U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

APR 2 9 2019

Mr. David S. Wilkins
Senior Vice President
Hilcorp Alaska, LLC
3800 Centerpoint Drive, Suite 1400
Anchorage, AK 99503

Docket No. PHMSA-2017-0091

Dear Mr. Wilkins:

On March 24, 2017, Hilcorp Alaska, LLC (Hilcorp) wrote to the Pipeline and Hazardous Materials Safety Administration (PHMSA) requesting a special permit to waive compliance from the pipeline safety regulations in 49 Code of Federal Regulations (CFR) 195.563 and 195.573 for the proposed Liberty Pipeline. The proposed Liberty Pipeline will be approximately 7.25 miles in length, and will be located in the Foggy Island Bay of the Beaufort Sea Outer Continental Shelf and State of Alaska waters. The Liberty Pipeline will come ashore in Alaska and traverse approximately 1.5 miles above ground and tie into the existing Badami Pipeline.

The regulations in 49 CFR 195.563 and 195.573 require hazardous liquid pipeline operators to maintain cathodic protection currents on steel pipelines, and to monitor the level of cathodic protection currents to prevent external corrosion or metal loss on pipelines. The Liberty Pipeline is planned to be a 12.75-inch diameter carrier pipe placed inside a 16-inch diameter casing pipe (pipe-in-pipe or PIP) for approximately 5.68 miles. Cathodic protection currents will be unable to reach and protect the 12.75-inch diameter carrier pipe from corrosion, and Hilcorp will be unable to monitor cathodic protection currents based on their planned design. The purpose of the Liberty Pipeline special permit with conditions, is to assure safety and environmental protection are maintained in lieu of compliance with these cathodic protection Federal regulations.

PHMSA is granting this special permit (enclosed) which will allow Hilcorp to operate the Liberty Pipeline at a maximum operating pressure (MOP) of 1,480 pounds per square inch gauge (psig), and without monitoring cathodic protection currents, or the cathodic protection currents reaching the 12.75-inch carrier pipeline. This special permit provides relief from the Federal pipeline safety regulations for a segment of the Liberty Pipeline, but requires Hilcorp to comply with certain conditions and limitations designed to maintain pipeline safety and to protect the environment.

My staff would be pleased to discuss this matter or any other regulatory matter with you. Mr. John Gale, Director, Standards and Rulemaking Division may be contacted at 202-366-0434, on regulatory matters, and Mr. Max Kieba, Acting Director, Engineering and Research Division, may be contacted at 202-493-0595, on technical matters specific to this special permit grant.

Sincerely,

Alan K. Mayberry
Associate Administrator for Pipeline Safety

Enclosure: Special Permit – PHMSA-2017-0091

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

Special Permit Information:

Docket Number:	PHMSA-2017-0091
Requested By:	Hilcorp Alaska, LLC
Operator ID#:	32645
Original Date Requested:	March 24, 2017
Original Issuance Date:	April 29, 2019
Effective Dates:	April 29, 2019 – April 29, 2029
Code Sections:	49 CFR 195.563 and 195.573

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the United States Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS),[1] grants this special permit to Hilcorp Alaska, LLC (Hilcorp),[2] owner and operator of the proposed Liberty Sales Oil Pipeline (Liberty Pipeline). This special permit waives compliance from various sections of 49 CFR Part 195. Specifically, the Liberty Pipeline special permit waives compliance with 49 CFR 195.563 and 195.573.

The Liberty Pipeline will originate on the Liberty Drilling and Production Island (LDPI), an artificial island located in federal waters. The submerged pipeline will extend southwards for approximately 5.68 miles through the Foggy Island Bay of the Beaufort Sea Outer Continental Shelf (OCS) and State of Alaska waters. The Liberty Pipeline will then come ashore, traverse approximately 1.5 miles above ground, and tie into the existing Badami pipeline. The Liberty Pipeline consists of a 12.75-

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

[2] Hilcorp Alaska, LLC is a wholly-owned, operating subsidiary of Hilcorp. The Liberty Project partners include Hilcorp Alaska, LLC, BP Exploration (Alaska) Inc., and ASRC Exploration, LLC.

inch diameter pipeline[3] approximately 7.25 miles in length. The 7.25-mile route includes approximately 5.68 miles of submerged, buried pipe which will be located in offshore waters. The submerged portion of the Liberty Pipeline will utilize a pipe-in-pipe (PIP) design. The maximum water depth along the route is 19 feet at the LPDI.

The Liberty Pipeline will transport crude oil. The 12.75-inch diameter carrier pipeline will be installed in 16-inch diameter casing pipe in the submerged offshore sections. The carrier pipeline and casing pipe will be bundled together with a 4.5-inch diameter utility pipeline and a fiber optic communication cable during construction prior to placement in the seafloor, see **Figure 1- Pipeline Bundle Cross Section**, Page 36 of 44.

Purpose and Need:

Hilcorp's request for a special permit is for its planned Liberty Pipeline, specifically, the submerged PIP segments, and proposes waiving compliance from the following corrosion control sections of the Federal Pipeline Safety Regulations:

1) 49 CFR 195.563, Which pipelines must have cathodic protection? and
2) 49 CFR 195.573, What must I do to monitor external corrosion control?

These Federal Pipeline Safety Regulations require hazardous liquid pipeline operators to have cathodic protection (CP) to prevent external corrosion and monitor the level of external corrosion control to ensure adequate protection of the pipeline. While PIP[4] design is intended to prevent the creation of a corrosive environment, if there is a failure of either one of the pipes, a corrosive environment will occur and compliance with these federal corrosion regulations would not be possible. Furthermore, the PIP design and operating temperature differentials introduce atypical loads and strains to the pipeline, and presents pipeline condition assessment challenges that must be addressed to stay in full compliance. The purpose of the Liberty Pipeline special permit is to assure safety and environmental protection in lieu of compliance with these Federal Pipeline Safety Regulations.

[3] The 12.75-inch diameter pipeline may be referenced as "carrier pipe" or "carrier pipeline" throughout this document.

[4] The PIP reference means the 12.75-inch diameter carrier pipe installed within the annulus of the 16-inch diameter casing pipe in the ***special permit segment***.

The special permit conditions are necessary to ensure the design, construction, and operation and maintenance (O&M) activities of the Liberty Pipeline are consistent with pipeline safety, specifically 49 CFR Part 195. The Liberty Pipeline will consist of a 12.75-inch diameter pipeline surrounded by an outer 16-inch diameter casing pipe. This PIP design creates a dry annulus that protects the carrier 12.75-inch diameter pipeline from exposure to electrolytes, such as sea water, saturated thermal insulation, or saturated soils. The special permit conditions apply to the design, construction, and O&M of the PIP system.

Specifically, the special permit conditions address the possible introduction of an electrolyte around the carrier pipe, which could create an environment allowing corrosion to occur. Further, the special permit conditions provide a means for assessing the condition of the carrier pipe to ensure its integrity is maintained if the PIP system is compromised. Finally, the special permit conditions are necessary to allow Hilcorp to safely operate the ***special permit segment*** at a maximum operating pressure (MOP) of 1,480 pounds per square inch gauge (psig) and a maximum operating temperature of 150 degrees Fahrenheit (°F).

I. Special Permit Segment:

Beaufort Sea and North Slope Borough, Alaska

The Liberty Pipeline starts at the LDPI (an artificial island) and travels across Foggy Island Bay of the Beaufort Sea OCS, to the northern Alaskan coast line located west of the Kadleroshilik River Delta. The proposed Liberty Pipeline route and location can be reviewed on **Figures 3 and 4** on pages 37 and 38 of 44.

The Liberty Pipeline ***special permit segment*** includes the approximately 5.68 miles of 12.75-inch diameter carrier pipeline installed within a 16-inch casing pipe, the two (2) casing to carrier pipe "bulkhead" connections located on each end of the PIP segment, the 16-inch diameter casing pipe, and the connecting 12.75-inch diameter carrier pipeline from the 16-inch diameter casing pipe to the in-line inspection (ILI) tool launcher and receiver from approximate Milepost (MP) 0.02 and MP 7.25. The 16-inch diameter casing pipeline will create a sealed annular space between the casing pipe and carrier pipe using welded "bulkhead" connections located on each end of the PIP segment.[5]

[5] The "Liberty Pipeline" refers to the entire approximately 7.25 miles of pipeline and supporting facilities that are jurisdictional to 49 CFR Part 195.

The special permit conditions require installation and operation of an ILI tool calibration spool, remote operated mainline valves located at MP 0.02 and MP 7.25, and ILI launchers and receivers. At the shore, the pipeline will transition to a single-wall, aboveground pipeline supported on vertical support members (VSMs) and continue south to tie into the existing Badami Pipeline. Product (crude oil) will be transported from the Liberty Pipeline through the Badami and Endicott Pipelines to the Trans Alaska Pipeline System (TAPS).

PHMSA grants this special permit based on the findings set forth in the "Special Permit Analysis and Findings" document, which can be read in its entirety in Docket No. PHMSA- 2017-0091 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov. The draft environmental assessment (DEA), which includes a plain-language explanation of the safety conditions, is included in the Docket at www.regulations.gov.

II. Conditions:

PHMSA grants this special permit for the ***special permit segment*** and the Liberty Pipeline[6] subject to Hilcorp implementing the following conditions:

General:

1) **Applicable Regulations**: The ***special permit segment*** and the Liberty Pipeline must be designed, constructed, operated and maintained in accordance with these special permit conditions and 49 CFR Part 195, with the exceptions of 49 CFR 195.563 and 195.573. In the event of a conflict between these special permit conditions and the applicable requirements under 49 CFR Part 195, the special permit conditions control.

2) **Maximum Operating – Pressure, Temperature, Strain and Stress Limits for the Pipeline**: Hilcorp must design, construct, and operate the ***special permit segment*** to meet the maximum operating conditions in **Table 1: Liberty Pipeline – 12.75-inch Diameter Carrier Pipe Design Properties**. The Liberty Pipeline ***special permit segment*** carrier pipeline MOP must not exceed 1,480 psig, including any surge pressures, and maximum temperatures must not exceed 150 °F in operating procedures and actual operations.

[6] The special permit conditions are applicable to the O&M of the Liberty Pipeline that can affect the ***special permit segment.***

Table 1: Liberty Pipeline – 12.75-inch Diameter Carrier Pipe Design and Operating Properties

Design and Operating Parameters	***Value***	***Unit***
Flow Rate, maximum	70,000	barrels of oil per day (BOPD)
ASME/ANSI Class Rating, minimum	600	n/a, rating is 1,480 psig
MOP	1,480	psig
Maximum/minimum Operating/Design Temperature	-50 to 150	°F
Normal Operating Pressure	0 to 1,000	psig
Normal Operating Temperature	90 to 120	°F
Maximum Allowable Combined Stress (S_{eq})	46,980	pounds per square inch (psi)

Note: Liberty Pipeline ***special permit segment*** carrier pipe design must be based upon maximum operating conditions.

