An Engineering Assessment of Double Wall Versus Single Wall Designs for Offshore Pipelines in an Arctic Environment

Final Report

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1. INTRODUCTION

This project originated with the public request for proposal: RFP 1435-01-RP-31004, and the 4 subsequent changes in referenceW-097 SN317445 issued by the US Dept of Commerce on behalf of the Minerals Management Service, US Dept of Interior.

The principal rationale for conducting this study as stated in the contract "is to assess if a double walled design provides the same or a greater degree of engineering integrity and environmental robustness as compared to a thicker walled single pipe design for an arctic offshore application and to appraise the economics of one selection over the other relative to the potential risks (real and/or perceived) associated with either application". The study included an appraisal of the economics of each pipeline system including life cycle costs, and an analysis of risks within the framework of statistics for performance of offshore pipelines. The risk statistics are derived from work by other experts for other offshore regions in the world. The name of the study has been abbreviated from "An Engineering Assessment of Double Wall Versus Single Wall Designs for Offshore Pipelines in an Arctic Environment" to "Arctic Offshore Pipeline Comparative Assessment".

The project commenced with a meeting in Anchorage, Alaska on 28 July 1999. Representatives of the Alaskan State and US federal government agencies and 2 representatives of the project team attended this meeting. The minutes of the meeting are on file. The project objectives, workscope and some parameters for the project basis were confirmed, discussed and modified at this meeting.

On behalf of the Minerals Management Service, the study team arranged the Alaskan Arctic Pipeline Workshop on November 8 and 9, 1999. This workshop facilitated the exchange of technical information on Alaskan arctic offshore pipelines between the public, engineering community and regulatory agencies. The objectives of the workshop were to bring together a group of diverse experts with experience and skills related to offshore pipeline design, operation, maintenance and inspection, to examine and discuss experience with offshore pipelines that would be relevant to arctic pipeline alternatives under consideration for Alaska's offshore oil and gas reserves. There were 27 invited presentations and 155 workshop participants. The workshop proceedings are summarised at http://www.mms.gov/tarp/workshop25.htm This information was used to assist the study reported here. A progress review meeting for this study followed the workshop on 10 November 1999.

2. STUDY OBJECTIVES

This study has several objectives. The main objective of this study is to conduct an extensive, non bias engineering assessment, considering both pro's and con's, of single versus double walled designs for offshore pipelines in an arctic environment. The principal rationale for conducting this study is to assess if a double walled design provides the same or a greater degree of engineering integrity and environmental robustness as compared to a thicker walled single pipe design for an arctic offshore application and to appraise the economics of one selection over the other relative to the potential risks (real and/or perceived) associated with either application.

The intent of the desired study is not to assess the alternatives for a single, specific ongoing arctic pipeline project. It is understood that to assess the actual benefits versus costs and risks associated with either a single walled or double walled design would require project specific analyzes. The purpose of the assessment is to accurately document the advantages and disadvantages (technical and non-technical) of either a robust single thick walled design to a pipe-in-pipe design considering the constraints associated with an offshore arctic pipeline project, i.e. ice cover, permafrost, scouring of the seafloor by ice, etc. and based on supporting quantitative information. The primary purpose of the study is to see if it is feasible to design a double wall pipe for arctic conditions and to assess advantages/disadvantages, risks/challenges and what resources would be required to meet or mitigate those challenges.

Another objective is to present the results in a format so that engineers, biologists, scientists and the public can comprehend the results and resulting conclusions. Also the results and conclusions must be presented in a way so that they are useful, concise, and defendable to all concerned in making decisions relative to long term integrity and environmental issues typical for an offshore arctic pipeline.

3. EXECUTIVE SUMMARY

3.1 Background

The principal rationale for conducting this study is: “to assess if a double walled design provides the same or a greater degree of engineering integrity and environmental robustness as compared to a thicker walled single pipe design for an arctic offshore application and to appraise the economics of one selection over the other relative to the potential risks (real and/or perceived) associated with either application”.

The objective of the study as stated in the contract authorizing the work is: “to conduct an extensive, non bias engineering and environmental assessment, considering both pro’s and con’s, of single versus double walled designs for offshore pipelines in an arctic environment”. It responds to a number of issues raised by stakeholders in relation to proposed offshore pipelines in Alaskan arctic.

The study team was provided with the issues that had been documented and they set out a program that was designed to address advantages and disadvantages.

A great deal of information was provided to the study team. Extensive background information was gathered from the July 28, 1999 kick off meeting from the stakeholders who attended. Of particular value was a workshop sponsored by the Minerals Management Services in Anchorage on November 8 and 9, 1999. The presentations covered a wide spectrum of design, construction and monitoring experience for offshore pipelines. The discussions were extensive and incisive. The team was also provided with selected documents from the proposed Northstar Pipeline and Liberty Pipeline projects. The study included an extensive review of the literature and a survey of offshore pipeline operators. Double wall pipe usage in the petroleum, petrochemical and chemical industry was identified to document current applications. Several offshore double wall pipe systems were identified, some of which have been in existence for over 20 years.

