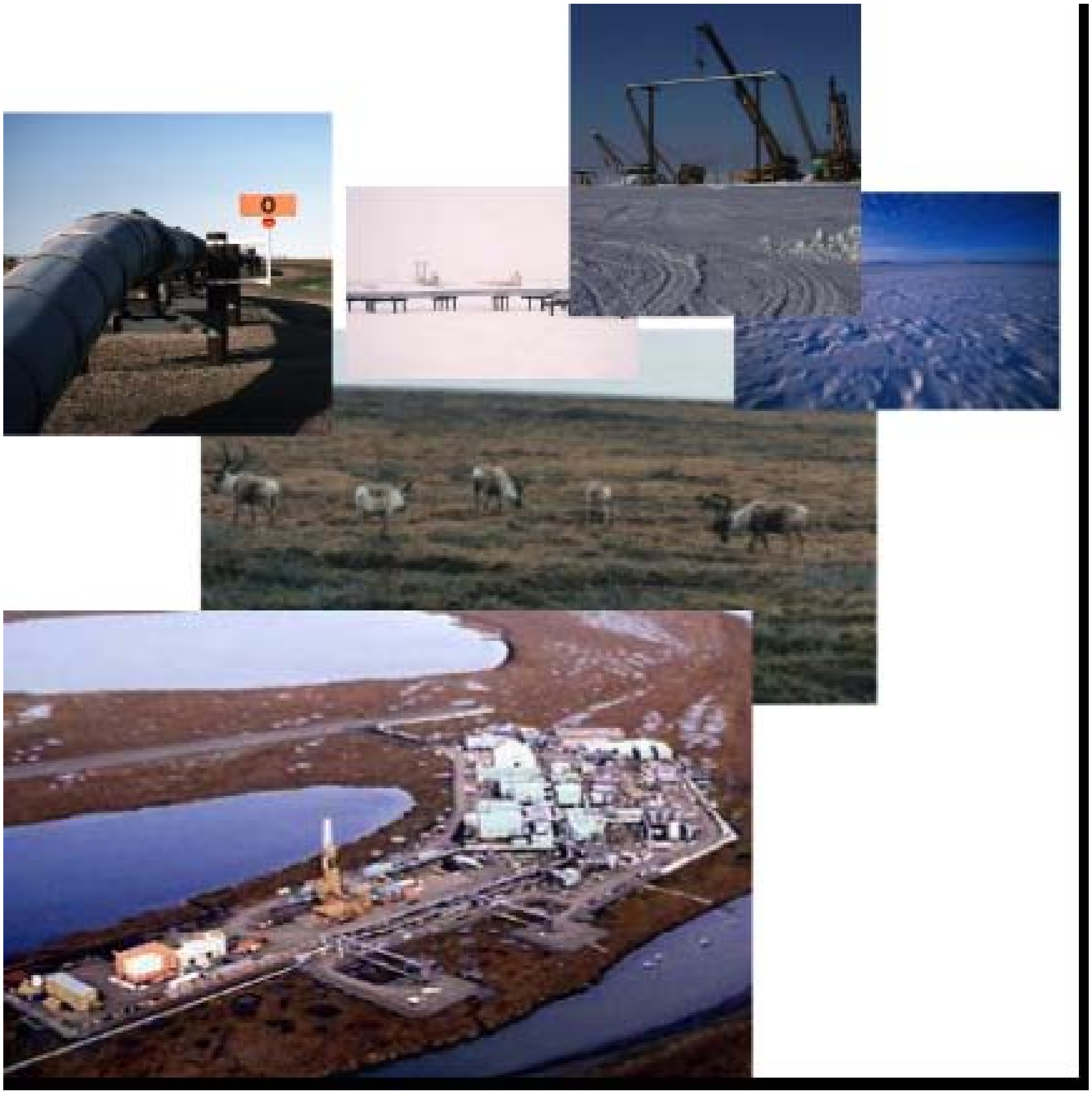
Eastern North Slope Gas Pipeline Design Basis



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LIST OF ACRONYMS AND ABBREVIATIONS

AISC	American Institute of Steel Construction
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CGF	Central Gas Facility
ESD	Emergency Shut Down
FDS	Fire Detection System
g	Gravitational Acceleration
HCA	High Consequence Areas
LBC	International Building Code
ICSS	Integrated Control and Safety System
MAOP	Maximum Allowable Operating Pressure
MAWP	Maximum Allowable Working Pressure
MSL	Mean Sea Level
PCS	Process Control System
scf	Standard Cubic Feet
SDV	Shut Down Valve
SIS	Safety Instrumented System
SMYS	Specified Minimum Yield Stress
SPCO	State Pipeline Coordinator's Office
stb	Stock Tank Barrel
TAPS	Trans-Alaska Pipeline System
TVA	Tuned Vibration Absorbers
UCP	Unit Control Panels
VSM	Vertical Support Members

1.0 INTRODUCTION

This document provides the basis for the design of the Eastern North Slope Gas Pipeline supporting the Pipeline Right-of-Way Lease Application.

1.1 Background

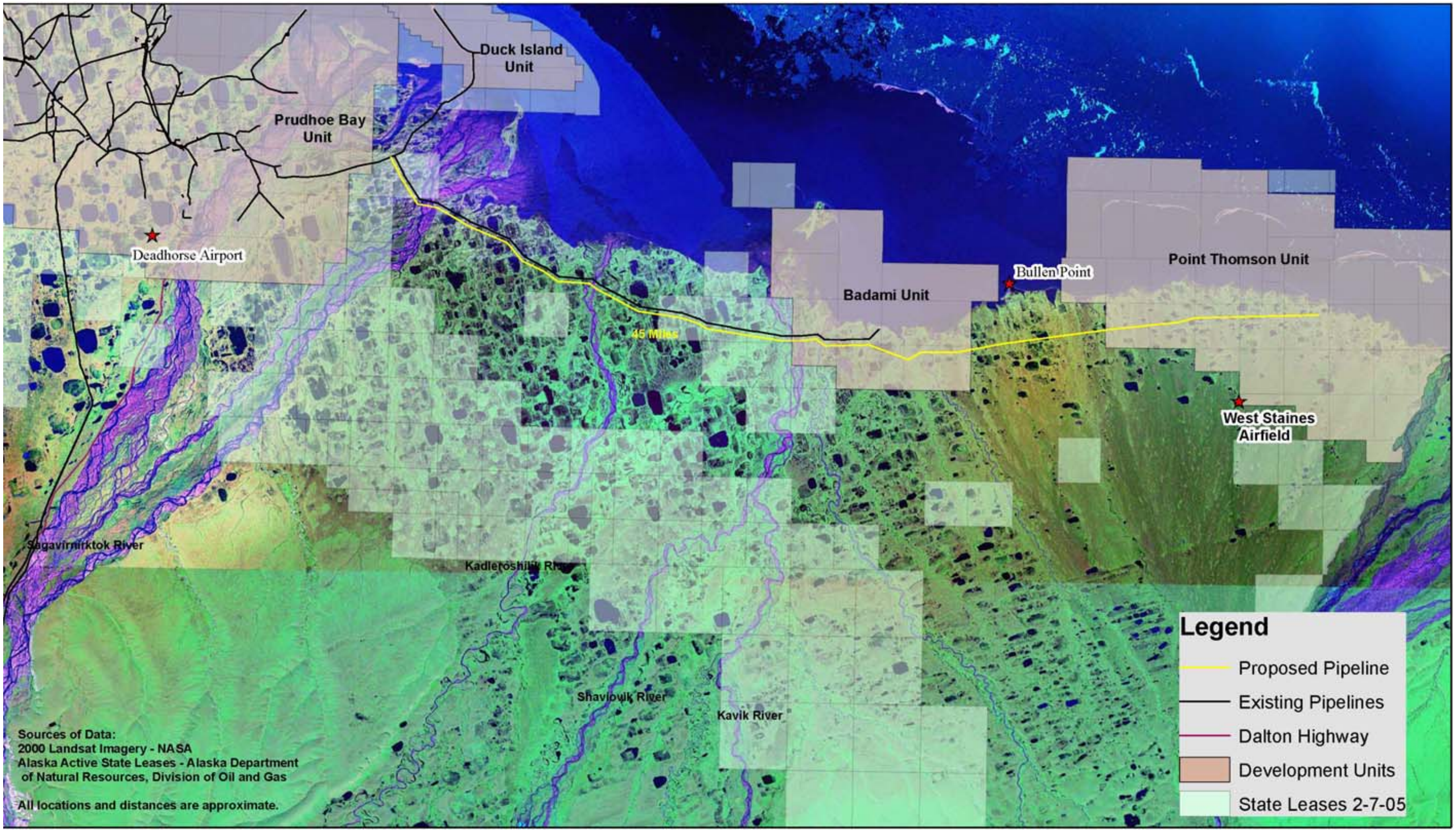
The Eastern North Slope Gas Pipeline Right-of-Way ends near Pump Station One, at a point of connection to the proposed Alaska Natural Gas Pipeline. Its start point is located approximately forty-five (45) miles east of the Prudhoe Bay field. Fields in this area are estimated to hold moderate-to-large volumes of gas. The proposed Right-of-Way could serve many potential gas fields; one example is Point Thomson. The Point Thomson reservoir is estimated to contain in excess of eight (8) trillion standard cubic feet (scf) and over four hundred (400) million stock tank barrels (stb) of condensate fluid.

