Expert Report:
Pipeline System Useful Life and Valuations; Contract 2015-190

Product 1 / Product 2 Consolidated Report

Multipliers for Asset Valuations; Gradient Variable Validation; Major Cost Component Breakdown; Base Value Evaluation Criteria

Prepared for:
Comisión de Regulación de Energía y Gas (CREG)

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Expert Qualifications

Greg Lamberson of International Construction Consulting, LLC is experienced in all phases of business, project, and construction management for upstream & midstream oil, gas, products, and energy-related projects. He is accomplished at working within complex, integrated work environments with multi-discipline and multi-cultural staffs to ISO, US, and various foreign standards, practices, procedures, and specifications in a variety of geopolitical climates on small, large, and mega-projects.

Mr. Lamberson's background includes over 35 years experience on both domestic and international assignments, in the management, engineering, design, planning, construction, and start up & commissioning of upstream & midstream oil, gas, and energy related facilities, LNG plants, pipelines, coal-bed methane (CBM) extraction, fuel storage and distribution systems, including onshore, near-shore and offshore marine facilities and structures; economic analysis and strategic planning and execution of energy projects in North, Central, and South America, the Caribbean, the Middle East, Central Asia, China, Russia, the Far East, and Africa.

Mr. Lamberson is currently consulting for multi-national oil and gas companies in the upstream & midstream energy sector on a domestic and international basis. Areas of expertise include both technical (engineering and construction) and commercial (contracts, finance packages, etc.) aspects gained while working with integrated multi-national oil and gas companies, partnerships and joint ventures as a solution integrator and key source of expertise.

His skills and credentials include extensive construction and engineering experience; developing contracting strategies, project & construction management, contract negotiations, independent project assessments (including risk assessments; constructability reviews, construction readiness reviews, operations readiness reviews), partner and subcontractor selections, security, field development planning, project execution development and troubleshooting, feasibility studies, conceptual and detailed cost estimates, tender preparation and evaluations, and risk management.

Mr. Lamberson's education includes a BS, Industrial Engineering and Technology, East Central University, Oklahoma, USA, 1983; and an MBA, Robert Kennedy College, Switzerland, focus on international business, 2005.

Mr. Lamberson has authored numerous articles, publications, and manuals including:

- "Staffing Strategies for Major Capital Projects", *World Pipelines*, June 2010 issue
- "Managing Transitions on Major Capital Projects", *Asian Power*, 2009.
- "Developing Optimum Contracting Strategies for Major International Projects", *World Pipelines*, March 2009 issue
- "Project Management – Common Pitfalls & How to Avoid Them", *Energy Today* magazine, a quarterly magazine covering the North American energy market, Spring 2009 issue.

- "Fundamentals of Gas Pipeline Metering Stations", *Pipeline & Gas Journal*, co-written with Mr. Saeid Mokhatab, January 2009 issue.

- "Managing Change – Manage Change on Major Projects", *World Pipelines*, November 2008 issue

- "Managing Execution Risks in Oil and Gas Processing Industry' EPC Projects", co-written with Mr. Saeid Mokhatab. To be published in a future issue of *Hydrocarbon Processing,* awaiting publications details.

- "Basic Guide to Pipeline Compressor Stations", *Pipeline & Gas Journal*, co-written with Mr. Saeid Mokhatab and Mr. Sidney Pereira dos Santos, June 2008.

- "Pipeline Systems - Control and Integrity Management", *Journal of Pipeline Engineering,* co-written with Mr. Saeid Mokhatab and Mr. Sidney Pereira dos Santos, December 2007, Vol. 6, No. 4 edition.

- "Project Execution Risk: A Key Consideration for Upstream Energy Project Management", *World Oil*, September 2007 issue; co-written with Mr. Saeid Mokhatab and Mr. D. Wood.

- "A Constructive Approach - Constructability's Role in Upstream Project Execution", *World Pipelines*, June 2007 issue

- Recognized contributor to Dr. Aurangzeb Khan, Assistant Professor, Dept. of Management Sciences, COMSATS Institute of Information Technology, Islamabad, Pakistan in providing material for the development of Project Management courses for post graduate students, 2006.

- "Managing Execution Risk in Upstream Projects", *World Pipelines*, December issue, 2006

- Corporate Constructability Program. 2005, Developed and implemented a complete Constructability Program for a major international EPC contractor. Program is comprehensive covering all aspects of upstream EPC projects, including project-specific Constructability Plan template, checklists, charters, sample agendas, program maintenance & feedback mechanisms, dispute resolution, etc.

- International Project Management System (IPMS), 2004, proprietary system for internal use as a guide for managing complex energy projects worldwide, from initial project assessments and feasibility studies to hook up, commissioning, and turn over. IPMS utilizes a phased approach that defines minimum deliverables required at specific phases along the project timeline. System also includes a prescriptive review process for passing into the next phase of project planning and execution.

- Construction Managers Handbook (CMH), 2003, proprietary for internal use, provides guidance for the overall Construction Management aspects of the formation, organization, establishment, and management of project site work. The CMH guides the Construction Manager through the major segments of a construction project including mobilization, managing interfaces, transitions, construction implementation, and demobilization.

- "Typical Hydrotest Water Intake and Discharge Mitigation Measure's", March 2002, published in ExxonMobil Global Share library system as an authoritative reference.

- "Guidelines for Preparing a Construction Execution Plan", February 2002, published in ExxonMobil Global Share library system as an authoritative reference.

- "Pipeline Construction", *Project Management Network Magazine,* January 2002 (credited contributor to Ken Silverstein – author)

- "Keys to Successful Execution of International Projects", *Project Management Institute*, Troubled Projects, Fall 2001, Volume 1, Issue 3

1.0 Pipeline Useful Life

1.1. Introduction

Determining a pipeline system useful life is a complicated undertaking and involves a wide-ranging number of factors. Most factors are common with both liquid and gas pipeline systems. However, this report is focused on liquid pipelines.

In the tender, CREG provided the following preliminary listing of factors that influence the useful life of pipeline infrastructure:

- Type of soil
- Type of vegetation
- Water level management techniques
- Sub-fluvial crossings
- Type of location.
- Seismic crossings
- Cultivated area
- Extreme terrain
- Topography.
- Dual joints
- Economies of scale by diameter
- Economies of scale by length
- Type of materials, associated with the metallurgy at the time of construction.

The Author was requested to take into account the above listed factors as well as others considered relevant, justifying any inclusions. The Author will purpose to discuss the relevant factors/variables in Section 1 of this Report and provide an overview of each factor. The full listing of factors influencing the useful life of a pipeline system along with the corresponding weighted effects can be found in the Pipeline System Useful Life Model in P1 Appendix A.

It should be pointed out that while pipeline diameter and length do have a linear cost correlation for both CAPEX and OPEX, there are no correlations for overall useful life. The design codes level the playing field for all diameters and lengths of pipelines; in other words, each pipeline irrespective of its diameter or length are designed using the same code and parameters and hence, their basic useful life will be consistent.

The primary life cycle for a pipeline system as it relates to useful life is:

- Design, engineering, and procurement
- Construction
- Operations and maintenance

Within these primary phases, many decisions are made that have a direct impact on the ultimate useful life of a pipeline system. In this Section of the Report, the Author will identify the major components and issues that come into play in determining the useful life of a pipeline system and provide discussion on the topics that will provide a deeper understanding of the decisions required and why come of the issues are critical.

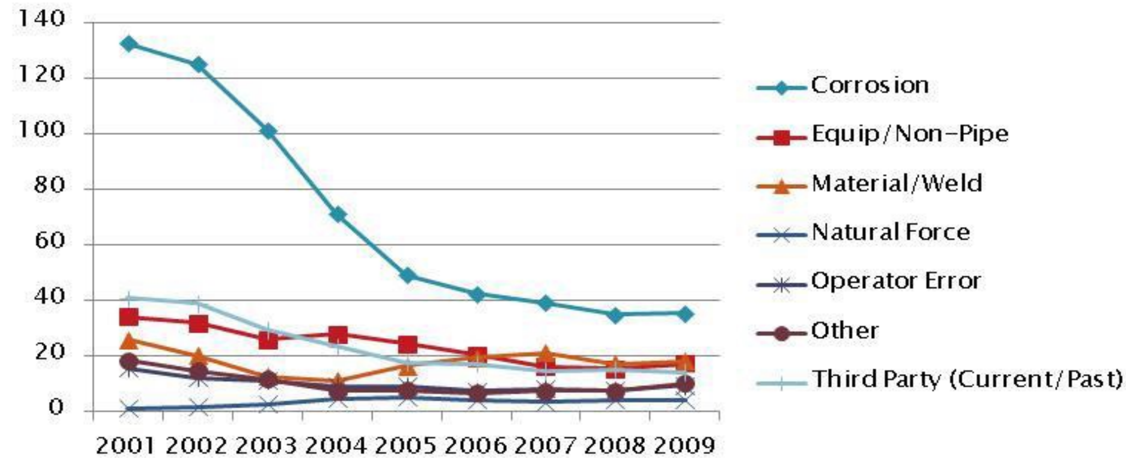
The Pipeline System Useful Life Model contained in Appendix A is the result of the narratives found in Section 1 of this Report. It must be emphasized that the factors developed are a normative process based on over 30 years of experience in pipeline construction as well as operations and maintenance. Each of the factors has a multitude of potential variations within each factor that can influence it; therefore the Author has taken neither a conservative nor a liberal approach, but has instead tried to keep the factor impacts near the middle of what the potential impacts may be.

The full listing of factors influencing the useful life of a pipeline system along with the corresponding weighted effects can be found in the Pipeline System Useful Life Model in Appendix A.

The Author is not aware of the existence of a database of the variations within each factor. Some major operators may have existing information on pipeline useful life, but it is considered proprietary, is protected very carefully and is not available for publishing or for use outside the Company. Therefore, these factors have been captured in a normative, single layer evaluation system.

For the purposes of this Report, the Author has utilized or referenced codes and regulations as they relate to pipeline design and construction in the US, specifically ASME B31.4 for liquid pipeline systems. The regulations and codes utilized are summarized in Section 1.2 below.

It should be emphasized that corrosion related items are the most important factors related to shortening or extending the useful life of a pipeline system. As a summation of the control of corrosion, it is estimated by most pipeline operations experts that corrosion could adversely affect a pipeline systems useful life by up to 30%. In unusual, extreme cases with highly corrosive fluids where no cathodic protection is used, this could have as much as a 90% impact which is normally only seen in some gathering systems with high H_2S, very poor designs, and a lacking operations & maintenance program. The graph below of measurable releases from 2001 to 2009 is indicative of the impact corrosion has on pipeline systems.



On the positive side, a robust corrosion design, solid installation, and a vigorous operations & maintenance program, including those outlined in Sections 1.3.2; 1.3.3; 1.5.1; 1.5.6; and 1.5.8 could extend lifetime up to 50% or more.

The two principle methodologies for assessing the corrosion of a pipeline are ASME B31G (Manual for Determining the Remaining Strength of Corroded Pipeline) and RSTRENG (Remaining Strength of Corroded Pipe). These are assessment tools that evaluate the remaining strength of a pipeline at a given point in time.

The remainder, in the Author's opinion, have minor or no effect on overall useful life of the pipeline system, although they would individually have isolated effect on maintenance and repair programs.

The Model contained in Appendix A of this Report contains the pertinent variables that can have an impact on a pipeline system's useful life. There are a few relevant points the Author wishes to clarify regarding the variables and the resulting impacts:

- The base case is considered to be a 40-year design life, which is considered an industry standard.
- Some key variables when selected are indicated by the Model to have "no impact" (i.e. 0%); however, this indicates the variable is considered to be a "base case" selection in order to achieve a 40-year design life. In other words, the variable when selected will assist to achieve a 40-year design life and will not extend it further nor reduce it less.
- When looking at the "worst case", the Author chose selections that are not favorable to a 40-year design life that an Operating company may select for a variety of reasons, including:
    - Limited capital at the time of project execution
    - The need to have a pipeline with a shorter design life, for example in a field with high production, but a sharp decline rate the Company expects to only use for a short period of time, or
    - Lack of technical expertise in certain areas

- Should all of the "poor choices" be selected, the model will return an overall negative useful life. Clearly this is not possible; however, the model has taken into consideration that Operating companies will make the best decisions they can at the time of installation and it is not conceivable an Operating company who has plans to continue in business will make all of the wrong choices.

The last bullet point above is underscored by the data below.

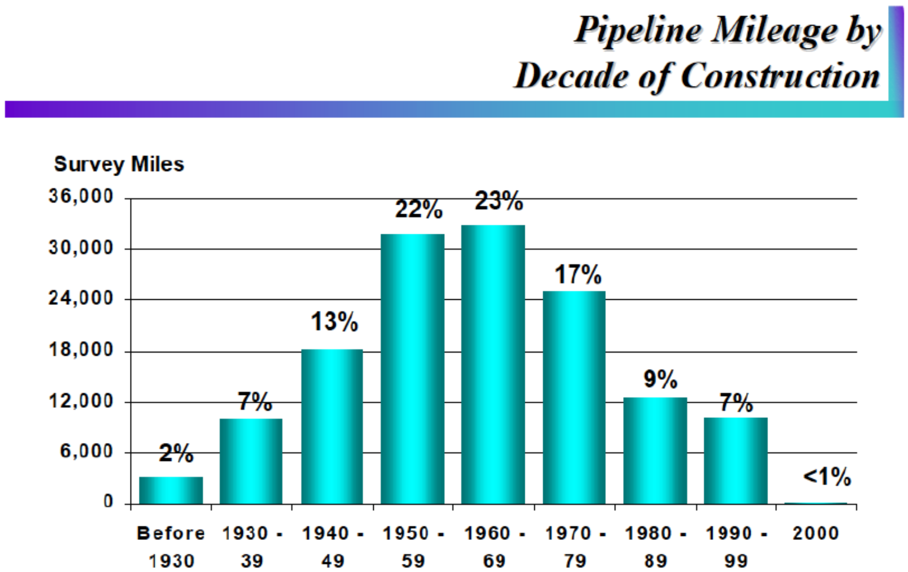
According to a study conducted by the API titled Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction, the following findings were issued:

General Findings

- Age – the number of years a pipeline has been in service – is an unreliable indicator of the condition of a pipeline system. A better first indicator is the technologies that are represented in the manufacture and construction of the system when it was first placed in service. Even the decade of original construction, however, is only a first indicator. Also critical to a pipeline's condition are the renovation, inspection, and maintenance practices that have been applied since construction.
- Industry-wide information comparing the performance of pipeline systems based on the decade in which a system was constructed provides important broad indicators for operators to examine further in assessing their own systems.
- Specific techniques can prevent or slow deterioration in pipeline systems. Hence, determining the specific types of deterioration that a pipeline system or pipeline segment may experience over time is an important aspect of conducting pipeline- specific risk assessments.
- In recent years, the industry has developed specific techniques that contribute to the overall improved performance of pipe and pipelines installed since 1970, including:
  - Universal use of non-destructive testing during construction, such as radiography and coating inspection
  - Greater depth of cover
  - Greater use of boring or directional drilling
  - Greater use of pipeline corridors
  - Improved backfilling techniques
  - More effective, less vulnerable coatings
  - More identifying markers along pipeline rights-of-way
- Other techniques have contributed to the overall improved performance of pipe and pipelines installed in any decade, including:
  - Universal pipeline industry support of one-call centers
  - Greater use of risk management techniques
  - Improved training

The current oil pipeline mileage by decade of construction can be seen in Figure 1 below.

Figure 1 – Pipeline Mileage by Decade of Construction



Findings for 1930s and 1940s Pipe

- 1930s and 1940s pipe is almost 20% or about 19,000 miles of the nation's oil pipeline system.
- The overall performance of 1930s and 1940s pipe is comparable to later decades, except for external corrosion incidents.
- 1940s pipe has a higher rate of accidents from third party (excavation, farming) damage than other decades of construction.

Recommendations for 1930s and 1940s Pipe

Because corrosion protection technology was in the early stages of development, 1930s and 1940s pipe should be evaluated for corrosion damage that may have occurred prior to the application of cathodic protection. When developing risk factors or risk indexes for 1930s and 1940s pipe, the following conditions should be assigned relatively greater weight during risk assessment unless specific renovation or mitigation has been conducted:

- The pipeline system is not now under cathodic protection.
- The length of time the pipe remained without cathodic protection and what testing and renovation was conducted at the time cathodic protection was installed.
- The length of time the pipe has lacked adequate cathodic protection without hydrostatic testing or inspection using in-line inspection tools suitable for identifying corrosion.
- The pipeline remains uncoated.

Because of conditions specifically related to the construction of pipelines during World War II (availability and quality of steel, shallow pipeline cover), 1940s pipe should be evaluated with special consideration for protection from excavation damage, including the use of depth-of-cover surveys in populated areas or in areas subject to modern deep plowing techniques or drainage tiling.

Findings for 1950s and 1960s Pipe

- 1950s and 1960s pipe is about 45% or about 90,000 miles of nation's oil pipeline system.
- The overall performance of 1950s and 1960s pipe is comparable to later decades.
- Although overall defective pipe and pipe seams comprise only 8% of all failures, such failures are over-represented in 1950s and 1960s pipelines.

Recommendations for 1950s and 1960s Pipe

1950s and 1960s pipe should be rated along a continuum for pipe and pipe seam and pipe weld failures. The following conditions should be assigned relatively greater weight during risk assessment unless specific mitigative actions have been conducted:

- Pipe has not undergone a hydrostatic test and has had seam failures
- Pipeline system operates at high pressure versus minimum yield strength

Findings for 1970s, 1980s, 1990s Pipe

- 1970s, 1980s, and 1990s pipe is about 33% or 66,000 miles of the nation's oil pipeline system.
- Pipeline constructed since 1970 represents the current state of the art in the metallurgy of steel, pipe mill practices, and construction techniques.

Recommendations for 1970s, 1980s, 1990s Pipe

- Follow established industry procedures and practices.
- Utilize risk management and integrity management programs

This is underscored by a study conducted by the Interstate Natural Gas Association of America (INGAA) in 2012. This study found almost half of all U.S. interstate transmission mileage was installed between 1950 and 1970. The percentage of natural gas pipeline mileage by decade installed is shown in Figure 2 below.

The cumulative percentage by decade installed is shown in Figure 3 below and is summarized below:

- 12% of the pipeline infrastructure was installed prior to 1950,
- 37% was installed prior to 1960,
- 60% was installed prior to 1970,
- 70% was installed prior to 1980,
- 80% was installed prior to 1990, and
- 90% was installed prior to 2000.

The above list and graphs below show the vast majority of Companies strive to make the best choices possible.

Figure 2. Percentage of Pipe Mileage Installed by Decade

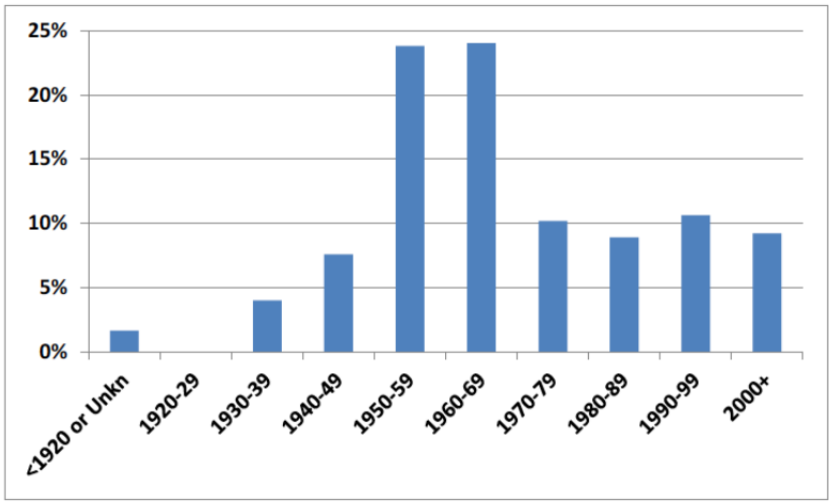
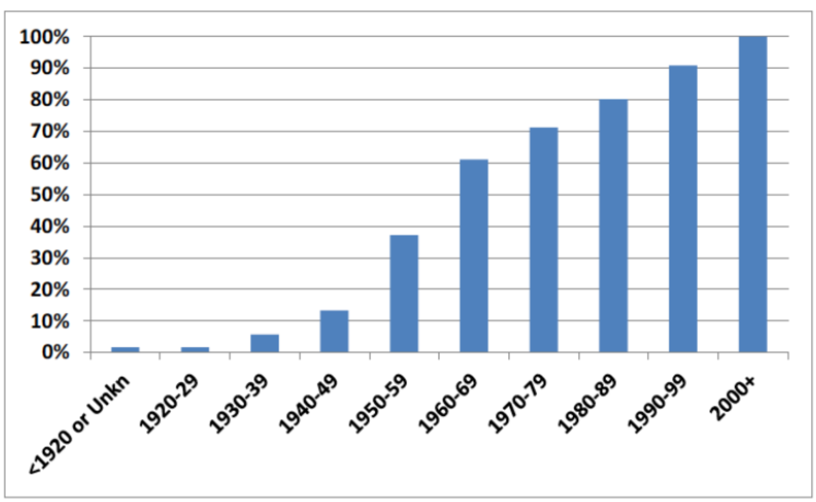


Figure 3. Cumulative Percentage of Pipe Installed by Decade



Based on the above referenced studies and the Author's experience, the following is the suggested minimum, average, and maximum useful life of liquid pipeline systems:

Minimum – 10 years (see Product 3 for an example)
Average – 40 years (see Appendix A)

Maximum – 65 years (see Product 3 for an example)

1.2. Regulations and Codes

Regulations governing interstate hazardous liquid and gas pipeline facilities are typically established and enforced on a federal level.

Title 49, Code of Federal Regulations (CFR) Parts 191, 192, and 195 and ASME Codes B31.4 and B31.8 have subparts or chapters devoted to pipeline operating and maintenance procedures and records.

Broadly, these require: written plans for normal and emergency procedures, periodic updating of procedures, operation in compliance with procedures, records, training of personnel, and education of authorities and the public regarding hazards and emergency action programs.

State regulations may have further requirements. These are generally described and are normally considered minimum standards.

1.2.1. Regulatory Jurisdictions

1.2.1.1. United States

Regulations governing interstate hazardous liquid and gas pipeline facilities are established and enforced on a federal level. Intrastate pipeline facilities are subject to federal authority unless the state certifies that it will assume responsibility. The state must adopt the same regulations or more stringent, compatible regulations.

Regulations for hazardous liquid pipelines are covered in Title 49, Code of Federal Regulations, Part 195 (49 CFR 195), Transportation of Hazardous Liquids by Pipeline.

Section 195.2 defines a hazardous liquid as petroleum, petroleum products, or anhydrous ammonia. Section 195.1(b) excludes onshore gathering lines in rural areas and onshore production facilities and flow lines. Pending regulations are expected to include supercritical CO_2 pipelines under Part 195.

In the U.S, piping on offshore facilities can be performed using ASME B31.4 or B31.8, however, most companies perform their design in accordance with ASME Standard B31.3.

1.2.1.2. Colombia

For the purpose of this Report, the Author has applied US regulations, codes and standards.

1.2.1.3. Other Locations

Legal requirements for pipeline design and operation in other geographical locations must be determined individually. If regulations do not exist or are less restrictive than

U.S. regulations, the pipeline facilities should be designed to the applicable ASME code.

In other countries, similar standards apply with minor variations. Again, for simplicity, the Author will utilize the U.S. standards in this Report.

1.2.2. Codes

The following is a discussion regarding the applicable codes as well as addressing the nuances that are contained in pipeline systems when facilities are included in the pipeline system.

1.2.2.1. ASME Code B31.4

ASME Code B31.4, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols is incorporated by reference in 49 CFR 195. It is also a sound basis, although not legally required, for cross-country water and water slurry pipelines, allowing their future conversion to oil or other hazardous liquid service.

