CIPL Cross Inlet Extension Project

Tyonek W 10 Pipeline

Basis of Design

Public Document

Hilcorp Alaska, LLC

HARVEST PIPELINE

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1.0 Abbreviations

AAC	Alaska Administrative Code
API	American Petroleum Institute
ARO	Abrasion Resistant Overlay
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
BPL	Beluga Pipeline
CFR	Code of Federal Regulations
CIGGS	Cook Inlet Gas Gathering System
CIPL	Cross Inlet Pipeline
CP	Cathodic Protection
F	Fahrenheit
FBE	Fusion Bond Epoxy
lbs	pounds
MAOP	Maximum Allowable Operating Pressure
mil	one thousandth of an inch
mmscfd	Million Standard Cubic Feet Per Day
NACE	National Associated of Corrosion Engineers
psi	pounds per square inch
psia	pounds per square inch atmospheric
psig	pounds per square inch gauge
SCADA	Supervisory Control and Data Acquisition
SDV	Shutdown Valve
USGS	United States Geological Survey

2.0 Project Overview

The Tyonek W 10 pipeline is a new 10” nominal steel pipeline for natural gas service between the Tyonek Platform and the existing Beluga Pipeline (BPL 16), located at BPL Junction. This work is part of an overall project, called the CIPL Cross Inlet Extension Project, that modifies the oil and gas pipeline systems in Cook Inlet in order to eliminate the need for Drift River Terminal and overwater transportation of crude oil.

2.1 System Design

The Tyonek W 10 pipeline will provide a redundant path for gas flow across Cook Inlet. Currently gas flows across Cook Inlet through the 10” dual marine CIGGS pipelines. These pipelines are located adjacent to each other, located between Kaloa Junction on the west side and East Forelands on the east side. One of these pipelines will be converted to crude oil service as part of the overall CIPL Extension project. The new Tyonek W 10 pipeline provides a new parallel path in the cross-inlet gas system with equal capacity to the existing, which is about 120 mmscfd total between the remaining CIGGS and new Tyonek W 10 routes. It also spatially separates the two gas pipelines to provide better redundancy.

The Tyonek W 10 pipeline is designed for bidirectional flow. It connects to the BPL 16 through a new hot tap. Surface facilities at the BPL connection point include a pig trap, shutdown valve, meter, blowdown valve, and pressure relief valve. From the BPL Junction surface facilities, the pipeline is routed below grade to the south east to Ladd Landing at the edge of Cook Inlet. The pipeline is buried through the transition (tidal) zone, then routed south easterly on the seafloor to the Tyonek Platform. At the Tyonek Platform, the pipeline is connected to the existing Tyonek N 10 and Tyonek S 10 pipelines that originate at Moose Point on the west side of Cook Inlet and the existing 10” riser that exits the southwest leg of the Tyonek Platform. The connections are through two new piggable wyes that are located on the south side of the Tyonek Platform. Connections will be through new flanged collet fittings installed on the existing riser and Tyonek N 10 and Tyonek S 10 pipelines and flanged tie-in spool. Subsea valves are provided to allow any of the pipeline sections or the riser to be isolated, providing maximum capability to maintain flow in the east-west gas transmission system.

2.2 Pipeline Length

The on-shore section of pipeline from BPL Junction to Ladd Landing is 7,180 feet (1.4 miles). The off-shore section of the pipeline from Ladd Landing to Tyonek Platform is 29,000 feet (5.5 miles).

2.3 Subsea Pipeline Construction

The subsea portion of the Tyonek W 10 Pipeline will be fabricated on-shore at Ladd Landing, then pulled from shore to the Tyonek Platform using a pull barge. The pipeline will be fabricated in approximately 1/2-mile long segments on-shore. The lead segment will have a flanged end and will be connected to a pulling sled that will plow the pipeline partially into the seafloor as it is pulled. The plan is to utilize two pulls, each approximately 14,500 feet long. The fabricated 1/2-mile long segments will be welded, inspected, hydrotested, and coated on-shore. The first segment will be pulled out into Cook Inlet, then the next segment welded to the end on-shore, with the weld inspected and coated before pulling is continued. The pipe will be controlled while onshore during the welding and pulling process to limit the stresses to within elastic range. The bluff will be being cut down and the pipeline supported to have a gentle transition from the bluff area to the beach.