Gas be gathered from the well pads and sent to a Central Gas Facility (CGF), where gas will be conditioned to meet sales-quality specifications and shipped via the Eastern North Slope Gas Pipeline to the Trans-Alaska Gas Pipeline, when constructed.

1.2 Pipeline Description

The facilities to which this Design Basis pertains consist of the Eastern North Slope Pipeline Right-of-Way, which begins at the central gas processing plants and terminates at a point of connection to the TAPS facilities. The route is approximately forty-five (45) miles long and is illustrated in the route shown in Figure 1. The pipeline begins at the locations described in the Lease Application, and ends at the isolation valve adjacent to the tie-in to the Termination of the pipeline. The Eastern North Slope Gas Pipeline will either be (1) insulated and installed above ground on vertical support members for its entire length or (2) buried at least thirty (30) inches below grade (as measured from the top of the pipe) and the contents chilled to prevent permafrost melting.

This Design Basis sets out the criteria and standards to which the Eastern North Slope Gas Pipeline shall be built. The purpose of this document is to establish an engineering baseline that will subsequently be used to use for final design of the pipeline. The Design Basis will be used to verify that requirements are met and that the pipeline will be engineered to standards that meet modern codes, are appropriate for arctic climates, and protect Alaska State land and the environment



Duck Island
Unit
Prudhoe Bay
Unit
Deadhorse Airport
45 Miles
Badami Unit
Bullen Point
Point Thomson Unit
West Staines
Airfield
Sagavirnirktok River
Kadleroshilik River
Shaviovik River
Kavik River
Sources of Data:
2000 Landsat Imagery - NASA
Alaska Active State Leases - Alaska Department
of Natural Resources, Division of Oil and Gas
All locations and distances are approximate.
Legend
Proposed Pipeline
Existing Pipelines
Dalton Highway
Development Units
State Leases 2-7-05

Figure 1

1.3 Facilities

River crossings may be above-ground or buried. If buried, they will be installed using either the trenching method or the HDD (horizontally directionally drilled) method. These water-crossing methods are viable only for larger rivers, which have a sizable volume of thawed soil beneath their beds.

Alternatively, the gas may be chilled and constructed as a buried pipeline for most or all of its length. The choice between buried and above-ground will probably depend upon the diameter that is selected. A larger pipeline will be more likely to be buried and *vise versa*.

1.4 Building within the Right-of-Way

The Eastern North Slope Gas Pipeline and its engineering, construction, quality control, safety and environmental requirements can only be described in general terms in this application, because its purpose is to serve gas fields that are only in the exploratory and conceptual stages. State regulations, procedures and practices will be relied upon to produce a pipeline that meets applicable codes, standards and regulations, and ensures integrity, safety, good operational and engineering practice, and protection of the environment.

1.5 Good Design Practice

Nothing in this document shall be interpreted to preclude good design practice. Criteria, standard, code, calculation, regulation, or other requirements shall not result in engineering or construction that contravenes good practices, laws, codes or regulations, or a reduction in safety, efficacy or environmental protection. The responsibility for good design, operations and construction of pipelines within the Right-of-Way shall lie solely with the pipeline owner(s).

2.0 GENERAL DESIGN AND CRITERIA

2.1 Fluid Properties and Characteristics

The composition of the materials shipped within the Eastern North Slope Gas Pipeline cannot be fully described at this time, since all developments are in conceptual or exploratory phases. It is anticipated that natural gas will be transported. This material is typically over 99.9% methane and is conditioned and processed to remove other substances, such as sulfur dioxide and moisture, prior to transport.

At the minimum, the following characteristics (as shown in Table 1) will be developed for engineering and design:

PHYSICAL FLUID PROPERTY VALUES

MW
Enthalpy (BTIJ/lb)
Cp (BTIJ/lb-°F)
Density (lb/ft3)
Thermal Conductivity (BTU/hr-ft-°F)
Viscosity (cP) at 0 psig and 100°F

TABLE 1: Fluid Properties and Characteristics

Where appropriate, these values will either be in standard conditions (1 atmosphere & 60 F) or in design operating conditions (temperature and pressure).

2.2 Facilities Description

The facilities will commence at a defined point (e.g. butt weld or flange connection) on the shipping pump discharge piping downstream from the shipping pumps (or compressors), and include flow control and pressure relief facilities. Any associated pig launcher and block valves and piping are considered part of the subject facilities.

The pipeline will be required to have facilities to launch and receive both maintenance pigs, such as cleaning, gauging and dewatering pigs) and ILI (In-Line Inspection) devices, such as smart pigs, geopigs and anomaly detection devices. Refer to Figure 2 for typical pigging facilities.

The facilities will terminate at a defined point (e.g. butt weld or flange connection) at the tie-in between the Eastern North Slope Gas Pipeline and Pump Station 1. The Pipeline and all associated VSMs, if any, between the points of commencement and termination of the subject facilities will be considered part of the facilities.

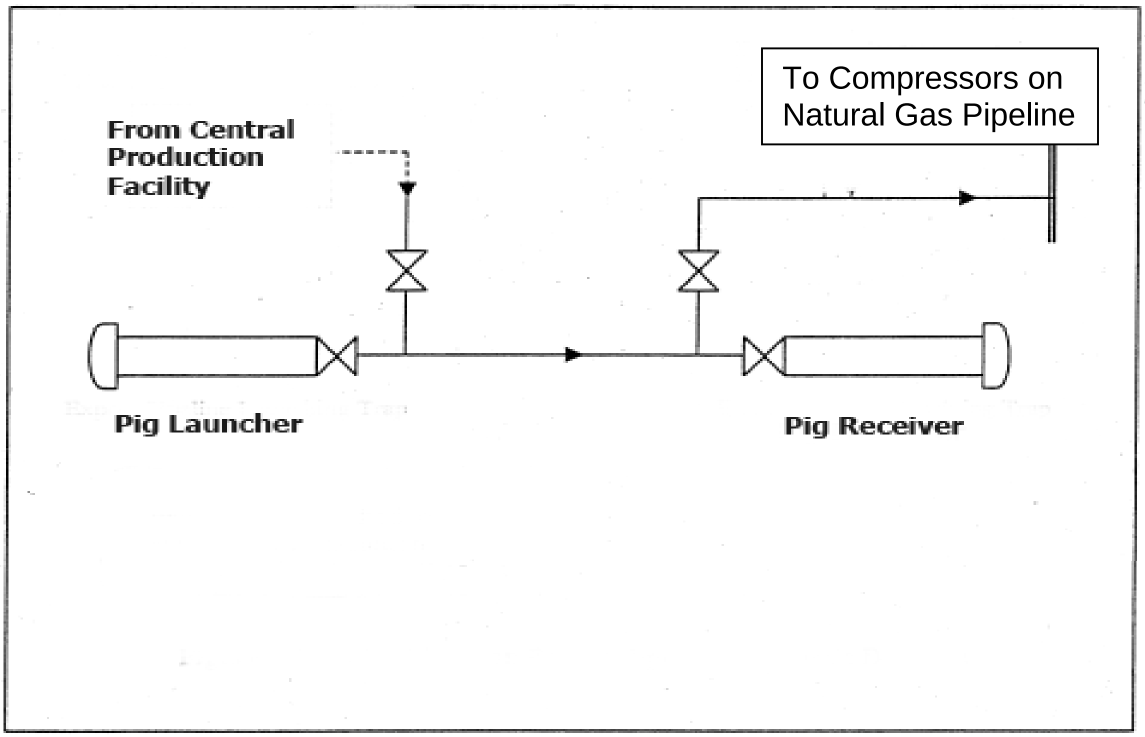


Figure 2: Generic Pigging Facilities

2.3 Regulations, Standards and Codes

The pipeline and associated facilities will be designed in accordance with, but not limited to, the following regulations, standards and codes:

- ASME B31.8, "Gas Transmission and Distribution Piping Systems," latest edition at the time of construction, including the latest Addenda.
- Code of Federal Regulations Title 49, "Transportation," Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards," latest edition at the time of construction, including the latest Addenda.
- "ASC GPTC Z380.1, American Gas Association Guide for Natural Gas Transmission and Distribution Piping Systems," latest edition at the time of construction, including the latest Addenda.

