Kenai – Kachemak Pipeline Project
Design Basis and Criteria

Prepared for:

Kenai-Kachemak Pipeline, LLC

KENAI-KACHEMAK PIPELINE PROJECT

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Contents

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Figures

Tables

Baker

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List of Acronyms

APC	Alaska Pipeline Company
BTU	British thermal unit
CP	Cathodic protection
CFS	Cubic feet per second
DCE	Design Contingency Earthquake
DOE	Design Operating Earthquake
DOT/PF	Alaska Department of Transportation and Public Facilities
HDD	Horizontal directional drilling
HEA	Homer Electric Association
INGAA	Interstate Natural Gas Association of America
KGF	Kenai Gas Field
KPB	Kenai Peninsula Borough
KKPL	Kenai-Kachemak Pipeline
LBM	Pound mass
LLC	Limited Liability Corporation
MAOP	Maximum allowable operating pressure
OSHA	Occupational Safety and Health Administration
ROW	Right-of-Way
SMYS	Specified minimum yield strength
SPCC	Spill Prevention, Control, and Countermeasure
SPCO	State Pipeline Coordinators Office

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Section 1.0 Introduction and Project Description

Presented in this document are design basis and criteria for the Kenai-Kachemak Pipeline (KKPL). The KKPL is a proposed natural gas transmission pipeline to be constructed on the Kenai Peninsula of Alaska

1.1 Project History

The proposed Kenai-Kachemak Pipeline Project will provide a transportation system to ship natural gas reserves from development sites to the Kenai Peninsula and other locations, such as Anchorage, see Figure 1-1. Marathon and GUT LLC, a wholly owned subsidiary of UNOCAL, have formed a limited liability corporation (LLC) to construct a natural gas transmission pipeline identified as the KKPL. The corporation is identified as the Kenai-Kachemak Pipeline, LLC (KKPL LLC). NORSTAR Pipeline Company has been authorized by the KKPL LLC to be their agent for the permitting and engineering phase of the project.

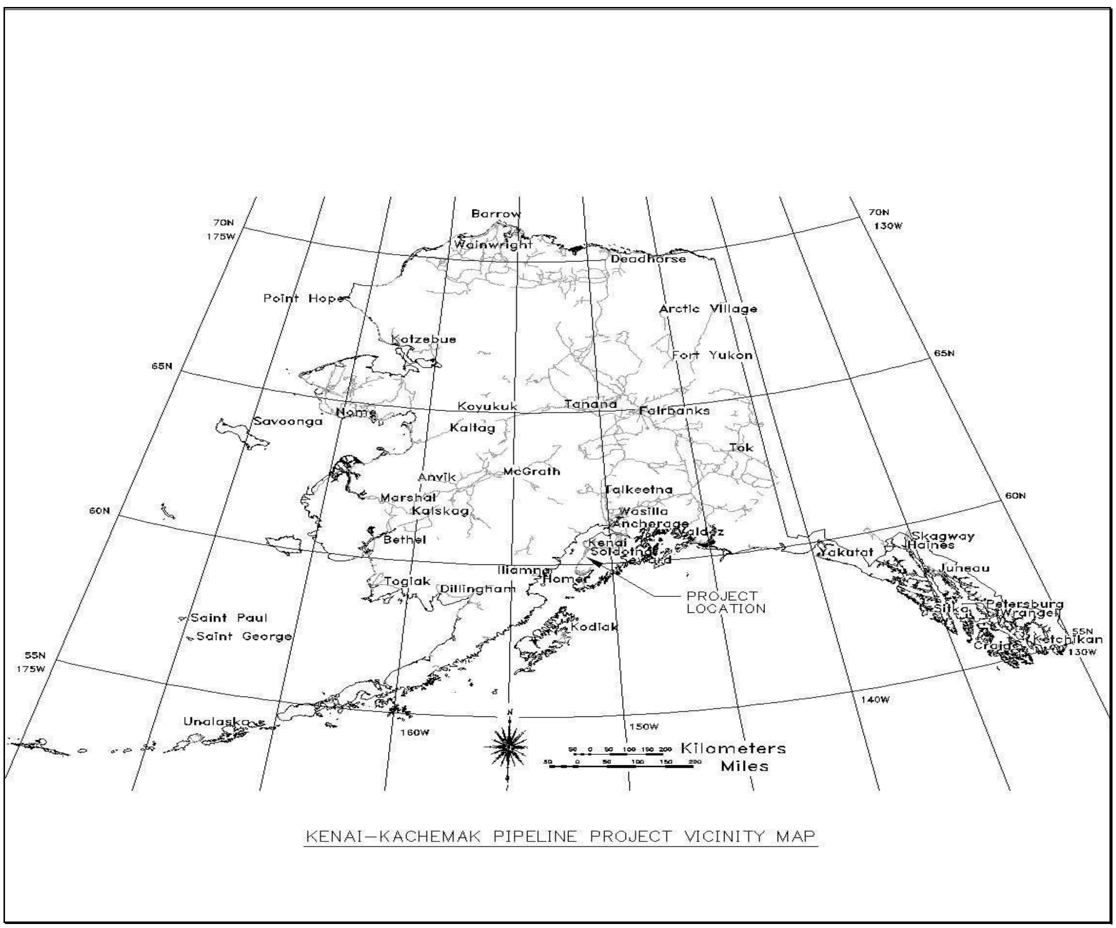


Figure 1-1 Project Vicinity Map

The main line will be approximately 32 miles of buried steel pipe with a nominal diameter of 12 inches. The pipeline will extend from a transfer of custody point east of the proposed Susan Dionne production pad near Sterling Highway milepost 128, to the Kenai Gas Field (KGF) near the Marathon 400 Master Meter Building (located east of Kalifonsky Beach Road), as shown on Figure 1-2. Pig launching and receiving facilities at each end of the pipeline will be abovegrade on private property.

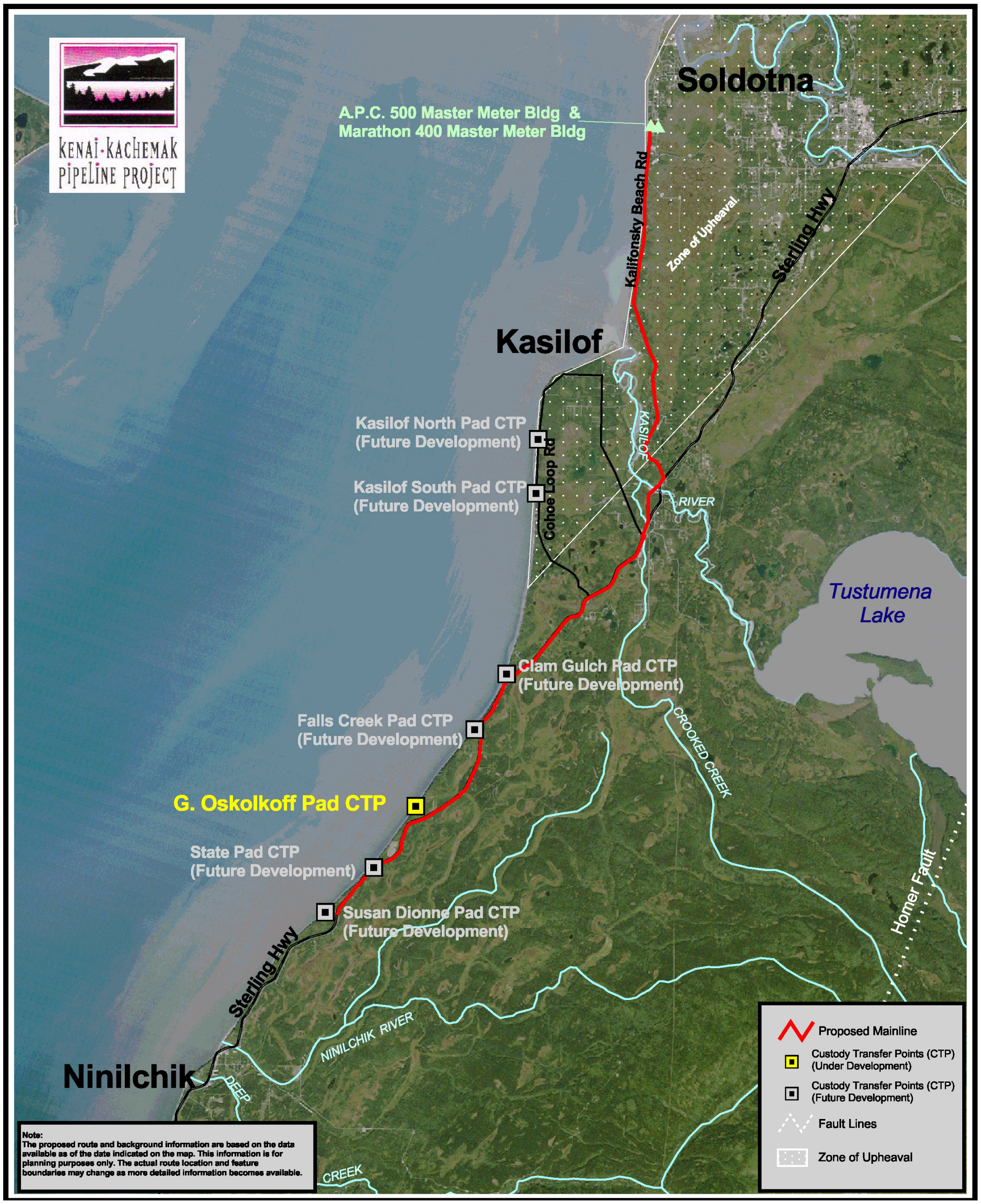


Figure 1-2 Project Location Map

The scope of this project is the natural gas transportation system. The exploration, development, and distribution of the natural gas will be separate projects by Marathon, UNOCAL, other exploration and production companies, or Enstar Natural Gas Company. The beginning of the transmission line occurs at the intersection of the unit boundary for the gas lease and the Alaska Department of Transportation and Public Facilities (DOT/PF) right-of-way (ROW). The transmission line ends at the flange upstream of the new flow meter building near the Marathon 400 Master Meter Building. A full and detailed legal description of the pipeline has been presented to the State of Alaska as part of a separate permit application package, and is not repeated herein.