Code B31.4 establishes requirements for safe design, construction, inspection, testing and maintenance of pipeline systems transporting liquids such as crude oil, condensate, natural gasoline, natural gas liquids, liquified petroleum gas, liquid alcohol, liquid anhydrous ammonia, and liquid petroleum products. Among the facilities that fall under B31.4 include pump stations, tank farms, terminals, pressure reducing stations and metering stations.

Code B31.4 does not apply to auxiliary station piping such as water, air, steam, lubricating oil, gas and fuel; piping at or below 15 psig, piping with metal temperatures above 250°F or below -20°F; or field production facilities and pipelines.

1.2.2.2. ASME Code B31.8

Incorporated by reference in 49 CFR 192 for natural and other gas, ASME Code B31.8, Gas Transmission and Distribution Piping Systems, applies to field gathering, transmission and distribution pipelines for natural gas. It covers the design, fabrication, installation, inspection, testing, and safety aspects of gas transmission and distribution system operation and maintenance. Figure I8 in Appendix I of Code B31.8 shows the range of facilities covered by the Code, including gas compressor stations, gas metering and regulation stations, and closed-pipe gas storage equipment.

Code B31.8 does not apply to piping with metal temperatures above 450°F or below -20°F, vent piping operating at substantially atmospheric pressures, wellhead assemblies, or control valves and flow lines between wellhead and trap or separator.

While this Report focuses on liquids pipelines, ASME B31.8 was included in an effort to be thorough as many liquid facilities require some portions of their systems designed to B31.8, for example fuel gas lines and facilities having the potential of producing gas as a by-product.

1.2.2.3. API 1160

API 1160, Managing System Integrity for Hazardous Liquid Pipelines, is a recommended practice based on the Code of Federal Regulations, 195.452, Pipeline Integrity Management in High Consequence Areas. Although API 116 is a recommended practice, the development of integrity management programs is required under 49 CFR 195.452 of the U.S. federal pipeline safety regulations.

API 1160 is specifically designed to provide the operator with a description of industry-proven practices in pipeline integrity management. The guidance is largely targeted to the line pipe along the right-of-way, but the process and approach can be applied to pipeline facilities, including pipeline stations, terminals, and delivery facilities associated with pipeline systems. Certain sections provide guidance specific to pipeline stations, terminals, and delivery facilities. It outlines a process that an operator of a pipeline system can use to assess risks and make decisions about risks in operating a hazardous liquid pipeline in order to achieve a number of goals, including reducing both the number and consequences of incidents.

Based on the requirements of API 1160, Liquid Pipeline Operators are required to develop Integrity Management Plans for their pipelines starting in 2001 to the present

The result has been an increased focus and resources to pipeline risk assessment, data integration, understanding threats, preventive and mitigation programs

1.2.2.4. Producing Field Flow and Gathering Lines

The ASME Codes do not clearly define the extent of producing field flow and gathering lines, and CFR regulations do not cover oil and gas gathering lines in rural areas. Therefore, where practices have not already been established, it is suggested that designs for field liquid pipelines follow Code B31.4, and, for gas pipelines, Code B31.8.

49 CFR 192 and 195 apply within the limits of any incorporated or unincorporated city, town, village, or other designated residential or commercial area. They require compliance with ASME B31.4 and B31.8.

49 CFR 195.2 defines a liquid gathering line as a pipeline sized NPS 8 or smaller from a production facility. 49 CFR 195.1(b)(6) excludes transportation through onshore production facilities (including flow lines). 49 CFR 192.3 defines a gas gathering line as a pipeline that transports gas from a current production facility to a transmission line. Where a line handles liquid-gas two-phase flow, the more stringent requirements of each code should be applied, and special consideration should be given to the effects of slug flow along the system.

1.2.2.5. Producing Field Facilities

For on-plot production facilities such as wellhead piping, separators, traps, tank batteries and gas gathering compressors, most Operators use ASME Code B31.3, Chemical Plant and Petroleum Refinery Piping.

1.2.2.6. Pipeline Stations and Terminals

Design and construction of piping at pump stations, compressor stations, and terminals should comply with Code B31.4 or B31.8, as appropriate. Some Operators use the more conservative Code B31.3 for piping design, however, due to the increased cost of B31.3 over B31.4, this is purely a business decision whether to use this practice.

Terminal facilities within a refinery are designed to Code B31.3, unless they are confined to a separate and defined pipeline area adjacent to refinery facilities.

1.3. Design, Engineering, and Procurement

The key to successful engineering and design of pipeline systems is the use sound engineering judgment. A few examples where special consideration should be given are:

- Extraordinary service conditions such as earthquake, high wind, other unusual dynamic loadings, or unusual superimposed dead loads
- Cold climates that may require special materials to avoid brittle fractures
- High H2S concentrations that may place restrictions on valve trim and weld hardness
- Use of lighter wall pipe for low pressure systems
- Use of higher yield strength materials when economics dictate
- Variation in corrosion allowance or selection of material for handling of corrosive/erosive material

Special studies are needed to make final selection of pipe and coating for the length of the pipeline. The selection must meet Code B31.4 or B31.8 requirements, and will be influenced by economics and timely availability of materials.

1.3.1. Pipeline Design

Some of the most critical portions of the overall pipeline or pipeline system system's useful life is developed during the design and engineering phase. It is at this phase the pipeline system design life is determined by the Operator, which is commonly forty (40) years.

The other key components that are designed that have the most direct bearing on design and useful life are:

- Pipe Selection
- Coating Selection
- Design of the cathodic protection system

1.3.1.1. Pipe Selection

Typically API 5L is used to provide a line size based on a preliminary choice of pipe grade and coating, and wall thickness. Further studies are needed to make final selection of pipe and coating for the length of the pipeline. Selection must meet Code B31.4 or B31.8 requirements, and will be influenced by economics and timely availability of materials.

Generally, economics will dictate use of the higher grades of line pipe, with resultant thinner wall and lower tonnage; the effect of incremental cost per ton for the higher grades is small compared to reduced tonnage of pipe.

Also, consideration must be given to providing sufficient wall thickness to resist mechanical damage and structural flexing in handling during construction. If Grade X70 and higher pipe is considered (or for sour service Grade X60 and higher), material testing should be carried out prior to making a final decision.

1.3.1.2. Pipe Stress and Wall Thickness Calculations

The following sections of Code B31.4 Chapter II (Design) are particularly important for pipeline design:

- Part 1, Conditions and Criteria
  – Section 401, Design Conditions
  – Section 402, Design Criteria
- Part 2, Pressure Design of Piping Components
  – Section 403, Criteria for Pressure Design of Piping Components
  – Section 404, Pressure Design of Components

<u>Allowable Pipe Stresses</u>

Section 402.3.1(a) of Code B31.4 establishes the allowable stress value S for new pipe as:

$$S = 0.72 \times E \times SMYS$$

where:

- 0.72 = Design factor based on nominal wall thickness. In setting this design factor, the code committee gave due consideration to and made allowance for the underthickness tolerance and maximum allowable depth of imperfections provided for in the specifications approved by Code B31.4
- E = Weld joint factor per Section 402.4.3 and Table 402.4.3 of Code B31.4. For pipe normally considered for new lines, E = 1.00
- SMYS = Specified minimum yield strength, psi

Although mill tests for particular runs of pipe may indicate actual minimum yield strength values higher than the Specified Minimum Yield Strength (SMYS), in no case where Code B31.4 refers to SMYS shall a higher value be used in establishing the allowable stress value; (Section 402.3.1(g) of Code B31.4). Table 402.3.1(a) of Code B31.4 tabulates allowable stress values for pipe of various specifications, manufacturing methods, and grades, based on the above, for use with piping systems within the scope of Code B31.4.

Sections 402.3.1(b),(c), and (d) of Code B31.4 cover allowable stresses for used (reclaimed) pipe, pipe of unknown origin, and cold-worked pipe that has subsequently been heated to 600°F or higher. Section 402.3.1(e) limits allowable stress values in shear and bearing. Section 402.3.1(f) limits tensile and compressive stress values for pipe and other steel materials when used in structural supports and restraints.

Section 402.3.2 of Code B31.4 covers allowable stress values due to sustained loads and thermal expansion for the following stresses:

- Internal pressure stresses. The calculated stresses due to internal pressure shall not exceed the applicable allowable stress value S determined by 402.3.1 (a), (c), or (d) except as permitted by other subparagraphs of 402.3.
- External pressure stresses. Stresses due to external pressure shall be considered safe when the wall thickness of the piping components meets the requirements of 403 and 404.
- Allowable expansion stresses (as for heated oil lines). The allowable stress values for the equivalent tensile stress in 419.6.4(b) for restrained lines shall not exceed 90% SMYS of the of the pipe. The allowable stress range, SA, in 419.6.4(c) for unrestrained lines shall not exceed 72% of SMYS of the pipe.
- Additive longitudinal stresses. The sum of the longitudinal stresses due to pressure, weight, and other sustained external loadings (see 419.6.4(c)) shall not exceed 75% of the allowable stress value specified for SA under allowable expansion stresses."
- Additive circumferential stresses. The sum of the circumferential stresses from both internal design pressure and external load in pipe installed without casing under railroads and highways [see Code Section 434.13.4(c)] shall not exceed the applicable allowable stress value S determined by Code Section 402.3.1(a), (b), (c), or (d).

Section 402.3.3 of Code B31.4 covers limits of calculated stresses due to occasional loads in operation and test conditions.

1.3.1.3. Wall Thickness Calculations

Section 404.1.2 of Code B31.4 gives the basic pipe hoop stress formula relating internal pressure, pipe wall thickness, pipe diameter and stress value:

$$t = \frac{P_i D}{2S}$$

or

$$P_i = \frac{2St}{D}$$

where:

- t = pressure design wall thickness, in.
- Pi = internal design gage pressure, psi
- D = nominal outside diameter, in.
- S = allowable stress value, psi, (per Section 402.3.1(a) of Code B31.4)

Per Section 404.1.1 of Code B31.4 the nominal wall thickness of straight sections of steel line pipe shall be equal to or greater than the sum of the pressure design wall thickness, and allowances for threading and grooving, corrosion, and prudent protective measures:

$$t_n \geq t + A$$

where A = sum of allowances for:

- Threading and grooving (per Section 402.4.2 of Code B31.4) (zero for welded line)
- Corrosion (per Section 402.4.1 of Code B31.4) (zero if the line is protected against internal and external corrosion per Chapter VIII of Code B31.4). For stocks where corrosion (or slurry erosion) is expected, a corrosion allowance should be provided.
- Increase in wall thickness as a reasonable protective measure (under Section 402.1 of Code B31.4) to prevent damage from unusual external conditions at river crossings, offshore and inland coastal water areas, bridges, areas of heavy traffic, long self-supported spans, and unstable ground, or from vibration, the weight of special attachments, or abnormal thermal conditions

The nominal wall thickness shall not be less than the minimum required by prudence to resist damage and maintain roundness during handling and welding. The appropriate minimum should be evaluated for the particular installation conditions.

As a rough guide, the following is suggested:

- 0.188 inch wall for sizes up to and including NPS 12
- 0.219 inch wall for NPS 14 through 24
- A maximum D/tn ratio of 120 for pipe over NPS 24

These represent minimums for reasonable cross-country laying conditions. Consideration must also be given to buckling of double-jointed lengths of pipe and to fatigue stresses if extensive cyclical loading is possible during transport from the mill to the job site. The latter problem is discussed in API Recommended Practices RP 5L1, Railroad Transportation of Line Pipe; RP 5L5, Marine Transportation of Line Pipe; and RP 5L6, Transportation of Line Pipe on Inland Waterways.

1.3.2. Coating Selection

This section provides a brief overview of the recommended types of corrosion protection coatings for buried pipelines.

Fusion bonded epoxy (FBE) is, in general, the best coating for buried lines. Extruded plastics (Pritec and Mapec are preferred because of their high quality adhesive and plastic) are recommended when supply or economics rule out FBE. Tape wraps and coal tar enamel, while needed for certain applications, are not recommended for new pipeline construction.

When selecting a coating, installation costs must be balanced with the reliability expected. Using a tape wrap instead of FBE may save money in the short-term, but will increase the chances of long-term losses due to increased maintenance and possible early corrosion failure of the line. Other concerns are shipping costs, application site, chemical resistance, maximum service temperature, soil conditions, accessibility to the line, and storage and handling.

Tape wraps are no longer recommended for new pipelines because their low cost and the ease of over-the-ditch application are offset by a poor service history and high failure rate. However, tapes are useful for repairing mechanically damaged coatings, protecting large radius bends and tie-ins, and performing over-the-ditch coating refurbishment when other coatings are not flexible enough or cannot be field-applied.

Increasingly, liquid epoxies are being used to refurbish old coatings and for odd geometries. These two-part liquids have chemical and temperature resistance properties that are similar to FBE, and can be applied in the field. However, they do require a sand-blast cleaned pipe surface and are relatively expensive.

No matter which coating is selected, surface preparation is critical. Poor or improper surface preparation will cause any coating to fail prematurely.

Different coatings may be required to suit different terrain and soil conditions along the line. There are often a number of acceptable coatings, and the type and application method will depend primarily on the following:

- Ground corrosivity and effectiveness of cathodic protection
- Line temperature
- Cost of coating

In selecting coatings, attention should be given to factors such as:

- Data obtained from a field soils resistivity survey made early in the design phase of the project
- Level of ground water table throughout the year
- For cohesive clay soil, data on pipe-to-soil friction
- In rock excavations, damage to the coating caused by the pipe hitting the trench walls while being lowered, and by rocks in the backfill
- Potential damage to plant-applied coating in transit to job site
- For plant-applied coating:

  - Cost of plant application, and incremental shipping and handling costs
  - Incremental field handling costs, and cost of repairs in the field
  - Cost of field joint materials and application
  - Availability, feasibility, and cost of setting up and operating a modular coating plant near the job site
- For over-the-ditch coating:
  - Cost of coating materials, and shipping and storage costs
  - Construction costs for coating, including pipe cleaning
  - Capability of a construction contractor to apply the coating satisfactorily
  - Standard over-the-ditch coatings are far less reliable than plant-applied systems, particularly at higher-than-ambient temperatures and under wet conditions
- Use of additional coating thickness or higher quality coatings at highway, road and railroad crossings, either cased or uncased, and in developed areas
- Service life anticipated for the pipeline
- Comparative quality of the coatings over the service life the pipeline
- Differential cost, if any, for the cathodic protection system

1.3.3. Cathodic Protection

Two basic types of cathodic protection systems are used for onshore pipelines, active impressed current systems and passive sacrificial anode systems. Based upon the surveyed soil properties an active impressed current system is designed for the entire pipeline system. An impressed current system utilizing remote, deep well, anodes can be designed to give final protection potentials within the required ranges, and is more easily adaptable to seasonal and system changes, and often be more cost effective both on a capital and expense basis.

1.3.3.1. Sacrificial Anode System

Cathodic protection using galvanic anodes is more appropriate for small diameter pipelines and large diameter pipelines in low resistivity areas like water, swamps or marshes. These are also often recommended for use in localized (hot spot) areas to supplement ICCP systems.

Common sacrificial galvanic anode materials are aluminum, magnesium and zinc. However, for buried onshore pipelines zinc and magnesium anode in suitable backfill are used. Both of these anode materials have limitations in terms of maximum soil resistivity (Zn 30 ohm-m and Mg 50 ohm-m). This limits the throwing power of the galvanic anodes for successful corrosion protection of the steel pipeline. In order to achieve uniform protection for the crude oil pipeline, the total calculated anode mass has to be attached to the pipeline as a large number of anodes. This means that the pipe coating is required to be locally removed to enable thermit welding of anode connections to the pipeline.

1.3.3.2. Limitations of Galvanic Anode System

Sacrificial anode system capacity is fixed at installation. Any failures of cable connections will require excavations, local removal of pipe coating, installation of connection by thermit welding or pin-brazing etc. The process of mobilizing repair crew for work on long buried pipelines in remote locations and obtaining work permits from concerned authorities can present logistical problems.

1.3.3.3. Impressed Current System

Cathodic protection using impressed current system requires the provision of constant supply of d.c. voltage conventionally through a transformer/rectifier unit connected to an a.c. power supply. The negative is connected to the pipeline and positive of the d.c. supply is connected to non-corrodible anodes buried in a suitable low resistivity ground bed. Deep well anode beds installed 65 to 100m deep have been successfully used for corrosion protection of long buried cross country pipelines.

1.3.3.4. Advantages of ICCP System

ICCP system output can be adjusted to take care of any increase in protection current requirements arising due to coating defects that may occur during service. The protection current can be supplied to the pipeline over long distances. The ICCP systems are quite robust and require minimal maintenance.

1.3.4. Route Selection

The route selection is a critical part of the pipeline system design and can avoid many problems that can lead to additional capital costs as well as additional operating costs and can greatly impact the ultimate useful life of the pipeline system. A route study is often performed with the objectives being:

- Confirm the specific corridor route for the pipeline
- Identify and avoid obstacles along the pipeline route
- Examine the effect of construction techniques on the pipeline route
- Define required Construction and Operational ROWs
- Define a required Operational Safety Corridor width

<u>Socio-Economic</u>	a. Minimize Impact of Resettlement /Relocation b. Minimize Impact to Cultural Sites c. Minimize Impact to Long Term Agricultural Activities d. Minimize Impact to Long Term Fishing Activities e. Ease Land Acquisition, Right-of-Way f. Likelihood of Intervention by NGOs g. Enhancement of Infrastructure h. Susceptibility to Future Encroachment on Right of Way i. Negative Impact on Current Industrial Activities j. Ease of Decommissioning

Environmental	a. Long Term Disturbance of Natural Habitats & Wildlife b. Adverse Consequences of Constructional Footprint and Site Access c. Adverse Consequences of Operation d. Adverse Consequences of Hydrocarbon release on the Environment e. Potential to Promote Adverse Development of Pristine Areas
Health & Safety	a. Negative Impact of Hydrocarbon Release on Health b. Negative Impact of Hydrocarbon Release on Safety c. Risks to People from Construction Activities d. Risks to People Due to Operation of the Pipeline System
CAPEX / Construction	a. Cost of Facilities b. Identification of risk areas c. Avoidance of risk areas
Operability, OPEX	a. Site Accessibility b. Use of Existing Infrastructure to Support Operations c. Ease of Pipeline Operations d. Ease of Pipeline Maintenance
Reliability	a. Minimize the Risk of Downtime b. Susceptibility to Accidental Damage
Schedule	a. Minimize the overall schedule of the project b. Risk of Schedule Delays
Security	a. Susceptibility to Terrorism or Insurrection b. Susceptibility to Vandalism c. Susceptibility to Illegal Off takes

1.3.5. Line Pipe Shipping

It is imperative that the purchase order requirements for line pipe that is shipped by rail or ship mandate that API 5L be followed. API 5L decrees that based on the pipe diameter and wall thickness, certain shipping precautions are undertaken, especially regarding:

- Maximum height to stack the pipe during shipping
- Amount of dunnage or cribbing used to support the pipe

Following the requirements of API 5L per Section 3 greatly reduces the risk of cyclic loading and pipe fatigue which could shorten the pipeline's overall useful life.

The following is an example calculation for pipe shipping per API 5L Section 3:

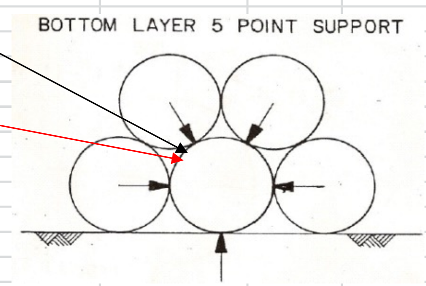
In accordance with 3.2. of Section 3, API RP 5L1 static load stress is calculated using the following formula:

$$\sigma s = 0.2 \sqrt{D} \frac{(nL)}{B} \frac{D}{t} \ln\left(\frac{D}{2t}\right)$$

Where:

n – stacking load factor, which is the number of rows in the pipe load, whether provided with separator strips or nested.
L – maximum length of individual pipe
B – effective number of bearing strips
D – OD of pipe in inches
t – wall thickness in inches

Is calculation for railroad car loading?	**No**	
Calculations:		
n =	**10**	**(number of rows to stack pipe)**
L =	40	
B =	3	
D =	24.00	
t =	1.160	
UTS =	60,000	
σs =	6,315	(if cyclic loading, i.e. rail car, then use 1.5 multiplier)
Cyclical σs =	9,473	
Max static load = 30% of UTS		
Maximum static load =	18,000	
# of Rows to Stack Okay	**Yes**	
Height of stacked pipe*:	19	feet



Bending stress	0.9382137
Moment of Inertia	0.1300747
Pipe wt per ft	282.96019
Pipe radius	1.000

1.4. Construction

In the USA, regulations for hazardous liquid pipelines are covered in Title 49, Code of Federal Regulations, Part 195 (49 CFR 195), Transportation of Hazardous Liquids by Pipeline. Section 195.2 defines a hazardous liquid as petroleum, petroleum products, or anhydrous ammonia. Section 195.1(b) excludes onshore gathering lines in rural areas and onshore production facilities and flow lines.

Per the requirements set forth in the Terms of Reference (TOR), the Author was asked to assess specific Variables identified by CREG and determine the cost impacts each would have on gas pipeline construction costs. The base cost for which the Variables will developed is a 50 kilometer, 4.500" x 0.083" wt, X-65 constructed in good conditions.

This Section will describe the various Variables requested by CREG to be specifically assessed and provide some information on each in order to assist CREG when evaluating the impacts of each Variable or variation thereof. In some cases, the Variable variations may be represented as having no impact. The reason being that a 40 year design life is based on a basic Design Basis and many of these variables would be considered as core variable decisions that would validate the 40 year design life; consequently it is not that they have no bearing on the useful life, in fact they are integral to achieving it.

1.4.1. Pipe Bending

Changes in direction and elevation of the ditch require bending of the pipe to fit the contour. Side bends will be laid in a horizontal plane; over bends and sag bends in the vertical; and combination bends in three dimensions. Normally bends can be of sufficiently long radius so that they are bent in the field. Tight bends need to be made in a shop equipped for induction-bending and then shipped to the field.

Care must be taken during field bending to prevent wrinkling of the pipe wall, flattening or buckling of the pipe, and damage to the coating. Bends should be checked to see that they are within tolerances for ovality. Pipe bends that exceed tolerance for reduction in diameter may obstruct the passage of scrapers during testing. Also, a flat spot in the pipe is a point of weakness.

Small-diameter pipe, generally NPS 12 or less, can be bent satisfactorily using a bending shoe attached at the bottom of the boom on a sideboom tractor. The angle of bend is visually judged by the bending crew.

Bending of larger-diameter pipe is accomplished by horizontal or vertical bending machines powered hydraulically or by cable systems. The angle of bend can be closely controlled with the machine. Ditch angles are usually measured by the bending crew with hand survey instruments in advance of the actual bending operation.

1.4.2. Welding and NDT

The most common method for welding pipelines in the field is the shielded metal arc welding (SMAW) process, using cellulosic (EXX10) electrodes. The direction of welding is normally downhill. Electrodes are selected to meet the mechanical properties (tensile strength and toughness) of the pipe and for welding characteristics needed to obtain sound welds.

Both welding procedures and welders are required to be qualified by the code covering the pipeline system. The codes require direct Company involvement in the qualifications of both procedures and welders. For welding procedures, this can be accomplished by either actually witnessing all qualifications or providing

Company qualified welding procedures. All welder qualifications should preferably be witnessed by the Company. Records must be kept of each qualified welding procedure being used and all welder qualification tests.

1.4.2.1. Regulations and Codes

The national regulations and codes that have requirements concerning pipeline welding are:

- 49 CFR 192 Transportation of Natural and Other Gas by Pipeline
- 49 CFR 195 Transportation of Hazardous Liquids by Pipeline
- ANSI/ASME B31.4 Liquid Transportation Systems for Hydrocarbons, Liquid
- Petroleum Gas, Anhydrous Ammonia, and Alcohols
- ANSI/ASME B31.8 Gas Transmission and Distribution Piping Systems
- API Standard 1104 Standard for Welding Pipelines and Related Facilities
- API RP 1107 Recommended Pipe Line Maintenance Welding Practices
- ASME Section IX Welding and Brazing Qualifications

Both ASME B31.4 and B31.8 permit qualification of procedures and welders to either API 1104 or ASME Section IX. Generally, API 1104 is the more appropriate code for pipeline welding and is the reference for discussion of welding procedure and welder performance qualifications in the sections that follow.