- American Institute of Steel Construction (AISC), "Code of Standard Practice for Steel Buildings and Bridges," latest edition at the time of construction, including the latest Addenda.
- AISC, "Manual of Steel Construction, Allowable Stress Design," latest edition at the time of construction, including the latest Addenda.
- AISC, "Manual of Steel Construction, Load Resistance Factor Design," latest edition at the time of construction, including the latest Addenda.
- American Society of Civil Engineers, "Minimum Design Loads for Buildings and Other Structures," latest edition at the time of construction, including the latest Addenda.
- Applicable to Pipeline Bridges and Other Crossings: American Association of State Highway and transportation Officials, Inc., "Standard Specifications for Highway Bridges," latest edition at the time of construction, including the latest Addenda.
- “International Building Code,” latest edition adopted by the State of Alaska at the time of construction. Note that the seismic design of the structures and pipeline shall be based, at a minimum, on the seismic maps and methodology contained in this Code.
- “International Mechanical Code,” latest edition adopted by the State of Alaska at the time of construction.
- NFPA 70, “National Electrical Code,” latest edition adopted by the State of Alaska at the time of construction.
- “API 5L Specification for Line Pipe,” latest edition at the time of construction, including the latest Addenda.
- “API 6D Specifications for Pipeline Valves,” cross-referenced to “API 6FA Fire Test for Valves,” latest editions at the time of construction, including the latest Addendas.
- “ASCE 7-XX Minimum Design Loads for Buildings and Other Structures”, (where XX is the edition recognized by the International Building Code adopted by the State of Alaska at the time of construction).
- “ASME B16.5, Pipe Flanges and Flange Fittings,” latest edition at the time of construction, including the latest Addenda.
- “ASME Boiler and Pressure Vessel Code, Section VIII: Pressure Vessels,” latest edition adopted by the State of Alaska at the time of construction.
- “NACE RP0169 Control of External Corrosion on Underground or Submerged Metallic Piping Systems,” latest edition at the time of construction, including the latest Addenda.
- “NACE RP0286 Electrical Isolation of Cathodically protected Pipelines.” latest edition at the time of construction, including the latest Addenda.

- "FHWA Hydraulic Engineering Circular No. 18 (HEC-18) Evaluating Scour at Bridges," latest edition at the time of construction, including the latest Addenda.
- "API 1102: Steel Pipelines Crossing Railroads and Highways," latest edition at the time of construction, including the latest Addenda.
- "API 1104: Welding of Pipelines," latest edition at the time of construction, including the latest Addenda.
- "API 1163: ILI Qualifications Systems Standards," latest edition at the time of construction, including the latest Addenda.
- For HDD Crossings: "PRCI Installation of Pipelines by Horizontal Directional Drilling: An Engineering Design Guide," latest edition at the time of construction, including the latest Addenda.

The design of the pipeline shall not only conform to the preceding regulations, standards and codes, but shall also meet the requirements of any regulations, standards and codes referenced within.

3.0 PHYSICAL FEATURES (CIVIL)

3.1 Topography/Oceanography

The project area is the Arctic Coastal Plain located between the Beaufort Sea and the Brooks Mountain Range. The land over which the pipeline traverses is a broad, relatively flat, treeless alluvial fan, rising from the Arctic Ocean toward the foothills of the Brooks Mountain Range. It is known as the Ancient Canning River Alluvial Fan, which is divided into a coastal zone and an inland zone. The coastal zone is located within two (2) to three (3) miles of the coastline and attains elevations of up to twenty-five (25) to thirty (30) feet above mean sea level (MSL). A poorly defined terrace face marks the transition from the coastal zone to the relatively higher, better-drained inland zone. Surface drainage in the coastal zone is characterized as channel flow, which consists of a network of shallow lakes and streams, while surface drainage in the inland zone is generally not confined to defined channels and is characterized as sheet flow.

The pipeline route is located in the coastal zone and passes close to numerous shallow lakes and crosses several stream channels. Along most of the route, drainage is poor, because of impermeable underlying permafrost. Typically, the permafrost only melts three (3) to seven (7) feet, and therefore water transport in the soil layer is limited to a relatively layer, even in late summer. In this area, runoff and water from thaw of the near surface soils accumulates above the permafrost, resulting in slow run-off into small streams and in the swampy character of much of the tundra during the summer.

Wind-oriented thaw lakes dominate the landscape on the Ancient Canning River Alluvial Fan coastal zone. The thaw-lake basins originate in areas of restricted drainage, where shallow ponding results in a warmer surface temperature that causes the underlying ground ice to thaw resulting in subsidence. Most of the ponds and lakes are relatively shallow. The thaw lakes are considered dynamic and impermanent, and often go through a cycle of development, expansion, drainage, and revegetation.

Topography is typically flat. Sharp topographic breaks and features are uncommon, although low ridges exist at lake and stream edges and adjacent to ice wedges. Small (e.g. typically less than one foot), seasonal variation in local tundra elevation due to freezing and thawing of the active layer is common. Aside from a DEW station and several remaining gravel exploration pads built and used in the 1970's to support oil exploration, the area along this pipeline route is essentially undeveloped.

The principal marine environment along the pipeline route, from Prudhoe Bay to the areas that the pipeline will service in the east, is a relatively shallow marine lagoon that is situated south of a barrier island complex with water depths typically between five (5) and thirteen (13) feet. Sea level variation due to tide action during the open water season is typically less than one (1) foot.

The Barrier Islands parallel the coast and along most of the Right-of-Way. The Barrier Islands partially protect much of the lagoon in this area from exposure to waves, storm surges and ice surges generated in the Beaufort Sea. Storm surges in the area along the pipeline route are generally less than three (3) feet above MSL, but during extreme storms can reach up to seven (7) feet.

3.2 Climate/Meteorology

The mean annual ambient temperature is approximately 9 °F (e.g. 9.8 °F at Barter Island). Ambient temperature ranges from a mean maximum of 45.1 °F during summer months to a mean minimum of -26.6 °F during winter months. Maximum summer temperatures reach 71 °F to 74 °F and minimum winter temperature can drop below -50 °F. The area annually experiences approximately 8,400-degree days °F freezing and approximately 600-degree days °F thawing. The main impact of these extremes is that the pipeline will have to be designed to arctic standards, including metallurgy for above-ground supports and pipe rated to a minimum -50F.

Winds are generally from the northeast (N70°E at Prudhoe Bay to N79°E at Barter Island), but wind shifts to the west or northwest are common throughout the summer. Strong westerly and southwesterly winds periodically occur during storms. Mean wind speed varies from a low of 11.9 mph during the summer to a high of 14.7 mph in the winter. Maximum instantaneous recorded wind speeds in this area vary from 38 mph in early summer to 81 mph in winter.

Mean annual precipitation is approximately five (5) inches per year, with total annual snow accumulation estimated to be approximately ten (10) inches.

3.3 Geotechnical

The entire onshore area along the pipeline route is underlain by permafrost. In winter, the permafrost extends to the ground surface, except for thaw pockets that are typically located beneath deep lakes and large river channels. By the end of summer thaw depth (i.e. the active layer) under the undisturbed tundra surface is generally less than three (3) to seven (7) feet. It should be noted that the thaw depths given are more than in most references. There is evidence of a warming of the permafrost since 1970, and these values represent more recent data.

Soils beneath the tundra in the area typically consist of a surficial layer of organic material and silt, with sand and gravel located at greater depth. The base of the silt is typically eight (8) to ten (10) feet beneath the tundra surface in the coastal zone. The silt base is generally shallower to the east and south of the Right-of-Way. Sand and gravel deposits at three (3) to six (6) feet depth are common between in this area. Soils vary from the eastern end of the Right-of-Way to the western end. The eastern end tends to have more silt and the west more gravel.

The underlying outwash material is typically composed primarily of sandy gravel and gravelly sand with some traces of silt. Although much of the outwash material is ice-bonded, the ice content is generally small in these soils. Occasionally massive bodies of segregated ice are found in this area, the shallower of which are probably associated with ice wedge development. In general, the ice content in soils found from the surface to a depth of fifty (50) feet typically ranges between fifteen (15) and twenty (20) percent.