1.2 Location

The KKPL is located on the west side of the Kenai Peninsula in southcentral Alaska. Natural gas will flow in the proposed pipeline in a generally south-north direction between the Susan Dionne Pad and the KGF near Kenai.

The proposed route generally follows the DOT/PF ROW along Kalifonsky Beach Road and the Sterling Highway. The pipeline route deviates from the DOT/PF ROW in some locations to optimize crossing the Kasilof River, to avoid population centers, and to access the transfer of custody points. A 20-foot ROW will be leased for operation of the pipeline. A 60-foot temporary ROW will be obtained for construction and as required for operation and maintenance activities. Temporary river crossing ROW permits (100-foot by 300-foot) will be obtained at select river/stream locations for construction activities.

1.3 Route Selection Process

During conceptual planning, alternative routes were evaluated for construction of the KKPL based on environmental, technical, and economic considerations.

Three routes were evaluated, and a fourth alternative was considered but eliminated from detailed consideration:

- DOT/PF ROW
- Homer Electric Association (HEA) Electrical Transmission Line ROW
- A combination of the DOT/PF ROW and HEA routes
- Beach route

Additionally, multiple river crossing alignments were evaluated for the Kasilof River and Crooked Creek.

Pipeline route selection was affected by several factors including avoidance of natural and man-made obstacles, land ownership and land interests, river and stream crossings, environmental impacts, and cost. Resources such as aerial photography, satellite imagery, USGS maps, Kenai Peninsula Borough (KPB) maps, and on-the-ground inspections were used to evaluate alternative crossings and routes. The selected route is a combination of the DOT/PF ROW and HEA ROW. This route satisfied all project requirements while minimizing impacts to the environment.

1.3.1 High Consequence Areas

High consequence areas are part of proposed regulations and are an operational rather than design consideration. The pipeline will comply when the regulations are adopted. The entire pipeline will be designed and built to Class Location 3 requirements in accordance with 49 CFR Part 192.

1.3.2 Class Location

The majority of the KKPL lies in Class 2 locations, as defined in 49 CFR 192. However, the entire pipeline will be designed as Class 3 to avoid having to upgrade the classification if future developments cause a change in class location. There are no Class 4 locations on the KKPL.

1.4 Kenai Natural Gas Field History

Natural gas has been produced from the KGF since the 1960s. The KGF is located south of the Kenai River across from the town of Kenai. Natural gas is still produced from the KGF, as well as from other sources both onshore and offshore of the Kenai Peninsula.

1.5 Existing and Proposed Natural Gas Production Sites

Unocal and Marathon are currently conducting exploration/drilling activities on the Lower Kenai Peninsula. The well locations and testing programs are targeted to prove the extent of reserves to support construction of the pipeline. Well locations are shown in Figure 1-2.

1.6 Natural Gas Composition and Qualities

Natural gas produced from existing Kenai Peninsula productions sites is dry natural gas, composed almost completely of methane. Results of a typical natural gas composition analysis are listed in Table 1-1. This is the natural gas composition used for design.

Table 1-1 Standard/Dry Analysis of Natural Gas

Component	Mole Percent
Methane	99.123
Ethane	0.179
Propane	0.046
(C6+)	0.001

Component	Mole Percent
Moisture	0.000
Nitrogen	0.449
CO_2	0.203
TOTAL	100.00

The test was performed by EG&G Chandler Engineering on August 6, 2001 on a sample from the "GO-1" well (Ninilchik Unit), from the Tyonek test interval Number 2, perforated between 10,026 feet and 10,070 feet. The heating value of the natural gas was 1010 BTU/cubic foot and had an absolute density of 42.8518 lbm/1000cubic feet. Gas sales contracts allow for up to 4 grains per 100 cubic feet of hydrogen sulfide (H_2S).

Section 2.0 Physical Environment

2.1 Geology

The KKPL Project area on the western side of the Kenai Peninsula in southcentral Alaska encompasses the physiographic provinces of the Nikishka lowland north of the Kasilof River. The hummocky surface includes marsh and muskeg areas. Glaciers in the surrounding mountains deposited a complex series of moraines in the area.

The project area is part of the Kenai Lowland, a broad coastal shelf 20 to 50 miles wide, between Cook Inlet and the Kenai Mountains. This linear basin contains sedimentary rocks and sediments that were laid down during the past 30 million years. The Kenai Lowland is less than 500 feet in elevation, and local relief generally ranges form 50 to 250 feet. The surficial geology of the area consists mostly of terraces and alluvial plains and morainal belts with some areas of muskeg, swamp, and elevated tidal flats. There are numerous undrained depressions containing small lakes, ponds, and marshes. The lakes and marshes make up more than one-third of the total surface. Muskeg covered benches are underlain by finely stratified sand and gravel. The area is covered by quaternary surficial deposits comprised of unlithified fluvial floodplain, colluvial, glacial, alluvial fan, landslide, and swamp deposits. Stratified silt, sand, and gravel predominate the area.

A recent geotechnical program was performed in the project area, focused exclusively on river and road crossings. Typical soil conditions found at the rivers included a few to several feet of peaty soils in the marshy areas, underlain by varying thicknesses of sands and gravels. A silt layer was commonly encountered at depth. Layers and inclusions of coal were encountered in the southern project area, commonly interbedded with fine sand and silt strata. Shallow groundwater was found in most areas near the river crossings.

2.2 Geography

The project is located between the parallels of 60° to 61° north longitude and the meridians of 151° and 152° west latitude, on the Cook Inlet coastal margin of the Kenai Peninsula. The KPB lies directly south of Anchorage, the largest city in Alaska. The waters of the Gulf of Alaska and Prince William Sound border the Peninsula to the south and east, while the Chigmit Mountains of the Alaska Range border the Borough to the west. The Cook Inlet divides the KPB into two landmasses. The Peninsula itself comprises 99 percent of the borough's population and most of the development. The Kenai Mountains run north and south through the peninsula, contrasting to the lowlands lying to the west.

The Kenai area is populated with moderate to dense forest. The area exhibits two vegetation types: coastal spruce-hardwood forest to the south and an open, low-growing spruce forest to the north.

2.3 Climate

The climate on the western side of the Kenai Peninsula is classified as transitional between the relatively mild maritime climate and the dry, cold, continental climate of the interior. The area is in a rain shadow of the Kenai Mountains. Annual precipitation and temperature are shown in Table 2-1 (National Climatic Data Center). Major rains fall July through September and the dry season is in the spring. The dry spring in terms of precipitation is offset by snowmelt runoff. The average snowfall for the area is sixty inches with an average maximum depth of less than three feet.

Table 2-1 Average Monthly and Annual Precipitation and Temperatures

	Average Precipitation (Inches)			Mean Air Temperature (°F)		
	Homer	Kasilof	Kenai	Homer	Kasilof	Kenai
Jan	2.3	1.0	1.1	22.8	13.3	12.6
Feb	1.8	1.1	1.0	25.3	17.1	16.5
Mar	1.6	1.0	1.0	28.8	23.4	23.0
Apr	1.3	0.7	0.8	35.4	33.3	33.4
May	1.1	0.8	1.0	42.6	41.9	43.7
June	1.0	1.1	1.2	49.1	49.5	50.2
July	1.6	1.6	1.9	53.1	53.8	54.5
Aug	2.6	2.5	2.7	52.9	52.3	53.6
Sept	2.9	3.0	3.4	47.3	46.0	46.9
Oct	3.4	2.4	2.4	37.8	34.3	34.7
Nov	2.7	1.5	1.5	29.1	21.0	21.0
Dec	2.8	1.6	1.3	23.7	15.1	14.5
Annual	25.0	18.3	19.3	37.2	33.3	33.6

Surface winds in the region tend to be strong and persistent. Strong winds are channeled up the inlet and mostly affect the shoreline. Average wind velocities at the Kenai Airport between 1992 and 1999 are shown in Table 2-2 (Alaska State Climate Center). Prevailing wind direction is north from September to April and south from May to August. The wind has the highest probability to blow north, however the wind may blow in any direction on any day of the year. Wind speed is generally less than 28 knots with an annual mean velocity ranging between 5 and 10 knots depending on direction.

Table 2-2 Kenai Average Annual Wind Speed

Average Annual Surface Wind Speed-Kenai Airport (knots)						
Calm	**1-3**	**4-6**	**7-10**	**11-16**	**17-21**	**22-27**
17.3%	6.3%	29.2%	27.3%	16.0%	3.2%	0.5%

2.4 Seismicity

Cook Inlet and the Kenai Peninsula are seismically active. No earthquakes with a magnitude greater than 8.0 on the Richter scale with an epicenter in the Cook Inlet region have been recorded. However, from 1899-1974 a total of 26 earthquakes with a magnitude of 6.0 on the Richter scale or greater with an epicenter in the Cook Inlet region occurred, including one of magnitude 7.3.

The project area is located in the zone of tectonic interaction between the North American plate and the relatively northwestward-moving Pacific Plate. The average rate of convergence near the southern Kenai Peninsula over the past 3 million years is 2.5 inches per year (Hastie and Savage 1970).

2.4.1 Seismic Zone

The Cook Inlet-Kenai Peninsula region is included in Seismic Probability Zone 3, an area of potential major damage from earthquakes greater than Richter Magnitude 6 (Evans et al. 1972).

2.4.2 Faulting

Known faults in the area trend northeast-southwest. No active faults are known to cross the pipeline route, based on research of United States Geological Survey (USGS), Alaska Division of Geological and Geophysical Surveys (DGGS), and other sources. There are, however, numerous faults both east and west of the pipeline route. The closest faults, Homer and Sterling, lie approximately 18 miles to the east. Other faults in the area include the Border Ranges Fault, Eagle River Fault, and the Bruin Bay Fault. Subsidence of the region including the Kenai Lowlands from the Great Alaskan Earthquake of 1964 was estimated to range from 2 to 4 feet.