No existing offshore double wall pipe systems have been constructed to provide secondary containment in the event of a failure of the product line. Most were configured to provide insulation for the inner pipe. The Colville River crossing of the Alpine pipeline is the only pipeline known to have been designed to provide product containment in the event of a leak.

At the time the literature and operator survey was carried out, there were no known failures of offshore double wall pipes during operation. As the original draft of the report was being completed the study team became aware of a failure of a double wall pipeline in the Erskine field of North Sea. The cause of the failure is unknown but both the inner and outer pipes failed. Considering the total miles and length of service of existing double wall pipelines, this failure would indicate an annual probability of containment failure of $2x10^{-3}$, which is comparable to offshore pipeline failure statistics presented at the Alaskan workshop.

3.2 Project Basis

A project design basis was formed in consultation with MMS for general conditions for offshore pipelines near Prudhoe Bay. The study parameters are documented in the report in Table 7.1-1. The detailed results of this study are sensitive to some of the parameters selected. The general conclusions presented are valid for the project basis and study assumptions considered (sections 7.1.1 and 7.6.1.5). The conclusions may change with changes to the project basis or assumptions.

For the base case, study Case A, the single walled pipeline was considered to be a grade X52 12.75" outside diameter (O.D.) pipe with a 0.500" wall thickness. The double walled system comprised two grade X52 pipes both with a 0.375" wall thickness. The inner pipe was 12.75" O.D. and the outer pipe was 14.00" O.D. Three alternative double wall pipe systems, designated Cases B, C & D, were studied and compared to Case A. Cases B and C considered fixed solid bulkheads and shear rings respectively. Case D is simply one pipe within another with approximately 0.5" clearance between the two outer pipes (section 7.7).

Only the outermost wall of all four pipeline study case configurations was considered to require a coating, as the annulus of double wall configurations is a potentially low corrosive environment (section 7.1).

Double walled systems have been adopted elsewhere for both onshore and offshore industrial applications for thermal insulation, leak containment and protection of flowlines (section 6.1). The project basis assumed the primary reason to use a double wall system, rather than a single wall pipeline, buried offshore in an arctic environment is leak containment.

3.3 Assumptions

A number of assumptions were necessary during the course of the study. The most important of these relate to 'functional failure' and 'containment failure'. A functional failure is defined as pipeline system damage without loss of product containment integrity to the environment. A containment failure is defined as pipeline system damage with loss of product containment integrity, that is product loss to the external environment. Hence a breach of either the inner or outer wall of a double wall pipe is considered as a functional failure, provided the other pipe retains its integrity or containment. Loss of containment through only one of the two pipes comprising the double wall system is not considered to be a containment failure of the system.

It is assumed that construction will take place during the winter season working from an ice-strengthened surface and that work will be completed within one season (sections 7.7 and 9.3).

It is assumed that the tensile strain capacity in the vicinity of the pipeline girth welds is about an order of magnitude lower than that of the parent pipe. The lower capacity in the weld vicinity dictates the tensile strain limit for the pipeline. Recent advances in welding and inspection techniques may increase this lower capacity under certain conditions towards that of the parent pipe material. This potential increase in tensile strain capacity is ignored in this study. Instead, for the double wall pipeline system, the girth welds on the inner and outer pipes are considered to be significantly offset (staggered) by several meters along the length of the system. The tensile strain limit of at least one pipe in any double wall cross section is then controlled by that of the parent pipe rather than the girth weld. This staggering of the welds is considered to be of benefit in maximising the structural integrity of the double wall system under flexure.

3.4 Design and Construction

The design and construction of a double wall pipe is more complex than a single wall pipe because of the additional pipe, associated welds and tie in procedures. There are numerous design, operating and monitoring difficulties associated with spacers and bulkheads or shear rings. There is no compelling reason to use them when the primary function of the outer pipe is secondary containment.

The study team selected Case D for the base case since it was the simplest, yet most viable alternative. This double wall system was subjected to detailed analysis of costs and risks, and was deemed to be viable for arctic conditions. The pipeline design process for an actual project may indicate that a robust single wall pipeline is the preferred solution over a double wall pipeline system due to specific project considerations.

The double wall pipe system may be assembled by pulling outer pipe lengths over the inner pipe lengths (section 7.7).

If the tensile strain limits of both systems are exceeded the single wall pipe could lose containment before both walls of the double wall pipe would lose containment provided the girth welds of the inner and outer pipes were staggered. Following section 7.6.1 and the tensile strain assumptions presented in section 3.3, the probability of a significant defect existing in both the inner and outer pipelines of the double wall system within a region of peak tensile strain is very remote. Considering these factors, the study team has concluded the probability of simultaneous failure of both walls of double wall pipe is lower than a containment failure of a single wall pipeline.