1.4.2.2. Welding Procedure Qualifications

Welding procedures are composed of two parts: the procedure specification and the procedure qualification. The procedure specification form is shown in Exhibit A of API STD 1104 and the information to be filled in ranges from process to speed of travel.

The procedure qualification form shown in Exhibit B of API STD 1104 documents the mechanical properties (such as strength, ductility, and hardness) of the welding procedure established in the welding procedure specification. Mechanical properties are determined by destructive testing of a test weld. After the welding procedure is qualified, changes to the procedure specification may be made providing they are not changes to the essential variables. Any changes to the essential variables require requalification of the welding procedures and revision of the welding procedure specification. The essential variables that have to be considered for the SMAW process are:

- Yield strength range of the pipe group
- Major change in joint design
- Welding position
- Wall thickness group
- Filler metal group
- Time lapse between root and hot pass
- Direction of welding
- Travel speed

There are additional essential variables for automatic welding, and API STD 1104 Section 9.0 should be consulted for these.

1.4.2.3. Welding Procedure Specification

The following is a discussion of the individual entries on the API STD 1104 procedure specification form.

Process (Essential Variable). Each process is identified by name and as manual, semiautomatic, or automatic. The most common process is shielded metal arc welding (SMAW), which is a manual process. Other processes are also recognized by API STD 1104. These are:

- Gas metal arc welding (GMAW)
- Gas tungsten arc welding (GTAW)
- Flux cored arc welding (FCAW)
- Submerged arc welding (SAW)

SAW is often used for double jointing of pipe where productivity gains can be achieved through automation. The other welding processes (GMAW, GTAW, and FCAW) can be used either semiautomatically or automatically depending upon the application.

1.4.2.4. Weld Inspection

This section discusses the requirements and procedures for inspection of pipeline girth welds. Normally, the Company's arrangements for pipeline welding inspection are independent of the pipeline contractor's organization. The contracts for welding inspection and nondestructive examination (radiography) are based on applicable codes, regulations, and Company requirements. However, the Company's quality assurance responsibilities must be carefully coordinated with the pipeline contractor to avoid lessening his sense of responsibility for the quality of the pipeline welding. The Company's responsibilities include:

- Preparation of clearly written specifications for the inspection and nondestructive examination (NDE) of the pipeline welds
- Providing qualified welding inspectors
- Assuring that welding procedures and welders are properly qualified
- Documenting or assuring documentation of all inspection results and providing quality control feedback to the pipeline contractor
- Spot visual examination of pipeline fit-up before welding, the welding in progress, and the completed welds
- Providing radiographic inspection through an inspection organization whose personnel are qualified to the American Society of Nondestructive Testing (ASNT) Recommended Practice No. SNT-TC-1A

1.4.2.5. Qualification of Welding Inspectors

API STD 1104 requires that welding inspectors be qualified on the basis of experience and training but does not provide specific requirements. The Company, then, has to establish its own requirements.

While welding experience is still important, a highly recommended alternative is Certification renewal is required every three years, and includes an eye examination, maintenance of welding experience, and payment of a fee. In addition, AWS requires reexamination every nine years.

API STD 1104 requires that the documentation of a welding inspector's qualifications include at least the following:

- Education and experience
- Training
- Results of any qualification examinations

1.4.2.6. Qualification of NDE Personnel

ASNT Recommended Practice SNT-TC-1A, for certification of personnel, assigns three levels of proficiency in various NDE methods (radiography, liquid penetrant, magnetic particle, etc.) based on training and experience. The levels are categorized as I, II, and III in ascending order of qualification. Contract inspection companies performing radiography are required to have their personnel certified to SNT-TC-1A. Welding inspectors who grade and interpret radiographs are also required to be certified to Level II or III.

1.4.2.7. Radiographic Inspection

After individual welds are completed and cooled, field radiographic inspection is done, following the inspection specifications. One, or more often two radiographers perform this work, using a radioactive source or a portable X-ray unit and a darkroom mounted on a heavy-duty pickup truck. Review and interpretation of radiographs of the day's welding progress should be completed by the end of that same day and be available to the Company welding inspector periodically during the day.

The use and frequency of radiographic inspection is established by the Company. Radiography is performed to the acceptability standards in Section 6.0 of API STD 1104.

1.4.2.8. Radiographic Procedure

Before any radiography can be performed on a pipeline, a detailed procedure for the production of radiographs must be prepared, recorded, and demonstrated by the radiographic contractor to produce acceptable radiographs, in accordance with Section 8.0 of API STD 1104. API STD 1104 requires demonstration on test shots that the radiographic procedure produces acceptable radiographs. A written procedure is required that includes at least the following:

- Radiation source.

- Intensifying screens.
- Film.
- Exposure Geometry.
- Exposure Conditions.
- Processing. The radiographic procedure should specify:
    - Automatic or manual processing
    - Time and temperature of solutions for development, stop bath (or rinse), fixation, and washing
    - Drying method
- Materials.
- Penetrameters.

1.4.2.9. Ultrasonic Testing

Ultrasonic testing is typically used when the automatic welding process is utilized. In ultrasonic testing, an ultrasound transducer connected to a diagnostic machine is passed over the object being inspected. The transducer is typically separated from the test object by a couplant (such as oil) or by water, as in immersion testing. However, when ultrasonic testing is conducted with an Electromagnetic Acoustic Transducer (EMAT) the use of couplant is not required.

There are two methods of receiving the ultrasound waveform:

- Reflection and
- Attenuation.

In reflection (or pulse-echo) mode, the transducer performs both the sending and the receiving of the pulsed waves as the "sound" is reflected back to the device. Reflected ultrasound comes from an interface, such as the back wall of the object or from an imperfection within the object. The diagnostic machine displays these results in the form of a signal with an amplitude representing the intensity of the reflection and the distance, representing the arrival time of the reflection.

In attenuation (or through-transmission) mode, a transmitter sends ultrasound through one surface, and a separate receiver detects the amount that has reached it on another surface after traveling through the medium. Imperfections or other conditions in the space between the transmitter and receiver reduce the amount of sound transmitted, thus revealing their presence. Using the couplant increases the efficiency of the process by reducing the losses in the ultrasonic wave energy due to separation between the surfaces.

1.4.3. Joint Coating

1.4.3.1. Holiday Detection for All Coatings

Inspection for holidays should be in accordance with NACE RP-0274-74. The coated pipeline should be 100% inspected with a pulse-type DC holiday detector employing an audible signalling device. Inspection is performed immediately prior to burial, i.e., after the last lowering-in side-boom. The electrode used for locating holidays must be in direct contact with the coating (with no visible gaps) and provide complete coverage of the whole coated surface. All holidays should be repaired and the repairs should all be checked with a holiday detector to verify that they are adequate. This final inspection procedure should be monitored by a Company Inspector.

The holiday detector requires an electrical ground. In most cases, this is a flexible bare wire approximately 30 feet long which is attached to the detector and trailed along the ground. Wet or damp ground is best. Dry ground may not complete the circuit; in this case attach the wire to a sideboom tractor. The travel rate of the detector's electrode should not exceed 1 ft/sec nor should it remain stationary while the power is on.

The calibration of the holiday detector should be checked at least twice per 8-hour shift against a calibrated voltmeter and adjusted as necessary. The functional operation of the holiday detector may be checked in the field by making a small artificial holiday in the coating (not more than 1/8 inch in diameter.) If the detector is working properly, it will reliably signal the presence of the artificial holiday.

Holidays should be clearly marked immediately upon discovery. The Inspector should certify that the defective areas have been repaired prior to burial. The Inspector usually keeps a daily record of the number of coating repairs per joint.

1.4.3.2. Field Inspection of FBE Coated Field Joints

The inspector should check the following details for FBE field joints. If a joint coating fails any of these tests, test adjacent (in both directions) girth weld coatings until acceptable coatings are found. All defective coatings should be completely removed and the areas recoated. At least one of the repaired areas should be reinspected and the subsequent inspection frequency should be as given below.

Thickness. Check the thickness on each coated weld joint using an approved, calibrated magnetic dry film thickness gage (e.g., Microtest, Elcometer or equivalent). The instrument should be zeroed before use with calibrated insulating shims of a thickness comparable to the coating film thickness to be measured. A minimum number of six readings should be taken on each field joint coating to verify compliance with the thickness requirement above. The readings should include the weld seam.

Cure. On the first five joints of the job and twice each day thereafter, the quality of cure should be checked by maintaining a MEK-soaked pad in contact with the coating surface for 1 minute and then rubbing vigorously for 15 seconds. There should be no softening of the coating or substantial color removal from the coating.

Holiday Detection. Perform detection in conjunction with the regular holiday detection for the coating, before lowering into the ditch.

Destructive Testing. Using a sharp knife with a narrow flexible blade, make two, approximately 1/2-inch long incisions through to the metal substrate to form an X. Starting at the intersection of the X, attempt to force the coating from the steel substrate with the knife point. Refusal of the coating to peel constitutes a pass. Partial or complete adhesion failure between the coating and the metal substrate constitutes a failure. Cohesive failure caused by voids in the coating leaving a honeycomb structure on the specimen surface also constitutes failure.
Perform this test once every hour. When five consecutive tests are successful, the frequency should be reduced to once every 2 hours.

1.4.3.3. Field Inspection of Heat Shrink Sleeves

The following inspection methods and acceptance criteria are applicable to all heatshrink sleeve applications. Additional inspection requirements (if any) for specific types of sleeves should be given in the sleeve manufacturer's recommended installation procedure.

Nondestructive Inspection. The shrunk-on sleeves should exhibit the following characteristics:

- Both ends of the sleeves must be bonded around the entire circumference
- The sleeve should be smooth. There should not be any dimples, bubbles, punctures, burnholes, or any other signs of holidays in the coating or of entrapment of foreign matter in the underlying adhesive
- For wrap-around sleeves, the total slippage of the closure patch during application should not exceed 1/2 inch
- The sleeve should overlap the adjacent mill coating by at least 2 inches on each side

Holiday Detection. Perform detection in conjunction with the regular holiday detection for the coating, before lowering into the ditch.

Destructive Inspection. Perform window testing on one sleeve of every 50 installed or twice per shift, whichever is the greater. On each sleeve tested, cut at least one window in each of the overlap area, across the field girth weld, and in the body of the sleeve. There should be no evidence of either voids extending to bare metal (or mill coating) or areas of no adhesion. The girth weld should be completely covered by adhesive.

Sleeve application is acceptable if both of the following requirements are met:

- The maximum dimension of any of these defects does not exceed 2 inches
- At least 95% of the adhesive layer is free of voids and/or lack of adhesion

If the sleeve does not meet the acceptance criteria above, the adjacent sleeves in both directions should be destructively tested until acceptable installations are found.

1.4.4. Lower-In and Backfill

The pipeline should be lowered into the trench closely after the field joints are complete, using two or more sideboom tractors, by lifting and guiding the pipe into the ditch with roller cradles. Final "jeeping" of the line is done as it is lowered in, and any repairs to coating defects should be made immediately. As mentioned above Section 1.4.3.3, for lines coated over the ditch lowering-in is done in conjunction with the coating operation.

In rocky areas, care must be taken in lowering-in that scraping against the sides of the trench does not damage the pipe coating.

1.4.4.1. Backfilling

Backfilling the line should follow closely behind lowering-in and be complete within a few hundred feet of the lowering-in operation at the end of each day, because thermal expansion and contraction of the exposed pipe may cause coating damage where the pipe lies on hard, uneven trench bottom. Tie-in and weld repair locations, cathodic protection test station locations, and block valve and scraper trap sites are backfilled as those items of work are completed.

With rock-free soil, backfilling is effectively accomplished by angle bulldozers or by special tractor-mounted backfiller attachments. Backfill soil should be placed so it rolls down the sloping face of the backfill, and is not dropped directly onto the pipe. Backfill material should be mounded up over the ditch to allow for settlement.

The amount of berm (crown or roach) required depends on size of the ditch and soil conditions, and should be determined locally. If the right-of-way or permit agreement requires that excavated topsoil be placed as the top portion of backfill, backfilling must be done accordingly.

Where rocky soil is not suitable for backfilling, suitable "shading" material should be placed a minimum of 6 inches around and over the pipe. As with padding, shading dirt or sand will need to be brought in from another source. Shading needs to be done with care so that rocks from the sides or edges of the trench do not become loosened and fall onto the pipe. As with backfilling, sufficient shading should be done on the same day as lowering-in to prevent damage to the coating by thermal movements or by rocks falling from the sides of the ditch. Once the line is satisfactorily shaded, backfilling with excavated rocky spoil can proceed, but the next 12 inches of backfill should be graded so there is no rock over three inches in diameter.

In rocky terrain, if no source of suitable padding and shading material is available within reasonable distance, "rockshield" wrapping around the pipe to protect the coating is suggested. Various types are available; the "rockshield" should be perforated or a mesh, so as not to shield cathodic protection currents from the pipe.

On steep slopes where backfill is likely to wash out in heavy rains, trench plugs—sandbag "breakers" or urethane-foam plugs—should be placed at intervals around and over the pipe to fill the trench to control surface runoff and limit the length of backfill that would be washed out by erosion.

1.4.5. Hydrostatic Testing

Completion testing of a pipeline after construction normally involves:

- A scraper run of a series of pigs propelled by water
- Hydrostatic pressure testing of the line with water
- Dewatering and/or drying
- Baseline intelligent pig run

1.4.5.1. Procedure

Along with the source of water, the most important concern in developing a procedure for testing a long cross-country pipeline is the test pressures for different sections of the line. These depend on design operating pressures, maximum allowable pipe pressures for various wall thicknesses, and ground elevations.

A procedure may be incorporated in the construction specification, but is more often developed by the Company field organization in coordination with the construction contractor. The procedure needs to be carefully thought through to achieve an efficient and safe testing program.

1.4.5.2. Preliminary Testing

Preliminary testing of pipe strings before installation is recommended for sections of line that may not be accessible later, such as major river crossings. Similarly, it may be prudent to test short sections of line immediately after installation in cases where later pipe or weld replacement would be difficult (and much more costly) after the installation crew and equipment have left the site; for instance, at major highway and main line railroad crossings, main irrigation canal crossings, etc.

1.4.5.3. Records

Clear and accurate records should be kept of all testing procedures and data. This is required for lines under most governmental jurisdiction and by all ASME Codes.

1.4.5.4. Completion Scraper Run

The pigs run for the completion test serve to:

- Displace air in the line with water. A line “packed” with water, without air pockets, is needed for reliable hydrotesting.
- Push construction debris ahead of them out of the line. The pigs will partially clean mill scale, weld spatter, and dirt from the line, as well as larger trash, rocks, etc., that were not removed by spread crews.
- Check the internal cross-section of the line. A pig equipped with a gaging plate will confirm that the line does not have dents, buckles or excessive ovalling at bends. If any such are present, the pig will either be stopped by

the deformed pipe, or will arrive at the incoming scraper trap with a severely bent gaging plate.

1.4.5.5. Gaging Plates

The gaging plate diameter should be 93% of the minimum nominal internal diameter of pipe in the particular section of line being tested. The plate should be accurately machined, and the diameter, measured by micrometer calipers, should be stamped on the plate. Three-eighths inch minimum thickness is suggested for a steel plate (one-half inch if aluminum), so that it is not likely to be deformed by a restricted pipe cross-section. The leading edge of the plate should be chamfered.

For large-diameter lines a steel reinforcing plate slightly smaller than the gaging plate may be advisable.

If after running through the line, the gaging plate is deformed, nicked, or gouged, possible causes should be reviewed and judgment made on accepting the line as satisfactory. A gaging plate may catch on weld “icicles,” small pebbles, or other acceptable irregularities at line appurtenances, as well as unacceptable deformed pipe.

1.4.5.6. Completion Hydrotesting

After displacing the air and filling the line with water during the completion scraper run, hydrostatic testing of the line (or section) can proceed. This involves pumping with suitable pressuring pumps to raise line pressure to a specified test pressure, blocking the line in to hold pressure, and observing line pressure for a period of time to determine if the line is tight.

1.4.5.7. Code Requirements

Section 437.4 of ANSI/ASME Code B31.4 covers hydrotesting of liquid lines, and requires proof testing of every point in the system to not less than 1.25 times the internal design pressure at that point for not less than 4 hours, followed by a reduced pressure of not less than 1.1 times the internal design pressure for not less than 4 hours. In other words, where lines are designed for maximum design pressures stressing the pipe to 72% of specified minimum yield strength (SMYS), the test pressure produces stresses of 90% of SMYS. API RP 1110, Recommended Practice for Pressure Testing of Liquid Petroleum Pipelines, gives guidelines for hydrotesting procedures and equipment, and a test record and certification form.

Section 841.3 of ANSI/ASME Code B31.8 covers testing of gas lines, and requires testing for at least 2 hours to the pressures tabulated in Code B31.8 Table 841.322 (e). Depending on the Location Class the test pressure ranges from 79% to 56% of SMYS if the maximum design pressure is based on design factors 0.72 to 0.40.

1.4.5.8. Test Procedure and Program

A detailed procedure for completion testing should be prepared. This procedure should be carefully reviewed and agreed to by Company field personnel and contractor supervisory personnel involved in the testing. The procedure should include the following elements:

- A ground profile for the section of line to be tested, with a diagram showing locations of scraper traps, block valves and check valves, pressure instruments, and temperature instruments
- A diagram of the pumping and metering system for the scraper run and line fill, from water source to the pipeline connection, including pressure-measuring instruments, and a list of equipment data. If filtering or treatment of the water is needed, the diagram should include this equipment
- A list of pigs to be run, gage plate diameter, and volumes of water to be pumped ahead of and between pigs
- A list of detection devices for following and locating pigs
- A diagram for the pressure test pump system, from water source to the connection to the pipeline, including equipment for measuring volume of water pumped into the line, pressure-measuring instruments, provision for overpressure relief, and a list of equipment data
- Maximum and minimum test pressures at the pump and the primary pressure instrumentation
- Calculated test pressures at other locations along the line
- Minimum period for holding the line at test pressure
- Calculation methods for analyzing effects of water temperature change, air volume in the line, and water compression
- Identification of connections and appurtenances on the line that must be blinded, plugged or disconnected. Mainline valves may be equipped with body relief valves that must be plugged or removed. Hydrotest pressure should not be applied to a closed valve if the pressure differential across the valve exceeds the valve test shutoff pressure
- Precautions and measures required if ambient or night chill temperature is below freezing
- Procedures required if daytime temperature and solar radiation effects on exposed pipe or test equipment are likely to cause pressures to increase above the maximum
- Safety precautions
- Communications units for Company and contractor
- Test personnel organizations for Company and contractor
- Notification of government agencies, where test witnessing is required
- List of agencies to be notified in event of a water spill resulting from a line rupture
- Arrangement for aerial inspection service in event of line rupture or leak
- The overall testing program should be described in outline form, with a tentative schedule for the scraper run and pressure testing. This should indicate personnel duties and work schedule for testing crews. Testing

usually is done on a 24-hourper- day basis, possibly with a short interval between line fill and pressure testing. A definite hour-by-hour schedule for the program cannot be set, since the rate of pig travel and times to build up to pressure test and hold at test pressure can only be estimated. Allowances must be considered for maintenance of test equipment and possible pipe leaks and repairs.

1.4.6. Water Crossings and Marsh Lands

Pipeline waterbody crossing techniques can generally be divided into four main categories:

(a) Wet Crossings, which typically involve construction activities that are in direct contact with the live waterbody.

(b) Dry Crossings, which involve the use of measures to isolate trench excavation and pipe placement activities from the live waterbody or open water.

(c) Non-Buried Crossings, which involve attaching the pipeline to a structure to suspend the pipe across the watercourses or involve the laying of the weighted pipeline on the bottom of the watercourse.

(d) Trenchless Crossings, which involve the drilling or tunneling of the pipeline under the waterbody with the most common form being directional drilling. Detailed information regarding the horizontal directional drilling technique can be found in the following two publications: (1) Installations of Pipelines by Horizontal Directional Drilling (1995); and, (2) Drilling Fluids in Pipeline Installations by Horizontal Directional Drilling (1994).

The selection of the method and the equipment to be used is dependent upon a number of variables. The following sections describe each of the methods; as well, the advantages and disadvantages are identified from both the construction and environmental standpoints. The appropriate uses for each technique are outlined. The objective in selecting a crossing technique is to choose the most environmentally appropriate and cost effective method. Impacts to water quality and habitat are to be minimized by:

- Use of the appropriate crossing technique.
- Timing construction to avoid environmentally sensitive periods.
- Completing the crossing in the shortest possible time frame.
- Implementing erosion and sediment control measures.
- Stabilizing and restoring the site as quickly as possible.

The two types of waster body crossings quantified in this Report are Wet Crossings and Trenchless Crossings, in this case Horizontal Directional Drilling (HDD).

<u>Wet Crossings</u>

For saturated wetlands, the ditch should be excavated using tracked excavators working off of swamp mats, board roads, timber riprap, or similar devices. Excavated spoil should be stockpiled on the non-working side of the ROW.

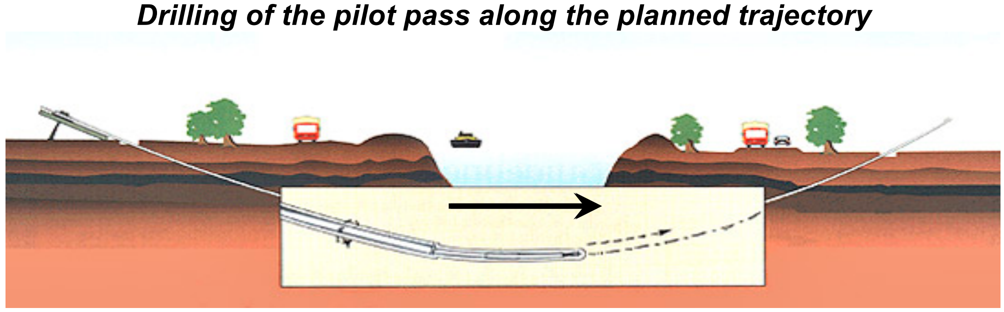
Pipe will contain buoyancy control by either means of continuous concrete weight coating or set-on type weights.

The extent of disturbance will be restricted to that which is required for the excavation of the ditch. Traffic through the wetland is normally restricted to only those equipment/vehicles necessary to install the pipe, to the extent practical.

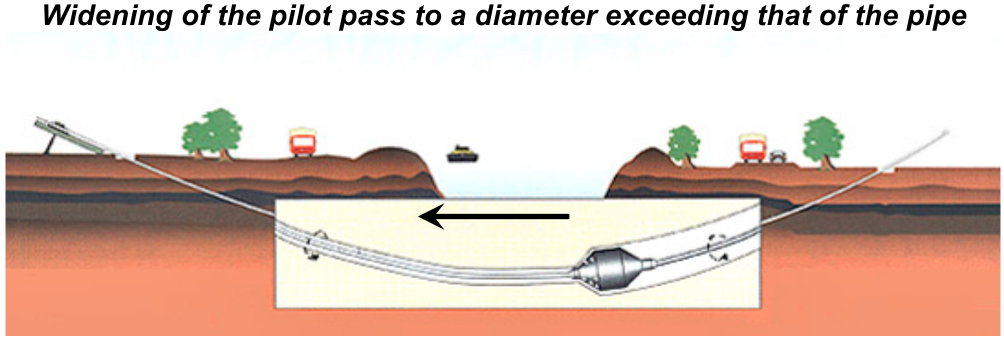
Flooded wetlands often have to be excavated using either tracked excavators or draglines working off barges or similar devices, or using marsh equipment excavators. Spoil is generally piled adjacent to the pipe ditch and then backfilled with the same type of equipment.