The plan is for one subsea joint in the pipeline near the mid-point using flanged ends and a flanged tie-in spool. If required, the pipeline will be further segmented to meet pull load limitations (either equipment or axial load on the pipeline).

2.4 Pressure Test

After installation and connection of the pipeline to the subsea wyes, the overall Tyonek W 10 (from BPL Junction to the Tyonek Platform) will be hydrotested per ASME B31.8 to at least 1,850 psig (1.25 x design pressure) to confirm mechanical integrity.

3.0 Jurisdiction and Criteria

The pipeline is used for transportation of natural gas, so falls under the State of Alaska Department of Natural Resources State Pipeline Coordinator's Section.

The State of Alaska Administrative Code, 3AAC52.080, references 49 CFR Part 192 – Transportation of Natural and Other Gases by Pipeline, revised as of January 1, 1972. The CFR has been updated since 1972, and this design uses the October 1, 2011 Edition.

In addition to pressure loads covered in the CFR, this pipeline is subject to external loads from current and spans. Part 192 references ASME B31.8 – Gas Transmission and Distribution Piping Systems, November 2007, for design of pipelines subject to external loads. B31.8 has been updated since 2007, and this design uses the 2014 Edition.

4.0 Pipe Properties

4.1 Offshore and Transition Segment

The offshore pipeline segment between the top of the bluff at Ladd Landing and the Tyonek Platform is shop coated with 14 mil fusion bond epoxy (FBE) and 40 mil abrasion resistant overlay (ARO). Pipeline joints are double random.

Grade	API 5L-X42 PSL 2 seamless
Outside Diameter, Do	10.75”
Wall thickness, t	0.719”

Table 1: Offshore and Transition Pipeline Properties

4.2 Onshore Segment

The onshore pipeline segment between KPL Junction and the top of the bluff at Ladd Landing is shop coated with 14 mil fusion bond epoxy (FBE) and 14 mil abrasion resistant overlay (ARO). Pipeline joints are double random.

Grade	API 5L-X42 PSL 2 seamless
Outside Diameter, Do	10.75”
Wall thickness, t	0.365”

Table 2: Onshore Pipeline Properties

5.0 Pipeline Design

5.1 Structural Pipeline Design

The Tyonek W 10 Pipeline is designed to remain within allowable stresses stated in 49 CFR 192 and ASME B31.8 through the range of construction and operating loads that are expected and prescribed by the codes. See section 0 for the loading scenarios for the design of the pipeline.

5.2 Geotechnical

Sea floor and subsea floor conditions were surveyed along the length of the pipeline corridor over a width of 2,000ft. Seafloor conditions vary from a silty surface near the tidal transition zone, to sand and gravel/pebbles, and exposed areas of bedrock. Subsea floor conditions indicate areas of exposed bedrock, and confirm locations of loose boulders vs. pinnacles projecting from bedrock. General seafloor conditions consist of a hard seafloor surface, as verified by grab bucket sampling. In addition, the survey included locating all boulders in the 2,000ft survey corridor in order to optimize pipeline routing.

5.3 Scour and Erosion Mitigation Measures

Scour and erosion from currents within the Cook Inlet can affect the subsea section of the pipeline by seafloor material being displaced across the pipeline surfaces and by movement of seafloor material resulting in loss of support under the pipeline. The movement of material can also be beneficial if it results in partial or complete burial of the pipeline as it provides additional stabilization.

The pipeline design includes measures for mitigating erosion of the pipeline from materials passing across the surface of the pipe using ARO coating. The coating is resistant to abrasion and is applied over the entire length of the pipeline, including the field welded joints.

The pipeline monitoring and maintenance program provides the mitigation for loss of material under the pipeline. Annual pipeline surveys are conducted to determine the pipeline position and support conditions, and if necessary support is reestablished through pinning if spans develop that exceed the maximum allowed.