2.4.3 Tsunami

No tsunami resulting from the Great Alaskan Earthquake of 1964 affected the Kenai Lowland. A large earthquake with an epicenter located in the Cook Inlet area could conceivably generate a tsunami that might damage shoreline structures. However, such a tsunami would not affect the project area because it is atop a high bluff above the coastline with substantial separation between the proposed pipeline and the crest of the coastal bluff.

Although waves as high as 24 feet were reported at Homer, Seldovia, and Halibut Cove as a result of the Great Alaskan Earthquake of 1964, no tsunamis were reported along the coast adjacent to the Kenai Lowlands. The proposed pipeline is located atop a bluff 50 feet high along Kalifonsky Beach Road and approximately 500 feet from Cook Inlet. Further south along the pipeline route, the bluff is 200 feet high and the pipeline is at least 800 feet from the water. Additionally, tsunamis affecting Cook Inlet are rare because of the relatively shallow water of the Cook Inlet.

The constriction effect of the Cook Inlet and the shoaling effect of the Barren Islands at the entrance to the Cook Inlet cause some reflection and scattering of the tsunami energy so that waves penetrating into Cook Inlet evolve at shorter periods. Their heights, too, would undergo considerable reduction from energy loss at the entrance and energy dissipation through refraction and diffraction into the wide basin of the lower Cook Inlet.

2.5 Environment

The transitional nature of the area environment is seen in the climate, vegetation, and diversity of animal population. Both black and brown bears range in the project area as well as porcupine, moose, otter, beaver, chipmunk, lynx, mink, fox, marten, marmot, mice, and moles. A wide variety of birds and fish inhabit the project area with major runs of red, silver, king, pink, and chum salmon in the area's rivers.

2.6 Hydrology

The project area is divided into two major watersheds with the predominant drainage pattern in each trending east to west. The northern watershed encompasses an area of approximately 750 square miles. The Kasilof River, Coal Creek, and Crooked Creek are included in this watershed. The southern watershed includes the Ninilchik River and Deep Creek, south of the southern end of the KKPL.

Runoff in the project area is characterized by minimal stream flows in February through April, with occasional low flow during dry summer months. Large glacier-fed streams continue to have high flows throughout the summer months. The Kasilof River is partially fed by glacial meltwater. The other streams are non-glacial and exhibit only moderate flows in late summer and fall. Peak flows typically occur in spring and are associated with snowmelt. Significant midsummer rains can also cause high water levels. Maximum flood runoff rates range from approximately 10 to 82 cubic feet per second (cfs) per square mile.

Surface water quality is generally good. High concentrations of naturally occurring calcium and bicarbonate ions are typical. The water is low in dissolved solids, chloride, and hardness. Most surface waters meet drinking water standards except for iron content and color. Due to glacial contributions, the Kasilof River contains moderate amounts of glacial flour and has generally lower concentrations of silica, dissolved constituents, iron, hardness, and color than the non-glacial streams.

Section 3.0 Technical

3.1 Criteria, Codes and Standards

This design basis and criteria was prepared based on applicable U.S. codes and standards, latest editions. All work will be performed in accordance with codes, standards, specifications, recommended practices, figures, and/or exhibits, which are part of the project design documents.

3.1.1 Codes and Standards

- ANSI – American National Standards Institute
  - ASC GPTC Z380.1, American Gas Association Guide for Natural Gas Transmission and Distribution Piping Systems, 2002
- API – American Petroleum Institute
  - 5L, Specification for Line Pipe, 2000 Edition
  - 6D, Specifications for Pipeline Valves, 2002 Edition
  - 6FA Fire Test for Valves
  - 1102, Steel Pipelines Crossing Railroads and Highways, 1993 Edition
  - 1104, Standard for Welding Pipelines and Related Facilities, 1999 Edition
- ASCE – American Society of Civil Engineers
  - 7-98, Minimum Design Loads for Buildings and Other Structures
- ASME – American Society of Mechanical Engineers
  - B16.5, Pipe Flanges and Flanged Fittings, 1998 Edition
  - B31.8, Gas Transmission and Distribution Piping Systems, 1999 Edition
  - B16.34a Valves-Flanged, Threaded, and Welding End, 1998 Edition
- CFR – Code of Federal Regulations
  - Title 49, Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, October 1, 2001
- EERI –Earthquake Engineering Research Institute (EERI)
  - Earthquake Design Criteria, Housner and Jennings, 1982
  - Ground Motion and Soil Liquefaction During Earthquakes, Seed and Idriss, 1982
  - Seismic Design Codes and Procedures, Berg, 1982

- NACE - National Association of Corrosion Engineers
  - RP0169-96, Control of External Corrosion on Underground or Submerged Metallic Piping Systems
  - RP0177-2000, Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
  - RP0286-2002, Electrical Isolation of Cathodically Protected Pipelines
  - RP0572-2001, Design, Installation, Operation, and Maintenance of Impressed Current Deep Groundbeds

3.2 Class Location

In accordance with 49 CFR 192.5, the majority of the proposed natural gas pipeline is identified as Class 2 location with a few areas identified as Class 3 location. To avoid upgrading the class location in the future due to changes in human occupancy, the entire pipeline and immediate branches will be designed to meet or exceed Class 3 DOT requirements.

Based on the Class 3 designation, the design factor, F, for steel pipe construction is 0.50 per 49 CFR 192.111.

3.3 Overpressure Protection

Overpressure conditions caused by production facilities will not be evaluated under this design basis. The pipeline operator will coordinate with the designers of the production facilities that will provide gas to the KKPL to ensure that the pipeline overpressure protection requirements of applicable codes and regulations are met.

3.4 Pipe Load Conditions

The design development for a pipeline system requires the identification of expected forces, imposed movements, and other external effects. The design loading conditions are based upon the loads anticipated during the useful lifetime of the system. Two general categories of design loading 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. These loadings are established in ASME B31.8. The loadings for the design operating condition on the belowground pipeline are:

- Internal design pressure
- Hydrostatic test pressure
- Temperature differential
- Dead and live loads

- Differential pipe movement
- Overburden loads
- Traffic loads

The design contingency condition is defined to include the sustained loadings for normal operating conditions combined with occasional loadings due to loss of soil support or earthquakes. Design contingency conditions will occur rarely, if at all, during the lifetime of the system.

Surge analysis is not applicable for natural gas due to the physical properties of the product.

3.4.1 Internal Design Pressure

The internal design pressure for the pipeline system is 1480 psi. This is based on the maximum allowable pressure for ANSI 600 Class, Material Group 1.1 in accordance with ASME B16.5.

The maximum allowable operating pressure (MAOP) in the pipeline system is equal to the internal design pressure used to calculate the minimum wall thickness of the pipe. The internal design pressure containment capacity of any component (fittings, valves, and line pipe) at any point within the pipeline system will meet or exceed ANSI 600 Class requirements.

3.4.1.1 Minimum Wall Thickness

The minimum wall thickness will be calculated in accordance with 49 CFR 192.105. The design wall thickness may be greater if determined necessary by stress analysis described in Section 3.4 to ensure resultant stresses remain within the allowable limits.

3.4.2 Hydrostatic Test Pressure

All pipe and components will be hydrostatically tested to a pressure not less than 1.5 times the MAOP per 49 CFR 192.503. The maximum hoop stress during hydrotest will be less than the Specified Minimum Yield Strength (SMYS). The pipeline will be designed to accommodate the test conditions as an operating basis loading. The minimum hydrostatic test duration will be in compliance with 49 CFR 192.505.

3.4.3 Temperature Differential

The maximum and minimum design operating temperatures for the buried pipeline (including HDD and bored road crossings) is 120°F and 20°F, respectively. For aboveground pipe, the maximum and minimum design operating temperatures are 120°F and -40°F, respectively.

3.4.4 Dead and Live Load

The dead loads include the pipe weight, external coatings, piping components, and buoyancy control devices. The live load is the weight of the pipe contents.

3.4.5 Differential Pipe Movement

Differential pipe movement may be caused by frost heave, settlement, flotation, and thermal expansion and contraction. The potential for thaw settlement is low, as permafrost is not generally found on the Kenai Peninsula. Applying appropriate buoyancy control measures will control flotation. Frost heave will not be a significant concern due to the burial depth of the pipe and the fact that the natural gas will not be chilled. Differential movement caused by thermal expansion will be minimal due to restraint by the trench backfill. Axial friction and passive soil restraints will limit the pipe movement at the sidebends. The pipe will be designed to accommodate a 2-foot differential movement. Greater differential movement may be tolerable in some cases, and shall be allowed if validated by site-specific analysis. Differential pipe movement will be considered a secondary load.

A buried pipeline is essentially continuously supported by the ditch bottom. It is recognized, however, that certain geotechnical conditions could cause movement of the supporting soil.

For short sections, the pipe will be able to span an unsupported section without exceeding the design criteria. The vertical displacement of the pipe will be resisted by the stiffness of the pipe, by the strength of the supporting soil on each side of the span of settlement, and by the longitudinal restraint provided by the soil.

Frost heave is a potential source of differential pipeline movement. However, it is not expected to be a significant design consideration for the KKPL. In order for frost heave to occur:

1. There must be a freezing front.
2. There must be a water source capable of supplying ice growth at the freezing front.
3. The soil must be capable of supporting capillary transfer of water (a function of the abundance of soil particles 0.02 mm in diameter and finer).

Conditions 2 and 3 almost certainly occur at some points along the pipeline route, and it is impractical to attempt to mitigate either of these factors. Condition 1 is the reason frost heave is unlikely to cause significant differential pipe movement.