Justification for any change in design and operating parameters in Table 1 must be provided to the PHMSA Western Region Director or Project Designee for review, and must receive a "no objection" letter prior to implementation. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

3) **Integrity Management Program**: Hilcorp must incorporate the ***special permit segment*** into its written integrity management program (IMP) as a "covered segment" in a "high consequence area (HCA)" or "could affect HCA" in accordance with 49 CFR 195.452.

Design and Materials:

4) **Design, Specifications and Procedures**: Hilcorp must develop and implement design, construction, and O&M specifications and procedures in accordance with these special permit conditions and 49 CFR Part 195 for the ***special permit segment***. These specifications and procedures must prevent stress[7] and strain[8] for the carrier pipe, carrier pipe girth welds, the casing pipe, and casing girth welds from exceeding the defined operational limits under the operational conditions for the ***special permit segment*** as outlined in **Condition 2 - Maximum Operating – Pressure, Temperature, Strain and Stress Limits for the Pipeline**.

[7] Maximum allowable combined stresses are defined in Table 1.

[8] Strain 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). Strain is limited to the specific longitudinal strain value that cannot be exceeded, which for this special permit is 0.5% strain.

5) **<u>Pipe – Carrier</u>**:[9] The Liberty Pipeline ***special permit segment*** carrier pipe must be manufactured per American Petroleum Institute Specification 5L (API 5L), Specification for Line Pipe,[10] Grade X52 product specification level (PSL) 2, including supplementary requirements for offshore pipelines in API 5L Annexes J and K. The Liberty Pipeline ***special permit segment*** carrier pipe must be constructed of 12.75-inch diameter, 0.500-inch wall thickness, grade X52 or greater overall strength (wall thickness and grade combined), carbon steel pipeline.

6) **<u>Carrier Pipe Toughness</u>**: Charpy V-Notch (CVN) impact testing must be conducted on the carrier pipe in accordance with API 5L. Tests must be conducted on each carrier pipe steel heat and those test results must meet the following requirements:

   a) CVN impact test temperature must be negative 50 °F, and
   b) Minimum energy levels on full-size specimens must be 50 foot-pounds (ft-lb) average and 40 ft-lb minimum at negative 50 °F.

   <u>Note</u>: The pipe seam (weld centerline and heat affected zone) must be evaluated by CVN impact tests if the pipe has a manufactured, longitudinal seam.

7) **<u>Carrier Pipeline Design Factor</u>**: The Liberty Pipeline ***special permit segment*** design must comply with 49 CFR 195.106, utilizing a design factor of 0.72 or more conservative for the carrier pipeline. The ***special permit segment*** bulkhead fitting and tie-in piping (2 pipe joints of each side of bulkhead for the 12.75-inch diameter carrier pipe) must be designed for a hoop stress design factor of 0.60 and a combined stress load design factor of 0.72;

8) **<u>Bends</u>**: The buried segments of the Liberty Pipeline ***special permit segment*** (carrier and casing) must not include manufactured or hot bent pipe bends. The transition segments at each end of the buried LSOP bundle (onshore transition segment and island transition segment) must gradually sweep to the surface. The directional changes of the pipeline must be designed to maintain **<u>combined stress levels</u>** within ASME B31.4-2016[11], section 403.3.1, Table 403.3.1-1

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[9] The Liberty Pipeline 12.75-inch diameter carrier pipe is used to transport crude oil and is subject to 49 CFR Part 195. The casing pipe is the 16-inch or larger diameter pipe that will be used as a double barrier to keep crude oil from getting into offshore waters if the carrier pipe leaks.

[10] Hilcorp must use the edition noted for this standard that is incorporated by reference in 49 CFR 195.3.

[11] Hilcorp may use the 2016 edition of ASME B31.4 as noted or may use the edition incorporated by reference in 49 CFR 195.3.

allowable limits below 46,980 psi for API 5L X52 pipe[12] (0.90 times the carrier pipeline minimum yield strength).

9) **Flanges and Fittings**: All flanges and fittings must comply with American Society of Mechanical Engineers (ASME)/American National Standards Institute (ANSI) B16.5 and B16.9,[13] respectively, for a ANSI Class 600 system and 1,480 psig or greater and must be designed based upon the maximum and minimum operating pressures and temperatures in **Condition 2 and Table 1: Liberty Pipeline – 12.75-inch Diameter Carrier Pipe Design Properties.**

10) **CP – Carrier and Casing Pipe**: The PIP portions of the Liberty Pipeline ***special permit segment*** will not have a CP system to protect the 12.75-inch diameter carrier pipe from corrosion. Corrosion protection is provided by the dual layer fusion bonded epoxy (FBE) coating and by maintaining a dry inert environment during construction and operations and the sealed 16-inch diameter casing (PIP seal) during operations.

    a) The 16-inch diameter casing must have a CP system that meets the requirements for a buried or submerged pipeline in 49 CFR 195.563.

    b) The CP system for the 16-inch diameter casing must be installed with a distributed galvanic anode system consisting of aluminum anodes spaced throughout the offshore subsea buried segment.

    c) The anodes must be connected to the 16-inch diameter casing and the weld area must be coated.

    d) The 16-inch casing must be externally coated for corrosion protection. The 16-inch diameter casing pipe must also be internally coated[14] with the exception of a short segment (less than 6-inches wide) at pipe girth welds.

    e) The 16-inch diameter casing must have equipment to monitor pressure and temperature of the PIP annulus at all times, except during equipment maintenance activities which must be completed within one 12-hour shift and with the knowledge of Liberty Pipeline controllers.

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[12] Carrier pipe must be manufactured in accordance with the incorporated by reference edition of API 5L specified in 49 CFR 195.3.

[13] Hilcorp must use the editions noted for these standards that are incorporated by reference in 49 CFR 195.3.

[14] The internal coating for the 16-inch diameter casing pipe must be a coating that protects against atmospheric corrosion such as Valspar – Pipeclad Flowliner 930R.

11) **PIP Design**: The PIP design must have specifications and procedures implemented for the following:

a) Casing isolators must be clamped to the 12.75-inch diameter carrier pipe to isolate it from the 16-inch diameter casing pipe. Spacing of the isolators must maintain separation between the 12.75-inch diameter carrier and 16-inch diameter casing pipe throughout the entire length of the PIP section.

b) The PIP annulus[15] must be sealed at each end of the 16-inch diameter casing.

c) The dew point[16] of the inert gas in the annulus must be sampled prior to commissioning of the PIP system. The dew point of the inert gas must be maintained at negative 10°F or lower at all times.

d) The annulus must be filled with an inert gas, such as nitrogen or argon.

e) The PIP annulus must be connected to a vacuum system to maintain the annular back-pressure. The annular space must be maintained below atmospheric pressure at negative 10 psig or less at all times.

f) The vacuum system must be connected to the 16-inch diameter casing pipe at the LDPI. The vacuum system must include block valves, a pressure regulator, pressure relief valves, a vacuum pump, sample ports, and associated piping. The vacuum system must be operational at all times, except during maintenance activities which must be conducted during one 12-hour shift and with the knowledge of Liberty Pipeline controllers.

g) The annulus must be monitored for pressure and temperature changes that would indicate changes in the gas composition in the annulus.

h) Pressure transmitters to monitor pressures of fluids or gases in the annulus must be placed at each end of the PIP annulus system above ground at LDPI (MP 0.02) and above ground at the Alaska shoreline (MP 5.7)

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[15] "PIP annulus," "annulus," or "annular space" refers to the space between the carrier pipe and the casing pipe.

[16] Typically, for corrosion to occur, it requires an electrolyte (such as water) and air to be present. The inert gas in the annulus significantly reduces the potential for external corrosion on the NPS 12 LSOP by removing the oxygen from the surface of the carrier pipe. The inert gas will also be unsaturated, or dry, with a dew point sufficient to keep any water from dropping out of the gas for all operating temperatures of the PIP system. Corrosion generally is inhibited when the relative humidity is maintained below 30%. To account for potential presence of hygroscopic dirt, a minimum relative humidity of 20% is recommended for this application. The PIP system will be installed in a subsea trench where the lowest ambient conditions are above 25 °F. The effective dew point at 20% relative humidity and 25°F is -7 °F. Therefore, a -10 °F dew point should be sufficient to prevent liquid drop out as low as 25 °F.

i) Temperature transmitters to monitor temperature of the annular space must be placed at each end of the PIP annulus system, one (1) above ground at LDPI and one (1) adjacent to the onshore PIP transition.

12) **PIP Bulkhead Design**: Hilcorp plans to rigidly connect the 16-inch diameter casing pipe and the 12.75-inch carrier pipeline by means of a forged bulkhead, similar to what is presented in **Figure 2** on page 36 of 44.[17] The bulkheads must be placed above grade where the alignment transitions from buried to aboveground installation. Installation of the bulkheads must create a sealed annulus between the 12.75-inch diameter carrier pipeline and the 16-inch diameter casing pipe.

a) The PIP bulkhead design must meet both 49 CFR 195.106, *Internal Design Pressure*, and ASME B31.4 -2016, Table A402.3.5-1, *Design Factors for Offshore Pipeline Systems*. The bulkhead design and connecting piping must be treated as piping on an offshore platform for determining hoop, circumferential, and combined stresses.

b) The PIP bulkhead must be hydrostatically tested by the manufacturer in accordance with the Design Proof-Test requirements of the Manufacturers Standardization Society of the Valve and Fittings Industry, Inc., MSS SP-75-2014 *High-Strength, Wrought, Butt-Welding Fittings* or ASME B16.9-2012 *Factory-Made Wrought Butt-welding Fittings*, in accordance with 49 CFR 195.118.[18] The PIP bulkhead must be pressure tested with the pipeline after onsite installation in accordance with 49 CFR 195.304 and 195.306.

c) The PIP bulkhead fitting must be designed for:

i) Loads: thermal force, pressure force, cap force, and friction force;

ii) Design Safety Factor for all Combined Stress loads must not exceed: 0.72;

iii) Design Factor for Hoop Stress must not exceed: 0.6; and

iv) Minimum Factory Test Pressure: 5,700 psig for continuous 4-hours minimum.

d) PIP bulkhead and pipeline loads must be analyzed using Finite Element Analysis (FEA) for the carrier pipeline, casing and bulkhead operating conditions, and design safety factors

[17] Hilcorp may use another method of sealing the PIP design instead of the bulkhead outlined in **Figure 2**, but any design must meet 49 CFR Part 195 and these ***special permit conditions***. Hilcorp must give PHMSA Western Region Director or Project Designee notice of any changes to the sealing method for the PIP design and must get a "no objection" letter from PHMSA of the sealing method. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

[18] Hilcorp may use the editions noted for these standards (2014 and 2012) or may use the edition incorporated by reference in 49 CFR 195.3.

over the life span of the Liberty Pipeline ***special permit segment***. The FEA must meet the design factors listed in **Condition 12(c)**.