5.4 Trenching design and Ice Hazard Mitigation

To avoid the hazard of ice hitting the pipeline, the pipeline is trenched below grade in the transition zone from onshore to offshore. The pipeline is trenched a minimum of 6ft below the sea floor in the transition zone. At Mean Lower Low Water (MLLW) the pipeline exists the transition zone in 8ft to 12ft of water, on its way to the Tyonek Platform. Therefore, the pipeline is never exposed to ice hazards.

5.5 Pinning of Subsea Pipeline

The subsea pipeline will be pinned with sandbags to stabilize the pipeline on the sea bottom. A pin is essentially a pile of sandbags that are placed under (if needed), alongside and over the pipe to create a stabilization point. This method is used on all of the pipelines in Cook Inlet. Pins are maintained through annual pipeline surveys. The pins will be nominally placed 150ft apart when the pipeline is fully touching the sea floor (in its grounded position). For free spanning sections of the subsea pipeline, the pinning will be set to limit free spans to 75ft or less. Section 7.1.2 shows the results for the pinning length calculations.

5.6 SCADA, Communications and Control System

The Tyonek W 10 pipeline will be monitored and controlled through Hilcorp's existing SCADA system. The primary control and operations center for the pipeline is located at the Kenai Gas Field facility. The backup control room is located at KPL Junction.

The SCADA system will enable pipeline operators to efficiently and effectively supervise pipeline operations in real time. Data acquisition and storage will be provided, along with provision for report generation using historical data. Data retention and management will comply with applicable federal and state regulatory requirements. Additionally, some control functions will be provided through the system to allow for manual operational control and testing when necessary.

The SCADA system scan rate will be fast enough to minimize overpressure conditions, provide very responsive abnormal operation indications to controllers and detect small leaks within technology limitations.

The SCADA system will incorporate a real-time database and historian. The information on these databases will be used to generate operations reports and trends.

The SCADA system will send necessary information to a business database/historian. The information on this historian will be used to file reports to outside entities such as government regulators and provide information for business analysis.

The SCADA system will collect measurements and data along the pipeline, including flow rate through the pipeline, operational status, pressure, and temperature readings. This information may all be used to assess the status of the pipeline. The SCADA system will provide pipeline personnel with real-time information about equipment malfunctions, leaks, or any other unusual activity along the pipeline.

In addition to the manned facilities at the Tyonek Platform, other locations are unmanned and controlled remotely by the pipeline operator in the main control room.

5.7 Operating Philosophy and Valve Configuration

5.7.1 BPL 16 Pipeline

The BPL 16 pipeline is existing and will continue to operate with the existing control scheme.

5.7.2 BPL Junction

The Tyonek W 10 pipeline will be tied into the BPL 16 at BPL Junction. At BPL Junction a bi-directional ultrasonic flow meter will measure Tyonek W 10 gas flows in either flow direction. This meter communicates with the BPL Junction flow computer, and the SCADA system has the capability to interrogate both the meter and the flow computer via Modbus/TCP.

An automated shutdown valve (SDV) at BPL Junction will stop gas flow through the Tyonek W 10 in the event of an emergency shutdown or process shutdown.

5.7.3 Tyonek Platform

At the Tyonek Platform, the Tyonek W 10 pipeline connects to the Tyonek 10 riser and connects to the existing Tyonek S 10 and Tyonek N 10 pipelines, through a subsea valve and wye skid. The Tyonek platform compressor discharge will be pressure controlled by a new pressure control valve. The discharge of this pressure control loop ties into the Tyonek 10 Riser, to transport gas to the Tyonek W 10, Tyonek S 10 and Tyonek N 10 pipelines.

An automated SDV in the piping on the Tyonek Platform will stop gas flow through the Tyonek 10 Riser, which connects to the Tyonek W 10 at the subsea wye, in the event of an emergency shutdown or process shutdown.

There are two hydraulically controlled valves on the subsea wye for the Tyonek N 10 and Tyonek S 10 pipelines. These valves can be manually closed through a hydraulic power unit on the platform if the Tyonek N 10 or Tyonek S 10 pipelines need to be isolated in an emergency. There are also manual operated subsea valves on each pipeline to allow any of the pipeline sections or the riser to be isolated, providing maximum capability to maintain flow in the east-west gas transmission system.