Permafrost temperatures in these depths vary, depending on the season, depth, moisture content of the active layer, albedo of the ground surface, solar exposure, and insulation provided by snow cover. Temperature profiles taken at borings located inland from Bullen Point in April 1982 exhibited a near-linear temperature increase from 5°F to 17 °F from the ground surface to a depth of thirty (30) feet and a constant temperature from thirty (30) to fifty (50) feet depth. More recent (August 1998) soil temperature data from the general vicinity of the Pipeline Right-of-Way route found temperatures of 16.6 to 19.2°F at 40 feet depth. Because of this uncertainty and because of the observed permafrost-warming trend, any pipeline built within the Right-of-Way shall include a soil temperature study, conducted along the length of the route.

Soil conditions found during 1998 investigations in the vicinity of the Point Thomson, located near the west end of the route, indicate that along most of the Eastern North Slope Gas Pipeline route, overburden thickness ranges from three (3) to six (6) feet. Where the overburden is thin, massive segregated ice was found in the upper twenty (20) feet of outwash material. Near the western end of the route, visible ice content within ten (10) feet of the surface was as high as twenty (20) percent. However, below ten (10) feet deep, ice was largely interstitial.

3.4 Hydrology

The project area is located on the Arctic Coastal Plain, which (as was previously noted) is generally poorly drained, because of the underlying impermeable permafrost and the low slope of the terrain. Most streams in the area of the Right-of-Way are poorly developed, because the frozen ground resists erosion. Small drainages form when near-surface ground ice melts, often along ice-wedge polygon boundaries. The surface in this area consists of polygons, a feature unique to cold regions with low snowfall. Because of the extreme temperature swings of the soil near the surface, expansion and contraction breaks the surface into large interlocking polygons. Ice-water infiltration and freeze-thaw cycles expand the cracks, once they form.

Drainage channels in this area are largely the result of subsidence of soils, due to the melting of ground ice. As the water in the drainage channels commingle and as the drainage channels grow larger as they run toward the coast, the water attains sufficient energy to erode beds and banks and to transport sand and gravel. Lateral erosion of the banks of small streams is restricted by frozen ground. Erosion of frozen banks is a process of melting of frozen soils and subsequent slumping, often called thermal erosion, where blocks of frozen soil are undercut and fall into the river to thaw and erode away.

Most of the five (5) inches of average annual precipitation falls in the form of snow. A substantial portion of the precipitation is lost to sublimation, a process by which ice and snow evaporate into the air. An average of about three (3) inches of snow generally remains on the ground throughout the winter in small drainages areas. The actual amount available in a particular small drainage basin can vary widely, depending on the ability of the local relief to trap snowdrifts.

The first run-off in early spring occurs as sheet flow over the ground surface. Infiltration into the underlying soil is practically nonexistent, due to the underlying frozen ground. When break-up commences, the first snowmelt runs along the frozen surface of small streams or ponds behind snowdrifts. As break-up progresses, the small snowdrift dams are breached and the accumulated melt water is released to flow downstream until it again ponds behind a larger snowdrift. The storage and release process results in a highly peaked run-off hydrograph with flow during break-up being unsteady and non-uniform.

Usually, once the break-up crest passes, recession is rapid. Typically, the flow on a small stream two weeks after the breakup crest will be less than one (1) percent of the peak flows, and the smallest drainages can be completely dry within two weeks. During break-up, the bed and banks of small drainages tend to remain frozen, and erosion rates are low.

During the winter, sheets of ice form on streams that sustain winter flow, and smaller streams that are normally dry in winter become blocked by snowdrifts. These winter snow and ice blockages play three (3) important roles during break-up:

- Collection and release of run-off with increased rate of discharge.
- Decrease of available channel area to convey water, thus increasing the water elevation for a given discharge. The increased water causes more area to be flooded, and may increase the freeboard requirements.
- Diversion of flow to adjacent stream channels.

Summer floods are not anticipated to produce design floods for the Arctic Coastal Plains streams. The magnitude of the flow at break-up time is so large that rainfall any other time of the year will not produce a flood stage close to that experienced at break-up (which occurs in late May or June). Rainfall intensity is low and tundra and thaw lakes have a relatively large capacity to absorb summer-storm runoff

Watersheds affecting the area along the pipeline route range considerably in size. The larger watersheds are typically long and narrow. Prior to the final design of the pipeline, hydrology studies on the lakes and streams crossed by the pipeline shall be performed and the data integrated into the design and engineering of the pipeline.

Snowmelt progresses from south to north during the early stages of break-up, and then combines with a general melt in the area bordering the coast, from the edge of the Arctic Ocean to five (5) to ten (10) miles inland. This is the area in which the Right-of-Way is located.

The narrow shape of many of the watersheds resulted in a concentrated run-off hydrograph exhibiting rapid rise and recession. The break-up of most of the streams crossed by the pipeline route has been monitored by oil companies active in this area, such as Exxon at Point Thomson and BP at Badami, and by the Alaska DOT/PF, as part of a proposed Bullen Point Road. Therefore, much hydrological information for this area already exists. However, for final design the pipeline will be required to have a separate hydrology study and be designed to withstand flood return periods of a minimum of two hundred (200) years.

3.5 Seismicity

The area is considered to be a region of low to moderate earthquake activity. In the general vicinity of Point Thomson, at the eastern end of the Right-of-Way, approximately two hundred (200) earthquakes were recorded between August 1965 and December 1993. These included a magnitude of 5.3 on the Richter scale, offshore near Barter Island in 1968, and a 5.1 event about one-hundred (100) miles southwest of the area in 1969.

Most seismicity in the area is shallow (less than twenty (20) mi. deep), indicating near-surface faulting, but no active faults are recognized at the surface in this area. Seismic engineering calculations for this area typically uses a 10% probability of exceeding 0.05 g earthquake-generated horizontal acceleration in bedrock during a fifty (50) year period in this area (where g = acceleration due to the earth's gravitational field). It should be noted that this is the methodology accepted by the International Building Code and adopted for structures by the State of Alaska.

For comparison, ground acceleration in Anchorage during the great 1964 earthquake was estimated at 0.16 g. Accelerations in areas underlain by thick, soft sediments are likely to be higher than in bedrock due to amplification. Thick permafrost, which underlies the project area, may cause the earthquake response of the alluvial sediments to act more like bedrock, limiting amplification and tending to prevent earthquake-induced ground failure such as liquefaction.

The project area is in the North Slope seismic region, 70° to 71° N Latitude and 146° to 151° W Longitude. This region was previously classified a Design Seismic Zone One (1), the lowest-risk category in Alaska, under the previous governing code, the Uniform Building Code. The current governing code is the International Building Code, 2003 edition, Section 1615, which requires that design be based on the mapped spectral accelerations for the proposed site location. The project area is in the North Slope seismic region, 70° to 71° N Latitude and 146° to 151° W Longitude. This region was previously classified a Design Seismic Zone 1, the lowest-risk category in Alaska, under the previous governing code, the Uniform Building Code. The current governing code is the International Building Code, latest edition adopted by the State of Alaska, Section 1615, which requires that design be based on the mapped spectral accelerations for the proposed site location. The North Slope is considered to be an area with low to moderate seismic risk.

The minimum seismic requirements for the pipeline are covered in ASME B31.8 and the International Building Code. The pipeline may cross more than one zone on the current maps for the design spectral response acceleration for maximum earthquake ground motion. If the maps adopted by the State at the time of construction indicate that the pipeline crosses zones, the stricter requirements shall apply to the entire pipeline. This avoids use of multiple seismic criteria.

3.6 Pipeline Right-of-Way Routing

The Pipeline Right-of-Way route is illustrated in Figure 1 and is approximately forty-five (45) miles long. The Right-of-Way route parallels the Badami pipeline on the western end. On the eastern end, its route is standalone, and runs across undeveloped tundra.

One of the two modes for the pipeline is insulated pipe installed above ground on standard North Slope VSMs, or vertical-support members, which are essentially shallow piles.

Criteria used for an above ground pipeline route includes:

- Avoid locating VSMs in lakes and streams. Minimize the need for VSMs in active channels and ensure long-term integrity of VSMs adjacent to the streams.
- Utilize straight pipeline sections wherever possible, and minimize overall length.
- Incorporate nominal separations of a minimum 500 feet between linear structures (such as roads or pipelines), to facilitate wildlife movement. Alternatively, group pipelines together.
- Minimize impact on environmentally sensitive areas and valuable habitat such as salt marshes and drained lake basins, as much as possible.