Since gas entering the KKPL will not be chilled and hydraulic operating conditions will not induce Joule-Thompson cooling, the only potential mechanism for providing a freezing front will be seasonal freezing. Since the pipeline will be buried with a minimum 4 feet of cover and the pipeline diameter will be 12-inches, the bottom of pipe will be 5 feet below the ground surface. Seasonal frost on the Kenai Peninsula will not reach deeper than 5 feet in most years; particularly not when there is a significant thickness of snow cover. In order for deeper frost penetration, there generally needs to be a combination of very cold temperatures, little or no snow cover, and/or coarse soils with low moisture content. Coarse soils with low moisture content do not present a frost heaving risk.

If frost were to penetrate deeper than the bottom of pipe, it would not penetrate significantly deeper. Furthermore, the thermal resistance resulting from more than five feet of frozen soil overlying the freezing front is very high. It is unlikely that the heat transfer necessary to allow freezing of a significant thickness of segregated ice at this depth would be sufficient to result in frost heaving. In addition, the heaving forces would need to be extremely high to push the pipeline upward, since the upward movement is resisted by 4 feet of frozen soil over the top of pipe.

Frost heaving has not presented problems for Enstar Natural Gas Company in over 40 years of operating buried gas pipelines in Southcentral Alaska.

3.4.6 Overburden Loads

Overburden is the backfill soil that is placed around and over the pipe in an excavated ditch. The pipe will be designed to withstand the maximum overburden load experienced. The weight of the soil above the pipe will be considered a primary load.

3.4.7 Traffic Loads

The Sterling Highway and Kalifonsky Beach Road are classified as major road crossings. All other public roads are classified as minor road crossings. Minor roads will be crossed using open cut and major roads will be bored. If wall thickness is to be increased based on external load calculations, the increased wall thickness will extend a sufficient distance from the edge of pavement to ensure pipeline integrity.

Pipeline burial depths for road crossings will be determined based on load calculations in accordance with API 1102 and DOT/PF requirements (if any). The pipeline will be sized to safely withstand internal and external loads at road crossings.

3.4.8 Loss of Soil Support

Erosion, scour, and liquefaction are phenomena that could lead to loss of soil support. Erosion is the most likely circumstance that could lead to loss of soil support and forms the basis for setting loss of support criteria. The project approach to stream and drainage crossings where there is significant risk of erosion is to install the pipeline by HDD, and placing it well below the depth to which scour or erosion could occur. Thus, the crossings where risk of loss of support due to scour or erosion is highest are smaller streams that are installed using conventional methods.

The streams and drainages that fall into this category are typically less than 10 feet wide. Potential scour or erosion would almost certainly be confined within banks. To address uncertainty in predicting the loss of support under these conditions, a generous safety factor is warranted. Therefore, the design loss of support for the project will be 50 feet.

3.4.9 Earthquake Loads

The pipeline will be designed to resist seismic forces. The KKPL project area is located in an active seismic region. The available engineering survey data has not indicated zones of potential soil liquefaction or surface fault locations along the route. The significance of any seismic hazard will be assessed on completion of the engineering surveys. Potential seismic hazards that will be considered for the pipeline include:

- Liquefaction
- Fault Displacement
- Ground Motion

3.4.9.1 Liquefaction

Liquefaction risk is greatest where soils are medium to fine grained clean sand in relatively loose state, and saturated. Liquefaction ground failure risk is greatest where liquefaction-susceptible soils occur on or beneath a slope. The principle risk to the pipeline from liquefaction is from large ground movements that may result from slope failure. Primary mitigation of this risk is in pipeline routing. The pipeline has not been routed across major cut or fill slopes or other slopes that are known to be unstable.

Additional evaluation of liquefaction risk for this project will include the following:

- **Liquefaction Surveillance** – Route surveillance may be conducted in areas where liquefaction may be suspected. This activity would include searching for areas that may have experienced liquefaction failures in the past, identifying potentially unstable configurations, collecting surface samples, and performing a screening analysis.

- **Additional Investigation** – If any areas are found where liquefaction is judged to be a potentially significant risk, additional investigation may be performed. This investigation could include analysis of existing soils data, calculations, analysis with commercially available computer models, or additional field investigation. The appropriate form of additional investigation may be determined based on the conditions found.

Results of this work will be transmitted to the SPCO.

3.4.9.2 Fault Displacement

Previously published geological studies indicate that the pipeline ROW does not cross any active fault zones (see Section 2.4.2). Therefore, consideration of fault displacement for pipeline design is not required.

3.4.9.3 Ground Motion

For the evaluation of the buried pipeline subjected to earthquake ground motion, it may be assumed that the pipeline and the ground will essentially move in unison. However, the strain transmitted to the pipeline will be substantially less than the strain induced in the soil. Nonetheless, a conservative approach to calculating pipeline strain is to assume that the pipeline strain equals the soil strain. The soil strain is calculated as follows:

$$\varepsilon = \nu / 2c \text{ (Newmark 1973)}$$

where:

ε – *Pipeline strain*

ν – *design ground velocity*

c – *Speed of seismic wave propagation*

Literature from the Earthquake Engineering Research Institute (EERI) recommends a design value of 33 in/sec (85 cm/sec) for ν for a liquefied natural gas (LNG) plant in southern California. The Trans-Alaska Pipeline System (TAPS) Design Basis (as updated in 1997) recommends a value of 29 in/sec for new designs. The value of 29 in/sec has been adopted for this project.

Values of c range from less than 7,000 in/sec to 30,000 in/sec based on the properties of the upper 100 feet of the site profile (ASCE 7-98). The value of 14,400 in/sec has been adopted for this project, to reflect the characteristics of the overconsolidated soils underlying surficial deposits.

The maximum axial strain in the pipeline resulting from ground shaking is 0.001. The stress associated with the calculated strain will be included in stress analysis for the gas pipeline as a contingency load (Design Contingency Earthquake). The design ground velocity for the Design Operating Earthquake (DOE) will be taken as one-half of the value for the Design Contingency Earthquake (DCE).

Aboveground pipeline components will be designed to withstand forces generated by earthquake ground motions in accordance with ASCE 7-98.

3.5 Pipe Stress Criteria

The KKPL project is subject to the requirements of 49 CFR 192. This federal regulation places limitations on the allowable internal pressure but does not specify other loads, loading combinations, or limitations on combined states of stress. Detailed industry requirements are addressed by the ASME Code for Pressure Piping B31.8.

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

- **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. The stresses caused by the following loads are considered as primary stresses: internal pressure, external pressure including overburden, and dead and live loads.

- **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. The stresses caused by the following loads are considered as secondary stresses: temperature differential, differential settlement, and earthquake motion.

- **Combined Stresses** – Stress criteria limitations were imposed for combinations of primary and secondary stresses. The stress state in any element of the pipeline is defined by the three principal stresses acting respectively in the circumferential, longitudinal, and radial directions. 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.

3.5.1 Load Combinations

Pipe load conditions will be analyzed in the combinations shown in Tables 3-1 and 3-2. When calculating equivalent stresses, the most unfavorable combination of loads that can be predicted to occur will be considered. Equivalent stresses will be calculated using the Tresca equation.

For the purpose of calculating equivalent stresses, hoop stress will include all relevant circumferential stresses and be based on nominal values of diameter and wall thickness.

Table 3-1 Cross Country Pipeline Load Combinations

		Pipeline Load Combinations										
		Testing		Operating						Contingency		
Load Type	**Description**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Primary	Internal Pressure			X		X	X		X	X	X	X
Primary	Hydrotest Pressure	X	X									
Primary	Dead Load		X			X	X	X	X	X	X	X
Primary	Live Load		X[1]			X	X	X	X	X	X	X
Primary	Soil Overburden		X			X	X	X	X	X	X	X
Primary	Traffic Loads		X					X	X			
Secondary	Earthquake Ground Motion					X	X					X
Secondary	Temperature Differential		X[2]		X		X		X	X	X	X
Secondary	Differential Pipe Movement									X		
Secondary	Loss of Soil Support										X	

[1] Live load for hydrotest is the loading from the hydrotest fluid.

[2] Temperature differential for hydrotest is based on the difference between tie-in temperature and hydrotest temperature.

Table 3-2 HDD Pipeline Load Combinations

		HDD Load Combinations										
		Construction	Testing		Operating							Contingency
Load Type	Description	1	2	3	4	5	6	7	8	9	10	11
Primary	Internal Pressure				X		X	X	X	X	X	X
Primary	Hydro Test Pressure		X	X								
Primary	Dead Load	X		X			X	X	X	X	X	X
Primary	Live Load			X[1]			X	X	X	X	X	X
Primary	External Pressure	X		X			X	X	X	X	X	X
Primary	Buoyancy	X		X				X		X		
Primary	HDD Pulling	X										
Secondary	Temperature Differential			X[2]		X			X	X	X	X
Secondary	HDD Curvature	X		X			X	X	X	X		
Secondary	Earthquake Ground Motion										X	X

[1] Live load for hydrotest is the loading from the hydrotest fluid.

[2] Temperature differential for hydrotest is based on the difference between tie-in temperature and hydrotest temperature.

3.5.2 Allowable Stresses

Circumferential, longitudinal, shear and equivalent stresses will be calculated considering stresses from all relevant load combinations. Calculations will consider flexibility and stress concentration factors of components other than straight pipe.