<u>HDD</u>
Installation of a pipeline by horizontal directional drilling (HDD) is a two-stage process. The first stage consists of drilling a small diameter pilot hole along a designed directional path. The second stage involves enlarging this pilot hole to a diameter that will accommodate the pipeline, and then pulling the pipeline back into the enlarged hole. The following diagrams explain the general process:

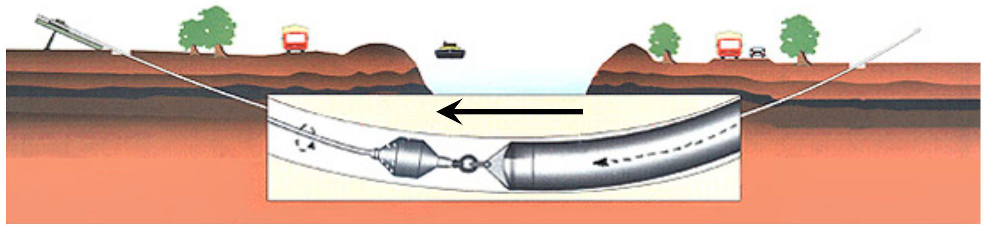
Drilling of the pilot pass along the planned trajectory



Widening of the pilot pass to a diameter exceeding that of the pipe



Installation of the pipe



Regardless of the techniques selected for the crossing, there will be a considerable increase in environmental oversight & mitigation measures required.

Aerial Crossings
Installation of a pipeline by aerial crossing means the pipeline will be suspended over an obstacle. The pipe will be installed above ground and will be supported at a minimum at each end and often will have interim supports depending on the size of the pipe and the length of the crossing.

1.4.7. Seismic Crossings

Seismic crossings have significant design and material requirements due to the high degree of risk imposed. Material and design costs were not included in this cost variable exercise as only construction costs were to be included.

Below is a general discussion of the types and reasons for impacts in construction costs that seismic conditions may have on construction costs.

(a) Pipeline Burial Depths at Fault Crossings
Pipelines crossings at faults are typically trenched and buried. Burial depths should be calculated, but are not normally extreme.

(b) Trench Configurations at Fault Crossings
Two trench configurations are normally utilized at fault crossings: a 'trapezoidal trench' configuration at the center of the fault crossing; and a 'sand padded trench' configuration at each side of the fault crossing.

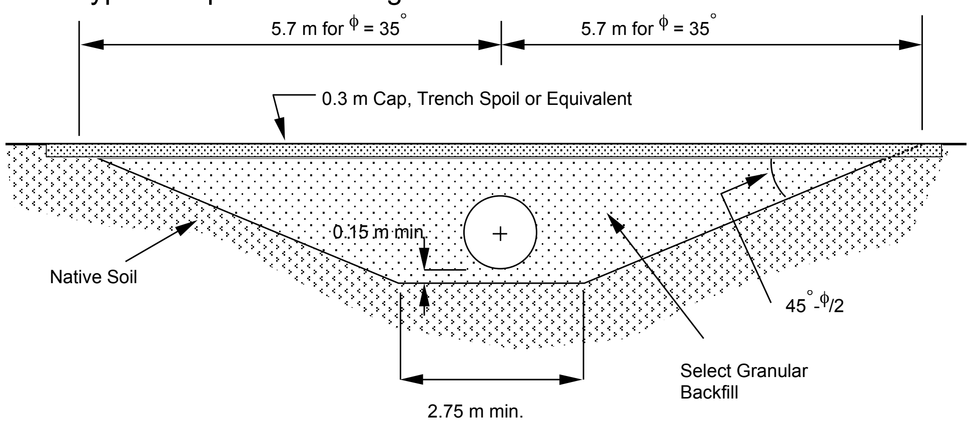
Trench configurations are part of the seismic study and typically one may substitute the 'trapezoidal trench' in place of the 'sand padded' trench configuration resulting in only one fault crossing trench configuration; but it is not advisable to substitute 'sand padded' in place of 'trapezoidal' trench configuration.

The minimum length of trapezoidal trench, centered at the fault location, is calculated and may run from 150m to upwards of 1,000m each side from the centerline of the fault.

(c) Trapezoidal Trench Configuration

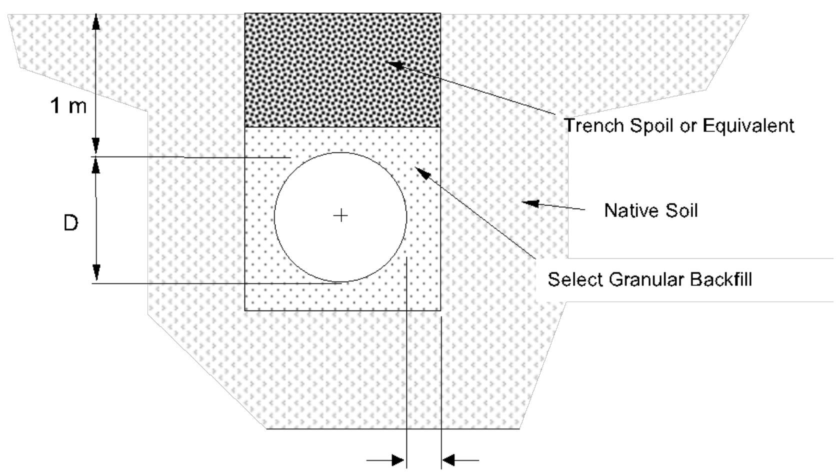
The trapezoidal trench cross section typically has sidewall slopes less than 1:2 vertical to horizontal and a minimum trench bottom width of 2.75m. Trench backfill material is to be select backfill.

A typical trapezoidal configuration is shown below:



(d) Sand Padded Trench Configuration

The sand padded trench is typically constructed as per the figure below.



(e) Select Backfill Requirements

Select backfill is typically a loose granular material such as well-graded loose to moderately dense sand, or equivalent, to provide a minimum internal angle of friction of 35 degrees or less. 100% of the backfill material aggregate should be less than 30mm diameter. Crushed rock is normally not allowed to be used. Backfill is normally moderately compacted to a relative density of less than 66%.

(f) Pipeline Wall Thickness at Fault Crossings

Seismic crossings typically require an engineering study that normally requires a different strength of steel and wall thicknesses used over the entire length of special fault crossing construction.

1.4.8. Extreme Terrain

Extreme terrain present numerous safety and construction challenges. Additional ROW work is required to get the terrain into as suitable condition for construction as possible. The sequential work itself is much slower through extreme terrain, increasing as the terrain difficulties increase and may include utilizing winches and cables to allow equipment to work on the slopes.

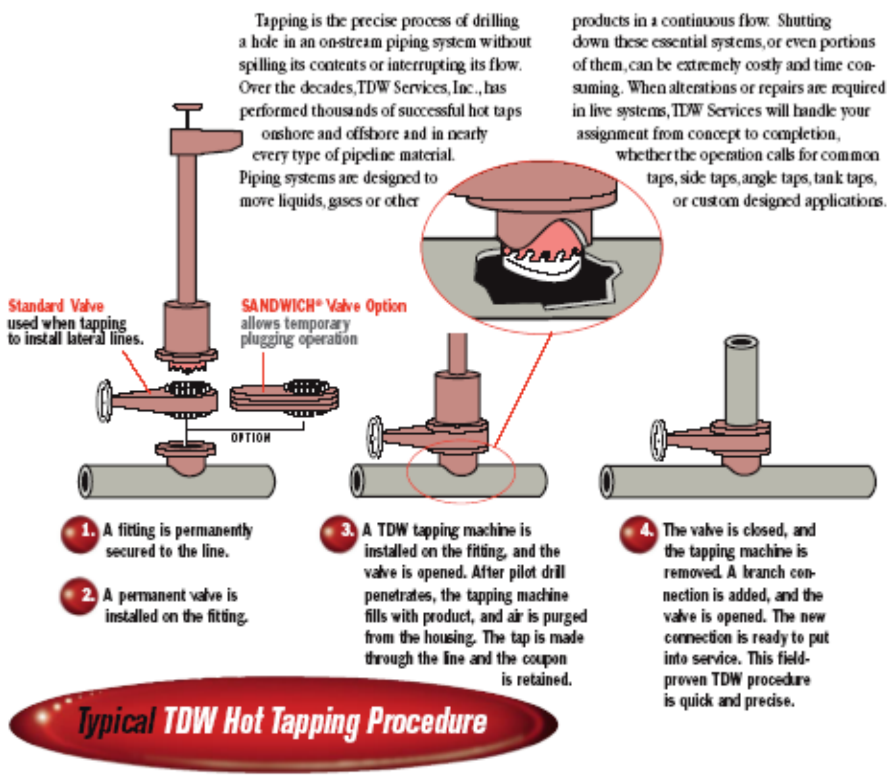
1.4.9. Connections

When making a tie-in to an existing pipeline where the pipeline will remain "in-service" during the tie-in, a hot tap utilizing a stopple and a by-pass is typically used. See Section 2.10.1 through 2.10.3 for a brief overview of the process.

Other connections considered as cost variables include:

1) ***Hot tap, stopple no by-pass***. Same as described in Sections 2.10.1 through 2.10.3 with no by-pass installed. This method requires a full shutdown of the pipeline system.
2) ***Hot tap*** (see Figure 1 below from TD Williamson)
3) ***Cold cut***. This method is simply the use of a cold cutting machine, normally for smaller diameter it is used manually, for larger diameter (over 16") normally a mechanized cold cutter is used. This method requires a full shutdown of the pipeline system.

Figure 1: Hot Tap Overview



1.4.10. Block Valves

A full port gate or ball valve should be used as a block valve for the tapping machine.

1) The valve should be of adequate pressure rating for the intended service and should be shop pressure tested (shell) and leak tested (seat/closure) prior to the installation. The valve pressure/ temperature rating should not be less than that of the existing piping system.
2) When the valve is to be left in place after completion of the hot tap, the following should be suitable for the intended service, pressure, and temperature:
   a) Valve body
   b) Trim
   c) Packing materials

1.5. Operations and Maintenance

1.5.1. Pipeline Integrity Management Regulations and Standards

The Hazardous Liquids Integrity Management Program (IMP), outlined in 49 Code of Federal Register (CFR) Part 195 and promulgated by the U.S. DOT-Pipeline and Hazardous Materials Safety Administration (PHMSA)-Office of Pipeline Safety (OPS), establishes rules for pipeline integrity management in high consequence areas for hazardous liquid pipeline operators. These rules specify regulations to assess, evaluate, repair and validate, through comprehensive analysis, the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, unusually sensitive areas (drinking water or ecological resources) and commercially navigable waterways. Additional information regarding ILI requirements and standards can be found in:

- Managing System Integrity for Hazardous Liquid Pipelines, American Petroleum Institute (API) Standard 1160;
- In-line Inspection Systems Qualification Standard, First Edition, API Standard 1163;
- Standards of Pressure Piping, American Society of Mechanical Engineers (ASME) Publication B31;
- In-Line Nondestructive Inspection of Pipelines, National Association of Corrosion Engineers (NACE) TR 35100, Item No. 24211;
- Recommended Practice: In-Line Inspection of Pipelines, NACE Standard RP0102-2002, Item No. 21094

The Author has sought to highlight the areas of integrity management in the following Sections that most impact the useful life of pipeline systems.

1.5.2. Spill Contingency Plan

Governmental regulations and permit conditions require preparation of written plans and procedures for dealing with accidental spills from liquid pipelines. A comprehensive spill contingency plan must be included with the pipeline operating and maintenance procedures. The contingency plan and procedures should comply with 33 CFR 153, Navigable Waters, and 40 CFR 112, Protection of the Environment.

A spill contingency plan needs to consider a wide variety of factors:

- Geographical elements—topography, surface conditions, soil type, drainage pattern, accessibility, etc.
- Environmental conditions—weather, hydrology, rare and endangered species, developed areas
- Pipeline system elements—pumping rates and controls, line draindown volumes, block valve locations, and closing response times
- The response procedures for each major surface drainage pattern area incorporated in the plan need to cover:
    - Organization of the spill response team—Company personnel plus local officials and contractors as appropriate
    - Procedure to locate and assess the spill and initiate control and cleanup procedures
    - Notification of government and local authorities and public relations information
    - Procedure to control or limit the amount spilled, evaluating threats to public safety and sensitive areas
    - Procedure to clean up and restore contaminated ground, shorelines,

and water surfaces
  - Availability and location of equipment, materials, and labor crews needed for all response actions
  - Documentation of the spill incident, response, cleanup, and restoration
  - Training plan and safety coordination
  - Procedure for handling damage claims

1.5.3. Minimizing the Potential for Damage to the Pipeline

Risk of damage to a pipeline by activities of others can be minimized by:

- Surface markers, identifying the location of the line and giving information regarding the proper Company contact to notify before proceeding with work
- Frequent surveillance of the route, on the ground and by air, to observe activities by others and changes in ground conditions—new construction, maintenance work, agricultural cultivation and grading, canal maintenance, erosion, land slips and slides, etc.—over or near the pipeline or progressing toward the line from another area
- Participation with Underground Service Alert Center or equivalent agency established to coordinate notifications regarding work on underground facilities
- Regular contacts with owners, authorities and contractors regularly working in the vicinity of the line to learn about planned and forthcoming construction that might jeopardize the pipeline

1.5.4. Managing Risk, In-Service Inspection and Testing

Pipelines, by their nature, are difficult to inspect, hard to protect and can run through sensitive areas. Like other facilities, pipelines can be crucial to local production. They may contain hazardous materials. Long and/or large diameter pipelines are a large capital investment. Consequences resulting from an incident can be quite severe. The risk associated with pipelines, therefore, is among the highest in the Company.

Risk assessment (see Section 1.5.5 below) is the typical method used by Operators to quantify and manage the risks associated with operating pipelines and pipeline systems.

In-service inspection and testing are prudent measures that should be taken for verifying the integrity of an operating pipeline system over the years. The following topics should always be addressed as part of a robust risk management approach:

- Wall thickness inspection by electronic inspection pigs
- Corrosion coupons inspections
- Hydrostatic testing
- Coating quality inspection
- Cathodic protection surveys

The Department of Transportation requires that the operator of a pipeline system prepare an operations and maintenance plan (see 49 CFR 195.402 and 192.605), but specific inspection and testing measures and frequency are not defined. Each pipeline operating organization should therefore develop a program suitable for its particular facility. Other than where federal or state regulations mandate specific inspection and testing intervals, the program should be tailored to the individual pipeline system.

1.5.5. Risk Assessment

The purpose of this section is to help Operators quantify and manage the risks associated with pipelines.

1.5.5.1. Identifying Risk

An "incident" is an occurrence that negatively impacts business. Pipeline incidents include, but are not limited to, oil spills, gas leaks, injury, lost revenue, and negative press coverage. Operators must determine the likelihood of an incident occurring and understand the potential consequences. These two elements combined, consequence and likelihood, represent the risk.

Once the risks are clear, the Operator chooses whether to:

- Take action to prevent the incident from occurring;
- Attempt to mitigate the consequences; or
- Monitor for impending failure.

Preventing an "incident" is preferred unless the cost to do so is excessive compared to the consequences.

It should be the stated goal of the Operator to be a safe, socially responsible and profitable. Risk assessment helps achieve these goals.

1.5.5.2. Risk Assessment Overview

An incident is rated as "high risk" if it is extremely likely to occur and would result in severe consequences. An incident is rated as "low risk" if it is unlikely to occur and would result in only minor consequences.

Once risk is determined and rated, the Operator can choose to:

- Prevent the incident from occurring or reduce the probability of occurrence. This is a good way to reduce risk and should be considered first.
- Monitor for impending failure. Sometimes this is more practical. Inspection for corrosion is an example of monitoring a risk. Because all pipelines eventually corrode, we monitor corrosion in order to predict a leak and take action before it occurs. It is more practical to monitor for corrosion than to replace the line every ten years.
- Mitigate consequences. Mitigation starts with the assumption that the incident will occur. Projected consequences are then reduced through pre-planning. Oil spill drills and initial route selection are examples of mitigating consequences.

1.5.6. Electronic Inspection Pigs

Electronic inspection pigs are primarily used to detect pipe wall thickness anomalies, record them electronically for playback at the end of the run, and determine the location of observed defects along the length of the line. Crack detection, hard spot detection, geometry, camera, leak detection, and mapping smart pigs are also available.

Capability to run inspection pigs should be provided in the design of the pipeline and appurtenances. Input should be obtained from one or more inspection services as to limitations affecting design of a particular pipeline, such as:

- Minimum radius of bends, and corresponding minimum pipe internal diameters.
- Minimum length of straight pipe between bends
- Spacing between branch connections, size of side taps, and if the side taps are
- barred
- Length of the inspection pig
- Duration of batteries and maximum memory data storage capability (to determine length of line that can be inspected in one run for a given flow rate)
- Installing permanent position markers for locating the position of the pig along the line
- The types of valves (check, gate, ball, etc.) and the minimum bore of the valves through which the inspection pig will have to pass.

Electronic intelligent pigs (smart pigs) are the most effective way to assess pipeline integrity for corrosion defects. Although smart pig runs can be quite expensive, they provide a detailed survey of almost 100% of the pipe wall while searching for areas of metal loss or cracking.

Smart pigs can be used while a pipeline is either in or out of service:

- When a pipe is in service, force to push the pig down the line comes from pressure drop across the pig.
- When a line is out of service, tethered smart pigs are pulled through the pipe using a wire line (or tether).

After the run, data is retrieved from the pig and analyzed.

1.5.6.1. Inspection Methods

The accuracy of location and measurement of anomalies by the intelligent pigs has continued to improve. Initially, the electronics and power systems were so large that intelligent pigs could be used only in lines 30 in. and greater in size. The continued sophistication and miniaturization of the electronic systems used in the intelligent pigs has allowed the development of smaller pigs that can be used in small-diameter pipelines. Newly enacted DOT pipeline-integrity regulations and rules acknowledge the effectiveness of the intelligent pigs and incorporate their use in the pipeline-integrity testing process.

Pig selection

Pig runs of between 50 to 100 miles are normal, but pig runs exceeding 200 miles should be avoided as the pig may wear and get stuck in the line. Cleaning pigs may be constructed of steel body with polyurethane cups or discs and foam pigs with polyurethane wrapping, solid urethane disc, and steel body with metallic brushes. Drying pigs are usually low-density foam or multicup urethane. The intelligent pigs may be:

- Magnetic flux leakage (MFL)
- Ultrasonic (UT)
- Elastic/shear wave
- Transponder/transducer, or
- Combinations of the above

Most Operators however utilize either MFL or UT:

- MFL can be used in either oil or gas lines. When using MFL tools in gas lines it can be difficult to control the speed of the tool. Gas bypass is available on some tools to control the speed and minimize impact on production.
- Ultrasonics are easiest to use in liquid systems (UT needs a liquid couplant to work). However, UT tools can be adapted for gas lines by sequencing the tool in a "liquid pill" between two cleaning pigs.

Recent developments in UT have seen tools developed for detecting external stress corrosion cracking and tools with a gas bypass to minimize production impact on high volume lines.

Specialized MFL and UT tools are designed to:

- Use in sour service
- Maximize travel distance
- Negotiate tight bends.
- Optimized to allow pigging through multiple line sizes
- In hot systems
- Optimized for very thick wall pipe, or very thin wall pipe
- Map out the line using inertial referencing (often called geopigs)
- Size the ID or look for dents (often called caliper pigs)

1.5.6.2. Line Design May Preclude Pigging

Original line design may preclude smart pigging. Some lines, however, may be modified to make them piggable without spending a great deal of money. Lines may be poor candidates for intelligent pigging under the following circumstances:

- The line contains bends with a radius of 1.5D or less. Note some of the newer tools have been configured to allow pigging down to and including 1.5D bends.
- The line contains miter joints over 10 degrees. Miter joints are unusual except on very old lines.
- The line contains unbarred branch connections. Depending on branch size,

orientation, flow direction and control over pig speed, smart pigging may be possible.

- The line contains reduced port valves (often done on older lines to save money on valve costs).
- Line diameter changes by one or more standard pipe sizes. Again, depending on specifics, smart pigging may be possible.
- The line does not have pig launching or receiving capability. Note there are pipeline service companies that will rent horizontal and vertical pig traps for smart pigging use.

1.5.6.3. Maintenance Pigging

Pipeline cleanup

Operations may conduct pigging on a regular basis to clean solids, scale, wax buildup (paraffin), and other debris from the pipe wall to keep the pipeline flow efficiency high. In addition to general cleaning, natural-gas pipelines use pigs to manage liquid accumulation and keep the pipe free of liquids. Water and natural-gas liquids can condense out of the gas stream as it cools and contacts the pipe wall and pocket in low places, which affects flow efficiency and can lead to enhanced corrosion.

Batch transportation

Pigs are used in product pipelines to physically separate, or "batch," the variety of hydrocarbons that are transported through the line. Product pipelines may simultaneously transport gasoline, diesel fuel, fuel oils, and other products, which are kept separated by batching pigs.

Prevention of solid accumulation and corrosion

Crude-oil pipelines are sometimes pigged to keep water and solids from accumulating in low spots and creating corrosion cells. This can be especially necessary when flow velocities are less than 3 ft/sec. Multiphase pipelines may have to be pigged frequently to limit liquid holdup and minimize the slug volumes of liquid which can be generated by the system.

Inspection

Pigs are being used more frequently as inspection tools. Gauging or sizing pigs are typically run following the completion of new construction or line repair to determine if there are any internal obstructions, bends, or buckles in the pipe. Pigs can also be equipped with cameras to allow viewing of the pipe internals. Electronic intelligent, or smart, "pigs" that use magnetic and ultrasonic systems have been developed and refined that locate and measure internal and external corrosion pitting, dents, buckles, and any other anomalies in the pipe wall.

Inspection sensitivity depends on the number of sensor heads in the tool:

- Smart pigs that use more sensor heads (making them highly sensitive) and give quantitative wall thickness data are commonly called high resolution tools.
- Tools that use fewer sensor heads are called conventional resolution tools.

These tools provide qualitative data. Conventional resolution pigs are considerably less expensive than high resolution.

Conventional resolution tools can be cost effective where the line is in relatively good condition with few areas in need of repair and where repair cost is low. Conventional resolution tools have been used where the accessibility for cut out is good. For example, in CCR in some lines where conventional resolution tools were used, all defects greater than 30% of wall loss were cut out. However, conventional resolution tools, even when run by a reputable vendor, can miss problems. This occurred at least once. A significant site of external corrosion was missed and a multi-million dollar spill resulted. The cause is suspected to have been thick, tight magnetic OD corrosion scale saturated with high conductivity water. These conditions are thought to have allowed the scale to carry more magnetic flux, making the pipe wall look thicker than it really was. This line is now inspected using a high resolution ultrasonic pig at a cost premium of five times over the prior conventional resolution technique.

Conventional resolution results are higher in false positives than high resolution tools. If cost to repair is very high, like subsea lines, high resolution tools may be justified. High failure costs may also justify use of high resolution to obtain the maximum protection against a multi-million dollar incident.

Tethered tools are typically used on shorter sections in lines where just a river crossing, for example, may have a high failure consequence. Short, high consequence inspections like these can be done at reasonable cost. Tethered tools have now been developed for use to impact the riser section of offshore platform pipelines.

Key to getting the most value from a smart pig is working closely with the vendor to ensure that all of the many details are communicated correctly and acted upon. Overlooking or not handling correctly just one detail can potentially cause a pig to stick in the line. Once a pig is stuck, the line must be shut down, the pig located and cut out of the pipe, and both the line and the pig must be repaired. Usually, unpleasant discussions with Operations follows such an event. Avoid this situation by working with the vendor who will suggest a preparation plan of cleaning and sizing pigs to prevent such problems.

After a successful run, review the results and verify that they are consistent with known features and corrosion hot spots. Interpretation errors have been known to occur.