It should also be noted that to facilitate wildlife movement along the Right-of-Way, the above-ground pipeline will be a minimum seven (7) feet above the surface. This will be measured from the highest point on the ground beneath the pipeline to the lowest surface on the pipeline (usually the bottom of the insulation jacket), so average clearances will be higher than seven feet. No structures, such as PVDs, will be allowed to hang under the pipeline.

The other mode for the pipeline is buried. A buried pipeline would be buried at a minimum of thirty (30) inches (measured from the ground surface to the top of the pipe). The gas would be chilled to a temperature that is equal to the mean annual ground temperature. This is intended to not just prevent melting of the permafrost along the pipeline but to avoid any changes of the thermal regime of the *in situ* soil. This is important to prevent long-term moisture migration, ice formation and ice inclusions from forming in the soil around the pipeline.

3.7 Road Crossings

The pipeline may cross a road in at least one location, if the proposed Bullen Point Road is built. The detailed design of road crossings shall conform to the following:

- Preserve pipeline integrity particularly through minimization of accumulation of water around the pipeline.
- Minimize settlements that may induce additional loading on the pipeline.
- No interference with adjacent pipelines.
- Allow convenient and inexpensive routine inspection of road crossings.
- Protect the underlying tundra from damage and thaw settlement.
- Promote long-term integrity of the road surface.

- Avoid pocketing of water externally in the road casing.
- Avoid having sheet run-off in the tundra flow through the casings.
- Minimize external and internal corrosion.
- Design per API 1102, Steel Pipelines Crossing Railroads and Highways, latest edition at the time of construction, including the latest Addenda.
- Avoid water drop-out and pocketing internally.
- Case the pipeline and electrically isolate the casing from the pipeline.

Oversized casings with carrier pipe isolators, carrier pipe coating beneath insulation and additional insulation beneath casings will be required. A minimum of six inches clearance will be maintained between the OD of the insulated jacket and the ID of the casing, and a minimum of four inches between the top of any isolators and the top inside surface of the casing. This will allow for some subsidence prior to the casing resting on the top of the pipe and possibly causing damage or a leak.

3.8 High Consequence Area Evaluation and Selection

High-consequence areas (HCA) that could be affected by the pipeline will be identified and evaluated according to the requirements of federal regulations. Data available from the Office of Pipeline Safety and generated during the design of the pipeline will be used to determine the presence of HCAs along the proposed pipeline alignment. HCAs, if present, will be identified on pipeline alignment drawings and integrated into an integrity management plan. An HCA evaluation and risk assessment procedure will be prepared to assist identification of any potentially affected areas.

If the pipeline identified as having an HCA, the area will be identified and a baseline integrity assessment must be completed before product enters the pipeline. Reinspection intervals for integrity assessments will be based on federal regulatory requirements.

3.9 Tie-Ins and Off-Takes

The Eastern North Slope Gas Pipeline may have intermediate tie-ins to commingle streams of fluids from different gas fields. Using a common pipeline to carry gas from several fields is an effective and efficient method to optimize pipeline usage and minimize the number of pipelines servicing an area. Additionally, taps may be made in the pipeline to provide fuel gas to different sites. All of the proposed sites under current consideration are industrial and related to the oil and gas industry.

4.0 STRUCTURAL

4.1 Vertical Support Members

Vertical Support Members (VSMs) may support the pipeline(s) in the Right-of-Way in all locations except where pipelines are buried in stream or road crossings. Use of buried pipelines in the Right-of-Way is also a possibility. If the pipeline is buried along its entire length, VSMs will not be necessary.

Each VSM will consist of a horizontal steel beam connected to a vertical steel pipe pile. The pipe pile will be embedded and slurried with a sand/water mixture to a specified depth in the ground. Design of the VSM structural members and pile foundation will be based on the International Building Code, accepted North Slope design standards, and information received from the geotechnical and hydrology reports.

4.2 Design Loads

The design loads and forces will be per the IBC and State/Local codes. The VSMs will be, at a minimum, designed to accommodate the following loads:

1. Dead Load (D): to include equipment and piping.
2. Operating Loads (F): to include fluid in pipes, and other long-term loads that result from the operation of the facility (including pipeline anchor, guides, and slide loads).
3. Live Loads (L)
4. Thermal Load (T): shall be per the IBC and a comprehensive pipeline stress analysis
5. Wind Load (W): shall be per the IBC, and be, as follows:
   A. Basic Wind Speed: V = 110 mph
   B. Exposure Factor = 0.7
   C. Importance Factor =11 or above
   D. Total lateral wind force per foot on the supporting pipeline pipe will be considered

6. In addition to the wind loads previously listed, forces and fatigue induced by Wind-Induced Vibration (WIV), a condition unique to long suspended structures, will be considered in the design.
7. Seismic Load (E): shall be per the IBC.
8. Frost Jacking Force or Frost Heave (J): shall be per Table 2.
9. Snow Load (S): shall be per the IBC, where Design Ground Snow Load, Sg = 50 psf.
10. Ice Load Forces (Lice): shall be per IBC 2000 and data received from the preliminary hydrology report.
11. Stream or River Crossing Ice Flow Forces: per data developed in a hydrology report, to be conducted prior to design and engineering of the pipeline.

4.3 VSM Configuration

The top of VSMs will be set to ensure that clearance between the tundra surface and the bottom of the pipe or attachments to the pipe will be a minimum of seven (7) feet. Pipe-support VSMs will be a single steel pile system with a horizontal steel support beam. Anchor-type VSMs may be a multiple-pile system, with a single horizontal steel support beam. All structural steel shall be rated to a minimum -50F, as established by accepted ductility and other testing for arctic design.

4.4 Foundation Design

Based on geotechnical information for the project area, the soil profiles are typical of those encountered on previous North Slope pipeline projects. As noted in Section 3.3 of this document, the sand and gravel layer is generally encountered at a depth of less than six (6) feet in this area. The active layer depth at the end of the summer in undisturbed tundra used for design will be five (5) to seven (7) feet.

In general, the pile foundation design will be based on:

- The tangential adfreeze bond strength at the pile to slurry interface to resist the vertical loads, both structural (down) loads and heave (uplift) loads.
- The resistive strength between the slurry and native soil to resist frost jacking (heave) forces. The required depth of pile embedment will be dependent on these forces.

Typical adfreeze and frost jacking (heave) stresses for North Slope VSMs is shown in Table 2.

TOP OF TUNDRA (DEPTH BELOW)	COMPRESSIVE OR TENSILE LOADING		FROST JACKING (HEAVE)	
	SUMMER	WINTER		
0' -2'		10 PSI	JACKING FORCE	40 PSI
-3'	0 PSI			
-9'	10 PSI	10 PSI	RESISTIVE FORCE	12.5 PSI
-14'	15 PSI	15 PSI		18.75 PSI
-25'	20 PSI	20 PSI		25 PSI
	25 PSI	25 PSI		31.25 PSI

Table 2: Typical Adfreeze Stresses for VSMs

NOTES:

1. *The capacity of a VSM to resist frost heave shall be the lesser of the following:*
   a) The summation of the allowable adfreeze bond stresses between VSM and slurry.
   b) The summation of the allowable stresses between the slurry and the native soil or ice.
2. *The adfreeze bond strength shown assumes that the piles are placed in competent soil. Competent soil is assumed free of ice lenses and other deleterious inclusions.*

The frost-jacking force shall be a minimum forty (40) psi, applied over the entire pile perimeter area in the active layer. This heaving force shall be combined with each load combination in those cases where a net upward load will result. No reduction in ad freeze bond strengths shall be made for net uplift loads for load combinations that include heaving forces. The axial capacity of the piles will be based on Adfreeze-bond stress versus time to initiate tertiary creep (ultimate strength) for a design life of one-hundred (100) years. Vertical loads shall be resisted by tangential adfreeze bond strength developed below the 30°F isotherm. The vertical load capacity of sand-water slurry piles will be based on the tangential adfreeze bond strength at the pile to slurry interface.

4.4.1 Pile Embedment

The depth of pile embedment shall be calculated for each pile diameter. The embedment depth shall be designed to resist the frost jacking (heave) force. Often, on North Slope pipelines, the heave force is the governing factor for VSM depth.

4.5 River and Stream Crossings

The proposed pipeline route will cross several streams. VSMs, if used, may be installed within the active stream channel flood plain area. The active channel is defined as the portion of streams containing flowing water or ice during the entire year. The active channel for small streams with poorly defined channels and/or for channels that are seasonally dry is that portion of the stream in which ice or water resides longest. The location of VSMs within the active channel will be avoided wherever possible. A hydrology report shall be prepared for the pipeline. The report shall analyze the hydrological characteristics of streams along the proposed pipeline route.