Table 3-3 Pipeline Allowable Stresses

Criterion	Value	Basis	Load Combination
Hydrotest Stresses			
Hoop Stress (hydrotest pressure)	1.00 SMYS	B31.8, 841.322	1
Longitudinal Stress (hydrotest pressure, hydrotest temperature, hydrotest live and dead load)	1.00 SMYS	Project Design	2
Primary Stresses			
Hoop Stress (design pressure)	0.50 SMYS	49 CFR 192.111 B31.8, 841.11	3
Secondary Stresses			
Longitudinal Stress Range (temperature differential, tie-in to operating)	0.72 SMYS	B31.8, 833.4	4
Combined Stresses			
Longitudinal Stress (design pressure, live and dead load and other operating loads)	0.75 SMYS	B31.8, 833.4	5 & 7
Longitudinal Stress (design pressure, live and dead load, temperature differential, and other operating loads)	1.00 SMYS	B31.8, 833.4	6 & 8
Longitudinal Stress (design pressure, live and dead loads, temperature differential and contingency loads)	1.15 SMYS	Project Design	9, 10 & 11

Table 3-4 HDD Allowable Stresses

Criterion	Value	Basis	Load Combination
Construction Stresses			
Longitudinal Stress, (dead load, and construction loads)	1.00 SMYS	Project Design	1
Hydrotest Stresses			
Hoop Stress (hydrotest pressure)	1.00 SMYS	B31.8, 841.322	2
Hoop Stress (hydrotest pressure) and Longitudinal Stress	1.00 SMYS	49 CFR 192.111 B31.8, 841.11	3
Primary Stresses			
Hoop Stress (design pressure)	0.50 SMYS	49 CFR 192.111 B31.8, 841.11	4
Secondary Stresses			
Longitudinal Stress Range (temperature differential, tie-in to operating)	0.72 SMYS	B31.8, 833.4	5
Combined Stresses			
Longitudinal Stress (design pressure, live and dead load and other operating loads)	0.75 SMYS	B31.8, 833.4	6 & 7
Longitudinal Stress (design pressure, live and dead load, temperature differential, and other operating loads)	1.00 SMYS	B31.8, 833.4	8, 9 & 10
Longitudinal Stress (design pressure, live and dead loads, temperature differential and contingency loads)	1.15 SMYS	Project Design	11

3.6 Hydraulics

The pipeline will be sized to handle a maximum flow rate of 260 MMscfd with a maximum pressure drop of 750 psi. For hydraulic purposes, the maximum inlet pressure of the pipeline system is 1454 psi, and a design gas temperature of 20°F is used based on a corresponding typical ground temperature. The outlet pressure of the pipeline is 700 psi. Based on gas composition, pipeline hydraulic profile, and local experience, neither water condensation nor the formation of distillates are expected. Pipe design parameters for hydraulic analysis are summarized in Table 3-5.

Table 3-5 Pipe Design Parameters for Hydraulic Analysis

Diameter (in)	[1]MinimumWall Thickness (in)	Assumed Gas Temperature (°F)	Minimum Outlet Pressure (psi)	Maximum Inlet Pressure (psi)
12.75	0.330	20	700	1454

[1] The minimum wall thickness is based on a SMYS of 60 ksi.

3.7 Pipe Properties

The pipe will have an outside diameter of 12.75 inches. Typical wall thickness will be 0.330 inch based on API 5L material grades X60. The wall thickness for HDD and river crossings will be 0.500 inch based on API 5L material grade X52. The SMYS will not exceed 70 ksi for any pipe material. Wall thickness is based on Class 3 Location (49 CFR Part 192) and an internal design pressure of 1480 psi. No additional wall thickness will be provided as a corrosion allowance.

3.8 Geotechnical

Near-surface soils along the proposed pipeline route are variable. However, the only design parameter that changes as the soils change is the need for buoyancy control. As the pipeline passes from silt to sand to gravel, the basic design and construction mode remains the same. When the pipeline passes through high groundwater areas containing peaty soils that provide little vertical upward restraint, buoyancy control will be applied. Other special conditions (such as occurrence of boulders or sharp, angular rock in the backfill that require coating protection) will be handled during construction in accordance with project specifications.

Geotechnical investigations for the proposed pipeline have been limited to subsurface borings at selected river/creek crossings. Previously published geotechnical reports were also reviewed with respect to the river crossings (DOT/PF, 1963).

3.8.1 Thermal Design Data

The Kenai Peninsula including the limits of this project is generally free of permafrost. The route is moderately forested and the region is physically referred to as lowlands ranging in elevation from approximately 50 to 250 feet above sea level. Environmental factors, as published in the Alaska (Hartman and Johnson 1978), which effect depth of freeze are outlined below:

- Freezing Index — 900 to 1500 degree-days
- Design Freezing Index — 2200 to 2400 degree-days
- Thawing Index — 3000 degree-days
- Design Thawing Index — 3900 degree-days

3.8.2 Buoyancy Control

Pipeline segments below the water table (or submerged) will have an associated buoyancy force acting upward on the pipeline. Buoyancy control methods will be developed to counteract the effects of buoyancy.

Possible buoyancy control measures include:

- Geotextile swamp weights

- Concrete coatings
- Additional wall thickness
- Bolt-on weights
- Concrete weights

The buoyancy control measure size, spacing, and installation method must be reviewed in order to assure that deflection and stress on the pipe are not exceeded during installation or after backfill. The pipeline will be designed to achieve a minimum 5% negative buoyancy.

Wetland segments identified in the project planning phase will be designed with buoyancy control. Additional segments encountered during construction that require buoyancy control will be identified and mitigated by the Construction Engineer in accordance with project specifications.

3.8.3 Soil Properties

The scope of the geotechnical investigation for this project was limited to drilling and sampling 26 borings at locations of potential river/creek crossings and select highway crossings. Section 2.1 describes the project geological characteristics as well as a brief description of subsurface findings. Table 3-6 presents basic properties of soils identified during the geotechnical investigation along the proposed alignment:

Table 3-6 Soil Properties

Soil Type	USCS Designation	Moisture Content Range (%)	Dry Unit Weight Range (pcf)
Peat	PT	50-250	10-25
Silt	ML	10-60	80-110
Sand	SP and SM	2-30	90-120
Gravel	GW	5-25	120 - 135

3.9 Corrosion Protection

3.9.1 External Coating

A primary corrosion control external coating in accordance with 49 CFR 192.461 and 49 CFR 192.479 will be applied to all buried and aboveground pipes, respectively. A dual layer coating system comprising of a primary layer for corrosion protection and a secondary outer layer for mechanical protection is recommended for HDD crossings. Appropriate quality assurance and quality control measures including use of a high voltage electrical holiday detector will be employed to verify the integrity of all coated pipe.

3.9.2 Cathodic Protection

The cathodic protection (CP) solutions will consider the annual variations in soil resistivity due to seasonal frost. The design of impressed current facilities will consider the impact on pipeline coating response or damage that may arise from excessive voltage or current.

The impressed current CP system will be designed in accordance with 49 CFR 192.463 and the guidelines in NACE RP0169-96 and the electrically isolated in accordance with requirements in 49 CFR 192.467 and NACE RP0286-97, respectively.

3.9.2.1 Test Stations

Two wire potential test stations will be located at specified intervals along the pipeline route. Four wire current span test stations will be installed at each end, the midpoints, and at specified intervals along the pipeline route. Where the pipeline crosses other conductive objects or utilities, or passes through an insulated area or fitting, additional test stations designed specifically for that configuration will be installed. Separate test stations shall be provided where bonding between metallic structures is needed.

Thermite welding shall be used to attach pipe leads. Thermite welds to the pipe shall not use a charge greater than 15 grams.

3.9.2.2 Cathodic Protection Design

Conductive connections to the pipeline will be strictly controlled. The deep well anode beds will be installed in a drilled hole at depths based on the soil strata observed during installation. Use NACE Standard RP0572-95 to design deep anode beds. The anodes will be based upon cast high-silican chromium iron center-connected tubular anodes. Rectifiers will be used at each deep anode bed. For monitoring and controlling the output of individual anodes, junction boxes with slots for each anode will be used. Venting of the anode bed is required.

3.9.2.3 Low-Resistance Grounding

To achieve low-resistance grounding, the pipeline will be electrically isolated from infrastructure such as electrical cables and ground grids, instrumentation and controls, wiring, associated raceways, piling systems, and reinforced concrete fabrications. Valves shall be individually grounded. Piping into and out of operating facilities shall be isolated.

3.9.3 Stray Currents

A characteristic of the isolated pipeline is that it may become a good conductor of induced currents generated by local high voltage power lines, electrical fault currents, and lightning strikes. To minimize this possible hazard, the pipeline will be grounded. Solid-state DC stray current blocking devices (e.g., polarization cell replacements (PCR)), that allow AC grounding will be used to de-couple the cathodically protected pipeline from the potential stray currents. These devices are approved by United States Department of Transportation Office of Pipeline Safety (USDOT/OPS) for use on buried pipelines for this purpose, and have been used successfully in Southcentral Alaska.

3.9.4 Isolation

An isolation system will be installed to control stray electric currents in the pipeline, and facility piping systems. The isolation system will also increase the cathodic protection system effectiveness and confine or eliminate electrolytic corrosion. Isolation joints will be installed at above ground tie-ins as required. Belowground isolation requires prefabricated isolation joints meeting the requirements of 49 CFR 192 and ANSI B31.8.

3.10 Welding

Welds will be compatible with the base material in order to avoid local corrosion of weldment and heat-affected zone. Welding and nondestructive examination (NDE) on the pipeline will be performed using procedures and operators qualified in accordance with 49 CFR 192 Subpart E and API 1104.

Section 4.0 Pipeline System Components

4.1 Pipeline

The mainline pipeline will be designed as an ANSI 600 Class system and will comply with API 5L. Minimum wall thickness will be based on calculations per 49 CFR 192.105 and will be increased to the nearest standard API 5L thickness.

4.2 Bends

The minimum bend radius will be five times the nominal diameter of the pipe. Field bends will be fabricated in a manner that ensures pigging of the line is maintained. Where field bends are not feasible, induction bends will be installed. All bending of pipe will be accomplished in a manner to ensure the capability to perform maintenance pigging and to accommodate internal inspection tools (pigs).

4.3 Flanges and Fittings

All flanges and fittings will be designed for normal operational requirements (design pressures, temperatures including expected variations, pressure test, and load effects) in accordance with applicable codes, standards and specifications, including:

- ASME B16.5a, Pipe Flanges and Flanged Fittings. NPS ½ through NPS 24

Forged tee fittings or, for small diameter branches, standard weld-o-lets will be installed at all pipeline branch locations. Both field welding and shop welding are acceptable provided the weld design is sufficiently analyzed to ensure adequate strength. All branch tees on piggable sections of the line will be barred.