1.5.6.4. Data Developed by Smart Pigging

The amount of data developed by smart pigging is measured in gigabytes. The computer revolution is just barely keeping up in its ability to analyze data in a timely fashion. The latest technique developed to improve piggable distance is the use of real time data filtering on board the pig. Desktop computers have made a big improvement in the ability to review results of high resolution tools.

The major high resolution vendors now deliver the data on floppy or compact disk with special application software which allows the client to manipulate the information or combine it with other data bases. The software can also automatically perform strength calculations based on the inferred shape and depth parameters. It then prioritizes the defect areas based on maximum allowed operating pressure at the defect. However, a waiting period of a month or more is still common before the results of the run are analyzed by the vendor and returned.

1.5.6.5. Corrosion Coupons

For corrosive fluids, for which a specific corrosion allowance has been provided in determining the pipe wall thickness, it may be advisable to install corrosion coupons at points in the system representative of flow conditions and where they can be isolated and removed. These would normally be in the station or terminal piping or on flowing branch lines, rather than on the main pipeline. Where the piping must be kept in operation while removing or replacing coupons, a valved by-pass can be provided.

If necessary to install a coupon in the main line, devices are available for withdrawing and re-inserting the coupon with the line in service.

1.5.7. Hydrostatic Testing

Two types of pressure testing of operating liquid lines are:

- Testing after displacing lines with water at hydrotest pressures at 1.25 times the maximum allowable operating pressure.
- Line pack or standup testing with the fluid normally handled after isolating the section, at a pressure not exceeding the maximum operating pressure

The maximum allowable operating pressure should be determined taking into consideration actual normal and abnormal operating pressures, limitations by design codes for pipe grades and wall thickness, and limitations by valves, flanges or other line appurtenances.

Operating demands usually limit the time available for testing. Therefore, the test procedure must be well planned, giving consideration to all aspects and contingencies.

All needed facilities, including communications, should be ready, as well as materials and construction equipment in event of a leak or a break. When testing in wet weather or wet areas, using a water-soluble dye in the test water may be warranted for identifying leak locations. Disposal of displacement water must be arranged to comply with environmental restrictions.

Lines that have been idle for over 3 months and up to a year should have a satisfactory standup test before returning to service. A line that has been idle for a year or more should be hydrostatically tested with water to 1.25 times the maximum operating pressure before returning to service.

1.5.8. Monitoring of Cathodic Protection and Pipe Coating

Overall quality of pipe coating to effectively protect the pipe from corrosion is indicated by cathodic protection surveys at frequent intervals and by monitoring the current from rectifiers needed to maintain cathodic protection on the pipeline.

If areas of severe coating failures and defects are suspected, coating holidays can be located with equipment such as the Pearson null-method detector manufactured by Tinker & Rasor, San Gabriel, CA, providing the pipe is buried in relatively moist soil conditions. The Pipe-CAMP PCS-2000 equipment recently developed and used in Australia is claimed to have greater sensitivity and ability to detect defects in dry and rocky soil and under pavement; it is available through US agents, such as Farwest Corrosion Control, Gardena, CA.

As regards frequency, checking cathodic protection potentials should be done at a minimum on an annual basis.

A Direct Current Voltage Gradient (DCVG) survey should be undertaken as a part of routine pipeline maintenance. DCGV is a technique used for assessing the effectiveness of corrosion protection on buried steel structures. In particular, oil and natural gas pipelines are routinely monitored using this technique to help locate coating faults and highlight deficiencies in their cathodic protection (CP) strategies. DCVG survey's should be done immediately after construction is completed to develop a system baseline. Afterward, DCVG survey's should be done every three (3) years.

If large swings in CP Potential were found it would be normal to follow up this anomaly with a DCVG survey.

Repairs would be carried out as required.

1.5.9. Leak Detection by Physical Methods

SCADA leak detection systems will trigger the need for corrective action or repairs and may indicate the general area of the suspected leak. To precisely locate a pipeline leak, however, on-the-ground detection methods must be used. These include:

- Visual observation by air or on the ground for evidence of line stock or effect on vegetation
- Combustible gas detectors

- Injection of odorants into gas and odor detectors
- Sonic instrumentation
- Pressure-wavefront instrumentation

Information on leak detection for gas lines is presented in ASME Code B31.8, Appendix M, Gas Leakage Control Criteria. Appendix M relates to gas distribution piping, not transmission pipe lines, so judgment should be used in considering the action criteria outlined in Section 5 of Appendix M.

Leaks would be identified, root causes recognized and repaired.

1.5.10. Pipeline Repairs

When pipeline repairs are required because of corrosion, defects, or damage to the pipe, the Company preference is to replace the section of pipe requiring repair. This generally entails cutting out the affected section and installing a new piece of pipe (pup). The circumferential welds to install the pup piece are straightforward pipeline welds that can be inspected by standard radiographic practices and the pipeline can be returned to service in good condition.

However, this practice requires shutting down the pipeline. When schedule considerations make this impractical, other repair methods have to be employed, such as Plidco sleeves and Stopple fittings, Clock Spring fiberglass coils, or full encirclement welded sleeves.

1.5.11. Maintenance Program in Areas of Unstable Soils or Seismic Activity

Nearly all pipeline systems are required to have normal operating and emergency contingency plans. These plans specify immediate operating action in event of landslide, subsidence, or earthquake.

In addition to normal maintenance surveillance, the following measures are suggested for areas of unstable soils and seismic risk:

- As-built documentation should be on hand so that any changes from design or design assumptions are recognized, documented, and evaluated for their effect on pipeline integrity
- The inspection plan should include a recognition of the key components of design, to ensure the integrity of the line, and a program for monitoring these components
- Measurement surveys should be conducted periodically to detect changes in field conditions and in the line
- A contingency repair plan should be prepared for corrective actions for situations of varying degrees of severity. It should identify (1) recurring problems requiring routine periodic correction, (2) problems that may arise for which standard procedures can be implemented without engineering

involvement, and (3) critical problems requiring engineering investigation and resolution. Necessary materials and construction equipment to make repairs on an urgent basis should be available near the areas of risk

- A postevent monitoring plan with checklist for reporting as soon as possible whether damage is severe or relatively minor. The initial inspection checklist should identify specific system components and ground conditions that are good indicators of damage. Ground condition indicators include: ground cracks; misalignment of roads, trees, fences, pole lines, railroad tracks, etc.; ground sags, sinkholes, or uplifts; signs of damage to other nearby utility lines. As soon as possible after strong events, a thorough investigation should be made by responsible operations and technical personnel to determine the condition of the pipeline, safety of resuming operations, and necessary corrective repairs or replacement

In making repairs to a line damaged by ground displacement, precautions should be taken in cutting the pipe to avoid fire or injury in case of likely sudden release of high-strain energy stored in the line. Precautions should also be taken for possible hydrocarbon spills in the soil and for unstable ground conditions.

1.6. Asset Retirement

Asset retirement is performed once a pipeline, portion of a pipeline or a system is deemed to be no longer required as part of the Operator's current and/or future plans for the development of their resources, or considered uneconomical to repair/reinstate.

Asset retirement does not have a relationship to useful life; however, the Author deemed it pertinent to include a short discussion on asset retirement in order to provide a full picture of a pipeline system from project initiation through the retirement of the asset.

A pipeline or portion of a pipeline may be considered no longer required if:

- A defect or several defects are identified in the pipeline or system, and repair is determined to be uneconomical, or
- Production from a particular well diminishes such that shut-in is required.

It should be noted that assessment of possible future work-overs of such wells would need to be done to assess the possibility of, for example, accessing deeper fields.

Any design changes or repairs/alterations performed on pipelines shall adhere to the following primary industry codes and regulations:

- ASME 31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and other Liquids
- ASME 31.8 Gas Transmission & Distribution Piping
- Code of Federal Regulations 49, "Pressure Testing" (Sub Part E)
- Code of Federal Regulations 80, "Installation, Testing and Repair Requirements for DOI Pipelines" (Sub Part J)

Other documents that could be referenced include:

- API Recommended Practice 17A, Design and Operation of Subsea Production Systems
- Code of Federal Regulations (CFR) Title 30 - Mineral Resources Chapter II – Minerals Management service, Department of the Interior, Part 250 – Oil and Gas and Sulphur Operations in the Outer Continental Shelf, 2001
- Article 60.3 (1982) of The 1958 Geneva Convention and the Nations Convention of the Law of the Sea (UNCLOS)

1.6.1. International Regulations and Guidelines

The 1958 Geneva Convention and the Nations Convention of the Law of the Sea (UNCLOS) Article 60.3 of the UNCLOS (1982) states that:

"Any installations or structures which are abandoned or disused shall be removed to ensure safety of navigation, taking into account any generally accepted international organization. Such removal shall have due regard to fishing, the protection of the marine environment and the right and duties of other Sates. Appropriate publicity shall be given to the dept, position and dimensions of any installations or structures not entirely removed".

1.6.2. Pipeline no longer in use

If a pipeline is not in use for a period of up to one year it should be isolated with a blind flange or a closed block valve at each end.

If a pipeline has not conveyed hydrocarbons or water for a continuous period of one year, and is not considered likely to convey hydrocarbons or water for a further period of five years, that pipeline may be considered temporarily abandoned and treated accordingly.
Temporarily abandoned pipelines shall be returned to service within 5 years or be abandoned in accordance with the relevant requirements below.

1.6.3. Abandon

For all abandonment and temporary abandonment procedures the project must submit a brief pipeline abandonment application to the FE Supervisor for approval that includes the following information:

- Reason for the operation;
- Proposed abandoning procedures;
- Length (meters or feet) of segment to be abandoned; and
- Length (meters or feet) of segment remaining.

1.6.4. Abandoned in Place

You may abandon a pipeline in place when the Marine Supervisor determines that the pipeline does not constitute a hazard (obstruction) to navigation and commercial fishing operations, unduly interfere with other users of the area, or have adverse environmental effects.

If a pipeline is no longer in service, and is never intended to return to use, then all of the following conditions should apply:

- Pigged clean if feasible,
- Flushed of hydrocarbons to less than 40ppm,
- Filled with acceptable substance,
- Ends plugged and buried at least 3 feet or cover each end with protective mats,
- Remove all pipeline valves and other fittings that could unduly interfere with other users.

Abandoned pipelines will not be in the list for integrity management.

1.6.5. Abandoned by Removal

If a pipeline is no longer in service, and is never intended to return to use, then all of the following conditions should apply:

- Flushed,
- Pigged clean (if feasible),
- Flushed,
- Abandonment can be achieved through a reverse installation method, for example, the reverse lay method.

1.6.6. Temporary Abandonment

If a pipeline is no longer in service, but may be returned to service at a later date (1 to 5 years), then all of the following conditions should apply:

- Flushed of hydrocarbons to less than 40ppm,
- Pigged clean (if feasible),
- Filled with filtered and treated seawater (to include biocide and corrosion inhibitor),
- Blind flanged or skillets in place to provide a positive isolation from the process system.

Temporarily abandoned pipelines will receive limited integrity management, which is usually developed on a case-by-case basis. Prior to being returned to use, a temporarily abandoned pipeline shall undergo a full set of procedures to include correct disposal of contents, integrity verification and hydrotest to ensure it is fit-for-service.

1.6.7. Decision Method – Abandon or Temporary Abandonment

It is assumed that the pipelines under consideration for these procedures have been shut-in. If a pipeline (and associated risers) is no longer in use, a decision must be made whether to abandon the pipeline, or to temporarily abandon if there remains a possibility of a resumption of service in the future.

This decision should take into account such factors as:

- Cost of repair (if required); and
- Future utility of associated wells (e.g. are workovers possible in the future that will result in the use of the flowline that is being considered for abandonment?).

Once the decision has been made, the necessary steps to abandon or temporarily abandon should be undertaken, as shown below.

1.6.7.1. Isolation from the Process System

Pipelines taken out of service should be blind flanged or isolated with a closed block valve at each end.

It is preferable to attach a blind flange with a “bleeder” valve. This permits the pipe to be flushed again, if necessary, and provides for future use of the pipeline should the need arise. When fitting a blind flange/bleed valve assembly, the valve should be at least a 2-inch nominal size.

1.6.8. Ongoing Integrity Management Procedures

Partial ongoing integrity management should be maintained for pipelines that have been temporarily abandoned. This typically includes activities such as checking and maintaining any cathodic protection system. Each pipeline should be reviewed on a case-by-case basis to determine ongoing integrity management.

1.6.9. Recommissioning of Temporarily Abandoned Pipelines

Should it be determined to re-commission a pipeline at some point after abandonment, recommissioning will involve the following basic steps:

- Hydrostatic pressure testing.
- Repair of any defects detected during the hydrotest and reassessment as necessary.
- Repeat hydrotest and repair of defects until the pipeline passes the hydrotest.
- Dewatering of pipeline.
- Cleaning pigging.
- Recommissioning pipeline.

2.0 Pipeline System Valuations – Basis of Estimate

The Author has provided a pipeline system valuation in P1 Appendix B. We have seen over the last year the following impacts to some of the more major construction-related components:

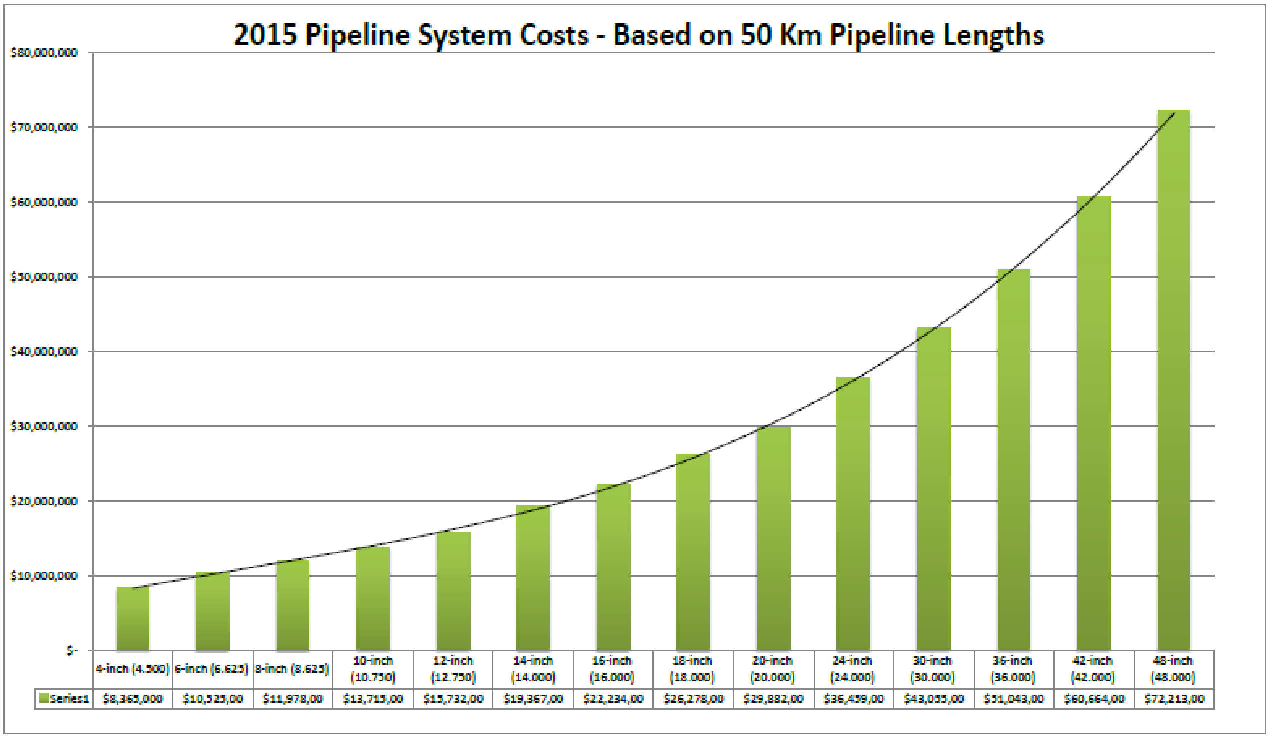
- Fuel — Decrease of 56%
- Labor — Increase of 2.46%
- General Materials — Decrease of 4.94%
- Pipe — Increase of 62%
- Equipment-General — Increase of 0.91%

2.1. Estimate Overview and Requirements

Following is an overview of the methodology that was used to develop the Class 3 Cost Estimate for the 4” base case:

- A Class 3 Cost Estimate was prepared in Microsoft Excel based on the Author’s proprietary Pipeline Cost Model for a generic 4” pipeline.
- All relevant cost data used to develop the cost estimate is included or referenced in the relevant documents of this Section 2, Estimate Basis.
- Uses of common unit pricing (similar metrics, rates, percentages, activities or tasks) are defined later in this document. They are consistently applied throughout estimate.
- Per the request of CREG, the remainder of the pipeline systems costs were are escalated to the actual diameter of the gas line being evaluated.

The following are the general results of the assessment:



The full breakdown of costs by diameter and length is found in P1 Appendix B.

2.2. Assumptions, Exclusions, and Clarifications for 4” Base Case

2.2.1. Assumptions

The following is a list of assumptions made for the purpose of developing the cost estimate not documented elsewhere in the Report. Assumptions made include:

- EPC Contractors will have the resources to meet the timing required for this project
- Labor will be in adequate supply for the entirety of the project
- Site conditions will be favorable and determinable, thus not impacting cost/schedule targets
- All project funding will be available for project to commence and move to completion timely.
- Pipe/steel prices will remain within an acceptable range of current market rates included in the cost estimate.
- Fuel prices will remain within an acceptable range of current market rates included in the cost estimate.
- As much as possible, the work will be planned and performed during the dry season.
- Owner’s will seek the most cost effective strategies for pipelines system replacement

2.2.2. Exclusions

The following is a basic list of exclusions from the Cost Estimates and document potential costs that may be incurred by the project but have not been included in the estimate:

- OPEX costs
- Defining specific items to be capitalized or expensed
- Drilling, workover, or field development costs
- Line pack costs
- Facilities, i.e. metering, compression
- Specific H2S handling equipment
- Land and land acquisition costs
- Market conditions that may impact EPC Contractors or pipeline construction contractors ability to competitively tender projects has not been considered

2.3. Cost Basis

The basis for this Cost Estimate is 3Q 2015. All dated costs (i.e. outdated vendor pricing), if applicable, have been escalated to the Estimate Date by using Nelson-Farrar or CE Plant Cost Index Report to ensure that the estimate reflects current market conditions and pricing.

2.3.1. Currency

The primary currency used to develop the Class 3 Cost Estimate for this project is the US Dollar.

The estimate has not taken into account currency rate fluctuations. These are normally handled on a corporate level and are not included in the cost estimates, contingency, or escalation.

2.3.2. Capital and Expense

The decision to address and assign project costs as expense or capital costs are outside the scope of this effort.

2.3.3. Tendering Costs

Costs for Owner's to manage the overall project, including developing tender packages, awarding, and managing the project have been included in the cost estimate.

2.3.4. Permanent Material/Service Quotes and Contractor Bid Pricing

Special consideration has been given to distinguish between cost and price when developing the base estimate costs. Pricing includes techniques and adjustments that bidders and contractors apply to a scope of work estimate to allow for overhead and profit, to improve cash flow, or to otherwise address market conditions and serve their business needs.

The estimate approach was to develop a standalone construction estimate as a construction contractor would develop and that would be included into the overall project related costs to determine the Total Installed Costs (TIC) for each pipeline system, including the full EPC scope of work, risk allocation, and final design specifications.

2.3.5. Shared Costs

For the purpose of this Report and cost estimate, shared costs, such as those that may be shared between the contractor and the owner and the assumptions regarding these costs have not been considered.

2.3.6. OPEX

Operating Expenditures are excluded from the base estimate and it is assumed that Owner's will include those from their own historical base business for the purpose of determining overall project economics.

2.3.7. Socioeconomic

Costs for socioeconomic programs have been included, which incorporate the hiring of local labor; training of local labor, anticipating some labor disruptions, and local infrastructure requests, such as water supply, educational and health programs, sustainable agriculture and fishing.

The costs included were meant to support Owner's' commitment to work with groups in the area to produce energy, strengthen communities and respect local culture in order to blend ethics of safety, environmental responsibility and shared success with important values of the people: kindness, friendliness and respect.

It was assumed 10% local labor (from local communities) would be utilized and a dollar amount commensurate with the length and location of the pipeline included for local infrastructure projects is included.

2.4. Project Execution Strategy

The execution basis for these projects was based on a standard Project Execution Plan (PEP) that is typically developed to guide the process. The following project documents are normally developed to form a part of the overall PEP and include the following:

- Execution Basis
- Environmental, Political & Business Conditions
- Project Approvals
- Project Management Team & Systems
- Appropriation and Control
- Cost and Schedule
- External Affairs
- Contract Plan (Scopes, Bidders, and Contract Type)
- Approved Vendor List

- Procurement Plan
- Construction Plan
- Construction Management Plan
- Organization & Resource Plan
- Security Plan
- Training Plan
- Logistics Plan
- Key Issues

Normally the PEP will drive the process and form the basis of the cost estimate; in this case as there were so numerous projects to develop, it was decided to use a generic PEP and allow the project details that went into the cost estimate to drive the process.

2.5. Contracting Basis

In order to develop costs estimates for these systems, it was necessary to make some essential contracting assumptions. A specific Contracting Plan was not developed, but some fundamental assumptions were made in order to effectively cost the potential interfaces that would exist between the multiple contractors. The contracting assumption made was to contract these systems out to a consortium or single company to manage the project on and EPC basis. Section 2.14 shows the basic WBS that was used as a guideline.

Contractors and EPC Contractors carry Construction All Risk (CAR) insurance.

2.6. Procurement Basis

It was assumed the overall EPC Contractor's responsibilities would be the full scope of work, i.e. Engineering, Procurement and Construction.

The Procurement scope of work will include the purchasing, expediting, and inspection coordination of all major equipment and materials and hundreds of bulk commodity items. This will include mechanical equipment, and instrumentation and electrical equipment and materials; and piping commodity items, such as pipe, valves, fittings and flanges. Procurement responsibilities will encompass the worldwide sourcing and purchasing of equipment, materials and services and will include Home Office and Field Expediting, Supplier Surveillance and Inspection at supplier facilities.

Procurement costs were estimated based on typical material control strategies to ensure the identified material requirements are available in a timely manner to support the construction schedule.

The 4.500" pipe was assumed to be purchased and coated from international pipe mills and was assumed to be X60.

Pipe cost per ton were based on current pricing received from several European pipe mills. The average pipe price per ton was found to be \$1,300/ton Ex-works and therefore does not include VAT and taxes. 20% VAT was included to bring the total cost per ton used in the estimates at $1,560/ton. Customs, taxes, and duties for importation into Colombia are covered in the estimate, but not included in the per ton pipe costs.

2.7. Execution Basis

The following items were considered in costing the overall project execution:

- Engineering durations were estimated based on the scope of work
- Construction is assumed to start once engineering is 75% complete
- Fabrication/integration,/installation locations, estimated distance to site
- Labor rate standard for EPC Contracting entities
- Resource planning methodology, crew size/mix expectations, capacity planning, travel/housing plan, local hire vs. expat employees
- Productivity factors (i.e. fabrication yard, construction site, etc.)
- Local content requirements
- Brownfield work/interfaces with existing facilities
- Project, shift, crew, and weather calendars by discipline and location
    - Holidays
    - Weather Windows
    - Lost productivity time periods
    - Extended workweek time periods
- Average and peak resource demand
- Average and peak performance progress that a typical project team can attain
- Permitting approval assumptions
- Labor, transportation, and construction equipment availability and limitations, including potential impact of any competing projects
- Storage facilities, lay-down areas, staging areas, and planned usage
- Material handling onsite and safety of the lifting/transport equipment
- Site Access and Security
- Construction of Temporary Facilities/Site Accommodations
- Coordination of Contractor Work (PM & CM Supervision)
- Subcontractor interfaces and work limitations
- Owner requirements (safety, quality control, regulatory, environmental, quality, etc.)