The hydrology report prepared prior to building in the Right-of-Way shall identify large and mid-sized streams and include the following information:

- Approximate location of the pipeline crossing
- An estimate of the 200-year flood-peak discharge.
- An estimate of the local scour coefficient.
- General and localized scour depths.
- Preliminary proposed bottom of pipeline elevation.
- Water surface elevation, water depth and velocity associated during a 200-year flood
- Probable conditions at freeze up.
- Ice forces exerted on a VSM within the stream crossings.
- Location and depth of thalweg.

4.5.1 Scour

The engineering and design of the gas pipeline shall consider both general and local scour. The maximum total scour depth at VSM locations shall be calculated, at a minimum, as the sum of local general scour depth and the local VSM scour depth, calculated using actual VSM diameter.

4.5.2 Ice Floes

Several factors affect the magnitude of the ice forces exerted on a VSM. Some of these factors include: the depth of water at the VSM, the velocity at which the ice floe is moving, and the length, width and thickness of the ice floe. The hydrological report shall present a minimum of two conditions for determining water-surface elevation, water depth and velocity:

Condition 1 is based on an open channel condition, the minimum probable hydraulic roughness on the vegetated portions of the cross section, and the greatest water surface slope.
Condition 2 is based on 50 percent of the channel being blocked by ice or snow, the maximum probable hydraulic roughness on the vegetated portions of the cross section, and the smallest water surface slope.

4.5.3 Bank Mitigation

When selecting the final location of the VSMs, every effort will be made to locate the VSMs away from the stream's riverbanks. Should the pipeline alignment and VSM-spacing require locating a VSM within the river-bank region, mitigation plans to avoid bank erosion will be considered as part of the detail design. Installing VSMs along the banks of a river or stream could lead to slope instability and erosion, and could threaten the natural habitat and environment by changing the surface drainage over large tundra areas. Detailed hydrology work shall include a bank mitigation study and recommendations for slope stabilization / riverbank erosion control methods where location of VSMs in the active channel may be necessary.

4.6 Antennas and Other High Structures

The use of antennas shall be minimized, in favor of fiber optics or other technologies that lessen environmental impact. Any construction of antennas must be approved by the Department of Natural Resources.

5.0 MECHANICAL

5.1 Hydraulics

The design and engineering of pipeline shall be sized in accordance with accepted standards and provide a hydraulic analysis as part of the documentation.

A full hydraulic analysis will be performed on the pipeline. Engineering design parameters that will be determined during final design of the pipelines are summarized in Table 3.

Outside Diameter	Min Wall Thickness	Normal Gas Operating Temp	Max Gas Operating Temp	Max Inlet Pressure	Max Outlet Pressure
(in)	(in)	(°F)	(°F)	(psig)	(psig)

Table 3: Minimum Pipe Design Parameters for Hydraulic Analysis

5.2 Surge Analysis

A surge analysis is needed.

5.2.1 Eastern North Slope Pipeline Right-of-Way

The Eastern North Slope Gas Pipeline will be analyzed from a surge perspective in conjunction with the downstream connecting pipeline system. Pipeline surge scenarios that will be verified are those associated with actuated valve closures, pump trips, and other anomalous events. Surge pressure will be controlled and shall not exceed 110% of the internal design pressure at any location, per Federal regulations.

5.3 Pipeline Design Loading Categories

Two general categories of design loading conditions are the design operating condition and the design contingency condition.

The design operating condition is defined to include all normal operating conditions and environmental loadings. The ASME B31.4 Piping Code establishes these loadings. The stresses and strains produced in the pipeline by these loadings are to be within the design-criteria limits established by accepted engineering practices and by the Piping Code. The loadings for the design-operating condition on the above ground pipeline shall include, at a minimum:

• Internal design pressure
• Surge pressure
• Temperature differential
• Dead and live loads
• Design earthquake
• Wind design load

The design-contingency condition is defined to include the sustained loadings for normal operating conditions, combined with occasional loadings from extreme environmental events. Design contingency conditions are anticipated to occur rarely, if at all, during the lifetime of the system. The stresses and strains produced in the pipeline by these loadings shall remain within design-criteria limits. The loadings for the design contingency condition on the above-ground pipeline shall include, at a minimum:

• Internal design pressure
• Temperature differential
• Dead and live loads
• Contingency earthquake
• Loss of a support
• Wind design load

5.3.1 Internal Design Pressure

The engineering and design shall clearly identify the internal design pressure, operating pressure, MAWP or MAOP (or equivalent) for the pipeline.

5.3.2 Surge Pressure

As previously stated, surge pressure will be controlled and will not exceed 110% of the internal design pressure at any location. Pipeline surge scenarios that will be verified are those associated with automated valve closures and pump trips and other anomalous events.

5.3.3 Temperature Differential

The temperature differential used in calculating stresses shall be based upon a minimum tie-in temperature and the maximum pipe wall temperature. If the minimum actual installation temperature is not known with complete certainty, the minimum ambient temperature (-50F) shall be used.

5.3.4 Dead and Live Loads

The dead loads include pipe weight, insulation weight, and insulation jacket weight. Additional dead loads include the weight of Pipeline Vibration Dampers (PVDs) where appropriate.

The live load is the fluid weight based on a specific gravity of the particular being transported. The weight of snow and ice is also a live load and will be applied as an occasional load. A minimum of ten (10) lbs/sf shall be included for ice and snow loads.

5.3.5 Design Wind Load

The minimum design operating wind speed for this area shall be one-hundred and ten (110) mph. The design wind pressure will be calculated using ASCE 7-XX (where XX is the edition recognized by the International Building Code adopted by the State of Alaska at the time of construction). The design wind exposure shall be "C" or higher, the importance category II or higher, and the topographic factor "k" is equal to 0.85 or higher for heights up to fifteen (15) feet. It should be noted that the maximum pipe height above tundra is generally less than fifteen (15) feet for a majority of the cross-country alignment. These parameters result in a calculated wind pressure of twenty-five (25) lbs/sf on the pipeline.

5.3.6 Earthquake Loads

Dynamic or equivalent static earthquake loads can be used in the analysis. These loads are generated as multiples of gravitational acceleration (g) as described in Section 3.5 of this document. The design earthquake loads pipelines will typically be at least 0.05g and the contingency earthquake load at least 0.10g. These values are to be considered the minimum for good engineering practice, but may be increased if warranted.

5.3.7 Loss of Support

The engineering and design of the pipeline shall evaluate scenarios involving loss of support. At a minimum, the scenario of support lost due to frost jacking or settling of at least one VSM shall be included in the design. This loss of support is evaluated as a design contingency condition. The pipeline will be designed to ensure that loss of a support will not buckle the pipeline or cause a loss of containment.

5.3.8 Wind-Induced Vibration

The susceptibility of the pipeline to Wind-Induced Vibration (WIV) will be determined using current state-of-the-art analysis techniques. All segments of the pipeline that are predicted to be susceptible to WIV will be mitigated using mass damper, such as PVDs, reducing the VSM spacing (L/D ratio) or randomizing support spacing. Engineering and design shall include WIV forces and fatigue.

5.4 Pipe Stress Criteria

The Eastern North Slope Gas Pipeline will be subject to the requirements of 49 CFR 195. These federal regulations place limitations on the allowable internal pressure but do not specify other loads, loading combinations, or limitations on combined states of stress. The ASME B31.4 code addresses detailed industry requirements for loads and stress criteria and shall be utilized. Note that Alaska Statute 18.60.850 mandates use of this ASME code.

Based on the nature and duration of the imposed loads, pipeline stresses are categorized as primary, secondary, and combined (effective) stresses. The general stress criteria are summarized below:

Primary Stresses - Primary stresses are stresses developed by imposed loads with sustained magnitudes that are independent of the deformation of the structure. The basic characteristic of a primary stress is that is it not self- limiting, meaning that no redistribution of load occurs as a result of yielding. Therefore, if the primary stress in the pipe exceeds the yield *strength of the pipe, the pipe will continue to yield until failure of the pipe or removal of the load causing the stress, whichever occurs first. The stresses caused by the following loads are considered as primary stresses: internal pressure, dead and live loads, surge (water hammer), earthquake motion, and wind.*

Secondary Stresses - Secondary stresses are stresses developed by the self-constraint of the structure. Generally, they satisfy an imposed strain pattern rather than being in equilibrium with an external load. The basic characteristic of a secondary stress is that it is self-limiting, meaning that local yielding and minor distortions can relieve the stress imposed by the load. Once stress relief has occurred, the pipe will not yield any further despite continued secondary loading. The stresses caused by the following loads are considered secondary stresses: temperature differential and differential support settlement.