13) **<u>Bundle and Fiber Optic Cable</u>**: The offshore subsea buried ***special permit segment*** will be installed as a bundle. The bundle will consist of the PIP system, utility line, fiber optic cable, spacers and bundle straps. See **Figure 1** on page 36 of 44 for a conceptual cross section of the Liberty Pipeline bundle. **<u>Note</u>**: The fiber optic cable will be located outside of the PIP system. The fiber optic cable is not within the 16-inch diameter casing.

   a) The fiber optic cable must be installed with accurate distributed temperature sensing (DTS) capability to allow for the immediate identification of any areas experiencing changes in soil temperature. The fiber optic cable must be operational at the time the Liberty pipeline is placed into crude oil service.
   b) The fiber optic cable must be installed with DTS instrumentation, capable of detecting and locating temperature anomalies within five (5) feet.[19]
   c) The DTS system must be able to sense all temperatures within the pipeline design capacity.
   d) The temperature profile of the bundle must be transmitted to the supervisory control and data acquisition (SCADA) system for continuous monitoring and recording.
   e) The 4.5-inch utility line shown in **Figure 1** is not part of the special permit or the special permit conditions. The 4-inch utility must comply with current Federal Pipeline Safety Regulations, and Hilcorp must notify PHMSA in accordance with 49 CFR 191.22(c) prior to placing it into 49 CFR Parts 192 or 195 service.
   f) The depth of cover for the bundle must be a minimum of seven (7) feet below the subsea mudline for the offshore subsea buried segment of the Liberty Pipeline ***special permit segment*** bundle; with the exception to the two (2) transition segments where the buried piping transitions to the surface.

14) **<u>Pipe – External Coating</u>**: Carrier and casing pipe must have an external coating system that consists of an external dual layer of Fusion Bonded Epoxy (FBE) coating. The dual layer FBE

[19] If the fiber optics cable should fail during the 12.75-inch diameter pipeline operational life, Hilcorp must develop and implement alternative operational procedures that maintain a similar level of safety and environmental protection. Hilcorp must submit these procedures and an implementation schedule to PHMSA Western Region Director or Project Designee and receive a response of "no objection" prior to implementation. If Hilcorp does not receive a "no Objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

consists of one (1) layer of standard FBE covered with a minimum of one (1) layer of an abrasion resistant overlay (ARO) to protect the primary FBE layer. The external pipe coating system must be applied to the Liberty Pipeline ***special permit segment*** in accordance with a coating application specification that addresses:

a) pipe surface cleanliness standards,
b) blast cleaning,
c) application temperature control,
d) adhesion for coating to pipe,
e) cathodic disbondment,
f) moisture permeation,
g) bending,
h) minimum coating thickness,
i) coating imperfection, and
j) coating repair.

15) **<u>Monitoring System</u>**: The Liberty Pipeline ***special permit segment*** carrier pipe must be monitored for operating pressure, temperature, and flow rate, including the following requirements:
    a) Pressure transmitters must be placed at each end of the Liberty Pipeline, one (1) at LDPI and one (1) at the pipeline tie-in at the Badami Pipeline.
    b) Flow meters must be placed at each end of the Liberty Pipeline, one (1) at LDPI and one (1) at the pipeline tie-in at the Badami Pipeline.
    c) Temperature transmitters must be placed at each end of the Liberty Pipeline, one (1) at LDPI and one (1) at the pipeline tie-in at the onshore Badami Pipeline.
    d) Valves at LDPI and at the pipeline tie-in at the Badami Pipeline must be remote closure and have pressure monitoring on both sides of the valves. The actuation of the valves may not result in an overpressure event of the carrier pipeline, and closure rates must be substantiated by a hydraulic surge analysis. The remote closure valve status and adjacent pipeline pressures must be monitored at all times, except during scheduled equipment maintenance activities, which must be completed within a 12-hour shift and with the knowledge of Liberty pipeline controllers.

16) **Casing Pipe – Design and Operating Properties**: The 16-inch diameter casing design properties must be as shown in **Table 2 below**.[20]

Table 2: Liberty Pipeline – 16-inch Diameter Casing Design and Operating Properties

Design and Operating Parameter	***Value***	***Unit***
Minimum Design Pressure	1,480	psig
Design/Operating Temperature Range	-50 to 150	°F
Normal Operating Pressure	-20 to 50	psig
Normal Operating Temperature	60 to 90	°F
Maximum Allowable Combined Stress (S_{eq})	46,980	psi
Relief Valve - Annulus	25 to 50	psig

a) The casing pipe must be a minimum of 16-inch diameter, 0.625-inch wall thickness, carbon steel pipeline manufactured per API Specification 5L, *Specification for Line Pipe*,[21] Grade X52, PSL 2, including supplementary requirements for offshore pipelines (API 5L Annexes J and K). The casing pipe may be of a larger diameter, thicker wall thickness, or higher strength (grade) to maintain equivalent strength (a minimum design pressure of 1,480 psig).

b) Charpy V-Notch (CVN) impact testing must be conducted on the casing pipe in accordance with API Specification 5L Annex G, with the following modifications:

   i) CVN impact test temperature must be negative 50 °F; and

   ii) Minimum energy levels on full-size specimens must be 50 ft-lb average and 40 ft-lb minimum.

c) The 16-inch diameter casing must be coated with an external coating system. The coating system must be installed in accordance with **Condition 17(b).**

d) The casing pipe overpressure relief valve data and/or annulus pressure data must be transmitted to the SCADA system to ensure timely pipeline shutdown should the annulus pressure exceed the established pressure thresholds in Table 2.

Construction:

[20] Justification for any change in the design and operating parameters in **Table 2** must be provided to the Western Region Director or Project Designee for review, and must receive a "no objection" letter prior to implementation. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

[21] Hilcorp must use the API 5L edition incorporated by reference in 49 CFR 195.3.

17) **<u>Construction Quality Control</u>**: Hilcorp must develop and implement a right-of-way (ROW) construction monitoring program and a pipeline construction quality control program for the Liberty Pipeline ***special permit segment***, as specified below:

a) **<u>ROW Construction Monitoring Program</u>**: A ROW construction monitoring program must include procedures, personnel training, and be implemented for all construction phases of construction. The ROW construction monitoring program must include procedures for:

i) **<u>Operator Qualification (OQ) Procedures</u>**: OQ Procedures must be developed and implemented for construction tasks that can affect pipeline integrity in compliance with 49 CFR 195.501.

ii) **<u>Construction Quality Assurance Plan and Procedures</u>**: Hilcorp must develop a Construction Quality Assurance Plan and corresponding Procedures that establish the project quality objectives and personnel accountabilities to construct the pipeline system as designed. The Construction Quality Assurance Plan and Procedures, at a minimum, must include procedures, specifications, and personnel training for:

1) pipe inspection,
2) hauling and stringing pipe,
3) welding,
4) non-destructive examination of girth welds,
5) applying and testing field applied coating,
6) lowering the pipeline into the subsea trench,
7) backfilling, and
8) hydrostatic testing including dewatering and drying.

iii) **<u>Subsea Trench Quality Plan and Procedure</u>**: Hilcorp must develop a Subsea Trench Quality Plan that provides quality objectives to ensure the pipeline system is placed in the subsea trench as designed. At a minimum, the Subsea Trench Quality Plan and Procedure must include quality assurance/control for:

1) periodic collection of samples of trench spoils to test for chemical and electrical properties related to pipe corrosion,
2) trench depth monitoring,
3) trench bottom roughness profiling, and

4) backfilling requirements.

b) **<u>Carrier and Casing Pipe Construction Quality Control Programs</u>**:

i) **<u>Coatings for Carrier and Casing Pipe</u>**: A coating application quality control specification must be developed, implemented, and personnel must be trained to ensure carrier and casing pipe surface cleanliness, application temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, and minimum coating thickness for girth weld and repair coatings. Both the carrier and casing pipe must be externally coated for corrosion protection.

ii) **<u>Non-Shielding Coatings</u>**: Pipe, girth weld, and repair coatings must be non-shielding to CP. Shielding coatings such as tape or shrink sleeves must not be used.

iii) **<u>Pipe Protection</u>**: Pipe end protection caps must be installed on the pipe joint weld bevels during the storage, handling, transport, and staging for all of the pipe included in the pipeline bundle to reduce the introduction of foreign materials including snow, ice, and water.

18) **<u>Carrier Pipeline Girth Welds</u>**: All girth welding procedures for the 12.75-inch carrier pipe must be in accordance with 49 CFR 195.214 that incorporates by reference, API Standard 1104.[22]

a) All pipeline girth welds must be non-destructively tested to meet 49 CFR 195.228, 195.230, and 195.234.

b) All pipeline girth welds with any type crack must be cut-out prior to placing the carrier into service with crude oil.

c) The 12.75-inch carrier pipe and coating must be protected from any weld splatter or other damage during welding of the 16-inch casing pipe.

19) **<u>Casing Pipe Girth Welds</u>**: All casing pipe girth welding procedures must be in accordance with 49 CFR 195.214 and API Standard 1104.[23]

a) All casing pipe girth welds must be non-destructively tested to meet 49 CFR 195.228, 195.230 and 195.234.

[22] Hilcorp must use the API 1104 edition incorporated by reference in 49 CFR 195.3.

[23] Hilcorp must use the API 1104 edition incorporated by reference in 49 CFR 195.3.

b) All casing pipe girth welds with any type crack must be cut-out prior to placing the 12.75-inch diameter carrier pipe into operational service with crude oil.

20) **<u>Casing Isolators</u>**: The Liberty Pipeline ***special permit segment*** must be supported by casing isolators at regular intervals throughout the PIP portion of the ***special permit segment***. A maximum casing isolator spacing interval of 10-feet or less must be used to minimize lateral deflection between isolators, prevent contact between the casing and carrier pipes, provide structural integrity of the PIP design during unexpected ground movement or creation of unsupported spans caused by localized seafloor scour, and to accommodate cyclic, thermally induced movement of the carrier pipe relative to the casing. The casing isolator spacing should facilitate installation of the carrier pipe within the casing. The casing isolators must consist of two high-density polyethylene half-shells with a continuous temperature rating of 225°F or greater so that the isolators will not lose structural integrity or degrade under loading or temperature conditions for the life of the pipeline.