4.4 Valves

Valves will be designed in accordance with applicable codes, standards, and specifications including:

- ASME B16.34a, Valves – Flanged, Threaded and Welding End
- API 6D, Specification for Pipeline Valves (Gate, Ball and Check Valves)
- API 6FA, Fire Test for Valves

Mainline block valves outside of mainline pipeline metering stations and smart pig launching/receiving stations (facilities) will be full port ball valves with weld end connections installed belowground, will have manual operators, and bypass/ blowdown piping.

Mainline block valves inside of the facilities will be full port ball valves with flange connections installed aboveground near the facility boundaries and include manual operators and bypass/blowdown piping will be installed on all mainline block valves.

Valve installation and backfill will be governed by project excavation and backfill specifications, which will address adequate supporting soils and backfill material for valves. All mainline block valves will have fences and security measures installed as appropriate.

4.5 Launchers and Receivers

Pipelines will be designed to accommodate maintenance and internal inspection tools (smart pigs). All pig launchers and receivers will be located on private property and will be designed in accordance with appropriate codes and standards, including:

- ASME B16.5a, Pipe Flanges and Flanged Fittings. NPS ½ through NPS 24
- ASME Boiler and Pressure Vessel Code, Section VIII: Pressure Vessels - Division 1, 2001

Design and location of pig launchers and receivers (traps) will consider the following:

- Provision and location of permanent pig traps or connections for temporary pig traps
- Safety of access routes and adjacent facilities
- Lifting facilities
- Isolation requirements for pig launching and receiving
- Requirements for venting and draining
- Minimum permissible bend radius
- Distance between bends and fittings
- Maximum permissible change in diameter
- Tapering requirements at internal diameter changes
- Design of branch connections and compatibility of line pipe material
- Internal fittings
- Pig location signals
- Spill prevention, protection and containment

A launcher will be located at the southern terminus of the pipeline. The receiver will be located at the pipeline northern terminus. The launcher and receiver will be equipped with valves capable of safely relieving pressure in the barrel before insertion or removal of pigs, as well as pressure indicators to ensure that pressure has been relieved. The pig trap will be equipped with the necessary appurtenances for efficient and safe operation of the pipeline system during the pigging process. Pig location signals will also be installed near the launcher and receiver.

All design, fabrication, and inspection of closures and details such as vent, drain, purge and kicker branches, nozzle reinforcements, saddle supports, and other items not classed as standard pipeline sections, will comply with ASME Section VIII, Division 1.

4.6 Future Natural Gas Supply and Discharge Points

Possible future gathering lines may tie-in to the mainline pipeline over the life of the project. Several potential input locations have been identified and may be connected to the mainline pipeline based on commercial viability of each site. These locations are distributed along the entire length of the mainline. Tie-ins may be accomplished by either hot-tapping the mainline or full cut-in of branch tees.

The possibility of future distribution lines being connected to the mainline also exists. The size and distribution of future supply lines will be installed dependent on the population density of the specific areas and the economics of potential natural gas sales. All future designs will comply with the criteria set forth in this document and will be submitted to SPCO for review prior to construction. Metering facilities will be provided where natural gas is added or removed from the mainline. These facilities may or may not be located adjacent to the mainline ROW depending on project specific criteria.

4.7 Supports and Anchors

Detailed analyses will be performed on any aboveground facilities as well as any transition areas between aboveground and belowground facilities to determine the requirements for supports, anchors, and expansion bends. These analyses will consider pipeline axial forces (installation temperature, operating temperature, ambient temperature, operating pressure), equipment cycles, soil strength, soil-to-pipe friction, and pipe/assembly size, weight, and orientation.

The pipeline and equipment will be adequately supported to prevent or dampen excessive vibration or expansion, and will be anchored sufficiently to prevent undue loads on connected equipment.

Section 5.0 Crossings

The proposed pipeline crosses numerous streams, rivers, wetlands, roads, other pipelines, and utilities. Each crossing will be designed to maintain pipeline integrity throughout the design life and to minimize environmental impacts. If unanticipated conditions force a crossing to be cased, the State Pipeline Coordinators Office (SPCO) will be consulted while making the decision.

5.1 River Crossings

River and stream crossings will be designed to maintain pipeline integrity under design scour and bank migration conditions. Construction of river and stream crossings will be scheduled with appropriate permitting agencies to minimize environmental impacts.

5.1.1 Hydrology and Hydraulics

Approach and criteria for hydrologic evaluation and hydraulic design are presented in this section. Results of evaluations and design data are presented in the KKPL Scour and Bank Migration Report (Baker 2002).

River and stream crossings will be designed using information collected during hydrological investigations, hydraulic calculations, and bank migration studies. Hydrological investigations will include land surveys to define the configuration of the river banks and floodplain in the vicinity of the proposed crossing at larger river crossings, cross-sections where appropriate, visual observations, discharge measurements, bank migration studies, and investigation of historical flow data.

Results of the hydrology and hydraulics work will include topographic maps and cross sections, design flood frequency and discharge, design bank migration limits, and design scour depths. Since no portion of the pipeline system will be aboveground near river or stream crossings, the height of the design flood is not relevant, and will not be estimated for this project. Results of this work will be used to define the pipeline configuration at the crossings, including design depth and scour control points.

Scour will be estimated using the Blench Method (Blench 1969). No portion of the pipe within a trenched stream crossing will be less than 4 feet beneath the thalweg (the line extending down a channel that follows the lowest elevation of the bed) at the crossing site or the computed scour depth, whichever is greater. The design flood will have a recurrence interval of 100 years.

Where necessary, bank migration will be investigated using aerial photographs. Recent historic aerial photographs of suitable quality for the reach containing the crossing will be obtained and studied. Bank lines visible in the historic photos will be compared to those from the recent photos. If bank loss has occurred during the period defined by the two photo sets, the rate of bank loss will be computed. This average annual bank loss will be multiplied by the design life of the pipeline to calculate the estimated bank loss. An appropriate buffer will be added to the estimated bank loss to define the design bank migration limits.

In order to minimize damage to the streambeds and banks, construction equipment will not be allowed to directly cross the streams except by bridge. Temporary bridges will span the ordinary high water elevation plus two feet of freeboard. During winter construction, ice bridges or low water crossings with concrete mats will be utilized. Construction activities will comply with an approved Storm Water Pollution Prevention Plan.

5.1.2 River and Stream Crossing Methods

River and stream crossings will be constructed using one of three methods. Small streams with manageable flow rates and not flowing to anadromous waters will be crossed using the open cut method. Streams where flow is too great for open cut or are flowing to anadromous streams will be constructed using the dam and pump method. Larger, anadromous streams will be crossed using HDD.

5.1.2.1 Open Cut Crossings

Open cut crossings of small streams will be done during periods of low flow to reduce the potential impacts to the stream. This option will only be used for small streams that have little or no flow during the winter months. Care will be taken to ensure that damage to the surrounding vegetation is reduced, and bank lines will be restored as close as possible to original condition. See Figure 5-1 for a typical trench cross-section, which is the same for open cut and dam-and-pump crossings.

5.1.2.2 Dam and Pump Crossings

In streams where environmental restraints preclude open cut, the dam and pump method will be used. This method will minimize environmental impacts and provide a suitable construction condition. In this method, dams are constructed upstream and downstream of the proposed river crossing, spaced a suitable distance apart to provide room for construction activities. Water is pumped or flumed around the work site, from above the upstream dam to below the downstream dam. If necessary, minimal amounts imported backfill may be used. The following will be evaluated when designing the dry cut river crossings:

- Control of sedimentation in the river
- Safeguarding wildlife, including aquatic life
- Energy dissipation at the pump suction and discharge or flume entrance/exits
- Dam construction and volume depending on the size, geology and other environmental constraints