Combined Stresses - The three principal stresses acting in the circumferential, longitudinal, and radial directions define the stress state in any element of the pipeline. Limitations are placed on the magnitude of primary and secondary principal stresses and on combinations of these stresses in accordance with acceptable strength theories that predict yielding.

5.4.1 Allowable Stresses

Allowable stress criteria are shown in Table 4. As stated by the ASME B31.4 codes, stresses due to wind and earthquake are not considered to occur concurrently. Circumferential, longitudinal, shear and equivalent stresses will be calculated considering stresses from all relevant load combinations. Calculations shall consider flexibility and stress concentration factors of components other than straight pipe.

5.4.2 Load Combinations

The load combinations described in Table 4 shall be summarized in the format shown Table 5. These load combinations will be part of any engineering for the pipeline and shall be analyzed using a recognized stress program. Two stress programs that are considered acceptable are CAESAR II and AutoPIPE, although equivalents may be evaluated and substituted. The resulting stresses will be compared to the allowable stresses in Table 5. The pipeline design will ensure that the stresses in all load combinations are below the allowable stress criteria.

5.5 Configuration

The following discussion is only for above-ground pipelines. Thermal expansion will be accommodated by including offsets in a “U” or "Z" or “diagonal” configuration, with pipeline anchors between each offset. The length of the offsets and thermal expansion stresses will govern the maximum distance between anchors. Figure 3 illustrates the "Z" configuration.

In a few cases, expansion may be accommodated at points of intersection (PIs) other than those included in the typical expansion joints or loops, as shown in Figure 4. These special cases will further limit the maximum distance between anchors and the design will ensure that the allowable stress criteria are met.

Criterion	Allowable	Basis[2]	Load Combination
Hydrotest Stresses			
Hoop Stress (pressure)	1.00 SMYS[1]	ASME B31.4.5 402.3.3(b)	1
Effective Stress during Hydrotest	1.00 SMYS	402.3.3(b)	2
Primary Stresses			
Hoop Stress (pressure)	0.72 SMYS	402.3.1	3
Longitudinal Stress (pressure, live, and dead loads)	0.54 SMYS	419.6.4	4
Longitudinal Stress (pressure, live, dead, and other occasional primary loads under Operating Design Conditions)	0.80 SMYS	419.6.4	5 6 7
Tresca Effective Stress (primary loads under Contingency Design Conditions)	1.00 SMYS	Project Design	8
Secondary Stresses			
Longitudinal Stress Range (temperature differential, tie-in to operating)	0.72 SMYS	419.6.4	9
Effective Stress			
Tresca Effective Stress (sustained loads, i.e. pressure, live, and dead loads, temperature differential, imposed support displacements)	1.26 SMYS	Project Design	10
Tresca Effective Stress (Operating Design loads under pressure, live and dead loads, temperature differential and wind)	1.52 SMYS	Project Design	11
Tresca Effective Stress (Operating Design loads under pressure, live and dead loads, temperature differential and operating earthquake)	1.52 SMYS	Project Design	12
Tresca Effective Stress (Design loads under pressure, live and dead loads, temperature differential and contingent earthquake)	1.72 SMYS	Project Design	13
Tresca Effective Stress (Design loads under pressure, live and dead loads, temperature differential and loss of support)	1.72 SMYS	Project Design	14
Surge Stresses			
Hoop Stress (Surge Pressure)	0.79 SMYS	402.2.4	15
Tresca Effective Stress (sustained loads, i.e. pressure, live, and dead loads, temperature differential and other sustained loads)	1.52 SMYS	Project Design	16

1 SMYS = Specified minimum yield strength

2. Basis refers to sections of ASME B31.4 code unless otherwise noted.

Table 4: Allowable Stress Criteria

			Testing		Operating										Contin-gency		Surge	
Load Type	Load	Description	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Primary	A	Internal Pressure			X	X	X	X	X	X		X	X	X	X	X		
Primary	B	Hydrotest Pressure	X	X														
Primary	C	Surge Pressure															X	X
Primary	D	Dead Load		X		X	X	X	X	X		X	X	X	X	X		X
Primary	E	Live Load		X[1]		X	X	X	X	X		X	X	X	X	X		X
Primary	F	Wind Load		X[2]			X						X					
Primary	G	Snow Load							X									
Primary	H	Operating Earthquake						X						X				
Primary	I	Contingency Earthquake								X					X			
Secondary	J	Temperature Differential		X[3]							X	X	X	X	X	X		X
Secondary	K	Imposed Support Displacement										X	X	X	X	X		X
Primary	L	Loss of Support														X		

1. Live load for hydrotest is the loading from the hydrotest fluid
2. Wind load for hydrotest is 33% of the design wind load
3. Temperature differential for hydrotest is based on the difference between the tie-in temperature and the hydrotest temperature.

Table 5: Load Combinations

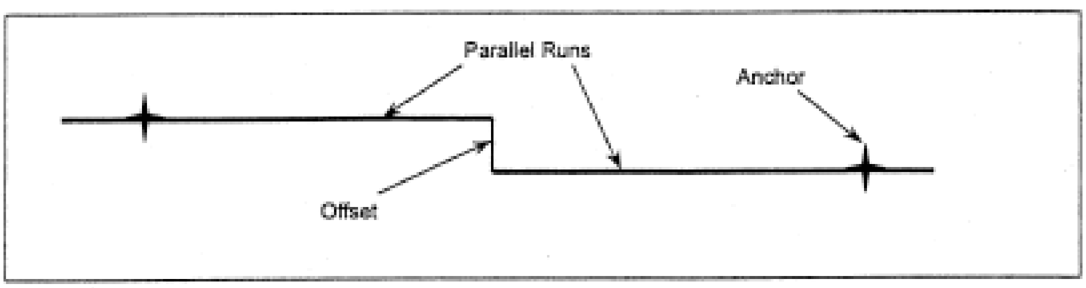


Figure 3: Z-Offset, a Type of Expansion Joint

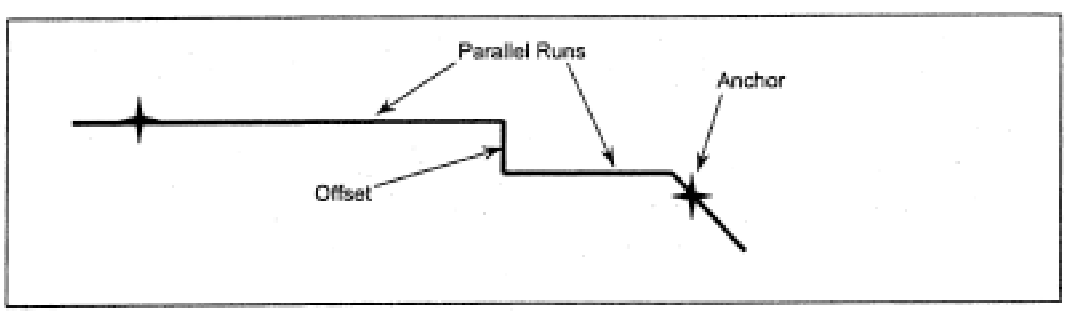


Figure 4: PT-Configuration

5.6 Facilities

Valve locations will be evaluated and determined in accordance with federal regulatory requirements. At a minimum, valves will be placed at the ends of the pipeline to isolate the pipeline from processing facilities and the connections to downstream pipelines. Other locations will be evaluated on a case-by-case basis. Federal regulations also require automatic shut-off valves on some river crossings.

The pig launchers and receivers shall be similar to those currently used on existing North Slope pipelines. The launcher and receiver will be located in the line at the processing facilities and at termination of the pipeline, respectively, located in such a manner as to maximize the length of pipeline between launcher and receiver. The launcher and receiver barrels will be isolated from the main pipeline by double block-and-bleed valves, as required by OSHA regulations for energy isolation. The trapping systems will be protected by a safety system so that the trap cannot be over-pressured and the access door cannot be removed when the barrel is under pressure. If the loading and unloading areas are indoors, they shall be protected with a fire detection and suppression system, unless the requirements are waived by the State Fire Marshal.

Per standard practice, each barrel will be provided with a thermal relief system to assure against over pressure caused by the heating of the fluid in the barrel once the isolation valves are closed. The system will be provided with instrumentation to signal the arrival of the pig at the launching or receiving station. All of the piping to be pigged will have 3 D bends or greater. Traps will be designed to handle all of the inspection tools (see section 9.2) as well as the full range of pipeline cleaning tools.