21) **<u>Relief Storage Tank</u>**: The PIP annulus of the Liberty Pipeline ***special permit segment*** must be configured so that any excessive pressure (as monitored under **Condition 11)** resulting from either crude oil or seawater entering the annulus can be discharged from an annulus relief valve (see **Table 2** for relief set pressure ranges) to either a "breakout tank, a portable tank, drum and flare system, or other pipeline" (relief storage tank) that operates at a pressure that is not higher than the 16-inch diameter casing maximum annulus relief valve pressure setting in **Table 2**. The relief storage tank must facilitate the removal of liquids from the annulus in an event the annulus relief valve discharges. The relief storage tank capacity must be based upon the time to shut-down and isolate the carrier pipeline and maximum flow volumes (see **Condition 16(d)**.

<u>O&M:</u>

22) **<u>O&M Procedures:</u>** In addition to the O&M procedures otherwise required by 49 CFR Part 195, Hilcorp must develop and implement O&M procedures for the ***special permit segment*** and the Liberty Pipeline, including the following:

- CP monitoring system on the 16-inch diameter casing pipe,
- PIP annulus monitoring,
- SCADA System for the Liberty Pipeline and PIP System,
- Integrity Management Plan for the 12.75-inch diameter pipeline and 16-inch diameter casing, and

- Data Integration Plan and Procedures to monitor and remediate any corrosion or excessive strains on the 12.75-inch diameter pipeline or 16-inch diameter casing pipe.

a) O&M procedures for the ***special permit segment*** and the Liberty Pipeline must technically assess all operating parameters that have an effect on the implementation of, or compliance with, all of these ***special permit conditions***; including, but not limited to:
   i) maximum and minimum pressures,
   ii) pipe corrosion,
   iii) oil and environmental (soil) temperatures, and
   iv) maximum and minimum operating temperatures of the carrier pipe and casing pipe.

b) Procedures for the carrier pipeline in the ***special permit segment*** must be developed and implemented to ensure the following conditions are evaluated:
   i) the effects of corrosion anomalies (defects),
   ii) the effects of mechanical damage (such as dents and gouges),
   iii) the effects of cracking on the stress and strain capacity of the pipe, casing, and girth welds,
   iv) the effect of tensile and compressive strain/stress capacity on anomalies in assessing pipeline integrity and fitness for service,
   v) the effects of corrosion anomaly interaction criteria of a minimum of 6t (where t is the pipe wall thickness) must be used for longitudinal and circumferential wall loss,[24] and
   vi) the 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).

c) Develop and implement procedures for strain demand monitoring systems, including the scheduling and selection of ILI tools, as specified in **Condition 23 - Monitoring and Determination of Pipeline Strains**, to verify the reliability and accuracy of these procedures. The strain demand monitoring procedures must:
   i) demonstrate that strain demand monitoring systems are technically justified for estimation of actual strain demand levels (tensile, compressive, and combined),

[24] Other anomaly interaction criteria may be used if engineering analysis shows they are more conservative than the required criteria.

ii) ensure strain demand from the monitoring systems 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, and

iii) include a requirement that when pipe strain magnitude greater than 0.5% is determined, the pipeline must be monitored or remediated in accordance with integrity remediation measures specified in **Condition 23**.

d) Develop and implement material properties surveillance procedures for any time-dependent degradation mechanisms found during material testing, construction, or ongoing operations that may affect the ***special permit segment***.

23) **Monitoring and Determination of Pipeline Strains:** The Liberty Pipeline ***special permit segment*** must be monitored for strain by evaluation of inline inspection tool data and as follows:

a) **Strain Monitoring Process and Devices**: When locations of high strain[25] are discovered after the Liberty Pipeline is placed into service, strain demand monitoring processes or devices must be installed and 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).

b) **Strain Monitoring Procedures**: Hilcorp must create strain demand monitoring procedures that take into account the limitations, accuracy, strain demand seasonal and location 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.

c) **Strain Trending**: Data acquisition and analysis must be performed frequently enough to ensure the strain demand limit is not exceeded before mitigation measures can be implemented. The frequency of monitoring may be adjusted based on procedures using site-specific strain growth rate calculations with safety factors.

d) **Site Specific Strain Data Requirements**: Whenever high strain conditions are identified, Hilcorp must evaluate the site-specific strain. For the strain limit evaluation, the site-specific data must include actual pipe geometry, stress-strain data, yield strength to tensile strength

[25] High strain is defined as a strain magnitude greater than the value corresponding to a longitudinal stress of 0.8 SMYS.

(Y/T) ratios, construction weld records, NDE results, and other recorded data that affects the strain capacity.

e) **Site-Specific Geotechnical Data Requirements:** Whenever high strain conditions are identified, Hilcorp must evaluate and remediate, as necessary, the site-specific strain demand. For the strain demand evaluation, the site-specific geotechnical data must include burial depth, soil type, subsurface temperature information, water table height, and other recorded data that contributes to the evaluation and understanding of strain demand and strain growth at this location. If site-specific geotechnical data is not available, engineering evaluations must be used to assess future strain demand growth.[26] The site-specific strain demand model must be calibrated to the pipeline strain measured at the high-strain location. Hilcorp must request a "no objection" letter from PHMSA's Western Director or Project Designee for procedures using engineering evaluations rather than site-specific geotechnical data prior to implementation. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

f) **Geospatial Pipeline Mapping**:
Multi-dimensional geospatial pipeline mapping ILI (mapping ILI) tools must be run through the entire ***special permit segment***. The mapping ILI tools (e.g. IMU) must be capable of mapping the pipeline location based upon its plan, elevation, and distance. The mapping ILI tools must be capable of mapping such features as pipeline alignment and the direction and orientation of horizontal and vertical with respect to angle, radius, direction, and location. To allow for accurate usage of engineering critical assessment (ECA) and to ensure O&M procedures for pipe and casing strains are capable of identifying and locating high-bending pipe and casing strain conditions, the mapping ILI tool must be able to meet the performance parameters listed in **Table 3: Summary of Bending Strain ILI Tool Performance.** Conditions that can cause additional stresses or strains on girth welds, but that are not measurable from mapping ILI tools, must be technically considered in the weld integrity evaluation.

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

Table 3: Summary of Bending Strain ILI Tool Performance	
	Bending Strain[1, 2]
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%.	

g) **Alternative Strain Demand Monitoring Methods**: Hilcorp must report and remediate high-strain conditions, as specified in **Table 4: Pipeline Segment Strain Demand Monitoring.** Alternatively, Hilcorp can propose a different strain-demand monitoring approach. The justification for any alternative strain demand monitoring approach must be sent by Hilcorp to an independent third-party engineering/expert firm for review and then to the PHMSA Western Region Director or Project Designee for review and Hilcorp must receive a response of "no objection" prior to implementation. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

Table 4: Pipeline Segment Strain Demand Monitoring		
Strain Demand Magnitude that Triggers Action		**Action Required[27]**
Level	***Strain Demand***	
1	Greater than 0.16% but less than 0.37% longitudinal strain	**Monitor**
2	Greater than 0.37% but less than 0.45% longitudinal strain	**Monitor, Report, and Develop** a site-specific strain growth rate and corresponding remediation plan to ensure the strain demand limit is not reached during the pipe's operational life. A remediation plan must be developed 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 0.45% longitudinal strain	**Report and Remediate** strain findings to the PHMSA Western Regional Director or Project Designee within five (5) days of discovery. Develop a remediation plan and submit it 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.

24) **Integrity Assessments**: Pipeline integrity assessments must be performed along the entire Liberty Pipeline ***special permit segment*** using ILI tools as follows:

a) **Pre-Commissioning Assessment**: A pre-commissioning assessment is required prior to placing the Liberty Pipeline into service or prior to raising the temperature above ambient temperature conditions. The commissioning assessment must include:

[27] Hilcorp must submit the Level 2 and 3 monitoring procedures and plans to the PHMSA Western Region Director or Project Designee and receive a response of "no objection" prior to implementation. PHMSA may also require an independent third-party engineering expert/firm review. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed. Level 1 monitoring procedures and plans require no reporting to PHMSA Western Region Director or Project Designee.

i) High Resolution Deformation (HR-Deformation) ILI survey utilizing deformation sensing fingers located outside the tool cups,

ii) multi-dimensional geospatial pipeline mapping tool, and

iii) confirmation that any anomalies defined in 49 CFR 195.452(h) or other known injurious anomalies have been remediated prior to commissioning (placing crude into the pipeline) the Liberty Pipeline in accordance with 49 CFR 195.401(b), 195.422, 195.452(h), and 195.585. All ***special permit segment*** carrier pipe denting located in the PIP must be treated as a top side (above the 4 and 8 o'clock positions) dent for scheduling remediation as required in 49 CFR 195.452(h).[28]

b) **Baseline Assessment**: Within one (1) calendar year, not to exceed 15 months, of placing the Liberty Pipeline into service, Hilcorp must perform a baseline assessment of the Liberty Pipeline ***special permit segment***. The baseline assessment must use, at a minimum, the following ILI devices:

i) High Resolution (HR) for Metal Loss,

ii) HR-Deformation ILI survey utilizing deformation sensing fingers located outside the tool cups, and

iii) multi-dimensional geospatial pipeline mapping tool.

c) **Second Assessment**: A second ILI integrity assessment must be conducted within 36 months, not to exceed 39 months, after placing the pipeline into service. The second ILI assessment must use, at a minimum, the following ILI devices:

i) an ultrasonic (UT) technology to determine metal loss and cracking,[29]

ii) a HR-deformation ILI survey utilizing deformation sensing fingers located outside the tool cups, and

iii) Multi-dimensional geospatial pipeline mapping tool.

d) **Periodic Assessments**: After the second ILI integrity assessment (**Condition 24(c)**), Hilcorp must perform ILI assessments at two (2) calendar year intervals. Hilcorp may conduct ILI assessments up to a maximum of three (3) calendar years, not to exceed 39 months. While the maximum interval between ILI assessments is three (3) calendar years, not to exceed 39

[28] ***Special permit segment*** carrier pipe denting or other deformations in the cased pipeline, PIP, would indicate the presence of unanticipated integrity-threatening forces and strains.