5.7.4 Moose Point

At Moose Point, gas flows from the Tyonek S 10 and Tyonek N 10 pipelines through pig traps and connects to the Tyonek E 16 pipeline, which transports gas to KPL Junction. Isolation valves on each pipeline are remotely controlled and monitored via SCADA.

At Moose Point, the Tyonek S 10 and Tyonek N 10 each have automated SDVs that will stop gas flow through the pipelines, which connect to the Tyonek W 10 at the subsea wye, in the event of an emergency shutdown or process shutdown.

5.7.5 KPL Junction

KPL Junction has multiple flow paths that can be operationally selected during different flow configurations. Depending on the flow configuration, either a flow valve or a pressure control valve will control the flow of the natural gas through the Tyonek E10 and E16 pipeline.

During flow configuration from the Tyonek Platform to KPL Junction, the flow valve will operate to the full open position to flow gas. The flow valve is operable locally or remotely, and is manually sequenced per the operating procedure. The pressure control valve will be put into manual mode by the operator and closed.

During flow configured from KPL Junction to BPL Junction, the flow valve will be operator sequenced to the full closed position. The pressure control valve will be put in pressure mode, and the pressure control loop will actuate the valve.

An additional optional bypass into the suction of the KPL compressors with manual block valves allows for an alternate flow path that will be manually sequenced by operators locally.

5.8 Leak Detection Systems

Leak detection is monitored on the Tyonek W 10 Pipeline using the following techniques:

5.8.1 Volume Account Balancing

This is accomplished by monitoring and trending meter volumes in the pipeline. Any volume discrepancies are identified and analyzed to see if there is a potential leak.

5.8.2 Pressure Monitoring

The pipeline system pressure is continuously monitored at key locations by the Harvest Kenai DOT Control Room. Any unanticipated pressure fluctuations are identified, investigated, and analyzed for potential overpressure or pressure loss scenarios.

5.8.3 Pipeline Patrols

Per 49 CFR 192.705, Gas Transmission pipelines located in a Class 1 or 2 location are patrolled annually, Class 3 locations are patrolled twice per year, and Class 4 locations are patrolled three times per year. The patrols include looking for unidentified 3rd party activities, ROW disturbance, pipeline leaks, vegetation decay that may be indicative of leaks, and any other abnormal operating conditions. The Tyonek W 10 is in a Class 1 location.

5.8.4 Pipeline Leak Surveys

Per 49 CFR 192.707, Gas Transmission pipelines located in a Class 1 or 2 location have leakage surveys performed annually, Class 3 locations are surveyed twice per year, and Class 4 locations are surveyed three times per year. The leak survey utilizes a portable methane detector to look for leaks along the pipelines and facilities.

5.9 Corrosion Control and Monitoring

The Tyonek W 10 pipeline is designed with a corrosion control system, provided by protective coatings and cathodic protection (CP). Applicable codes, regulations, and criteria were used for this design. The industry's primary technical organization responsible for the development of recommended corrosion control standard practices is the National Association of Corrosion Engineers International (NACE).

The pipeline coatings used are FBE and ARO, as discussed in section 4.0. At soil-to-air interfaces composite wraps are used as well.

At BPL Junction, the Tyonek W 10 pipeline is electrically isolated from the BPL 16 pipeline. Test stations are installed along the onshore pipeline for annual CP monitoring. Where the pipeline reaches shore, at Ladd Landing, a 600ft deep anode groundbed and rectifier are installed to provide active CP to the onshore and offshore portions of the pipeline.

At the Tyonek Platform, the existing CP system at the platform has the capacity to protect the offshore portion of the Tyonek W 10 pipeline. The CP system includes rectifiers on the platform and subsea anode sleds.

The complete offshore section of the Tyonek W 10 pipeline is protected by both the Ladd Landing deep anode groundbed and the existing Tyonek Platform CP system.