2.8. Quality Assurance and Quality Control

The cost estimate includes performing QA/QC of the EPC Contractor Site Team undertaken to ensure specified product quality requirements of the Project are met by the Site Team, and exclude all Engineering and Procurement scopes.

In general, the Site Team's quality activities in relation to the above can be split into 2 basic categories:

- Quality Assurance - Includes audit and document review. Document reviews include quality procedures, site queries, weld procedures, welder qualifications etc.
- Quality Control – Includes witness and monitoring of the Site Team fabrication, installation and commissioning activities.

All applicable industry standards for quality control and quality assurance requirements were followed. Personnel required to carry out these QA/QC functions have been included in the costs estimates as appropriate and required.

2.9. Turnover, Commissioning, and Start-Up Basis

It is envisioned in the cost estimate the EPC contractor will perform all pre-commissioning activities, including but not limited to the following:

- Drying the pipeline after hydrostatic testing to a -30^{o} dew point.
- Performing a Close Potential survey of the cathodic protection system
- Performing a baseline intelligent pig run

It has been assumed that Companies existing operations group will perform all commissioning and start up activities with support provided by the EPC contractor.

It is also envisioned that Simultaneous Operations (SIMOPS) will be performed by the EPC Contractor when working at existing facilities, this work may include hot taps, hot bolting, and general operations coordination.

Cost for these activities for both the EPC Contractor and Owner's are included in the cost estimate.

2.10. Work Breakdown Structure (WBS)

The cost estimate development and pricing is organized per a project work breakdown structure (WBS) format. The following cost summary breakdown is provided for each WBS line item or by subtotal when information for individual line items is not available:

- Material Quantity
- Material Units
- Material Unit Rate
- Material Cost
- Productivity Factor
- Labor Hours
- Labor Rates
- Labor Cost
- Subcontract Hours
- Subcontract Rates
- Subcontract Cost
- Subcontractor(s) Associated Profits
- Allowance % (Design, MTO, Trim and Waste)
- Allowance Cost (Design, MTO, Trim and Waste)
- Taxes and Duties Costs (Customs Duty, Withholding and Others, VAT)

The project cost estimates were developed based on the project scope as defined in the typical WBS shown in the next section.

2.11. Scope of Work

The EPC Contractor will provide the personnel, equipment, materials and consumables required for the complete installation, Mechanical Completion, Pre-Commissioning; and Commissioning and Start-Up assistance of the pipeline system awarded. This Report and cost estimate developed support the scope of work as described here.

The work will comply with all regulations, laws, decrees, procedures, and similar requirements stipulated by the governing authority, including, but not limited to, the operation of equipment, safety, environmental protection measures, notification to authorities, permits, and similar items. The work will be performed to the requirements of ASME B31.4 and will comply with standard requirements of Pipeline Design, and Installation Specifications. Additionally the performance of the work will with be in accordance with internationally accepted Health, Safety and Environmental requirements.

2.11.1. Facilities and Resources

EPC Contractor will provide all administration, management, supervision, professional and technical services, permitting, certification, all equipment and machinery, tools, labor, temporary facilities, temporary access ways, supports, temporary works, transportation, materials and scaffolding, construction tools including small tools, workman supplies, consumables, expendables, all fuel and lubricants, NDT services and all other services and equipment, except those provided by Owner's.

EPC Contractor will provide housing either via man-camps or by utilizing existing infrastructure on shorter pipeline lengths) and offices at field sites for the purpose of overseeing and inspecting the work, coordinating approvals as required, monitoring, auditing, reviewing of drawings, specifications and schedules and witnessing of all operations, and test and inspections. Accommodations, offices, consumables, catering, special tools, and similar items will be provided to The Owner's personnel to enable the performance of onsite inspections.

EPC Contractor will provide for Owner's, all communication links required during the performance of the work at all work sites. The communication systems will include, radio, telephone, satellite telephone communication, and Internet connections.

2.11.2. Management

EPC Contractor will provide, maintain, and be responsible for all project and work management during the performance of the work including, but not limited to, engineering, procurement, construction, quality assurance and quality control, project control, cost and schedule, administration, health/safety/environmental specialists, supervision, testing, Mechanical Completion, Pre-Commissioning, and Commissioning, Start-Up assistance, and handover.

Key personnel included in the cost estimate are based on fully qualified, experienced personnel and competent in the areas of Quality Assurance\Quality Control

- Construction Managers
- Engineering Managers
- Safety and Health Manager
- Environmental Managers
- Project Control Supervisor and Representatives
- Lead Engineers
- Welding Manager and Engineers
- Commercial Manager

2.12. WBS Level 3, Standard WBS Utilized

The Work Breakdown Structure that was utilized in principle to develop the overall EPC cost estimate is shown in Figure 1 below:

WORK BREAKDOWN STRUCTURE	
	ONSHORE PIPELINES
Project Management	**COMPANY**
FEED	**FEED Contractor**
Site Data Collection	**INTEC**
Geotechnical Survey	**AMEC**
EIA Review	**DAMES & MOORE**
Route Selection	**GULF INTERSTATE**
Survey / Center Line Survey	
R.O.W. Acquisition	**LS (ROW-RC)**
Line Pipe Procurement	**COMPANY**
Detail Engineering & Design	**EPC-LS CONTRACTOR**
Equipment & Bulks Procurement	
Infrastructure Construction/Fabrication	

Onshore HU&C	
Transport to Site & Installation	
O & M	**COMPANY**

Notes:
1. Project Management Team (PMT) consists of COMPANY, individual consultants and engineering contractor personnel, as required.)
2. PMT to procure long lead items, i.e. line pipe, and free issue to EPC Contractor for administration.
3. Infrastructure includes water wells, roads, camps, construction material offloading facility, administration areas and other buildings.

Figure 1 – Work Breakdown Structure

Any names or companies contained above are shown strictly as representative and does not indicate they were utilized nor preferred.

2.13. Engineering, Procurement, Project and Construction Management

The following broad categories of costs are considered as part of Owner or Owner's costs and are carried in the cost estimate as such.

Engineering

Engineering was calculated at 4% of construction costs, which is a standard percentage for pipeline systems.

However, to complement the engineering work to be done, some special surveys and studies were also considered where required, including but not limited to:

- Seismic Studies
- Geotechnical Surveys
- Regulatory Studies & Permits
- Environmental Studies & Permits
- Cultural Impact Studies

Procurement

Procurement services are included in both Owner's (for line pipe, major valves, L/R's, and long lead items) and EPC contractor costs (for all remaining materials procurement as well as local purchase, construction consumables) and include all procurement related costs, i.e. inspection costs, vendor surveillance, procurement, document control, QA/QC, and travel costs.

Project and Construction Management

The Owner and Contractor EPC costs are split and Owner EPC-related costs are included in the Owner's Cost section.

2.14. Transportation

All transportation costs are included in the overall cost estimate and include items such as:

- Transportation origins and destinations (distance to site)
- Transportation method(s)
- Items to be transported, volumes, and weights per transportation method
- Cost of standby and preparation
- Lease durations
- Scopes of work (Items, volumes, and weights) per transportation type
- Unit rates
  - $/Volume
  - $/Weight
- Additional basis for transportation costs

2.15. Permanent Materials (including freight, handling, contingency)

All pipeline construction and installation costs are included in the overall cost estimate and include items such as:

- Line Pipe
- Pilot Pipe (for road boring)
- Station Piping (including L/R's & hot bends)
- Valves
- Fittings/Stopples
- Coating Materials/Paint
- Equipment
- Electrical
- Instruments
- Misc Pipeline Materials
- Cathodic Protection
- Building Materials
- Concrete
- Rebar
- Fence Materials
- Structural Steel
- Misc Civil

2.15.1. Pipe for Special Crossings and Locations

The pipeline wall thickness calculations by diameter are found in P1 Appendix D. Special crossings such as seismic and HDD were calculated separately based on the respective installation stresses.

2.16. Pipeline Construction & Installation

All pipeline construction and installation costs are included in the overall cost estimate and include items such as:

- Construction Direct Labor

    - Mobilization and demobilization rates and time frames
    - Manpower requirements per discipline, by location
    - Inclusions in “all-in” rates for each type of skilled and unskilled worker
    - Work schedule(s)
    - List productivity factors incorporated into the above items
- Field In-directs
    - Temporary construction facilities
    - Yard Improvements
    - Construction Services
    - Construction supplies, equipment and small tools
    - Camp Facilities
    - Field Services
    - Field Staff
    - Camp Operating Costs
    - Communications
    - Manpower logistics
        - Aircraft
        - Site transportation
        - Recruiting
    - Permits
    - Insurances
    - Training/HES
    - Testing (Welding, etc)
- Construction equipment
    - Earth moving
    - Lifting
    - Bending
    - Welding
    - Generators/compressors
    - Tools and consumables
- Rigging and material handling/Heavy Lifts (cranes, hoists, side-booms)
- Labor supervision manpower quantity, duration, and cost basis
- Site work
    - ROW grading
    - Cubic yards of concrete
    - Rebar work, formwork, concrete pour, dewatering requirements
    - Excavation
    - Rock excavation
    - Backfill
    - Hydrostatic testing
    - Pipeline drying
    - Clean up & restoration
- Piping
    - Quantity installed
    - Welding rates (based on pipe type, diameters, and thickness)
    - Bolting and spool types and quantities

  - Hot taps, stopples, by-passes
  - Hydro testing, cleaning, joint coating, & non-destructive testing requirements
- Electrical/Instrumentation and Controls
- Special construction methods
- Material preservation/Equipment maintenance
- Site cleaning/removal of temporary material
- Catering requirements
- Requirements to use local materials
- Customs requirements

2.17. Communications and Control

For the purposes of the Cost Estimate, the following system architecture and structure were assumed:

- Communications & control system would be microwave with a satellite back up
- SCADA included at each Main Line Valve (MLV)
- SCADA included at each pig trap
- Tie in of all communications to the Central Control Room

2.18. Cathodic Protection

For the purposes of the cost estimate, the cathodic protection system is provided by a system of rectifiers and ground beds. Test connections are provided at intervals along the pipeline at 1km spacings and at road/railroad crossings.

2.19. Pipeline Markers

Pipeline signs and markers are included in the cost estimate to comply with API RP 1109 and the following:

- Standard pipeline warning signs will be installed on metal posts on each side of roads and railroads.
- Waterway warning signs will be installed on steel pipe (galvanized) supports on each side of streams 30 meters or more in width (water's edge to water's edge).
- Aerial markers will be installed at 10 kilometer maximum spacing and at every point of intersection in excess of 12.5 degrees. Aerial markers will be installed on galvanized steel posts.

2.20. Main Line Valve Spacing

Mainline valve (MLV) spacing and quantities is based on information provided by Owner's.

2.21. Land Costs (ROW, Laydown, Pipe Yards)

No land acquisition costs were included in the cost estimate.

2.22. Additional Funds Used During Construction (AFUDC)

AFUDC were calculated based on a standard cash flows for an EPC Contractor and an effective interest rate of 6.5%. AFUDC captures the interest payments required to finance the project from the EPC contractor's standpoint.

AFUDC was used on a case by case basis and not envisioned on smaller pipeline systems.

2.23. Hookup, Commissioning, & Startup

All hook-up, commissioning and start-up (HU&C) costs are included in the overall cost estimate and include items such as:

- Accommodations
    - Provided accommodations in project camp
- Hook-Up and Commissioning Activities and Support
    - Required manpower and supervisory/support personnel
    - "All in" daily rates per trade and premium/overtime rates ($/days/man)
    - Anticipated duration of services
    - Required equipment (testing equipment, tools, consumables, scaffolding, cranes) provided by EPC Contractor
    - Work schedules
    - Vendor Reps
    - Permit to Work System

3.0 Cost Adders per Terrain Gradation Changes

Extreme terrain present numerous safety, technical, construction, and cost challenges. Additional ROW work is required to get the terrain into as suitable condition for construction as possible. The sequential work itself is much slower through extreme terrain, increasing as the terrain difficulties increase and may include utilizing winches and cables to allow equipment to work on the slopes.

As the terrain becomes more severe, the amount of time and resources to safely and successfully install a pipeline increases. In the Author's experience, when estimating pipeline construction projects the following is the typical breakdown that is considered from a cost standpoint:

- 0% to 5% (considered normal terrain, i.e. no additional costs are included for it)
- 5% - 10%
- 10% - 15%
- 15% - 20%
- 20% - 25%
- 25%+

For the extreme terrain variables and how the additional difficulty impact construction costs for the above breakdown across the spectrum of pipeline diameters and lengths, see P1 Appendix C.

4.0 Cost Evaluations for Facilities

4.1. Introduction

The Author has developed a range of cost valuations for the following facilities associated with pipeline systems:

- Pump stations
- Meter stations

Pump and meter stations can have a wide cost range depending on the locations they are placed and the difficulties in accessing the areas. The cost estimates developed are considered generic and the Author has used both existing cost estimates in his files as well as factored costs on some items. These costs are inclusive of logistics, freight, engineering, construction, communications (assuming to be connected to the pipeline systems communications backbone), and start-up.

Section 1.2 and 1.3 below provide a basic overview of what the overall costs of the pump and meter stations are based upon. These costs are based on 2Q 2015 costs.

In order to provide a sound cost evaluation of the facilities, the Author used some of the following techniques:

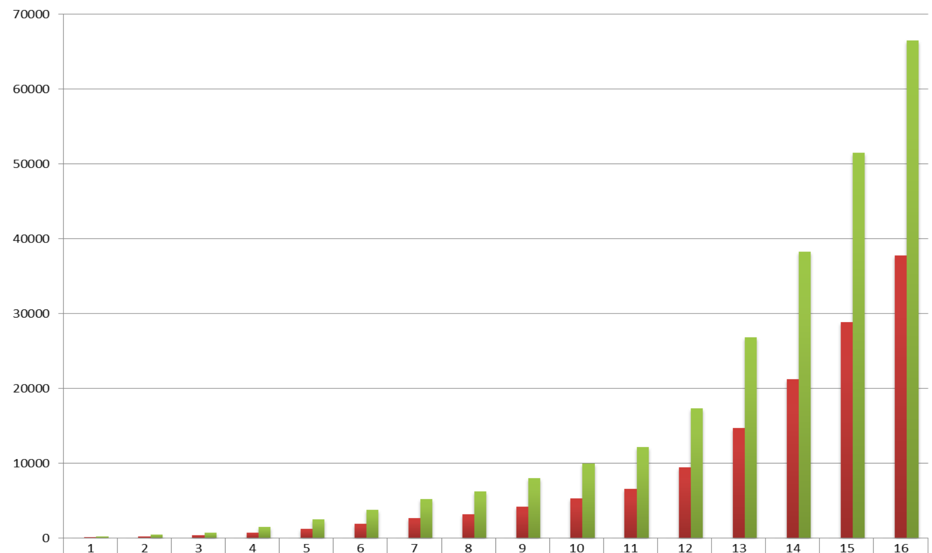
- Cost curves are principally used for major equipment pricing and are developed from historical data. This is based on such variables as plant capacity, horsepower, throughput, etc.
- Installation factors relate overall installed costs to the cost of major equipment.
- Industry published data for bulk materials and labor costs are available from many sources such as government labor bureau or specialist companies.

The pitfalls with developing cost evaluations without the required specifics are that pump stations and mater stations are never as similar as we like to believe and extrapolations beyond a certain range are often wildly inaccurate. Some types of plants require different exponents.

Based on the above process and the basic design basis contained in Sections 1.2 and 1.3 a generic cost per Horsepower (HP) installed was developed and then extended across various pipeline diameters and approximate throughput, assuming a 50% excess capacity to arrive at a total HP required for each pump station and from that an order of magnitude cost for each pump station from 2” though 48” resulted.

The graph below indicates the results of the pump station cost evaluation exercise:

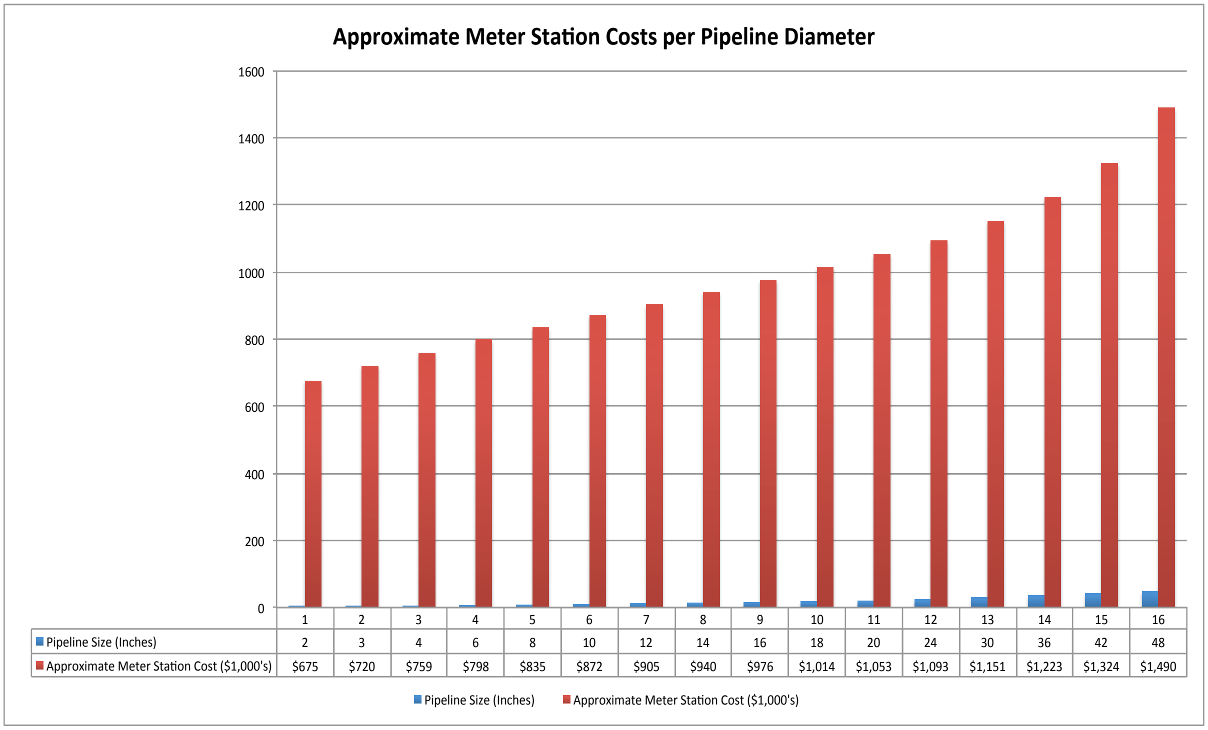
Pump Station Installed Horsepower and Approximate Cost per Pipeline Diameter



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Pipeline Size (Inches)	2	3	4	6	8	10	12	14	16	18	20	24	30	36	42	48
Installed HP (assumes 50% capacity)	110	240	380	740	1,260	1,910	2,700	3,230	4,200	5,330	6,570	9,450	14,760	21,260	28,920	37,770
Approximate Pump Station Cost ($1,000's)	$228	$492	$772	$1,488	$2,510	$3,768	$5,274	$6,248	$8,043	$10,003	$12,205	$17,373	$26,853	$38,271	$51,506	$66,544

Pipeline Size (Inches) Installed HP (assumes 50% capacity) Approximate Pump Station Cost ($1,000's)

The next graph below shows the results of the meter facility cost evaluation exercise:



As stated above, the results are considered a generic, Level 2 or 3 cost estimate that provides an overview of the level of magnitude pump stations and metering facilities may have on an overall pipeline system. See Section 5.0 for a table defining the cost estimate levels and their meaning.

The outcomes for both pump stations and meter facilities per pipeline diameter are shown in P2 Appendix A.

The numbers and spacing's of pump stations along a pipeline system are totally dependent of the terrain of the pipeline ROW and the hydraulics modeling that would be performed during detail design.

4.2. Pump Station Overview

The cost basis for the pump stations are that they have been designed and constructed in accordance with Pipeline Safety Standard, Title 49, Part 195 and ANSI/ASME B31.4 Pipeline Transportation Systems for Liquid Hydrocarbon and Other Liquids.

Below are typical pump station design parameters:

Pump Station - Design Parameters	
Station Site Conditions • Location	Based on description and GPS

 • Site Elevation • Outdoor Ambient Temperature • Wind Load Design	coordinates. 2,000 meters 100ºF Summer, 0ºF Winter 90 MPH
Station Design Pressure	1,440 psig
Pump Design Flow Conditions • Volume • Suspension Pressure • Discharge Pressure	 90,000 to 132,000 bpd 400 psig 1440 psig

4.2.1. General Pump Equipment Design Conditions

The following are typical design requirements for pumps:
Pipeline MOP: 1440 psig
Pump Case Design Pressure: 1440 psig minimum
Design Discharge Temperature: 120ºF (max. pipeline operating temperature)
Design Factor: 0.50
Area Classification: Class I, Division II, Group D
Available Power: 4160 volt/ 3-phase / 60 cycles per second

The pumps are considered to have been designed, fabricated, and tested in accordance with API Standard 610, Centrifugal Pumps for General Refinery Service.

Typically there will be a single ANSI 600 suction and discharge flange connection.

4.2.2. Driver

Below is a guideline for a basic VFD Electric motor to drive the centrifugal pump.
Enclosure: TBD
Speed: 3,600 rpm
Voltage: 4,160 volts
Frequency: 60 cycles per second
Phase: 3-phase
Motor Accessories and
Special Features include: Split sleeve bearings
Stator winding temperature sensor
Space heaters (120V)
Accelerometer or velocity transducer
Oil thermometer
Oil level gauge

The motor is considered to have been designed, fabricated, and tested in accordance with API Standard 540, Electrical Installations in Petroleum Processing Plants.

4.2.3. Main Piping Design

All station piping shall be designed in accordance with Title 49 Part 195 (Code of Federal Regulations) with a design factor of 0.50.

All pressurized NGL piping shall be carbon steel manufactured to an approved National Standard. For all station piping the pipe's Specified Minimum Yield Strength shall not exceed 60,000 psi and will be either ERW or SMLS depending on availability.

Wall thickness for each pipe size in each piping class shall be calculated in accordance with the governing codes.

Inlet suction and discharge headers shall be installed below ground, station isolation valves and main laterals may be installed above or below ground. Unit isolation valves for pumps shall be installed above ground. Other piping may be installed above or below grade as dictated by operating conditions or layout requirements. All underground lines in the yard area will have a minimum of one (1) meter of cover measured from the top of finished grade. All piping shall be placed underground as much as possible for noise reduction.

4.2.4. Piping Velocity and Pressure Drops

Piping shall be sized to meet the following conditions:

- Minimum velocity: based on final hydraulic analysis) ft/sec
- Maximum velocity: based on final hydraulic analysis) ft/sec
- Station Fire Valve to Pump Suction Maximum Design Pressure Drop: 10 psig
- Discharge from Pump to Station Fire Valve Maximum Design Pressure Drop: 10 psig (including discharge PCV)

Piping should be sized for a pressure drop of approximately 1 psig per 30 meters on main and auxiliary systems.

4.2.5. General Piping and Equipment Design

Stress analysis shall be performed on all main piping to determine the overall acceptability of the piping design.

The scope of the analysis shall be limited to large bore piping systems (8-inch and over) or piping undergoing significant thermal cycling. Stress analysis for piping shall be checked against the governing piping and equipment (where applicable) Code requirements. Outputs from the analysis are verified that loads and moments on equipment (in particular the pump) supports are located properly and that stress levels in piping are within allowable limits.

For auxiliary piping systems and other low-pressure systems, stress analysis will not be necessary unless susceptible equipment connections are involved.

4.2.6. Valves

All valves, 2-inch and larger, will be full opening gate valves except for pressure regulators, flow control, and vent and drain valves. Plug valves will be used for vents and drains.

4.2.7. Inlet Strainers

A basket strainer shall be installed on the suction side of the mainline pump units to provide protection for the pumps against potentially damaging debris. The strainer shall be equipped with a differential pressure indicator.

4.2.8. Auxiliary Systems and Piping

All station auxiliary piping shall be designed in accordance with ASME B31.3.