[29] UT ILI crack detection tool is not required for the 2nd Assessment Period unless the Baseline ILI tool runs detect denting (2 percent or greater) or the carrier pipe is touching the casing pipe. A UT ILI crack detection tool must be run during the 4th Assessment Period, if it has not been previously run.

months, a 3-year interval should only be utilized if it is supported by existing ILI data, data integration results, and the Liberty Pipeline Comprehensive Risk Assessment (CRA).

i) Hilcorp must use the CRA to determine if the ILI assessment interval can be extended from a two (2) to a three year (3) assessment interval only if the CRA shows no increased risk through data integration and application of integrity management risk assessment models.

ii) Each ILI assessment must include, at a minimum:

1) HR for Metal Loss,
2) HR-Deformation, and
3) Multi-dimensional geospatial pipeline mapping inspections.

iii) In order to extend the ILI assessment interval longer than three (3) years, Hilcorp must receive a "letter of no objection" letter from the PHMSA Western Region Director or Project Designee. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

e) **ILI Tool Types**: A UT ILI tool must be run at least every other integrity assessment. If any pipe cracking is found through ILI tool surveys, direct inspection or examination of the pipe, the subsequent ILI tool surveys must utilize an UT crack ILI tool. The pipeline operator may select an alternate tool technology as superior tools are made available through technology improvements, but must obtain a "no objection" letter from PHMSA Western Region Director or Project Designee. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed. Hilcorp Alaska must report the ILI tool used for integrity assessments in the annual report.

f) **Calibration Spool**: Hilcorp must install a calibration spool (on the downstream side of the PIP) in the 12.75-inch diameter mainline carrier pipe to detect general corrosion, pitting, and cracks with known defects (type, length, width, and depth). This installation must be downstream of the PIP segment and near the pig receiver location. ILI calibration spools must replicate the conditions of the cased 12.75-inch diameter carrier pipe, and must include at least one insulator and a girth weld to ensure that the ILI tool inspection signals accurately portray the PIP conditions. Hilcorp must request a "no objection" letter prior to implementation of any pre-built, calibrated pipe segments and procedures from PHMSA's

Western Director or Project Designee. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

g) **Denting or Wrinkling Assessments**: In the event of contact between the 12.75-inch diameter carrier and 16-inch diameter casing pipe, Hilcorp must run an HR-deformation ILI tool and multi-dimensional geospatial pipeline mapping ILI tool to identify any denting or wrinkling. Hilcorp must perform an assessment of the findings (stress, strain, denting and movement) and respond in accordance with response and remediation procedures defined in this special permit.

h) **Anomaly Repair**: Any anomalies defined in 49 CFR 195.452(h) or other known injurious anomalies found during ILI tool runs or other O&M activities on the carrier pipeline must be remediated in accordance with 49 CFR 195.401(b), 195.422, 195.452(h), and 195.585 and must take into account surge pressures in determining any temporary pressure reductions.

   i) Hilcorp must treat as an immediate repair condition to meet 49 CFR 195.452(h)(4)(i)(A) or (B) any 12.75-inch diameter carrier pipe ***special permit segment*** corrosion anomaly that has wall loss greater than 70% of nominal pipe wall thickness or has a failure pressure ratio that is below a pressure of 1.10 times "maximum operating pressure plus maximum surge pressure."

   ii) All ***special permit segment*** carrier pipe denting located in the PIP must be treated as a top side (above the 4 and 8 o'clock positions) dent for scheduling remediation as required in 49 CFR 195.452(h).[30]

   iii) Hilcorp must evaluate corrosion anomalies found during ILI tool runs or other inspections and develop growth rates to ensure they are repaired prior to reaching "immediate" repair status as defined by this **Condition 24(h).**

25) **Inline Inspection Tool Tolerance**: In the ***special permit segment*** Hilcorp must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs, and must document and justify the values used.

   a) Hilcorp must demonstrate ILI Tool tolerance accuracy for each ILI Tool run by usage of

[30] ***Special permit segment*** carrier pipe denting or other deformations in the cased pipeline, PIP, would indicate the presence of unanticipated integrity-threatening forces and strains.

calibration spools[31] and unity plots that demonstrate ILI Tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). Hilcorp must incorporate ILI Tool accuracy by ensuring that each ILI Tool service provider determine the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to Hilcorp. Hilcorp must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly. The unity plots must show the actual anomaly depth versus predicted depth.

b) ILI Tool evaluations using high resolution magnetic flux leakage (HR-MFL) technology must be evaluated for metal loss using "6t x 6t"[32] interaction criteria for determining anomaly failure pressures and response timing.

c) Discovery date[33] must be within 90 days of any ILI Tool run (e.g. HR-deformation ILI tools, high resolution HR-MFL ILI tools, or multi-dimensional geospatial pipeline mapping ILI tools).

26) **Engineering Critical Assessment for Cracks**: If cracks are found in the 12.75-inch diameter pipe, Hilcorp must evaluate the cracks using **Appendix A – Engineering Critical Assessment** for cracks up to 50% through wall thickness. Any crack over 50% wall thickness or with a failure pressure ratio[34] less than 1.25 must be treated as an "immediate response" and all other cracks must be remediated based upon a 49 CFR 195.452(h) response times.

27) **Leak Detection System:** The leak detection system (LDS) for the Liberty Pipeline must include operational procedures and monitoring of the 12.75-inch diameter pipeline, the PIP annulus, and the fiber optic cable included in the pipeline bundle. Leak detection methods must include a computational pipeline monitoring (CPM) LDS, in accordance with 49 CFR 195.444. The LDS

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[31] Calibration spools must have known dimensions of length, depth and width for anomaly features, such as general corrosion, pitting, cracks, gouges, and denting. Any pre-built, calibrated pipe segments and procedures used, Hilcorp must request and receive a "no objection" letter from PHMSA's Western Region Director or Project Designee prior to implementation. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

[32] "6t" means pipe wall thickness times six.

[33] Discovery date is the day, month and year that Hilcorp receives the ILI Tool run results from the ILI Tool service provider.

[34] A failure pressure ratio is the anomaly failure pressure divided by the Liberty Pipeline MOP.

must include three (3) independent leak detection methods for the Liberty Pipeline: a mass balance system including flow meters at the LDPI and the BSOP tie-in; PIP annulus monitoring system; and temperature monitoring of the subsea bundle through the fiber optic cable.

a) **Mass Balance System**: The primary leak detection method for the Liberty Pipeline must be a mass balance system monitoring pressure, temperature, and flow rates between metering stations. Pressure transmitters, temperature transmitters and flow meters must be located at each end of the Liberty Pipeline, above ground at the LDPI and above ground at the Badami Pipeline tie-in.

   i) Data from the transmitters must be transmitted to the SCADA system for analysis.

b) **PIP Annulus System Design for Secondary Leak Detection**: The PIP annulus pressure and temperature must be monitored for changes that would indicate loss of PIP containment whether through the 12.75-inch diameter carrier pipe or 16-inch diameter casing pipe.

   i) **Annulus Pressure**: The PIP annulus must be monitored for indications of rising interstitial pressure. Pressure transmitters must be installed on the 16-inch diameter casing at each end of the PIP annulus, above ground at LDPI, and above ground at the Alaska shoreline.

      i. Pressure transmitters, as described in **Condition 11(h)**, must be monitored for changes in pressure that may indicate leakage of oil or seawater into the annulus, or leakage of the inert gas from the annulus.

      ii. Pressure measurements of the annulus must be transmitted to the SCADA system for real time monitoring and recording.

   ii) **Annulus Temperature:** The PIP annulus must be monitored for indications of changes in the interstitial temperature.

      i. Temperature transmitters, as described in **Condition 11(i)**, must be installed on the 16-inch diameter casing at each end of the PIP annulus, above ground at LDPI, and above ground at the Alaska shoreline.

      ii. Temperature measurements of the annulus must be transmitted to the SCADA system for real time monitoring and recording.

c) **Fiber Optic Cable:** A fiber optic cable must extend between the LDPI and the onshore Badami Pipeline tie-in. The fiber optic cable must transmit data from the multiple sensors and flow computers to the leak detection software of the SCADA system.[35] The LDS must perform mass balance calculations and have remote operation of the tie-in pad valves capabilities.

28) **Monitoring Systems – Carrier Pipe, Casing Pipe and PIP Annulus**: Hilcorp must develop and implement monitoring systems and procedures for the 12.75-inch diameter carrier pipe, 16-inch diameter casing pipe and annulus for pressure, temperature, settlement, flow, and dew point monitoring, as follows:

a) **Carrier Pipe – Pressure, Temperature, Settlement, and Flow Rate Monitoring**:

i) Pressure monitoring equipment, as described in **Condition 15(a)**, must transmit data to the SCADA system for real time monitoring and recording.

ii) Temperature monitoring equipment, as described in **Condition 15(c)**, must transmit data to the SCADA system for real time monitoring and recording.

iii) A pipeline settlement protection system procedure must be developed and implemented to prevent the operating temperature from exceeding the design limit so thaw settlement limits are not exceeded.

iv) Flow rate metering equipment, as described in **Condition 15(b)**, must transmit data to the SCADA system for real time monitoring and recording. Flow and mass balance loss procedures must be developed and implemented to detect loss of crude oil from the carrier pipeline on a real time basis that is monitored through SCADA.

b) **Casing Pipe and PIP Annulus – Pressure, Temperature, and Dew Point Monitoring:**

i) Pressure monitoring equipment on the 16-inch diameter casing must transmit data to the SCADA system for real time monitoring and recording.[36] The PIP annulus between the 16-inch diameter casing and 12-inch diameter carrier pipe

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[35] In the event that the fiber optic leak detection cable fails after the Liberty Pipeline goes into service, alternative operational procedures and measures that maintain a similar level of safety must be developed and implemented. These alternative measures must similarly transmit data to the leak detection software or SCADA system.

[36] Monitoring of the PIP annulus pressure provides a method of leak detection. In an event that the pressure increases, high pressure could indicate a leak in the 12.75-inch diameter carrier pipe, in the 16-inch diameter casing, or both. Additional information from the Liberty Pipeline Leak Detection System would help to determine the location of the leak on the Bundle and to determine if the leak is on the casing pipe or on the Liberty Pipeline.

will be maintained below atmospheric pressure at negative 10 psig or less during normal operations, per **Condition 11(e).**

ii) Hilcorp must investigate and respond to pressure changes based upon a delta of 5 psi over two (2) hours, or annulus must be in vacuum, or using O&M procedures that were developed based upon plotted operational knowns, which must receive a "no objection" letter from PHMSA's Western Region Director or Project Designee. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

iii) If the pressure excursion is greater than 5 psi and less than 10 psi, Hilcorp must flush the annulus with dry gas to achieve positive 10 psig. Hilcorp must perform a leak test to determine whether a leak exists on carrier or casing.

iv) Hilcorp must investigate and respond to temperature changes and initiate remediation based upon a delta of 20°F over 30 minutes, not to exceed a total delta of 50°F, or on O&M procedures that are based upon plotted operational knowns, which must receive a "no objection" letter from PHMSA's Western Region Director or Project Designee. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

v) Dew point sampling equipment connected to the 16-inch diameter casing and annulus vacuum system must be installed. In the event of a dew point change of 10 degrees or greater, Hilcorp must immediately take remedial action including investigating the cause of the change in dew point and flush the PIP annulus to return the dew point within operating limits in accordance with **Condition 11**.

vi) Dew point samples must be taken prior to commissioning, during operations, and at each ILI assessment.

c) **<u>Bundle Monitoring</u>**: Temperature monitoring data via a DTS fiber optic cable must transmit data to the SCADA system for real time monitoring and recording. Hilcorp must investigate and initiate remediation based upon a temperature changes outlined in **Condition 29(b)**.