A Remote Monitoring Unit is installed at the Ladd Landing rectifier for monitoring of the CP rectifier power supply. CP rectifiers data is remotely monitored on a weekly basis.

6.0 Pipeline Loading Scenarios

Loads on the pipeline include both pressure loading cases and other loading cases. Loads are combined as prescribed by code and sound engineering practice. The pipeline stress checks include hoop stress from internal pressure; longitudinal stress from current, seismic, pulling, and gravity; and combined hoop, torsion, and longitudinal stresses for both grounded (fully supported) and span conditions. Span and support spacing are limited to maintain the stresses to code prescribed allowable.

6.1 Pressure Load Scenarios

The pipeline is designed for various pressure loading summarized as follows:

- Normal Operating Pressure: 800 psig (based on historical operating data for CIGGS / BPL pipeline systems)
- Maximum Allowable Operating Pressure: 1,035 psig (based on PSV set points at BPL, Moose Point, and Tyonek Platform)
- Design Internal Pressure: 1,480 psig (based on flange rating)
- Hydrostatic Test Pressure: 1,850 psig minimum (1.25 * Design Internal Pressure)

6.2 Offshore Pipeline Segment – Other Loading Scenarios

The offshore pipeline is also designed for non-pressure loading conditions, including:

6.2.1 Longitudinal Load from Pulling (Installation Load):

This load occurs during pulling and is a result of friction between the pipe and seafloor and pull back tension on the pipeline. A longitudinal friction coefficient of 0.4 is used for the design.

6.2.2 Residual Longitudinal Load from Pulling (Hydrotest Load and Operational Load):

This load occurs at approximately midsection of each segment that is pulled. The load is approximately 50% of the maximum pulling load, and occur at the segment midpoint, as the ends of the segment will be free and allow partial relaxation limited by the friction between the pipe and seafloor.

6.2.3 External Pressure:

14 psia to 70 psia (surface to 130 feet maximum water depth). External pressure loading is considered inconsequential, as the operating pressure of the pipeline is about 800 psig. External pressure is ignored in the hoop stress calculations.

6.2.4 Thermal Loads (Operational Load):

These loads result in a change in temperature in the pipeline walls. This pipeline will be located in a temperature stable environment as it is exposed on the seafloor and Cook Inlet water temperature is relatively stable. Additionally, the gas in the pipeline is ground temperature as there is no heat added from process that effects the temperature of this pipeline. The installation method will result in the pipeline temperature equalizing with the water temperature before operating pressure is introduced. The pipeline that is exposed on the seafloor is treated as unrestrained, as the sandbag pins do not provide restraint against rotation. The buried portion of the pipeline in the transition zone is considered to be restrained.

6.2.5 Current Loads (Hydrotest Load and Operational Load):

The pipeline will be located on or near the surface of the seafloor from the Tyonek Platform to the transition zone near shore at Ladd Landing, then buried through the transition zone. The subsea section will be subject to side loading form water current from tide, wave and wind events. Studies in Cook Inlet have been previously accomplished that establish the range of current velocities used for design of the exposed pipeline. The current velocity used for design loading is 7 ft/sec, similar to the existing CIGGS pipelines, under which is a maximum 1 year combined current event, and correlates to a surface velocity of about 18 ft/sec.

A check of the pipeline stress for a 9 ft/sec current velocity representing a 100-year combined current event coinciding with operating internal pressure is also included.

A study of near bottom current velocity was accomplished in November 2017 to gather information on expected direction and magnitude. The study indicates the maximum expected tidal current along the length of the pipeline is 5.2 ft/sec for the on-bottom sections and 6.3 ft/sec for the spanned sections, crossing the pipeline nearly perpendicular. This correlates to the velocities predicted in the CIGGS design, and validates the use of the design velocities.

6.2.6 Seismic Loads (Operational Load):

The pipeline is located in Cook Inlet, an area of high seismicity. The pipeline route does not cross any USGS mapped faults. The pipeline does cross the Beluga River fold about ½ mile from the shore where the pipe will be exposed on the seafloor. An equivalent lateral load of 0.315g and vertical load of 0.14g is applied to the exposed subsea pipeline. These loads were developed using the USGS mapped accelerations for the pipeline route and equivalent lateral force procedures of ASCE 7-10.