5.7 Material Selection

The pipeline will be built from material conforming to API 5L, Specification for Line Pipe. API 5L-X line pipe material conforms to ASME Code requirements is compatible with the pipeline contents and can be procured with suitable low-temperature properties for the service. The wall thickness of the pipe shall be determined using the design calculations provided by 49 CFR 195 and will be increased to the nearest API 5L. The selected pipe material will be adequate for the pipeline design temperature range from -50°F to the maximum design temperature.

Pipe insulation and jacketing shall be specified and selected to ensure pipeline operating performance within the flow and operating temperature limits indicated in Section 5.1. Insulation will be selected mainly on the basis of continuous performance at design temperatures. The selection of the outer jacketing will be shall consider protection of the pipe insulation from damage and degradation from the elements of the arctic environment. The jacketing systems shall also provide the greatest degree of protection against water intrusion commercially and practically available, since this is an important factor in external corrosion.

6.0 WELDING

6.1 Welding Criteria

Welding and inspection procedures for the pipeline will be performed using procedures and operators qualified according to 49 195 and API Standard 1104. All welds will be made with materials that are compatible with the line pipe to avoid local corrosion at the welds and heat-affected zones (HAZ).

7.0 INTEGRATED CONTROL AND SAFETY SYSTEM (ICSS)

7.1 General Description of ICSS

The Eastern North Slope Gas Pipeline facilities will be operated and controlled by an Integrated Control and Safety System (ICSS) comprised of the following major systems or their equivalent.

7.1.1 Process Control System (PCS)

This system is typically primary means to control and monitor all operations of the facilities. Larger production facilities will monitor the pipeline from a fully manned, centralized control room (CCR) at the processing facilities. Control rooms are typically used to control, not only the equipment at the processing facility, but also the remote wellheads, control and monitoring of the pipeline, and the downstream pipeline tie-in. The PCS will be a distributed control system (or equivalent) relying on a redundant communication backbone to connect all of its components, per Federal regulations. The operator, engineering, controls computers shall be standardized and the personal computers and servers shall be of a type and manufacture recognized under Federal regulations.

7.1.2 Safety Instrumented System (SIS)

The Safety Instrumented System (SIS) for the Eastern North Slope Gas Pipeline will be a high integrity system to provide safety shutdown and annunciation of all critical processes. This system, which must be completely independent of the PCS, will serve to protect the pipeline, equipment and personnel from process upset and emergency conditions and the unexpected release of hazardous hydrocarbon vapors.

7.1.3 Fire Detection System (FDS)

Where needed, an independent, fire detection and alarm system compliant with State of Alaska Fire Marshal requirements shall provide early and reliable detection of fire hazards, prompt notification of a fire condition and activation of the fire suppression system. It will have hardwired interface to the SIS (or equivalent) for shutdown coordination and alarming.

7.2 Communication System

Per Federal requirements, the pipeline shall have multiple communication links. Communication links will be established between the process facility Control Center, other Control Centers, the beginnings and ends of the pipeline, and appropriate downstream facilities. If applicable, other pipeline and oil and gas field operators utilizing the pipeline must integrate communication systems enabling a quick response, should an emergency situation arise.

7.3 Leak Detection System

The pipeline design will include a computational leak detection system. The system will perform real-time monitoring for pipeline leakage and will use operating data such as flow and pressure-meter data. The equipment, at a minimum, will be used to compute mass-balance calculations that will be able to detect a leak of a size that is considered Best Available Technology (BAT).

7.4 Fire Detection and Suppression System

A fire detection and suppression system will be installed throughout the appropriate facilities. Integration of fire alarm reporting with other fields in the area will be encouraged.

7.5 Gas Detection System

Where appropriate gas detection monitors will provide alarm annunciation and shutdown activities.

8.0 OPERATIONS

8.1 Flow Control

At the processing facility, fluid will be pumped using shipping pumps. This equipment will raise the pressure in the pipeline as required to achieve the target flow rate.

8.2 Pipeline Isolation

Pipeline isolation valves shall be installed to facilitate emergency response. Typically, these will be located downstream of the pig launcher and upstream of the pig receiver at the Termination of the pipeline tie in.

8.3 Pressure Monitoring and Relief

The pressure on the discharge of the shipping pump(s) or compressor(s) will be monitored real-time. The shipping pumps or compressors will have high-pressure shutdowns to prevent over-pressuring the pipeline. To conform to regulations, multiple independent pressure control methods will be required on pipelines.

Where appropriate, backpressure control of downstream pipelines shall be included. Additionally, the pipeline shall have a pressure-relief capability, coupled with vents and/or drains, where appropriate. Liquid pipelines shall not have bottom-of-pipe (BOP) drains, due to the potential of pocketing of water and freezing.

8.4 Start-up

The initial start up will be made using production fluid. The start-up procedures will be developed during the detailed design of the system and submitted to the Department of Natural Resources. Startup of the pipeline may be monitored by personnel from DNR.

8.5 Flow Constraints

Engineering and design shall consider the flow constraints of the pipeline, including:

- Maximum and minimum temperatures requirements for delivery.
- Maximum and minimum temperatures to maintain the fluid within process specifications.
- Minimum pressure for delivery to downstream facilities.
- Over/under pressure conditions and their effects at termination of the pipeline.
- How the operator will operate the pipeline to avoid excessive condensate or other deposits.

8.6 Normal Operations

Engineering and design shall evaluate how flow rates, temperatures, and pressures will be monitored and controlled and how this information will be used by the control room, SCADA and other control and reporting functions.

8.7 Planned and Unplanned Shutdown of Pipeline(s)

The pipeline should be designed so that it can be shutdown at any time for planned or unplanned events without additional work. The line would only need to be de-inventoried to make repairs. Restart will be designed so that it will not be a problem even if the fluid is at the minimum ambient temperature (-50F).

8.8 Maintenance and Pipeline Removal

If above-ground pipe supports are built to include a provision for more than one (1) pipeline, they shall be supported on VSMs using a method similar to other North Slope pipelines. The spacing of pipelines supported by common VSMs will allow for thermal expansion of the pipelines by providing expansion loops and by building sufficient space between pipelines to allow for safe and efficacious maintenance. Typical details showing the spacing of the pipelines on the VSMs are shown in Figure 2. Unless there are mitigating circumstances, multiple pipelines on one pipeline rack shall be designed with a minimum two-foot clearance (as measured jacket-to-jacket) for maintenance and quick emergency response. This clearance is needed for use of slings. No pipeline will be stacked vertically.

If multiple pipeline are buried in close proximity, the pipelines shall have a minimum six (6) foot clearance (outside to outside) and have sufficient signage to allow for emergency response, good maintenance practices, and comply with federal regulations.

Pipeline valves must be periodically inspected and serviced where necessary and partially operated to verify proper operation, per Federal regulations. All pipeline valves will be designed and located to facilitate inspection and access for emergency response.

Abandonment activities will be consistent with lease terms, requirements in the Unit Agreement, permit conditions, and other applicable regulatory requirements. Detailed abandonment procedures will be developed and presented to the Department of Natural Resources at the time of project termination.

8.9 Surveillance

Periodic surveillance of the pipeline right-of-way will be conducted in accordance with Federal regulatory and ASME B31.4 requirements. The surveillance will also be as determined in the ODPCP in accordance with the Alaska Department of Environmental Conservation Regulations (18 AAC 75).

9.0 CORROSION CONTROL AND MONITORING

9.1 Corrosion Control Measures

9.1.1 Internal Corrosion

At a minimum, the corrosive effects of the fluid will be monitored through the use of corrosion coupons installed in the flow path and examined periodically. Corrosion control programs that conform to federal regulations and provide substantive environmental protection and protection of the land shall be developed.

9.1.2 External Corrosion

External corrosion will be controlled in accordance with Federal regulations. Typically, an above-ground North Slope gas pipeline has polyurethane foam insulation, covered with a galvanized metal jacket and sealed to prevent water intrusion. Field weld joint insulation kits currently used on North Slope pipelines should be used to prevent water from contacting the pipe at the field weld locations. External corrosion monitoring must be provided, per Federal regulations. External corrosion coatings are required under regulations.

For buried gas pipelines, an active corrosion protection system must be installed. The pipeline may have passive systems installed at special locations as required to conform to close interval survey requirements. The corrosion protection system shall comply with NACE 0169-96 or a later edition.

9.2 In-Line Inspection

The pipeline will be designed to allow passage of internal inspection devices in accordance with state and federal regulations. An inspection plan using internal inspection tools shall be established prior to pipeline operation. The inspection plan shall be completed in accordance with regulatory requirements to establish a baseline for the pipeline and on a five-year interval thereafter to monitor both internal and external corrosion.