29) **<u>Monitored Response Procedures</u>**: Monitoring and Response Procedures for the ***special permit segment*** must include response plans for the 12.75-inch diameter carrier pipe, the PIP annulus, and the bundle monitoring system. The procedures must include; established operating limits of the Liberty Pipeline, troubleshooting variances, methods for identification of the source of the variances, and procedures for returning the Liberty Pipeline to established operating limits.

a) **<u>Carrier Pipe – Pressure and Temperature Monitoring</u>**:

The following procedures must be included in the Monitoring and Response Procedures and followed in an event that the temperature of the 12.75-inch diameter carrier pipe is not within the operating limits:

i) **<u>Immediate to 24 Hour response</u>**:

1. The temperature of the Liberty Pipeline ***special permit segment*** must not exceed 150 °F.
2. If the temperature exceeds the maximum operating/maximum design limit of 150 °F, the operating temperature must be reduced below the design limit within two (2) hours.
3. If the operating temperature of the pipeline exceeds the operational limit for more than 24 hours, PHMSA's Western Region Director or the Project Designee must be notified.

b) **<u>Bundle -Temperature Monitoring</u>**: A Monitoring and Response Program and Procedures must be implemented to identify the response for temperature anomalies in the soil surrounding the bundle.

i) If the temperature reading is reduced at a point along the bundle, it could indicate an exposure to seawater and loss of soil cover. Hilcorp must assess potential reasons for the temperature loss and loss of cover such as, strudel scour, ice keels, upheaval buckling, and natural erosion.

ii) An immediate temperature change could indicate a combined leak of both the 12.75-inch diameter carrier pipe and the 16-inch diameter casing. Alternatively, it could indicate seawater exposure to the casing. Hilcorp must immediately investigate and assess potential reasons for temperature fluctuation.

iii) DTS temperature changes that initiate investigation, response, and remediation must be based upon a temperature change of 20°F or more in any 30-minute period, total temperature changes of 50°F, or on O&M procedures that are based upon plotted operational knowns. O&M procedures for plotting operational temperature knowns must receive a "no objection" letter from PHMSA's Western Region Director or Project Designee. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

30) **<u>CP System Monitoring of the Casing Pipe</u>**:

a) A CP monitoring system must be provided on the 16-inch casing to determine the performance of the galvanic-based corrosion control system.

b) The CP monitoring system must, at a minimum, include test leads for the first 1,000 feet from each shoreline and at frequent enough intervals to demonstrate adequate CP of the casing pipe within that 1,000 feet. The CP monitoring system must also utilize periodic close interval surveys (CIS) over the entire length of the submerged pipeline casing at least once every five (5) years utilizing a silver/silver chloride reference electrode or other alternative (comparable) method. The CP monitoring system must be in place and a baseline CIS must be performed within one (1) year after construction of the ***special permit segment*** is completed.

c) Each monitoring point must be a minimum of ten (10) feet from a galvanic anode. Each monitoring point must include two (2) casing connections, a silver-chloride reference electrode, and two (2) coupons made from the same grade steel as the casing.

   i) The casing leads must be independently welded to the casing and the weld areas coated.

   ii) The reference electrode and coupons must be strapped to the casing.

   iii) Three (3) to five (5) lead wires for each monitoring point must be buried along with the casing and terminated in a junction box on shore. Each wire will be labeled with the approximate distance from shore and what it is connected to: casing, casing coupon, coupon, reference electrode. For each set of monitoring leads, one coupon lead will be bonded to one casing lead through a 0.01-ohm shunt so that the coupon receives CP like the casing but can be disconnected from the CP and provide instant-off and depolarized potentials.

d) Potential readings must be taken between the coupon and the local reference electrode. **Note:** CP current density can be established by reading the voltage drop across the shunt. The second casing connection and second coupon are primarily used for trouble shooting the monitoring point in the event there are unusual readings. This arrangement represents the best available technology for monitoring the adequacy of the CP system and correcting for voltage drops from directly connected anodes and telluric currents.

e) Potential readings must be taken for each coupon once every calendar year throughout the life of the pipeline.

f) The CP system must be operational and meet the requirements of this permit within six (6) months of placing the subsea segment into service.

g) If more than 20% of the test leads fail, then the close interval survey frequency must be decreased to a 2-year interval.

31) **SCADA and CPM Systems**: SCADA and CPM leak detection systems must be developed and maintained to provide remote monitoring and control of the pipeline system in accordance with 49 CFR 195.444 and 195.446.

32) **Data Integration**: Hilcorp must maintain data integration of all special permit condition findings and remediation in the ***special permit segment***. Hilcorp must create a data integration plan to integrate and analyze data pertaining to the integrity of the ***special permit segment***. The data integration plan must define the integrity management data elements required for integrity management of the ***special permit segment***, including, but not limited to, strain capacity assessment, determination and forecast of strain demand, and monitoring and remediation.

a) Data integration documentation and drawings must be completed to meet 49 CFR 195.452(g) and (h) and must include the data elements in **Table 5 – Data Integration Requirements.** If requested, this documentation must be submitted to PHMSA beginning with the second annual report of this special permit.

b) Data integration must be updated on an annual basis. Hilcorp must conduct, at least one annual review of the Liberty Pipeline integrity issues to be remediated.

Table 5: Data Integration Requirements

Category	*Data*	*Data Element*
Design	Pipe	Diameter, wall thickness, grade, seam type, pipe/girth weld coatings, abrasive resistance coatings, design factors, and maximum operating pressure
Construction	Depth of cover	Depth of cover surveys
O&M	Normal, maximum and minimum operating pressures	MOP, 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	CP test point survey readings; telluric current surveys, close interval surveys
	Other	High consequence areas (HCAs) (including boundaries on aerial photography or satellite imagery)
PIP Annulus	Normal maximum and minimum operating pressures	MOP, including normal and minimum operating pressures
	Bundle Monitoring	Review of minimum temperatures and effects on annulus. Note: If the temperature reading is reduced at a point along the bundle, it could indicate an exposure to seawater.
Casing Pipe	Casing	Diameter, wall thickness, grade, seam type, and external coating, if coated.
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 tools; HR-deformation tools; stress corrosion cracking; and mapping ILI tool results
	CP inspection	Monitoring electrode and CP coupon surveys, test stations, and periodic close interval surveys
	Coating condition inspections (DC voltage gradient)	Pipe coating surveys, pipe coating and anomaly evaluations from pipe excavations
	Other	Pipe exposures for any reason

33) **<u>Environmental Assessments and Permits</u>**: Hilcorp must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings needed to implement the special permit conditions for the ***special permit segment*** prior to the disturbance. If a land disturbance or water body crossing is required, Hilcorp must obtain and adhere to all applicable (federal, state, and local) environmental permit requirements when conducting special permit conditions activity.

<u>Reporting, Documentation, and Certification</u>:

34) **<u>Notices to PHMSA</u>**: In addition to the notifications required in the conditions above, Hilcorp must also provide the following notifications:

   a) Hilcorp must notify the PHMSA Western Region Director or Project Designee 14 days prior to construction or operational activities relating to **Conditions 5 (pipe manufacturing), 14 (pipe coating), 17 (construction) and 24 (integrity assessments)** so PHMSA can observe the activity. The PHMSA Western Region Director or Project Designee may elect to not require a notification for some activities.

   b) Hilcorp must notify PHMSA of immediate repair conditions no later than two (2) business days after a condition is discovered.

35) **<u>Annual Report</u>**: Within twelve (12) months following issuance of the Liberty Pipeline special permit, and annually[37] thereafter, Hilcorp must develop and submit annual reports that include the below information. The reports must be sent to the PHMSA Western Region Director or Project Designee, and Hilcorp must provide copies to the PHMSA Engineering and Research Division Director, the PHMSA Standards and Rulemaking Division Director and to the Federal Register Docket (PHMSA-2017-0091) at <u>www.regulations.gov</u> prior to placing the pipeline in service.[38] The annual reports must include the following information:

   a) Any integrity threats identified, such as through ILI or data integration, during the previous year in the ***special permit segment***, including Level 2 or Level 3 strains (*see* **Table 4: Pipeline Segment Strain Demand Monitoring**);

[37] Annual reports must be received by PHMSA by the last day of the month in which the special permit is dated. For example, for a special permit dated March 4, 2018, the annual report must be received by PHMSA no later than March 31st each year beginning in 2019.

[38] Upon notice to Hilcorp, PHMSA may update the reporting contacts for **Condition 35 - Reporting**.

b) Results of any ILI or direct assessments performed during the previous year in the ***special permit segment***;

c) Any reportable incident or leak reported on the DOT Annual Report in the ***special permit segment***;

d) All repairs that occurred during the previous year in the ***special permit segment;***

e) Any ongoing damage prevention, corrosion, and longitudinal strain preventative initiatives affecting the ***special permit segment***, as well as an evaluation of the performance of the initiatives;

f) Summary of all irregular annulus pressure changes, temperature changes, or dew point changes that required regional notification;

g) Any instance where the ***special permit segment*** exceeds any of the operating parameters in **Tables 1 and 2 and Table 4 - Strain Levels 2 or 3**;

h) Any mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the pipeline operating company; and

i) An overview of the Liberty Pipeline design and construction activities and schedules prior to the pipeline being placed into operational service. This summary is not required after the ***special permit segment*** is placed into operational service.

36) **<u>Documentation</u>**: Hilcorp must maintain the following records for the Liberty Pipeline ***special permit segment***. Hilcorp must maintain all documentation for the life of the special permit and provide such documentation to PHMSA upon request:

a) Documentation showing that Hilcorp complied with 49 CFR 195.304, 195.305, and 195.306, Subpart E, except the hydrostatic test must be for eight (8) continuous hours and at a minimum pressure of 1.25 times MOP. Hilcorp must retain all pressure test records in accordance with 49 CFR 195.310.

   i) If Hilcorp does not have hydrostatic test documentation, then the ***special permit segment*** must be hydrostatically tested to meet this requirement within one (1) year of receipt of this special permit and documentation must be maintained.

b) Documentation of mechanical and chemical properties (mill test reports) showing that all pipe in the ***special permit segment*** meets the wall thickness, yield strength, tensile strength and chemical composition of American Petroleum Institute Standard 5L, "Specification for

Line Pipe" (API 5L).[39] Pipe in the ***special permit segment*** that does not have mill test reports cannot be authorized per this special permit.

c) Documentation of compliance with all conditions of this special permit.