6.2.7 Accidental Loads (Operational Load):

The pipeline route does not traverse the main transportation routes in Cook Inlet, so significant anchor loads are not expected. There is a potential for personal watercraft anchors or set net tender vessel anchors to impact the pipeline. These loads are considered insignificant and are not included in the stress analysis.

6.2.8 Dynamic Induced Soil Loads (Operational Load):

The steepest slopes in the pipeline corridor are about 7%, so slope failure is not anticipated. An evaluation of pipeline deformation assuming offset between support points was completed.

6.2.9 Ice Loads (Operational Load):

The pipeline is buried through the transition zone, so ice loading is not applied to the pipeline for design.

6.3 On-shore Pipeline Segment – Other Loading Scenarios

The on-shore pipeline is also designed for non-pressure loading conditions, including:

6.3.1 Installation Load:

Pipeline will be installed by conventional trenching / cover methods. No unusual installation loads are anticipated. Changes in direction use manufactured induction bends and 5D radius fittings.

6.3.2 External Pressure Load (Operational Load):

14 psia to 22 psia (surface to 10 feet maximum soil cover). External pressure loading is considered inconsequential, as the operating pressure of the pipeline is about 800 psig. External pressure is ignored in the hoop stress calculations.

6.3.3 Thermal Loads (Operational Load):

Thermal loads result in a change in temperature in the pipeline walls. This pipeline is buried and considered to be restrained. The stresses are evaluated for winter installation (0F) and summer installation (70F) to cover the range of time allowed for construction. The gas in the pipeline is ground temperature as there is no heat added from process that effects the temperature of this pipeline.

6.3.4 Seismic Loads (Operational Load):

The pipeline is buried, and the route does not cross any USGS mapped faults or folds. No specific seismic loads are applied to the pipeline for design. The surface facilities at BPL Junction are designed for an equivalent lateral load of 0.315g and vertical load of 0.14g. These loads were developed using the USGS mapped accelerations for the pipeline route and equivalent lateral force procedures of ASCE 7-10.

7.0 Design Results

The pipeline meets the 49 CFR 192 requirements for hoop stress, summarized in Table 4.

Location	Pmax per CFR	P_{MAOP}	P_{Design}	P_{Hydro}
Offshore / transition	4,054 psig	1,035 psig	1,480 psig	1,850 psig
Onshore, Non-Traffic	2,058 psig	1,035 psig	1,480 psig	1,850 psig
Onshore, Traffic	1,715 psig	1,035 psig	1,480 psig	1,850 psig

Table 4: 49 CFR 192 Design Results

7.1 Offshore Segment:

The offshore pipeline segment is designed using B31.8, Chapter VIII. B31.8 takes into account hoop stress, longitudinal stress, and torsion. In all evaluations, the limiting condition is longitudinal stress resulting from combined loading.

7.1.1 Construction Stress Evaluation:

The offshore pipeline is evaluated for combined stress conditions during installation due to axial pulling load and bending load from current and gravity at free spans. The pipeline will not be pressurized during pulling, so no hoop stress is present. A pullback of 75,000 lbs is included in the pull load. The maximum span length varies with the location in the pipeline pull string, as the pull load is highest at the front end of the pipeline and lowest at the tail end since it is a function of friction. The maximum free span limits are summarized in Table 5, limited by a maximum longitudinal stress of 33,600 psi.

Location in Pipeline String	Pull Load	Maximum Span	Longitudinal Stress
Front (pull head)	301,000 lbs	134 feet	33,600 psi
¼ point	243,400 lbs	142 feet	33,600 psi
½ point	185,900 lbs	149 feet	33,600 psi
¾ point	130,400 lbs	156 feet	33,600 psi
Tail	75,000 lbs	163 feet	33,600 psi

Table 5: Construction Free Span Limit Summary

Based on the pulling corridor profile, the spans during pulling are expected to be under these limits.