All piping, 2-inch nominal diameter and larger, shall be welded or flanged. Piping less than 2-inch may be screwed or socket welded. There will be no screwed piping or flanged connections installed below grade. Weldments shall be limited to 2-inch maximum outlet size and shall be no greater in outlet size than 1/3 of the run pipe OD. Weld saddles or tees shall be used for all other branch connections less than 1/2 the run pipe OD.

Piping may be installed above or below grade as dictated by operating conditions or layout requirements. All underground lines in the yard area will have a minimum of one (1) meter of cover measured from the top of finished grade.

4.2.9. Depressurization, Venting, and Drain-up

During maintenance it is often necessary to depressurize, vent and drain piping and equipment. The pump station may be fitted with a closed drain sump system such that the system headers, vessels, pumps, and piping can be depressurized, vented, and drained to a safe location. Venting to a flare at pump stations is planned. In other cases, venting may occur to atmosphere.

4.2.10. Overpressure Protection

The normal maximum working pressure of the station is 1440 psig and the maximum design pressure of all the main piping is 1440 psig. The station discharge will protect the pipeline against overpressure by using the station discharge pressure control valve. This valve will be a fail-close design. A pressure sensor shall be provided to send an alarm signal to the Station Control Panel to slow or shut down the pumps if the discharge pressure exceeds 50 psig above MOP. In the event of an ESD, vent and drain valves and piping shall be designed to de-pressure the high pressure systems.

4.2.11. Fire Protection

Fire protection shall be designed generally in accordance with NFPA requirements and shall comprise appropriate hand-held and wheeled extinguishers. These extinguishers shall be strategically located in buildings and plant areas.

4.2.12. Gas Detection

Gas detection shall be designed generally in accordance with NFPA requirements.

4.2.13. Electrical, Instrumentation, and SCADA Overview

All installed equipment and distribution systems shall be provided in accordance with the Codes, Standards, and specifications. Equipment installation in the hazardous area classifications shall be rated for the area. In order to demonstrate that all electrical equipment is adequately rated, load schedules, lighting calculations, and any other relevant calculations will be prepared.

4.2.14. Electrical Power Distribution System Design

The electrical power distribution system design shall be such to ensure continuous plant operations for varying loading conditions. The design shall provide for equipment maintenance and integrity of supply during the maintenance period.

The local utility will provide the required power and transformer at its local drop box. All power feed will be routed from this feed point. Existing power will be upgraded to handle the existing and new electrical loads.

4.2.15. MCC/Control Building (Pump Stations)

The MCC/Control Building shall be a prefabricated/prewired building consisting of a control room, UPS room, MCC room, and storage area.

The building will be provided with HVAC system for maintaining an operating and working environment.

Gratings, sub-floor pipe ways, catwalks, ladders, pipe supports and other miscellaneous items will be located, designed and detailed as required. All stairs and landings shall be constructed from galvanized structural steel.

All protrusions through roof, walls or floor of the MCC/Control Building shall be properly sealed against ingress of water and other foreign objects. This shall include any openings for piping, ventilation systems, seal vents, cables, tubing, etc. Pipes penetrating the building will be electrically insulated from the building with the use of rubber material.

A motor control center shall be provided to service both "Normal" and "Standby" power via an automatic transfer switch. The automatic transfer switch (ATS) shall provide "Normal" power (when available) to the MCC connected loads or "Standby" power from the Standby generator and associated switchgear. The ATS shall be located in the low voltage motor control center.

The Motor Control Center shall consist of a NEMA rated grouping of structures with power bus incoming and outgoing circuits and various types of feeders and combination motor control unit compartments. The MCC shall be designed for 480 VAC, 3-phase, 4-wire, 60Hz braced to withstand 22,000 KAIC symmetrical RMS amperes. The continuous ampere rating of the horizontal bus shall be as shown on the particular MCC one-line drawing(s).

4.2.16. Distribution Panels

Low voltage distribution systems are required for the battery charging systems, communications systems, facility lighting and other applications. These will be serviced by low voltage step down transformer(s) feeding low voltage, 208/120 VAC (1-phase, 60 Hz) panel boards as applicable.

4.2.17. Uninterrupted Power Supply (UPS) System

The Uninterrupted Power System (UPS) shall be a Ferro resonant transformer type design in a NEMA-1 cabinet. The UPS shall convert DC power from a rectifier charger/battery to provide regulated AC output for powering the critical AC loads. The inverter DC input nominal voltage shall be 130 VDC (-19%/+8%). The output AC voltage shall be 120 VAC (+/- 2%), 1-phase, 2-wire, 60 Hz (+/1 Oa1%). The harmonic distortion shall be less than 5% THD.

An automatic static switch shall be included to automatically transfer output of failed or overloaded inverter to a bypass source of power without interruption. Also, a manual bypass switch (two position, make-before-break) shall be provided as part of the UPS to bypass the inverter and automatic status transfer switch for maintenance purposes. The UPS shall be provided only to provide power upon loss of utility power and successful starting of the standby generator.

4.2.18. Grounding System

All station facilities shall be protected with a common grounding system in accordance with the applicable Codes and Standards. Elevated structures will include lightning protection faulting to the ground system.

4.2.19. Cable and Wire

Electrical power and control conductors used in power and control circuits in general station areas shall be in accordance with the applicable Codes and Standards. Special instrumentation applications and specific applications such as grounding and ESD circuit design shall be in accordance with the particular specific area of the Codes and Standards.

4.2.20. Lighting and Low Voltage

The requirements for light fixtures, circuiting and layout, and illumination levels for general station areas for normal and emergency conditions shall be in accordance with industrial environments as defined in the Codes and Standards.

4.2.21. Conduit and Wiring Systems

Conduit systems for wiring above ground and in buildings shall be rigid galvanized steel. Underground conduit systems can be Schedule 40 PVC in red concrete duct banks with rigid steel PVC coated (inside and outside) including fittings, at the transition from underground to above ground.

In general, all electrical installations shall be with rigid metal conduit. Minimum conduit size shall be 3/4 inch. Approximately 10% spare conduits to the duct bank system will be installed to allow for unidentified future station expansion. Cable tray will be used in pump station to eliminate congestion of conduits.

4.2.22. Hazardous Area Classification

All electrical equipment and wiring installations in areas classified in accordance with Article 500 of the NEC shall conform to the requirements for equipment located in Class I, Group D, Division 1 or 2 areas as defined in Article 501 of the NEC as applicable.

The area classification drawings shall be prepared in accordance to API RP-500, *Recommended Practices for Classification of Locations for Electrical Installations at Petroleum Facilities,* as the guideline for depicting the classified areas.

4.2.23. Control Philosophy

Pump stations will be designed for unmanned operation with remote control and supervision from the Company Control Center. Only in the case of communications failure will full operations be required at the station level.

At the pump station there will be a local station control system from which the operation of the pump station can be conducted. The control system will be designed assuming that the unit(s) can be operated over the entire operating range.

4.2.24. Control System Configuration

The control system will be configured with a station control panel (SCP). The SCP will only monitor the facility operation. The pump units and station panel shall be a PLC based control system. PC based HMI (Human Machine Interface) is provided within the station control panel on all station functions and monitoring of pump units shall be networked together using the station panel as station information center.

4.2.25. Emergency Shutdown System (ESD)

Station Emergency Shutdown System shall, whenever possible, be independent of the above systems and be of “fail safe” design, redundant configuration, and high reliability.

The purpose of the Emergency Shutdown System (ESD) shall be to protect personnel, equipment and the environment from the consequences of an accidental or uncontrolled release of hydrocarbons or any other hazardous gas and/or fluid. A station shutdown shall be achieved by closing the pump inlet and outlet unit valves. A full ESD will be achieved by fully isolating the pump station from the sources and deliveries. Station bypassing is not included. A full ESD will be accomplished by isolation of the station.

The ESD System was designed with the following objectives:

- Maximum reliability/availability
- Openness, allowing easy future system hardware/software expansion, 30% usable spare capacity shall be provided for hardware, database and application software.
- Vent/drain valve(s) shall be sized to bring the piping to a safe pressure within three (3) minutes.

The station shutdown data shall be transmitted to the station control system by means of a serial link. A full ESD is transmitted to the station control system by means of an existing hardwired pressure switch located in the ESD system.

4.3. Meter Station Overview

To receive or deliver NGLs along the pipeline, it is necessary to install interconnect facilities at various plants. Each interconnect facility will have an associated meter station.

From a cost standpoint, only the meter facilities are included in P1 Appendix A. The interconnect costs were developed previously under a separate Report.

Each meter station shall be designed to meet acceptable industry standards. In general, the meter stations shall consist of an inlet filter, turbine (or Coriolis) meter, flow computer, densitometer, sampler, and associated piping and valves. Except for site plan variations and meter/piping sizing, the meter station design will be identical for all locations. Meter station may be skid mounted. If skid mounted, entire piping assembly will be hydro-tested at fabrication shop.

4.3.1. Piping Design

All station piping shall be designed in accordance with Title 49 Part 195 (Code of Federal Regulations) with a design factor of 0.50.

All pressurized NGL piping shall be carbon steel manufactured to an approved National Standard. The pipe's Specified Minimum Yield Strength shall not exceed 60,000 psi and will be either ERW or SMLS depending on availability.

Piping arrangement shall be based on the normal considerations of optimum layout with respect to economic installation and access, and special requirements to comply with stress analysis. Other particular requirements dictated by equipment manufacturer's specific recommendations shall be followed. Stress levels and nozzle loadings during operation shall be within acceptable levels and manufacturer guidelines.

Wall thickness for each pipe size in each piping class shall be calculated in accordance with the governing codes. Standard piping schedule wall thicknesses (i.e., Sch. 40, Sch. 80, etc.) shall be used wherever possible.

All piping 2-inch nominal diameter and larger shall be welded or flanged. Piping less that 2-inch may be screwed or socket welded. There will be no screwed piping or flanged connections installed below grade. Weldments shall be limited to 2-inch maximum outlet size and shall be no greater in outlet size than 1/3 of the run pipe OD. Extruded tees are preferred to saddles and shall be used for all other branch connections less than 1/2 the run pipe OD.

Piping may be installed above or below grade as dictated by operating conditions or layout requirements. All underground lines in the yard area will have a minimum of three feet of cover measured from the top of finished grade. All piping shall be placed underground as much as possible for noise reduction.

4.3.2. Pipe Velocity and Pressure Drops

Piping shall be sized for the following conditions:

- Minimum velocity: 3 feet/second
- Maximum velocity: 15 feet/second (excluding bypasses and blow downs)
- Inlet Filter to Meter Inlet Maximum Design Pressure Drop: 3 psig
- Meter Outlet to Densitometer Pressure Control Valve Outlet Maximum Design Pressure Drop: 3 psig (including Densitometer PCV)

Piping should be sized for a pressure drop of approximately 0.25 psig per 100 feet on main systems and 0.5 psig per 100 feet on auxiliary systems.

4.3.3. General Piping and Equipment Design

<u>Stress Analysis</u>

Stress analysis shall be performed on all main piping to determine the overall acceptability of the piping design.

The scope of the analysis shall be limited to large bore piping systems (8-inch and over) or piping undergoing significant thermal cycling. Stress analysis for piping shall be checked against the governing piping and equipment (where applicable) Code requirements. Outputs from the analysis shall be used to verify that loads and moments on equipment supports are located properly and that stress levels in piping are within allowable limits.

For auxiliary piping systems and other low-pressure systems, stress analysis will not be necessary unless susceptible equipment connections are involved.

<u>Valves</u>

All valves, 2-inch and larger, will be full opening gate valves except for pressure regulators, flow control, and vent and drain valves. Plug valves will be used for vents and drains.

Meters

The meter stations will utilize turbine or Coriolis meters. The measurement design shall include a complete skid-mounted unidirectional metering and regulation systems requiring only external piping and electrical connections to complete for operation in accordance with the latest industry measurement standards.

Meter Proving

Stubs and valves will be installed to allow the use of a portable meter prover.

Densitometer

A densitometer will be installed downstream of the meters to measure the density of the product. A pressure control valve will also be installed to hold a back pressure for the densitometer.

Sampler

A Y-Z Sampler will be installed to acquire product samples from the pipeline.

Flow Computer

A Daniels flow computer will be installed to calculate flows.

Inlet Filter

An inlet filter or strainer shall be installed on the inlet side (as applicable) of the meters to provide protection for the meters against potentially damaging debris. The inlet filter shall be equipped with a differential pressure indicator.

4.3.4. Auxiliary Station Piping

All meter station auxiliary piping shall be designed in accordance with ASME B31.4.

All piping, 2-inch nominal diameter and larger, shall be welded or flanged. Piping less that 2-inch may be screwed or socket welded. There will be no screwed piping or flanged connections installed below grade. Weldments shall be limited to 2-inch maximum outlet size and shall be no greater in outlet size than 1/3 of the run pipe OD. Weld saddles or tees shall be used for all other branch connections less than 1/2 the run pipe OD.

Meter isolation valves shall be installed above ground. Other piping may be installed above or below grade as dictated by operating conditions or layout requirements. All underground lines in the yard area will have a minimum of three (3) feet of cover measured from the top of finished grade. All piping shall be placed underground as much as possible for noise reduction. Process piping inside the meter station buildings shall be supported by pipe hangers, supports, etc.

4.3.5. Depressurization, Venting, and Drain-up

During maintenance it is often necessary to depressurize, vent and drain piping and equipment. The meter station may be fitted with a closed drain sump system or connect to an existing closed drain sump system such that the system headers, vessels, meters, and piping can be depressurized, vented, and drained to a safe location. Depressurization may be vented to atmosphere in some cases.

4.3.6. Fire Protection

Fire protection shall be designed generally in accordance with NFPA requirements and shall comprise appropriate hand-held and wheeled extinguishers. These extinguishers shall be strategically located in the buildings and meter station site areas.

4.3.7. Fire and Gas Detection System

The fire and gas detection system shall continuously monitor all process areas for abnormal conditions. In the event of a hazardous situation being detected, the system shall initiate protective actions and pre-determined alarms as defined by the Station Control System.

The fire and gas alarms, alert signals, status and back-up control of the protection systems shall be tie-in to existing mimic and annunciator panels where possible.
Fire and gas detectors shall be installed according to the risk identified for each area of the pump station.

5.0 Major Cost Component Breakdown Assessment

5.1. Overview

The Author was tasked with assessing CREG's major cost component breakdowns in order to more accurately assess costs in future years on an escalated basis.

In order to properly assess the breakdowns provided in the Terms of Reference, the Author assessed 1,975 separate pipelines installed between 1980 and 2015 in order to establish an average breakdown of the following overall cost components for the total installation of a pipeline system as requested by CREG:

- Material Costs
- Labor Costs
- Miscellaneous Costs

CREG provided the following values for assessment and input:

- Material Costs 35%
- Labor Costs 40%
- Miscellaneous Costs 25%

Miscellaneous costs are not precisely defined across the pipeline industry, but are generally taken to include:

- Engineering
- Supervision
- Surveying
- Interest
- Administration
- Land
- Overheads
- Contingencies
- AFUDC (Project Financing Costs)
- Permitting & other fees

The above is a general list. However most pipeline operating companies have their own classifications and are reported as such; therefore the *Miscellaneous* category is a very broad one that may contain all, some, or only a few of the above listed categories.

The pipeline system diameters assessed ranged from 2" to 48"'; in lengths from 200 meters to 1,427 kilometers; with total installed costs ranging from USD $11,940 to USD $3,434,329,000. The full list evaluated can be found in P2 Appendix B.

The average values found were (rounded)

- **Materials 30%**
- **Labor 43%**
- **Miscellaneous Costs 27%**

The following table indicates the full results of the assessment:

Description	**Materials**	**Labor**	**Misc**
Minimum Value of 1,975 Pipeline Systems Assessed	0.26%	0.21%	0.64%
Maximum Value of 1,975 Pipeline Systems Assessed	88.11%	88.60%	77.81%
Average Value of 1,975 Pipeline Systems Assessed	**30.00%**	**43.32%**	**26.68%**
Standard Deviation	12.81%	11.69%	9.56%

5.2. Additional Breakdown Recommendations

Considering the above major categories, the Author recommends the following additional breakdowns in order to more accurately assess escalation or changing conditions:

- For the pipeline construction component[1]; within overall pipeline construction costs (i.e. does not include permanent materials, engineering, client costs, allowances, contingencies. AFUDC, etc):

[1] This breakdown is within the overall pipeline construction costs and are compared as such, i.e. not compared against the total project costs.

Pipeline Construction	Average	Low	High
Labor	20.41%	15.57%	25.25%
Misc Materials & Supplies	10.78%	8.86%	12.71%
Fuel	17.17%	15.69%	17.92%
Construction Equipment (costs, spares, & repairs)	20.82%	19.01%	22.63%
Other Costs	30.54%	26.41%	34.67%

It should be noted that Contractors construction equipment is a complicated line item. Often Contractor's will use this as part of the tendering strategy. "Fuel" costs above are broken down as:

- 80% diesel
- 20% gasoline

- For the permanent materials, within the overall permanent materials, the following breakdown would be helpful for cost escalation:

Permanent Materials	Average	Low	High
Pipe	83.27%	80.44%	86.09%
Valves	5.29%	4.00%	6.59%
Other Misc Materials	6.48%	4.97%	7.99%
Communications Equipment	2.33%	1.47%	3.19%

6.0 Operations and Maintenance Cost Evaluation

As a pipeline is being planned and designed, a proposed organization structure, job categories, estimated personnel requirements, training programs and employee facilities are developed and implemented so that at the end of construction, the Operations and Maintenance organization can take over the operations of the pipeline system.

Each of the following activities must be taken into account when developing a pipeline system O&M cost estimate. Therefore, each system will be slightly different. Typically the O&M costs per year on average equate to between 4%-8% of the total installed costs of the system. As an example, if the pipeline system's total installed costs are $145,000,000; then O&M costs on an annual basis should cost between $5.8M and 11.6M depending on the complexity of the system. A more in-depth study would need to be made in order to determine representative costs.

The Author has included the following sections to provide an overview of what will often comprise an O&M program.

6.1. Operations and Maintenance Overview, Philosophy, and Plan

An Operations and Maintenance (O&M) Plan will be developed during engineering to provide the philosophy and the anticipated organizational structure to operate and maintain the pipeline system utilizing operational control, integrity monitoring, communications and maintenance technology.

The Plan is to serve as an outline for future development of detailed operating and maintenance procedures. Operation and maintenance planning will include methods to identify and employ experienced, trained and knowledgeable operating and maintenance personnel.

The O&M Plan is based upon an evaluation of the facilities required and the conditions encountered for the entire life of the gas transportation system. Additionally, the O&M Plan is predicated on current government, community and industry standards and regulations, as well as consideration of associated operating costs.

Environmental and cultural sensitivities will be considered during the development/implementation of the O&M Procedures, selection of the requisite operation and maintenance facility locations, engineering design, inspection requirements and selection of maintenance contractors as required.

The primary objective of the O&M Plan is to establish philosophies and anticipated staffing for the future development of detailed operating and maintenance procedures for the pipeline system that will assure that the pipeline will be safe and reliable.

Procedures will include not only routine operations but also procedures to follow in the event of leaks and emergencies, either on the pipeline system itself or at adjacent facilities that may put the pipeline at risk.

6.2. Organization Structure

The Operations and Maintenance (O&M) personnel will provide management, regulatory compliance, human resources, HSE, engineering, gas control operations, IT support, document control, pipeline integrity and surveillance roles for the pipeline system.

Typically an O&M district or regional office will be developed. Often this office will provide logistical and technical support for pump and meter stations, mainline block valves and the pipeline. This will include local supervision, materials coordination and expediting, and operation and maintenance technical support.

The Operator/Maintainers of the pipeline system and mainline block valves are typically dispatched from the District Offices and supported by specialists in electrical/instrumentation, mechanical equipment, valves and pipeline maintenance.

6.3. Operations and Maintenance General Tasks

The organization described in Section 3.2 will develop the basic tasks for the O&M of the pipeline system as described in Section 3.1 and listed below:

- **Routine Operations and Maintenance**

- Communications and Gas Control Center
- Voice and Data Communications
- Remote Control

- **Operating Responsibilities**
  - Oil Control Center
  - District Offices
  - Warehousing and Storage
  - Fuel Storage
  - Propane Storage
  - Safety and Personal Protective Equipment

- **Operation**
  - Normal Operations
  - Abnormal Operations
  - Leak Detection
  - Encroachments
  - Pump Station and Metering Facilities
  - Wastewater Disposal and Wastewater Treatment
  - Potable Water System

- **Maintenance**
  - Maintenance Contractor's Responsibilities as required
  - Line Patrol
  - Corrosion protection
  - Access Road Maintenance
  - Pipeline Maintenance
  - Maintenance and Inspection of Measurement Facilities
  - Pipeline Pigging
  - Repair Procedures

- **Emergency Plans**
  - General
  - Procedure s
  - Training
  - Records

- **Regulatory**
  - Reporting and Investigation of Accidents
  - Notification of Emergencies
  - Emergency Response Team
  - Investigation of Accidents and Failures
  - Reporting of Safety Related Conditions
  - Regulatory Record Keeping and Reporting
- **Development, Maintenance and Use of Facility Technical Data**

6.4. Operations and Maintenance Cost Overview

The following are some key components of an overall approach to pipeline operations, whether it is a liquids or a gas pipeline system.

6.5. Pipeline Integrity Monitoring System (PIMS)

Cross-country pipeline leak detection is a sound decision to make for both controlling/tracking loss of product as well as the environmental protection it affords. Typically flow measurement, pressure, and temperature values will be input into the PIMS leak detection system. These values are usually obtained from the main facilities metering and instrumentation systems at each end of each pipeline. The pressure and temperature values are obtained from instruments directly connected to the associated pipe segments. Typically the flow meter values will represent the total flow for the pipeline segments just inside of the facilities' respective pipeline pig launcher/receiver. The values may be generated from totalized discrete liquid and meters, and/or calculated values. The following are some typical values used:

1) The pressure instrumentation value maximum characteristic limits are:
   a) Repeatability: 0.1% of Span
   b) Accuracy: 0.1% of Span
2) The temperature instrumentation value maximum characteristic limits are:
   a) Repeatability: 0.5 deg. C
   b) Accuracy: 5.0 deg. C
3) The flow instrumentation value maximum characteristic limits are:
   a) Repeatability: 0.5% of Span
   b) Accuracy: 1.0% of Span
4) The sampling rate characteristic limits for the above values are a maximum of:
   a) Individual Sampling Rate: 2 seconds
   b) Aggregate Sampling Rate: 10 seconds
5) Additionally, the flow metering elements at the source and terminus ends of each individual pipeline will be of the same type/model of element with the same sampling rate.

6.6. Leak Detection System

The leak detection system usually uses a statistical leak detection based software. Temperature, pressure, valve position and flow rate at each end of a pipeline as well as temperature, pressure and valve position at some of the MLBV locations will be input into the program at frequent time intervals. Leak detection is performed using a statistical analysis of the pipeline process parameters measured and compared to previously measured conditions. A detected leak will initiate an alarm. The following is an overview of a leak detection system:

1) The leak detection system will provide real-time leak detection capabilities and include the following core functions:
   a) Interface with the ICSS/PCS systems
   b) Data validation
   c) Leak detection and location
   d) Data reporting

6.7. Cathodic Protection System

In the event that the pipeline's external coating is damaged, cathodic protection will lessen the corrosion of the buried pipeline or where a pipeline leaves a facility or well site.

6.8. Pipeline Pigging

6.8.1. Maintenance Pigging

Maintenance pigs are used to clean active pipelines to improve pipeline flow efficiency, remove undesirable material or debris such as wax, sand, corrosion by-products, carbonate scale, and water, and prepare the pipeline for an in-line inspection tool run. There are no regulatory requirements to perform maintenance pigging, although maintenance pigging is a very important element of a successful pipeline integrity management program.