37) **<u>Certification</u>**: Prior to placing the pipeline in service, a senior executive officer, vice president or higher, of Hilcorp must certify the following in writing:

a) The Liberty Pipeline meets the conditions described in this special permit or has procedures meeting these conditions for O&M activities that are completed after placing the Liberty Pipeline into operational service;

b) The written manual of O&M procedures for the Liberty Pipeline has been updated to include all additional operating and maintenance requirements of this special permit;

c) A compliance documentation summary showing Hilcorp implemented all conditions as required by this special permit; and

d) Hilcorp has reviewed the project compliance documentation summary of all special permit conditions with the PHMSA OPS Associate Administrator and designees within 30 days of placing the Liberty Pipeline into service.

e) Hilcorp must send the signed and dated written certifications with corresponding completion dates to the Associate Administrator for Pipeline Safety, with copies to the Deputy Associate Administrator for Field Operations; Director, OPS Western Region; Director, OPS Standards and Rulemaking Division; and Director, OPS Engineering and Research Division, as well as to the Federal Register Docket (PHMSA-2017-0091) at <u>https://www.regulations.gov/</u>. All certifications must be completed prior to placing the Liberty Pipeline into crude oil service.

III. 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 Hilcorp has complied with the specified conditions of this special permit.

[39] Hilcorp must use the API 5L edition incorporated by reference in 49 CFR 195.3.

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

3) Failure by Hilcorp to submit the certifications required by **Condition 37 (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. 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 Hilcorp sells, merges, transfers, or otherwise disposes of all or part of the assets known as the Liberty Pipeline, Hilcorp 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.

6) PHMSA grants this special permit to limit it to a term of no more than ten (10) years from the date of issuance. If Hilcorp elects to seek renewal of this special permit, Hilcorp must submit its renewal request at least 180 days prior to expiration of the ten (10) year period 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. All requests for a renewal must include a summary report in accordance with the requirements in **Condition 35 (Annual Report)** above and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from Hilcorp prior to granting any request for special permit renewal.

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

Issued in Washington, DC on APR 2 9 2019.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

Figure 1 – Pipeline Bundle Cross Section

- Sales quality crude oil will be exported from the island through a subsea nominal pipe size (NPS) 12 x 16 PIP system that is bundled to a nominal 4-inch coiled utility line, along with an armored fiber optic cable.

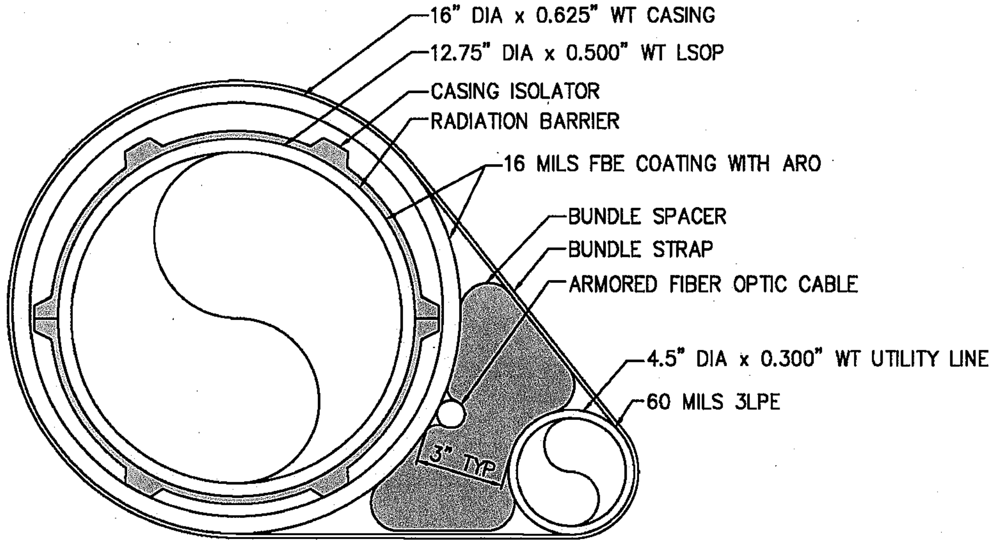


Figure 2 - Bulkhead Schematic for 12.75-inch Diameter Carrier and 16-inch Diameter Casing Tie-in

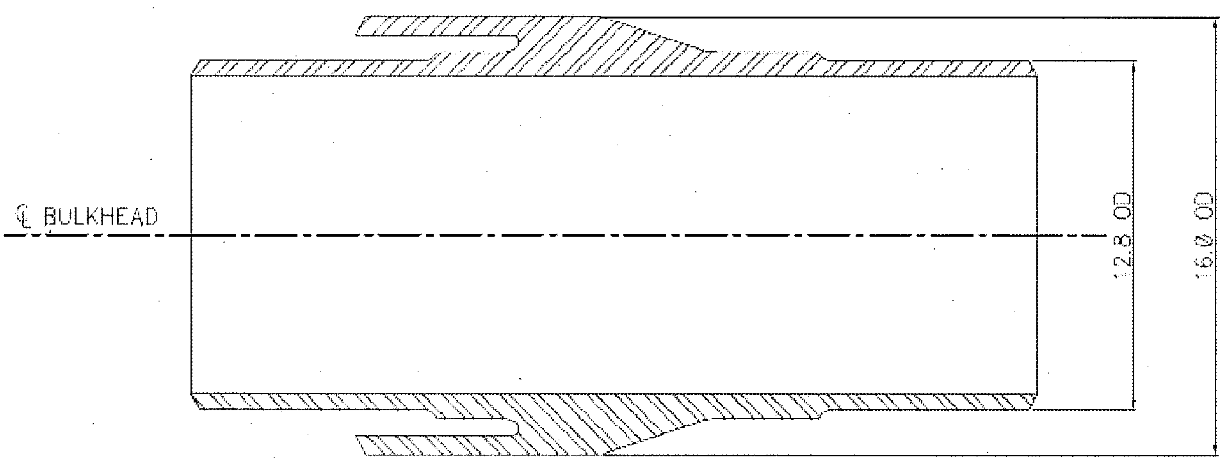


Figure 3 – Offshore Subsea Buried Pipeline Segment

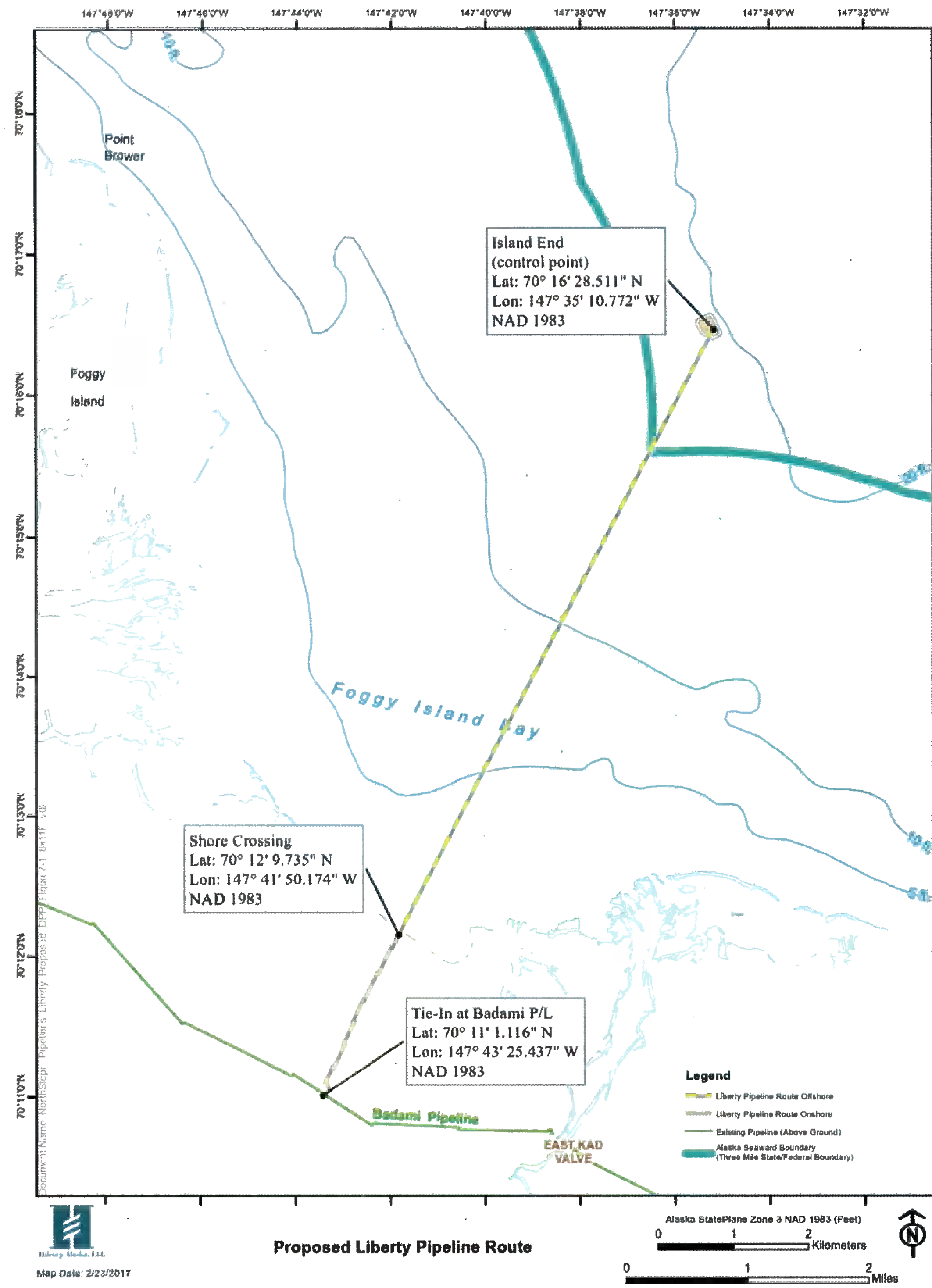
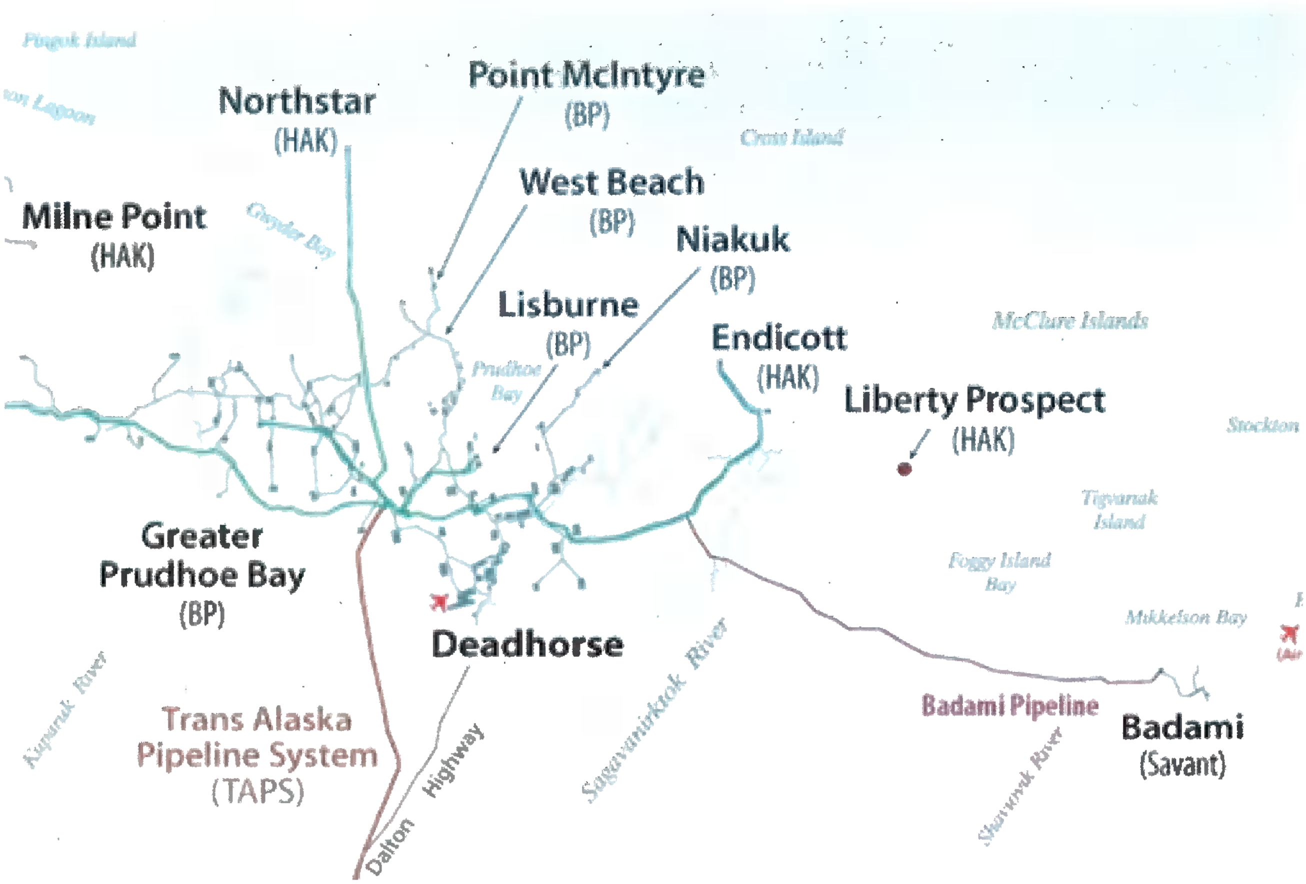