7.1.2 Installed Stress Evaluations:

Load Cases:

The offshore pipeline is evaluated for combined stress conditions after installation is completed due to internal pressure, residual load from the pulling operation and bending loads from current, gravity and seismic. Table 6 summarizes the loading combinations evaluated:

Load Case	Internal Pressure	Residual Pull Load	Current Load Basis	Seismic Load	Displacement Load
Normal Operation 1	800 psig	Maximum	7 ft/sec	Yes	No
Normal Operation 2	800 psig	Maximum	9 ft/sec	No	No
MAOP (PSV set points)	1,035 psig	Maximum	7 ft/sec	No	No
Design (600# ANSI)	1,480 psig	Maximum	7 ft/sec	No	No
Hydrotest (1.25 * Design)	1,850 psig	Maximum	7 ft/sec	No	No

Table 6: Load Case Summary

Free Span Condition:

The offshore pipeline is evaluated for combined stress conditions after installation is completed due to internal pressure, residual load from the pulling operation and bending load from current and gravity at free spans. At free spans, the current sheds around the pipe so no torsion is created. The maximum free span limits are summarized in Table 7, based on a maximum longitudinal stress of 33,600 psi.

Pipeline Pressure Condition	Internal Pressure	Maximum Span	Longitudinal Stress
Normal Operation 1	800 psig	136 feet	33,600 psi
MAOP (PSV set points)	1,035 psig	150 feet	33,600 psi
Design (600# ANSI)	1,480 psig	146 feet	33,600 psi
Hydrotest (1.25 * Design)	1,850 psig	116 feet	33,600 psi

Table 7: Operational Free Span Limit Summary

The evaluation assumes the span is coincidental with the mid-span of the pulled pipeline segment where the residual load from pulling is the maximum. The span would increase as the location moves away from the center of the segment toward either end of the segment, as the residual load from pulling decreases from maximum at the center to zero at the ends.

The maximum free span lengths exceed the design free span length of 75 feet. The design free span is based on the experience with maximum unsupported spans on other pipelines operating in Cook Inlet taking into account fatigue from vortex induced vibration. The pipeline stresses for a 75 feet free span are summarized in Table 8.

Pipeline Pressure Condition	Internal Pressure	Hoop Stress	Longitudinal Stress	Combined Stress (Von Mises)
Normal Operation 1	800 psig	5,581 psi	15,331 psi	13,440 psi
Normal Operation 2	800 psig	5,581 psi	15,714 psi	13,798 psi
MAOP (PSV set points)	1,035 psig	7,220 psi	14,474 psi	12,525 psi
Design (600# ANSI)	1,480 psig	10,324 psi	15,812 psi	13,905 psi
Hydrotest (1.25 * Design)	1,850 psig	12,905 psi	16,925 psi	15,315 psi
ASME Allowable Stresses	-	30,240 psi	33,600 psi	37,800 psi

Table 8: 75 Foot Free Span Stress Summary

The hoop, longitudinal, and combined stresses are all well within allowable stresses for the 75 feet design free span.

Grounded Condition:

The offshore pipeline will be grounded on the seafloor for a majority of the corridor. The grounded pipe will be subject to torsional loading due to current load being resisted by lateral friction on the bottom of the pipe. The pipeline is evaluated for combined stress conditions after installation is completed due to internal pressure, residual load from the pulling operation, bending load from current, and torsion load from current. The maximum grounded span limits are summarized in Table 9, based on a maximum longitudinal stress of 33,600 psi:

Pipeline Pressure Condition	Internal Pressure	Maximum Span	Longitudinal Stress
Normal Operation 1	800 psig	162 feet	33,600 psi
Normal Operation 2	800 psig	148 feet	33,600 psi
MAOP (PSV set points)	1,035 psig	188 feet	33,600 psi
Design (600# ANSI)	1,480 psig	183 feet	33,600 psi
Hydrotest (1.25 * Design)	1,850 psig	179 feet	33,600 psi

Table 9: Grounded Span Limit Summary

The evaluation assumes the span is coincidental with the mid-span of the pulled pipeline segment where the residual load from pulling is the maximum. The span would increase as the location moves away from the center of the segment toward either end of the segment, as the residual load from pulling decreases from maximum at the center to zero at the ends.

