*** added as engineering or construction of the pipeline progresses and conditions are found to be changed from design basis parameters. The ***DCP*** must be submitted to the PHMSA Western Region Director or Project Designee for a response of "no objection."[66]

The special permit requires milepost boundaries to be identified for pipeline segments that will be covered by the conditions. There are several factors that could cause a change of ***SBD Segments*** along the route after the time of initial submittal of the special permit application and issuance of a special permit. These factors include: reroutes such as those due to physical, environmental or regulatory determinations, additional subsurface information gathered from field geotechnical confirmation studies, changes in pipeline system design, changes in pipe or ditch design, and changes in construction planning.

The ***DCP*** will describe the process and procedures by which such changes are evaluated for their effect on the ***SBD Segments*** and, when an extension to an ***SBD Segment*** or new ***SBD Segments*** is identified, will specify the additional process of review for those ***SBD Segment*** changes. The ***DCP*** will also demonstrate adherence to QA/QC processes and procedures and will be part of the ***SBD Plan***, including applicable review under Condition 3(b).

1) At a minimum, the ***DCP*** content must include:
    a. Reason for change;
    b. Authority for approving changes;
    c. Analysis of implications;
    d. Acquisition of required work permits;
    e. Any required environmental reviews and permits;
    f. Documentation;
    g. Communication of change to affected parties;

[66] The ***DCP*** must be submitted by AGDC to the PHMSA Western Region Director or Project Designee and must receive a "no objection" response from PHMSA prior to implementation.

h. Time limitations;

i. Qualification of staff; and

j. A description of the data analysis procedure that impacts the determination of ***SBD Segment*** boundaries during the design and construction of the pipeline.

2) Review and approval of updates to ***SBD Segment*** mileposts or new ***SBD Segments***:

a. The beginning and ending mileposts of all ***SBD Segments*** or new ***SBD Segments*** are included in the SBD Special Permit;

b. AGDC must provide updates to the SBD mileposts when each SBD Plan Element described in Condition 3(a) is submitted to PHMSA.

c. For SBD Plan Element I, Design and Materials Specifications and Procedures, ***SBD Segment*** milepost changes, if any, must be based on any new data or project changes since issuance of the special permit, such as those listed below:

i. Additional geotechnical information;

ii. Route alignment changes;

iii. Design changes such as pipe wall thickness, grade, burial depth; and

iv. Changes in system design, e.g. changes in compressor station locations/design.

d. For SBD Plan Element II, Construction Specifications and Procedures, ***SBD Segment*** milepost changes, if any, would be based on new data or project changes, detailed in Paragraph 2 (b) of this Appendix B.

e. For the SBD Plan Element III, Operations and Maintenance Specifications and Procedures, the ***SBD Segment*** milepost changes, if any, would be based on changes during Construction that were made in accordance with the ***DCP***.

f. After the pipeline start-up, additional updates may be proposed to the ***SBD Segment*** mileposts by AGDC. AGDC must submit the ***SBD Segment*** mileposts to the PHMSA Western Region Director or Project Designee for a response of "no objection."

g. Any changes that add to the ***SBD Segment*** mileposts must be reviewed by PHMSA and an independent third-party engineering expert/firm in accordance with the approval process in Condition 3. Any additional ***SBD Segment*** length must comply with all the SBD special permit conditions. If the extension or the new ***SBD Segment*** was not initially built with pipe, welds, and procedures compliant with the ***SBD Conditions***, replacement of the segment with compliant materials and procedures will be required.

3) Non-SBD Segments: Any non-SBD segments found to experience axial or longitudinal strains more than 0.5% must be reported to the PHMSA Western Region Director or Project Designee within five (5) days of discovery. AGDC must submit an assessment of the suitability for continued operations and a remediation plan for these pipeline segments to PHMSA within 30 days of discovery. PHMSA must approve AGDC's proposed go-forward processes and procedures. PHMSA may determine that additional special permit notices and environmental assessments are necessary.

FINAL PAGE FOR SPECIAL PERMT FOR STRAIN BASED DESIGN