Figure 4 – Liberty Pipeline Location (Liberty Prospect)



Appendix A – Engineering Critical Assessment for Cracks

1) **Engineering Critical Assessment for Cracks**

   An engineering critical assessment (ECA) is conducted for any crack found that is over 10% wall depth on the 12.75-inch diameter Liberty Pipeline ***special permit segment***.

   Hilcorp must perform such ECAs in accordance with this **Appendix A** and **Condition 26**. The ECA must be performed to determine the predicted failure pressure of the as-discovered condition and the remaining life for the pipeline at the defect location. The ECA must use applicable fracture mechanics modeling techniques, pressure cycle analysis, crack growth fatigue models, and failure mode analysis (brittle, ductile, or both) for the microstructure (i.e., heat-affected zone, bond line, parent pipe, etc.).

2) **Predicted Failure Pressure Calculation**

   The predicted failure pressure must be calculated using technically proven fracture mechanics evaluation methods (see **Section 7 of Appendix A**) that are known to be technically appropriate for whether the crack defect is in ductile, brittle, or both material types.

3) **Crack Growth Analysis**

   The crack growth analysis must determine the remaining life of the largest remaining critical crack flaw, based on the operating parameters of the pipeline; any pipe failure or leak mechanisms identified during any pressure testing or other operations; pipe characteristics; material mechanical properties (including toughness); failure mechanism for the microstructure (ductile and brittle or both); location and type of defect; operating environment; operation conditions, including pipe operating temperatures; and pressure cycling induced fatigue. The analysis must use technically proven methods and procedures for analyzing crack growth (both length and depth), crack interactions, and crack coalescence within the cluster of cracks in the identified defect.

4) **Fatigue Analysis**

   Fatigue analysis must be performed using a recognized form of the Paris Law or other technically appropriate engineering methodology to give conservative predictions of flaw growth and remaining life. "Other technically appropriate engineering methodology" procedures must be submitted by Hilcorp to the PHMSA Western Region Director or Project Designee for a "no objection" letter prior to Hilcorp's implementation of the procedures. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

5) Crack Degradation & Analysis

When assessing other degradation processes (other than pressure cycling), an operator must perform the analysis using recognized rate equations where the applicability and validity are demonstrated for the case being evaluated. The analysis must include conservative estimates of time to failure for any known or potential remaining cracks in the pipe.

The analysis to determine the time to failure for a crack must include operating history, pressure cycles, pressure tests, pipe geometry, wall thickness, strength level, flow stress, Charpy V-Notch energy values for the operating temperature, other applicable operating conditions, and the operating environment for the pipe segment being assessed, including the role of the pressure-cycle spectrum and any significant changes in the actual versus predicted pressure-cycle spectrum.

6) Crack Analysis Data

Data used in the calculations must use all of the following, as appropriate:

a) Mechanical Properties

Mechanical properties of the pipe must be used in the analysis. The analysis must account for metallurgical properties at the location being analyzed. If properties of the pipe are unknown, Hilcorp must submit to PHMSA procedures of how pipe mechanical properties will be determined and Hilcorp must receive a "no objection" letter from PHMSA's Western Region Director prior to implementation of the procedures. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

Material strength and toughness values used in the analysis must reflect the local conditions at the defect location or segment being analyzed (such as in the properties of the parent pipe, weld heat-affected zone, or weld metal bond line) and use data that is applicable to the specific line pipe vintage and segment. When the strength and toughness and limits or ranges are unknown, the analysis must assume material strength and fracture toughness levels corresponding to the pipe vintage and type.

For pipe body or weld crack assessments, use the actual ranges of values of strength and toughness that are known from tests of similar material; conduct destructive material tests of the pipe; determine material properties based upon other appropriate nondestructive examination technology; or use conservative values based on technical research publications that an operator demonstrates provides conservative Charpy V-Notch energy values of the crack-related conditions and conservative strength values of the line pipe appropriate for the seam type.

Testing programs to determine pipe and seam material properties must conduct enough material testing to establish statistically valid mean and standard deviations from their results, and material property values used in ECAs, with a minimum of at least five (5) tests for each type of pipe.

b) Crack Dimensions

Crack length and depth dimensions must be obtained from *in situ* direct measurements on the pipe, from crack detection ILI tools for cracking, or from the largest calculated remaining crack from a hydrostatic pressure test.

ILI Tool Crack Detection

For cases that analyze remaining flaw sizes measured using crack detection ILI tool data, the analysis must use flaw dimensions and characteristics that conservatively account for ILI tool inaccuracies and measurement tolerances, and the operator must confirm inaccuracies and measurement tolerances through direct *in situ* non-destructive examination using technology that has been validated to detect and measure tight cracks. In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance, tool accuracy, tool tolerance, and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated.

Largest Calculated Crack from Hydrostatic Pressure Test

For cases where Hilcorp evaluates remaining life for pipe segments that have successfully passed a hydrostatic test, Hilcorp must conservatively determine the largest flaw size(s), i.e., crack length and depth, that could have survived the hydrostatic pressure test.

7) **Failure Mode Analysis**

The ECA must account for the likely failure mode of anomalies (such as brittle fracture, ductile fracture, or both). If the likely failure mode is uncertain or unknown, the analysis must analyze both failure modes and use the more conservative result.

a) **Fracture Mechanics Modeling**

Fracture mechanics modeling that is technically appropriate for the anomaly type must be used to determine failure stress pressures.

b) **Brittle Failure Mode Analysis**

Brittle failure mode analysis must use linear-elastic failure models such as the Raju/Newman stress-intensity solutions or other technically proven approaches.

c) **Ductile Failure Mode Analysis**

Ductile failure mode analysis must use technically appropriate failure models such as the Modified LnSec, CorLas, Pipe Axial Flaw Failure Criteria, API 579 Level-II, PipeAssess PI™, or other technically proven approaches.

d) **Other Failure Mode Analysis**

Other technically proven-equivalent engineering fracture mechanics models may be used, which can be shown to accurately predict the response for the feature of concern or the worst-case scenario, for determining conservative failure pressures for the specific failure mode.

8) **ECA Reassessment Intervals**

When establishing reassessment intervals for pipelines with known or suspected remaining cracks or crack-like defects, the maximum reassessment interval may not exceed one-half of the remaining life determined by an ECA. However, PHMSA will consider as "other technology," the use of a reassessment interval that is greater than one-half of the remaining life determined by the ECA, or if impractical due to tool availability, if technically documented and justified.

If changes to operating conditions exceed the assumptions included in the remaining life analysis, then the remaining life must be reanalyzed and recalculated within six (6) months of the change.

9) **ECA Documentation Requirements**

The following documentation must be retained from the ECA:

a) The technical approach used for the analysis, including procedures, evaluation methodology, and models used;

b) All data used and analyzed;

c) Pipe and weld properties including Charpy Impact values;

d) Direct in situ examination data, including in-the-ditch assessments;

e) ILI tool run information evaluated, including any multiple ILI tool runs;

f) Pressure test data and results, if applicable;

g) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

h) All finite element analysis results, where applicable;

i) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method, such that fatigue life models and fracture mechanics evaluation methods are documented;

j) Safety factors used for fatigue life and/or predicted failure pressure calculations;

k) Reassessment time interval and safety factors;

l) The date of the review;

m) Documentation confirming the results; and

n) Approval by responsible operator management personnel.

10) ECA Assessment Technology

Other technology for ECAs may be used if the operator demonstrates that the assessment provides an equivalent understanding of the condition of the line pipe. Such "other technology" methodologies may include different or improved crack assessment methodologies, fracture mechanics evaluation methods, crack growth evaluation methods, fatigue models, and remaining life models, as well as differing or less-conservative assumptions for pipe and seam properties, or any other aspect of the operator's ECA methodology that does not comply with the requirements of this section.

If the "other technology" option is selected, the PHMSA OPS Western Region Director or Project Designee must be notified by Hilcorp ninety (90) days before implementing the ECA and Hilcorp must receive a "no objection" letter from PHMSA prior to implementing the "other technology". If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

11) ECA Procedure Review by PHMSA

Hilcorp must submit the ECA procedure to PHMSA Western Region Director or Project Designee and Hilcorp must receive a "no objection" letter from PHMSA prior to implementing Appendix A. If Hilcorp does not receive a "no objection" letter from PHMSA within 90 days of the notification, Hilcorp may proceed. PHMSA will notify Hilcorp if additional review time is needed.

<u>THE END OF SPECIAL PERMIT</u>