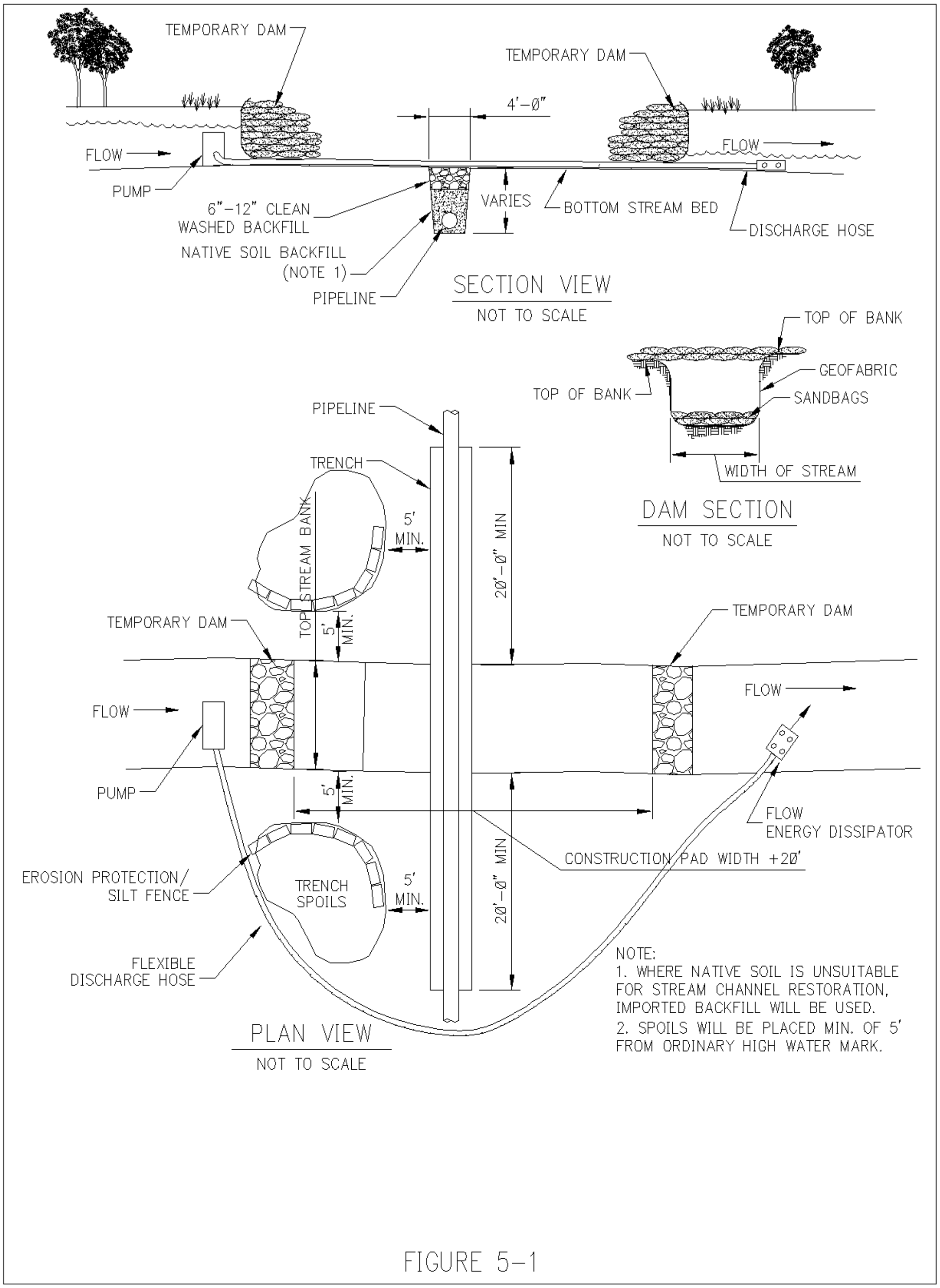


Figure 5-1 Dam & Pump Stream Crossing Plan & Section

5.1.2.3 Horizontal Directionally Drilled Crossings

For streams and rivers where other options are not appropriate, the pipeline will be installed using HDD, see Figure 5-2. This option is used to cross rivers where access is difficult or where trenching would not be appropriate. A pilot hole is drilled under the stream channel, starting well back from one side and exiting at a predetermined point on the other side. Locating devices are used during drilling to assist in steering the drill bit and determining the actual depth and location of the advancing drill bit. The depth of the bore below the river thalweg is set by determining an anticipated scour depth of the river and keeping a specified clearance below this point. After drilling the pilot hole to the desired configuration, successive reaming passes are made to enlarge the drill hole to the desired diameter, usually 6-inches to 10-inches larger than pipe diameter. The minimum radius of curvature for an HDD profile will be not less than 100 times the pipeline diameter, where the diameter is in inches and the radius is in feet.

HDD crossings will be installed using industry standard methods, in accordance with construction specifications and drawings.

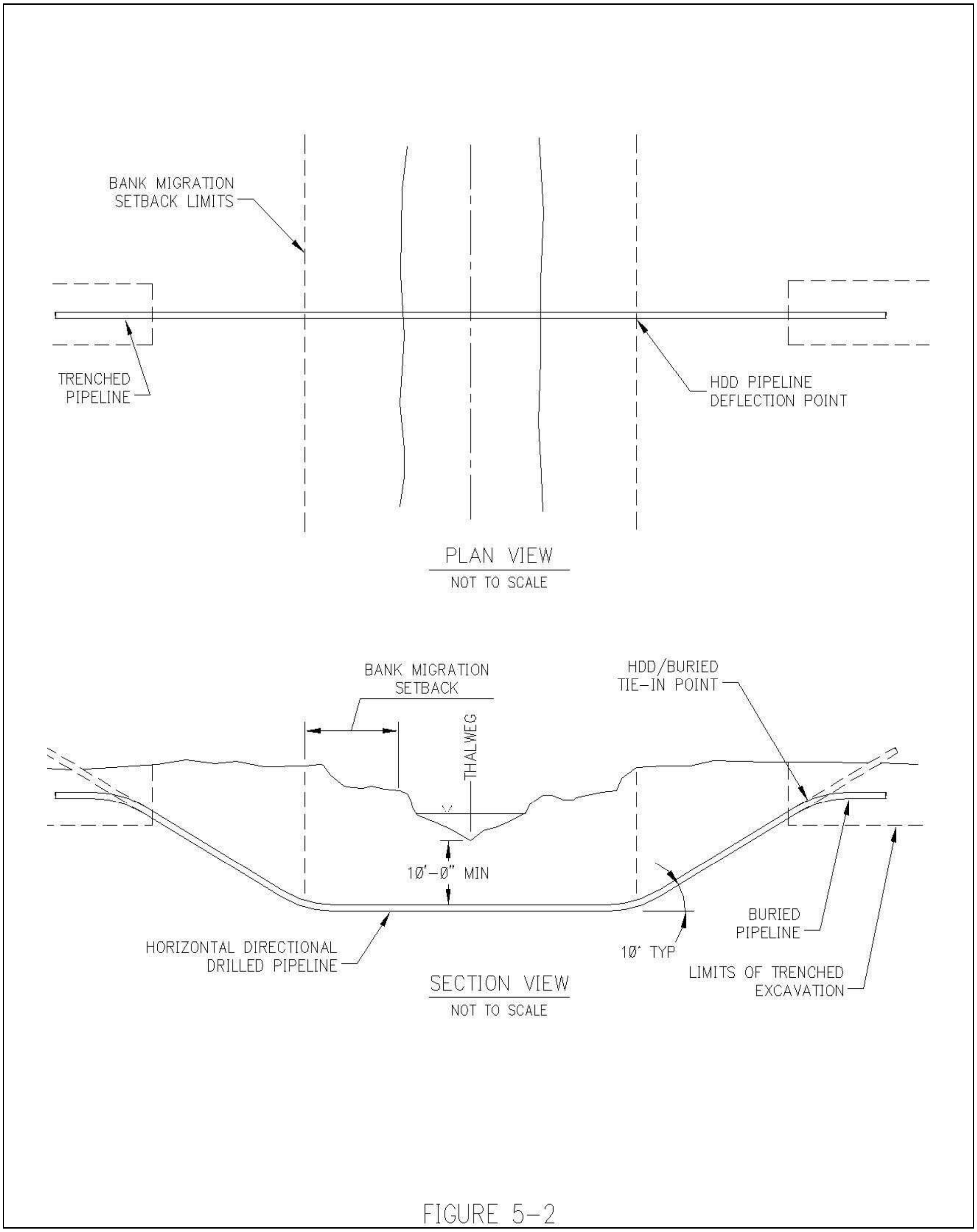


Figure 5-2 Typical HDD Stream Crossing

5.2 Road Crossings

The pipeline will be sized to safely withstand internal and external loads at road crossings. Loads on the pipeline at road crossings will be evaluated in accordance with the latest edition of ANSI ASC GPTC Z380.1. No road crossings will be cased. Depth of cover will be determined as a result of load calculations and in accordance with ROW agreement with the DOT/PF. However, the depth of cover will not be less than as specified in 49 CFR 192.327. Road crossings will be separated into two categories.

- Major Road Crossings – Sterling Highway and Kalifonsky Beach Road
- Minor Road Crossings – Other roads and driveways

The minor road crossings will be constructed by open trenching across the road. The amount of time any road or driveway is impassable will be minimized through construction sequencing or arranging alternative traffic patterns as approved by local authorities. The major road crossings will be constructed by either boring or jacking beneath the road in order to avoid traffic interruptions.

5.3 Other Pipeline Crossings

Pipeline crossings associated with this project are expected to be limited to buried pipes near the 400 Master Metering Building in the ROW at KGF. Utility locates will be used to identify location and depths of each existing pipeline. Each foreign pipeline will be excavated prior to construction by carefully supervised probe-and-dig methods to minimize risk of damage during construction. The KKPL will cross underneath other pipelines, with a minimum clearance of 12 inches.

5.4 Other Utility Crossings

Utility crossings will be limited because of the route of the proposed pipeline. Other utility crossings will likely be of the following type:

- Electrical (buried and aerial)
- Telephone (buried and aerial)
- Fiber optic cable
- Water
- Sewer
- Natural gas distribution

The pipeline will be installed beneath other buried utilities, and a separation distance of 12 inches minimum will be maintained. Stray currents induced at electrical line crossings will be mitigated with an appropriate grounding system. Additionally, pipeline insulators will be installed between electrical lines and the pipeline. As required, cathodic protection test stations will be installed at utility crossings consisting of metallic pipe.

5.5 Wetland Crossings

Buoyancy control may be necessary for wetlands crossings. If the weight of the pipeline is less than 1.05 times the calculated buoyant force, buoyancy control will be added. Buoyancy control will be provided via increased wall thickness, concrete coating, bolt-on weights, set on weights, earth anchors, or geotextile swamp weights.

Winter construction is the preferred method for pipeline installation in wetland to minimize the impact to wildlife and habitat, see Figure 5-3. The wetlands will be restored as near as practically possible to original conditions following construction.