The maximum grounded span lengths equal or exceed the design pin spacing of 150 feet. The pin spacing is based on the experience with maximum spacing on other pipelines operating in Cook Inlet to prevent pipeline movement.

Displacement Event:

The pipeline is a long slender structural element that has good ductility and reserve strength to handle seafloor displacement events. It was evaluated for an on-bottom horizontal displacement of the seafloor under normal operating pressure, maximum tidal current and at a location of maximum residual pull stress. The pipeline would be able to experience about a 3.8 feet displacement event and remain within allowable stress.

7.2 Onshore and Transition Segments:

The onshore and transition pipeline segments (buried segments) are designed using B31.8, sections 833 and 841. In all evaluations, the limiting condition is longitudinal stress resulting from combined loading.

7.2.1 Construction Stress Evaluation:

The onshore and transition pipeline segments will be constructed using trenching and backfill techniques. Bends are made using induction bends or forged fittings. No unusual loads are expected.

7.2.2 Installed Stress Evaluation:

The onshore and transition pipeline segments are fully supported and restrained by soil backfill. The onshore pipeline stress is summarized in Table 10 (winter install) and Table 11 (summer install). The transition pipeline stress is summarized in Table 12 (winter install) and Table 13 (summer install).

Pipeline Pressure Condition	Internal Pressure	Hoop Stress	Longitudinal Stress	Combined Stress
MAOP (PSV set points)	1,035 psig	15,241 psi	-2,968 psi	18,209 psi
Design (600# ANSI)	1,480 psig	21,795 psi	-1,002 psi	22,796 psi
ASME Allowable Stresses	Non-Traffic	30,240 psi	37,800 psi	37,800 psi
ASME Allowable Stresses	Roadways	25,200 psi	37,800 psi	37,800 psi

Table 10: Onshore Stress Summary – 0F Install Temp

Pipeline Pressure Condition	Internal Pressure	Hoop Stress	Longitudinal Stress	Combined Stress
MAOP (PSV set points)	1,035 psig	15,241 psi	10,277 psi	15,241 psi
Design (600# ANSI)	1,480 psig	21,795 psi	12,193 psi	21,795 psi
ASME Allowable Stresses	Non-Traffic	30,240 psi	37,800 psi	37,800 psi
ASME Allowable Stresses	Roadways	25,200 psi	37,800 psi	37,800 psi

Table 11: Onshore Stress Summary – 70F Install Temp

Pipeline Pressure Condition	Internal Pressure	Hoop Stress	Longitudinal Stress	Combined Stress
MAOP (PSV set points)	1,035 psig	7,737 psi	-5,219 psi	12,956 psi
Design (600# ANSI)	1,480 psig	11,064 psi	-4,221 psi	15,285 psi
ASME Allowable Stresses	Non-Traffic	30,240 psi	37,800 psi	37,800 psi
ASME Allowable Stresses	Roadways	25,200 psi	37,800 psi	37,800 psi

Table 12: Transition Stress Summary – 0F Install Temp

Pipeline Pressure Condition	Internal Pressure	Hoop Stress	Longitudinal Stress	Combined Stress
MAOP (PSV set points)	1,035 psig	7,737 psi	7,976 psi	7,976 psi
Design (600# ANSI)	1,480 psig	11,064 psi	8,974 psi	11,064 psi
ASME Allowable Stresses	Non-Traffic	30,240 psi	37,800 psi	37,800 psi
ASME Allowable Stresses	Roadways	25,200 psi	37,800 psi	37,800 psi

Table 13: Transition Stress Summary – 70F Install Temp

The hoop, longitudinal, and combined stresses are all well within allowable stresses for the onshore and transition pipeline segments at both non-traffic areas and roadways.

7.3 Design Summary

The Tyonek W 10 Pipeline is designed to remain within allowable stresses stated in 49 CFR 192 and ASME B31.8 through the range of construction and operating loads that are expected and prescribed by the codes. The pipeline meets the requirements of 49 CFR 192 and ASME B31.8.

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