Only pipeline segments of oil transmission lines operating at greater than 20% specified minimum yield strength (SMYS) that could affect high consequence areas are currently regulated under the integrity management program administered by DOT (49 CFR 195.452). Low stress pipelines, such as an oil transit line operating at less than 20% SMYS, are currently exempt from DOT regulation. Normally, pipeline operators will agreed to include low stress pipelines into their integrity management program. The State of Alaska has proposed regulations requiring that about 1500 miles of flow lines on the North Slope, currently exempt from DOT regulation, be included into the BP and CPAI integrity management programs. DOT-OPS has also proposed regulations requiring that low stress oil transit lines on the North Slope, that are not currently regulated by DOT, be included in the integrity management programs.

It is important to design a cleaning program for pipelines. Critical design information includes pipe characteristics and the type and estimated volume of material to be removed. Caliper tools and gamma ray scanning of above ground pipelines are techniques that can be used to develop estimates of debris quantities. Maintenance pigging experts also recommend obtaining a sample of the materials to be removed, preferably with a cut-out section of the actual pipe, to determine the appropriate pig design and evaluate the need for chemical solutions to enhance the mechanical cleaning efforts.

6.8.2. Intelligent Pigging

The integrity management program administered by DOT (49 CFR 195.452) focuses on managing the integrity of pipelines in high consequence areas. A pipeline operator's integrity management program should identify which segments of their pipeline are in high consequence areas, and must entail a baseline assessment. Scheduling baseline assessments for the various pipeline segments is established based on risk factors.

A robust integrity management program utilizes a qualitative risk assessment approach to evaluate relative risk scores and the consequences related to those risks for each segment of pipeline. These relative risk scores are used to schedule baseline assessments, develop risk mitigation and repair plans, and establish the frequency for subsequent pipeline integrity assessments. The baseline assessment can be performed using in-line inspection techniques, pressure testing, or other technologies.

The main internal inspection pigging technologies use MFL, UT, and geometry/deformation/caliper tools. DOT statistics show that pipeline operators use high resolution MFL most often to assess the integrity of their pipelines. MFL identifies and measures metal loss and detects cracks by inducing a magnetic flux at different orientations to the pipe wall. High-resolution MFL in-line inspection pigs have increased sensor density and sampling frequency and may be equipped with tri-axial sensors to detect magnetic flux leakage in the axial, radial and circumferential directions.

UT tools are very accurate and precise in-line inspection tools which use compression and shear waves to measure pipe wall thickness and metal loss and to detect longitudinal cracks, weld defects, and crack-like defects. The EMAT (Electro Magnetic Acoustic Transducer) system is a newer, highly-accurate crack detection and wall thickness measurement tool that is used in a non-liquid pipeline environment. Pipeline cleanliness is a major consideration for UT tools, as material buildup on the pipe wall, especially soft wax, can interfere with UT transmissions. In addition, UT tools operate best in a single-phase liquid line but can be batched in three-phase lines.

Geometry tools use cantilever-supported sensors to measure the pipeline bore and to identify dents, deformations, and other changes in the pipe circumference. In-line inspection pigs have inertial navigation systems to map out the pig's progress through the pipeline and obtain GPS coordinate of anomalies and above ground markers.

Some of the pipeline characteristics that need to be considered prior to running MFL, UT, and geometry/deformation/caliper tools include bore diameter, bend radius, flow velocity, etc. Prior to performing the in-line inspection tool runs, however, the pipeline segments will need to be cleaned. As discussed in the previous section, it may not be possible to adequately clean the pipeline for an in-line inspection tool run without the use of pig launchers and receivers and removal of tight or mitered bends or valve restrictions.

A pipeline operator must take action to address all anomalous conditions discovered through the baseline assessment, addressing the highest risk segments first. Excavations, known as digs, are used to verify and confirm the type and extent of a metal loss or physical damage anomaly. The priority for conducting digs and repairs is determined based on the severity of the anomaly and consequences associated with pipeline failure.

6.9. Maintenance

Instrumentation essential for the safe operation of the pipeline system should be kept well maintained and calibrated. Maintenance procedures should be developed that cover the temporary disarming or overriding of instrumentation and control, for maintenance or other purposes. The pipelines are normally designed to operate 24 hours per day, 365 days per year. Instrument installation details should allow for ease of calibration, repair, and replacement of instruments without interruption to pipeline operation.

Pressure transmitters should be equipped with three valve manifolds for ease of maintenance and calibration.

Emergency shutdown valves and MLBVs including actuators and associated control systems should be inspected and tested periodically to demonstrate that the whole system will function correctly and that valve seal leakage rates are acceptable.

It also should be possible to operate MOVs electrically in a local mode. To allow for ease of maintenance and provide for the unlikely event where powered operation of the valve is not available the MOVs should also be capable of manual operation.

6.9.1. Equipment

For this discussion control and data acquisition equipment will be separated into two groups, that equipment located at a remote MLBV site and that equipment located at a pipeline termination facility (pig launchers/receivers and pipeline limit valves).

MLBV site

The EPC2 pipelines will have main line block valves (MLBV) at selected positions along for the purpose of section isolation. Under normal circumstances these valves will remain open and have minimal effect on the pipelines.

Manually Operated site

Manually operated sites have no instrumentation other than the valve itself. Taps to the pipeline that may be used for instrumentation in the future may be provided. The valve should be equipped with a manual actuator having a mechanical valve position indicator.

Automated site

MLBV sites with instrumentation, control, and other equipment will often require that a shelter be located at the site.

Segment Isolation

Main Line Block Valves (MLBV) should be motor actuated and capable of both local and remote controlled operation. Valve position indication shall be provided via a mechanical position indicator. A local valve position indicator shall be provided.

Safety

A minimum of one fire detection alarm along with a fire system fault should be provided for the automated remote MLBV sites.

Security

An intrusion indication on the shelter (door switch) door is often used to indicate an unauthorized presence at a site.

Corrosion Protection and Monitoring

At MLBV sites the pipeline cathodic protection system often utilizes anodes and require no control or installed instrumentation of rectifiers.

6.9.2. Pig Launcher/Receiver and Pipeline Limit Valve Sites

Leak Detection (PIMS)

Leak detection instrumentation normally consists of two pressure transmitters and a temperature transmitter located at those pipeline limit valves connected to pipelines having PIMS monitoring.

Segment Isolation

Pipeline limit valves are often located at the beginning and end of each pipeline to provide pipeline segment isolation. These valves are normally motor actuated and capable of both local and remote controlled operation. Valve position local indication is provided via a mechanical position indicator. Valve position is transmitted to the ICSS. At these valves, buttons commanding Open, Stop, Close are provided and a Hand Off Auto (HOA) selector switch determines the source of these commands, local (hand) or remote (auto) and allow for disabling operation (off). These valves normally receive control input from the ICSS.

Corrosion Protection and Monitoring

At all locations where a pipeline leaves a facility or well site the pipeline cathodic protection system should be utilized and often an impressed current system is utilized which requires instrumentation and control. The impressed current cathodic protection system is usually a redundant design with 100% reservation and automatic switch over to the reserve system. Monitoring and control of these analog and discrete points are provided. Rectifiers may be scanned at a minimum rate of 1 scan/hr. Linear polarization detectors are usually scanned at a minimum rate of 1 scan/2sec. For each of the impressed current rectifiers, all analog and discrete instrumentation points should be wired to the ICSS marshaling cabinet. The installation of the linear polarization detectors includes wiring of analog points to the ICSS marshaling cabinet.

Electric Power

Electrical power is usually required at the facilities and well sites where the pig launchers/receivers and pipeline limit valves are located.

7.0 Additional Variable Multipliers

The Author has included in P2 Appendix C a listing of variables that impact the construction costs of a pipeline built in optimal conditions, i.e. clayish soil, class location 1, no sub-fluvial crossings, etc.

The variable impacts of each of the variables have been extended across all pipeline diameters on a percentage basis. Unless otherwise noted on the spreadsheet in P2 Appendix C, the variables are based on 5 kilometers of each Variable within a pipeline of 50 kilometers total for comparison

The following Variables were assessed, based on an updated data base of pipeline construction costs, with the results contained in P2 Appendix C:

- Variable 1a-Clay Soil
- Variable 1b-Sandy Soil
- Variable 1c-Rocky Soil
- Variable 2a-Tundra Vegetation
- Variable 2b-Temperate Broadleaf Forest Vegetation
- Variable 2c-Subtropial Rainforest Vegetation
- Variable 2d-Arid Desert Vegetation
- Variable 2e-Dry Steppe Vegetation
- Variable 2f-Savanna Vegetation
- Variable 2g-Tropical Rainforest Vegetation
- Variable 2h-Alpine Tundra Vegetation
- Variable 3a-Water Table-Sumps & Ditches
- Variable 3b-Water Table-Well Point System
- Variable 3c-Water Table-Cofferdams
- Variable 4a-10 km of Class I
- Variable 4b-10 km of Class II
- Variable 4c-10 km of Class III
- Variable 4d-10 km of Class IV
- Variable 5a-Wet Crossings (1 ea 45m crossing)

- Variable 5b-HDD (1 ea 300m crossing)
- Variable 5c-Aerial Crossing (1 ea 30m crossing)
- Variable 6a-Seismic Crossing (1 ea 45m crossing)
- Variable 7a-Cultivated land
- Variable 8a Terrain of 5%-10% (1 km)
- Variable 8bTerrain of 10%-15% (1 km)
- Variable 8c Terrain of 15%-20% (1 km)
- Variable 8d Terrain of 20%-25% (1 km)
- Variable 8e Terrain of 25%+ (1 km)
- Variable 9a-Double Joints
- Variable 10a-Connections (2 ea) Hot tap, stopple, by-pass
- Variable 10b-Connections (2 ea) Hot tap, stopple, no by-pass
- Variable 10c-Connections (2 ea) Hot tap
- Variable 10d-Connections (2 ea) cold cut
- Variable 11a-Congested area construction (5km)
- Variable 12 Fuel costs ($1/gal or $0.26/liter change +/-)

It should be noted the Variable impacts are primarily associated with initial construction installation costs. The impacts the Variables have on the useful life of the pipeline system, if any, is dependent on a variety of factors and decisions made during the life of the pipeline. See the Pipeline Useful Life Model in Appendix A of Product 1 of the Expert Report for how these Variables may impact pipeline useful life.

If proper decisions and mitigations are put in place, the Variables may have cost impacts for the Construction and Operations phases; however there should be a minimal impact to the 40 year design life of the pipeline system.

8.0 Additional Length Multipliers

The Author has included in P2 Appendix D a listing of additional length multipliers in addition to those included in Product 1. The additional lengths for all diameters include:

- 200 meters
- 500 meters
- 800 meters
- 30 kms
- 70 kms
- 130 kms
- 150 kms
- 180 kms
- 230 kms
- 250 kms
- 280 kms
- 300 kms

It should be noted that a final review of all pipeline lengths and diameters revealed some slight errors on the part of the Author, the majority were due in part to factors that were out of date and were carried over from the 2014 costs to the 2015 costs and in some cases there were slight errors in the formulas and algorithms used to develop the cost estimates.

The diameters and lengths that were updated are:

- 6" – 1 km & 50 km
- 16" – 50 km
- 18" – 50 km

Therefore, the list shown in P2 Appendix D should be considered the final list for all diameters and lengths for 2015 costs.

The following general comments should also be taken into consideration when looking at cost comparisons across pipeline diameters and lengths:

- On some smaller diameters of longer length, additional costs such as the use of man-camps is included, but the smaller diameters may appear slightly skewed as there is less diameter to spread the costs across when looking at a cost/dia-in meter comparison.
- On some larger diameter pipeline of shorter length, large equipment must still be used to handle the pipe, but there is less distance to spread the costs over.
- As diameters increase, there are certain additional specialty equipment that is needed that may skew the cost per dia-in meter. An example is when moving from 8" to 10" or possibly 12", internal line up clamps are used which increase the overall cost of the spread.
- As pipeline lengths increase, additional resources must be included to properly manage the pipeline spread and maintain schedule. The point at which these additional resources (which correspond to additional costs) are brought in (i.e. at 30

kms, 50 kms, 70 kms, etc.) is a judgment call and will vary from contractor to contractor and from project to project.

The above comments are meant to be used as an explanation of why costs between diameters and across lengths is not an exact science and may have variances that are not precisely linear.

The Author has used a proprietary cost estimating system to develop the costs represented in Appendix C and has used his judgement as to resources required and the schedule to complete the work depending on the pipe diameter and length of the pipeline. As such, based on the program used and the available cost information, the cost estimates presented, by the definitions determined by the Association for the Advancement of Cost Engineering (AACE)[2] in Recommended Practice 18R-97, should be considered as Level 1 cost estimate. Therefore, the accuracy of the costs represented in Appendix C should be considered as:

Low: -3% to -10%
High: +3% to +15%

The Table referenced in AACE's Recommended Practice 18R-97 is shown below:

	Primary Characteristic	***Secondary Characteristic***		
ESTIMATE CLASS	**DEGREE OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 70%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	70% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[2] Association for the Advancement of Cost Engineering. AACE International (formerly the Association for the Advancement of Cost Engineering) was founded in 1956 by 59 cost estimators and cost engineers during the organizational meeting of the American Association of Cost Engineering at the University of New Hampshire in Durham, New Hampshire.

9.0 Pipeline Valuation Methods

9.1. Overview[3]

This Section is meant to provide a basic overview of how pipeline valuations are reached. The typical life expectancy of a pipeline system built per applicable design codes and maintained properly is considered 40 years. Therefore, 40 years is the norm when considering pipeline valuations.

9.2. Background

In typical consolidated financial statements prepared in accordance with U.S. General Accepted Accounting Principles (GAAP), pipeline system assets are depreciated on a straight line basis for the estimated useful life of the pipeline system.

Until 2000, the internationally accepted useful life of a pipeline system was 25 years, which meant an annual depreciation of 4% was used. The industry accepted useful life of pipeline systems was changed in 2000 following a full scale re-determination of existing pipeline systems and set the useful life of gas pipelines at 40 years, that of compression stations at 25 years and that of distribution networks at 50 years.

Therefore, beginning in 2000 the value of pipeline system assets, net of amortization reserves as of 31 December 1999, is depreciated based on the residual useful life of 40 years under U.S. GAAP.

9.3. Accounting Details

Oil and gas accounting principles typically allow a choice of three basic methodologies for determining how pipeline systems are treated for discounting:

- **Replacement cost of asset**. Where the total revenue is set to recover costs with those costs to be calculated on the basis of a return (rate of return) on the value of the assets that form the pipeline system (capital base), depreciation on the capital base (depreciation) and the operating, maintenance and other non-capital costs (non-capital costs) incurred in operating the pipeline system.
- **Internal rate of return (IRR).** Where the total revenue is set to provide an acceptable IRR for the pipeline system on the basis of forecast costs and sales.
- **Net present value (NPV).** Where the total revenue is set to deliver a NPV for the pipeline system (on the basis of forecast costs and sales) equal to zero, using an acceptable discount rate.

9.4. Determining Pipeline Value

There are three (3) basic methodologies for determining pipeline value:

1. New Construction Costs
2. Income Base or Cash Value
3. Physical Evaluation or Appraisal Method

[3] Much of the information contained in Section 6.0 is derived from Pipeline Equities, a Houston based firm specializing in pipeline valuations.

9.4.1. Accounting Principles

Oil and gas accounting principles typically allow a choice of three basic methodologies for determining how pipeline systems are treated for discounting:
The basic steps in determining asset values, which correspond to the replacement cost of asset method, and includes:

1. Determine the capital expenditures required to put the asset into service.
2. Determine operating costs of the asset over the useful life
3. Determine a depreciations method (typically straight line depreciation is used)

The replacement cost of asset method is based on the current year cost of rebuilding the same diameter pipeline with the same length, terrain, vegetation, crossing, connections, etc. as the end of life pipeline contains and then discounting it based on a particular point in its life cycle.

The replacement cost is then depreciated to arrive at a discount that reflects the existing pipeline system has generated revenues which provides pipeline owner with a return of capital in addition to a commercial return on capital. This method also recognizes that the remaining life of the pipeline system is less than that of a new pipeline replacement system and should therefore have an appropriately discounted valuation.

A typical approach of determining a pipeline asset value is to discount the pipeline system at a rate of 2.5% per year of life or a total of 50% of the cost of new pipeline system construction in today's market.

The goal being to assign a value to the initial pipeline system capital base that is a fair value to all parties. For the initial pipeline system capital base value of the existing pipeline system to be fair to all parties, it should reflect a discounted value based on the historic depreciation which has been recovered by the pipeline owners.

9.4.2. Income Base or Cash Value

This method can be used for establishing a value for pipelines if they are generating or will generate a predicted cash flow. This method takes into account forecasted income based on throughput volumes and rates of the commodity transported. Expenses based on a historical or projected income stream are discounted.

Another variation of this method uses multiples of current cash flow where the average annual cash flow is multiplied by a factor of five to twelve. This can be done on annual or monthly basis much like values of oil and gas royalties are determined.

Many companies like to compare pipeline values to oil and gas mineral interests regarding value. Both can have an indefinite life and both can be reborn as new drilling or new discoveries are made in and area. These additional income streams can be discounted to find a present day value or Net Present Value (NPV) in some cases when using future multiples or income. For example, the future income after operating expenses of a gas pipeline might be $2,000,000 per year. A reasonable value might be five times that amount or $10,000,000. A buyer might determine that the net present value in dollars paid today might be 20% less than the $10,000,000 or $8,000,000 Net Present Value in today's dollars.

9.4.3. Physical Evaluations or Appraisal Method

In addition to the two methods outlined above, there is the appraisal method which considers as many as 40 different factors to make value determinations.

Apart from these, other factors depend on whether the product is purchased at the wellhead and resold, whether and to what extent the product is compressed, enhanced, treated, cleaned, or processed and by what procedures.

The appraisal method is a complicated and time-consuming technique of determining a pipelines value.

The different factors involved in pipeline appraisals include[4]:

- **Throughput value (transportation)** This method can be used to value based on revenue and can be incorporate into a multiple approach, net revenue approach, or forms of discounted cash flow (income).
- **Depth of coverage of pipe** Depth of pipe or coverage is often associated with age. Often age and condition can be somewhat ascertained when depth is known and date of installation is not.
- **Right of Way agreements** Right of way agreements tell much about value. It is basically the legal instrument that determines the conditions by which a pipeline can be laid, width of right of way, maintenance conditions, repair conditions, term of contract, disposition of assets on termination of usage or term in contract, etc.
- **Replacement Value (asset)** The replacement or cost basis is determined by the cost of replacing this same pipeline either on today's cost basis or on a depreciated basis.
- **Salvage Value** Salvage is determined by what material can be sold as in another venue; taken out of the ground and sold for the steel tubes or scrap value. In this way the pipe is treated as a commodity or secondary tubular steel.
- **Supply (other pipelines in area/scarcity)** Supply is where the product comes from to feed the pipeline. Are there other pipelines to take the product? Are there other sources of supply? What is the life expectancy of

[4] These 40 factors are based on the appraisal methods developed by Pipeline Equities who are a Houston based firm specializing in pipeline valuations.

the source for the supplier.

- **Demand (potential buyers?)** Is there sufficient demand to maintain or lay a pipeline? Is the demand stable and reliable? Is there room for future expansion with the demand group of buyers or transporters?
- **Customer value** In the area of local distributors, a per customer value is sometimes applied. This value can vary from one local to another depending on demographics and economics of the area: whether it is urban or rural, high or static growth, etc. A major factor can be number of industrial or commercial customers such as restaurants, schools, plants that consume gas in manufacturing, etc.
- **Surface Inventory (including appurtenances)** Generally pipelines are bought and sold including appurtenances which are all valves, risers, meters, and anything else connected to the pipeline that is part of it and contributes to its operation. This can include tanks storage facilities and terminals.
- **Sales Contracts / Length** If the pipeline depends on a certain customer, or group, then it is important to know the term of the sales contract.
- **Potential for replacement volume (new wells, tie ins)** The potential for new customers is worth noting. It there is room for growth and the potential or possibility of new growth then it could affect the premium or discount values.
- **Type of System, oil & gas, product, etc.** The type of system is significant for various reasons whether it be gathering, trunk, transmission, liquid, product, gas, or whatever.
- **Size of pipe** Size of pipe helps determine salvage as well as whether or not the pipe must be removed on termination of usage, etc. Mainly, size determines volume that can be transported and thus revenue potential.
- **Specification of pipe** specifications are important when determining value regarding salvage as well as dictates type of product and pressures that can be operating while the line is in service.
- **Management (front and field office)** Management can make or break any business, pipelines included.
- **Date of Installation** dates are key as they determine and reveal vintage of the pipe, coating, type of construction, and environmental considerations as of date of installation.
- **Maintenance of property** Care and maintenance reveal the type and attitudes of management and the company as well as general conditions. Most pipelines are buried and the appurtenances above ground reveal much of the overall care to a property.
- **Interconnects** The interconnects are different as they are considered a separate asset and not an attachment or appurtenance to the pipeline even though it is or has become part of the system. We consider it separately and value accordingly varying from one to another.
- **Cathodic protection** This corrosion protection of last resort is significant and the degree to which it is maintained is important. Conditions change

and can affect the efficiency of any system especially in rapid growing and transitional areas.

- **Pipe coatings (vintage)** Pipe coatings reveal age and sometimes the type of construction and vintage of pipe. Knowledge of pipe coatings is important because this is the first line of defense against corrosion. Often older pipelines present environmental concerns as they have asbestos fiber embedded.
- **Environmental concerns** This becomes a maintenance issue as much as anything as concerns center mostly around releases (spill, leaks) and what the oil, or any other kind of product might be transported.
- **Demographics- urban or rural?** Pipelines in and out of cities and in the path of rapidly expanding areas of the country pose different sets of problems and generally require more maintenance than pure rural and thus can add significantly to overhead and upkeep as well as create higher tax rates by some appraisers.
- **Appurtenances other than surface inventory** Often there is forgotten the fee land that is acquired with a pipeline. In many situations real estate of value is part of a system but not recognized for its value as an entity by itself. Others might include loading docks at terminal especially docks on important water transportation corridor (Intracoastal Canal, Mississippi River).
- **Appearance** Curb appeal is importance in buying or selling a pipeline as it is in buying and selling any kind of property. The appeal of any property is always enhanced by well maintained and clean, well kept appearances.
- **Reservoir studies** Reservoir studies are important when any system is dependent of a particular field or reservoir that feeds the pipeline system. It is important to know the life of the pool that is being depleted.
- **Market price of commodity** The price of the commodity determines the activity. Current high prices encourage much activity. When prices were lower, pipelines did not change hand very often for lack of motivated buyers.
- **Type of system: trunk, gathering, distribution, etc.** The type of pipeline system is significant because each has its own set of peculiarities. Gas distribution companies deal with retail customers; Oil pipelines generally require more operations personnel than gas transmission, etc.
- **Chemical content of transported product (H2S, CO2)** Aside from the obvious such as H2S and CO2 there are the myriad other chemicals, residues, and contaminants that are part of the process of eliminating cleaning and disposing of to some degree or another for safety as well as environmental reasons.
- **Market diversity** Does the transporter have any diversity or opportunity to sell to more than one designated buyer?
- **Proximity to markets** How far is the distance from the source to the market? Is there room for competition? Could another line be built economically to compete?

- **Geography** Geographical considerations can determine construction costs and when factoring in terrain, drainage, rivers, streams, and elevations.
- **River crossings** One or more river crossings on right of way can add asset base and value to a pipeline.
- **Diversity of suppliers** Is there another supplier on the horizon in case the current source changes in any way. What is the stability of the current supply?
- **Regulatory oversight or governmental factors** What kind of oversight. Is this a state regulated pipeline, FERC. To what agency does management report?
- **Social factors** These can relate broadly to demographic characteristics of the area of the pipelines: age and gender composition, population, and social attitudes.
- **Economic factors** This can relate to employment cost of money, inflation, rent levels, possible new development, and construction costs in an area.
- **Transportation** Is area accessible for new construction, maintenance, and repair?