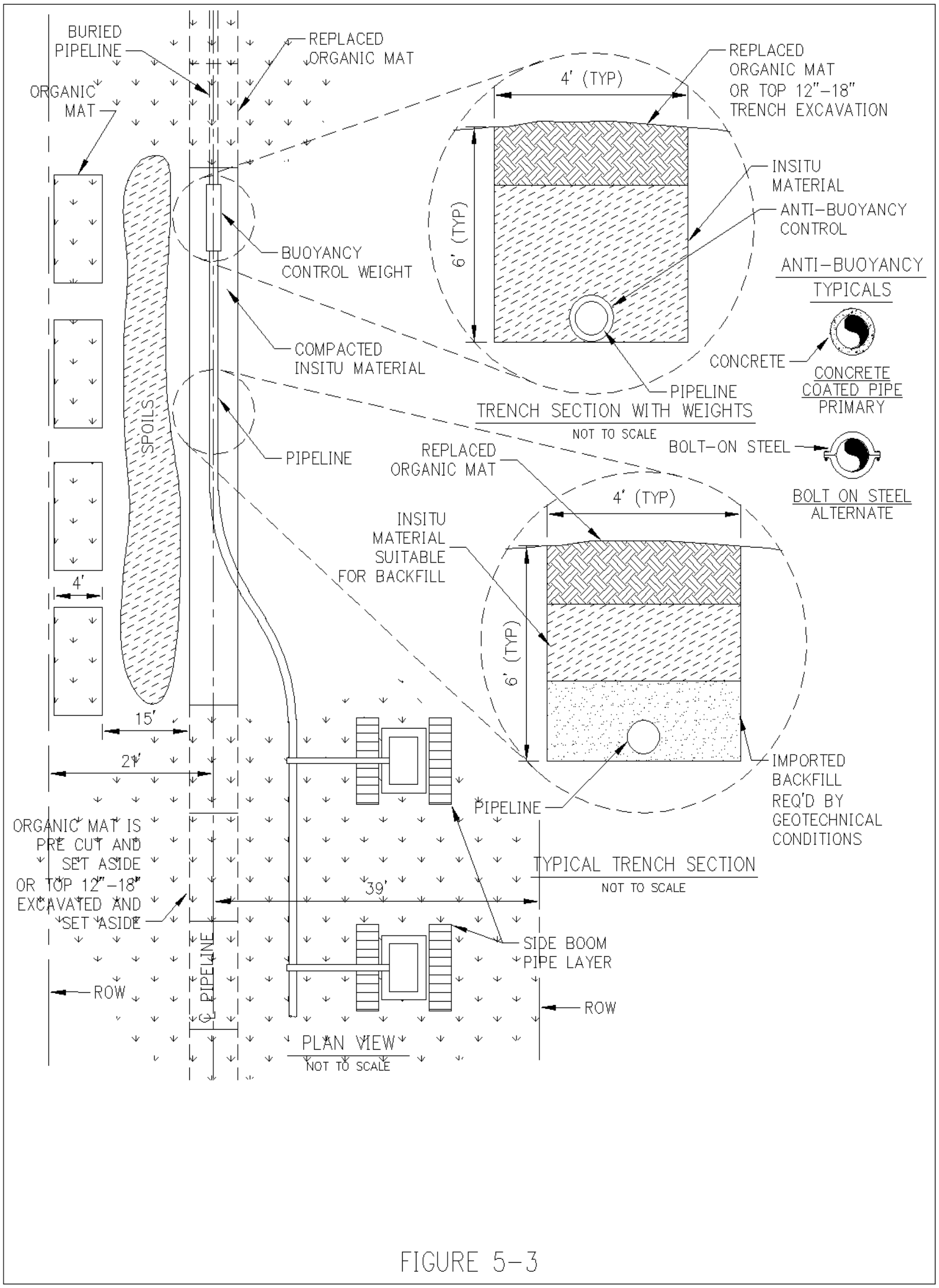


Figure 5-3 Typical Wetland Trench Details

Section 6.0 Construction

6.1 Grading and Leveling

Once the ROW is clear, the ROW will be graded and leveled. All grading will be finished to maintain the drainage or water flow conditions as near original as practical.

6.2 Excavation

Once the ROW is leveled, excavation of the trench will be accomplished by the use of backhoes and bucket type trenchers. Chain type trenchers may be used in frozen ground. The ditch will be excavated to the specified depth and the bottom graded as necessary. Spoils from the excavation will be placed within the ROW limits.

6.3 Stringing

Hauling and stringing the pipe includes loading the pipe at the storage yards onto a stringing trailer and hauling the pipe to the ditch side. The pipe coating will be protected at all times using belt slings, wood blocks, belt tie-downs and/or spreader bars with padded end hooks. The pipe is then unloaded, strung along the ditch on skids, and made ready for the bending and set-up. The pipe will be strung on skids with padding between the skid and the coated pipe. Additionally, the pipe may be strung on dirt berms if the material does not contain rocks or other material that may damage the pipe.

6.4 Bending and Set-up

After stringing, field bending of the pipe is done to conform to major changes in slope and direction. The pipe sections are then positioned in preparation for line-up and welding.

6.5 Line-up and Welding

The line-up and welding includes line-up of the pipe, applying the hot pass, stringer bead, followed by the fill and cap passes for each field weld. Refer to Section 3.9 for welding requirements and procedures.

6.6 Lowering-In and Backfilling

Lower-in and backfill will follow once all coating repairs to the pipe are complete. The pipe will be lowered into the trench as per project specifications. Care will be taken not to over stress the pipe or cause any damage to the pipe coating. Once the pipe is installed into the trench, the spoils pile will be used as backfill around the pipe. Backfill will be mounded to allow for settlement.

6.7 Ditch Plugs

Ditch plugs will be placed at appropriate intervals to reduce or eliminate the movement of surface water and groundwater in or along the trench, see Figure 6-1. Ditch plugs will consist of either silty material or sandbags with 5% concrete placed in the trench. If insitu material containing high amounts of silt is utilized as backfill, the need for ditch plugs is lessened due to the fact that groundwater will be less likely to migrate through silty backfill.

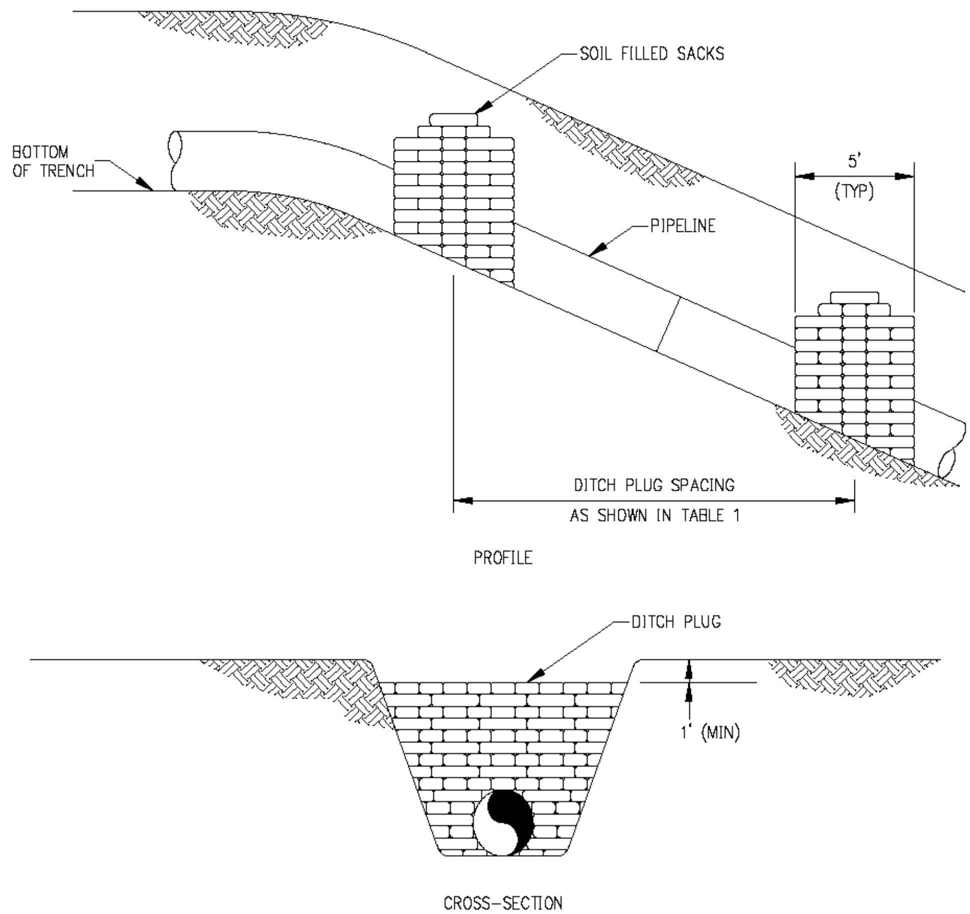
6.8 Drainage and Erosion Control

Drainage and erosion control during construction will be employed in accordance with the approved project specific Storm Water Pollution Prevention Plan. Drainage and erosion control will include:

- Diverting overland flow around disturbed areas to minimize the amount of erosion-generating runoff from the disturbed area.
- Diffusing or diverting flows to stabilized outlets to reduce problems associated with concentrated flows and velocities resulting from clearing of vegetation.
- Constructing dikes across the slope of a disturbed area to redirect sheet flow or concentrated flow runoff around disturbed areas.
- Sequencing construction activities to minimize the amount of area disturbed at one time. Final grading, clean-up and restoration and reclamation will be completed as soon as possible after construction is completed.
- Implementing temporary stabilization of soil prior to and during construction, and permanent stabilization of soil during and after construction. Stabilization practices include seeding, mulching, geotextiles, sodding, riprap, re-vegetation and other approved techniques.

6.9 Revegetation

Revegetation will primarily include reseeding and fertilization in the ROW in order to reestablish the native species in areas of disturbance. Temporary construction erosion measures may remain in place in areas of concern until the vegetative growth is well established. Revegetation plans and measures will be employed along with a sound erosion control plan.



NOTES:

1. DITCH PLUG CONSIST OF BURLAP BAGS FILLED WITH SOIL AND CEMENT. (TOPSOIL SHALL NOT BE USED IN TRENCH BREAKERS).
2. DITCH PLUG SHALL BE INSTALLED AT THE BANKS OF ALL MAJOR STREAM CROSSINGS.
3. DITCH PLUG SHALL BE LEFT IN PLACE WHEN THE TRENCH IS BACKFILLED.

Figure 6-1 Typical Ditch Plug

Section 7.0 Technical Issues to Monitor During Operations

No commitments were made during the right-of-way process to monitor technical issues during operations that do not fall under the realm of the federal pipeline safety codes presented in 49 CFR Part 192.

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Engineering & Energy

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