The strains induced in both pipeline systems during installation from the ice surface are considered to be less than those imposed under extreme environmental loads, such as an ice scour event.

The single wall pipe is simpler to construct than the double wall pipe (section 7.7). The double wall pipe has twice the number of girth welds as a single wall pipe. Construction requires inserting one pipe within the other with associated outer pipe tie-in welds, pressure testing, drying and charging the annulus following construction. The welds of the outer pipe can be inspected with the same techniques used for a single wall pipe except for the tie-ins (section 7.8). The tie-ins can be inspected by ultrasonic testing.

The double wall pipe restrains the monitoring of the outer pipe (section 9.5). It can be checked routinely for total integrity using a pressure based annulus leak detection system. This system can provide continuous integrity monitoring of both inner and outer pipes on a pass/fail basis only. The annulus also provides space for an external leak detection system, such as hydrocarbon sensing tape or a local corrosion monitoring system (section 7.9). Conventional pigging during operations with present day technology cannot reliably inspect the outer pipe of a double wall system, but pigging is equally reliable for the inner pipe as for a single wall system.

Interior corrosion rates of both product (inner) pipelines are similar as they are carrying the same product (section 7.6.2). External corrosion of the product (inner) pipe would be less in a double wall pipe since the annulus should provide a potentially low corrosive environment (section 7.6.2). The exterior wall of the outer pipe will operate at a slightly lower temperature than a single wall pipe and thus may have a slightly lower rate of corrosion. Corrosion failure of both the inner and outer pipes in a double wall pipeline would be required for loss of containment to occur.

Abrasion between the inner and outer pipes is not considered to be significant given the expected operating conditions of the system when no significant repetitive fluctuations in product pressure or temperature occur.

3.5 Operations and Maintenance

It is the opinion of the study team that double wall pipeline configurations offer moderate-to-significant operating and maintenance advantages relative to single wall pipelines because of the ability for secondary containment of oil in the event of an inner pipe failure (section 7.9).

The main operating and maintenance disadvantages of a double wall pipeline relative to single wall pipelines are the limited capability to inspect and monitor the condition of the outer pipe.

Double wall and single wall pipeline configurations have similar operating and maintenance requirements on the product (inner) pipe for operational condition monitoring, leak detection, chemical inhibition application, pipe cleaning, defect monitoring and evaluation, and cathodic protection testing, monitoring and maintenance (section 7.9).

3.6 Repairs

A double wall pipe would be more complex to repair than a single wall pipe but the greatest component of repair costs would be similar for both systems. A double wall section could be prepared during construction and stored for use in the unlikely event of a failure. The difference in repair costs in the case for a functional failure would be proportional to the difference in initial materials and fabrication costs. Similarly, repair costs of a double wall pipe for a total containment failure (failure of inner and outer pipes) would be greater than a single wall pipe by about the same proportion (about 25% higher).

3.7 Costs

The comparison of design, material and fabrication costs indicates the double wall pipe to be 1.27 ±25% times greater than a single wall pipe. Other costs such as the civil works costs comprising excavation, backfill and ice road during construction and abandonment are estimated to be the same for both alternatives. The operations and maintenance costs are estimate to be similar to the double wall pipe costs are estimated to be only 3.5% higher at present value over life relative to single wall pipeline configuration (section 8.5).

The greatest components of life cycle costs are civil works costs and operations and maintenance costs. They are similar for both alternatives. The upfront costs for a double wall pipe are greater but are less significant in life cycle costs at present value because of the dominance of the other cost factors, such as civil works and operations & maintenance costs.

If a containment failure occurs in both pipes of the double wall pipeline, the product loss would be the same as a containment failure of a single wall pipe of comparable robustness. Any leak to the external environment associated with a single wall (or double wall) pipe will require cleanup. The cost could be very high, depending on the length of time it goes undetected and the amount of product released to the environment. The potential cost of cleanup is not included in life cycle costs as the probability is so low and the cost so variable that it would distort life cycle costs.

3.8 Risk

No failure statistics exist on the probability of failure for arctic offshore pipelines, but experts have produced statistics for other offshore pipelines, relating these to different hazards such as internal corrosion, external corrosion, external loading and so on. Although the statistics differ somewhat in hazard source characterization and distribution, the data proved to be valuable in establishing a risk framework for arctic pipelines, taking into account the different environmental factors. This framework was used to evaluate the probability of failure of a double wall pipe and a single wall pipe.

The existing statistics cover a range of design standards, construction quality, inspection and operation & maintenance. They include failure statistics for pipelines constructed, operated and maintained to standards that would not be accepted for arctic offshore pipelines today. Such arctic pipelines are expected to have a probability of failure an order of magnitude lower than older pipelines.

The analysis of hazard frequency estimates for buried arctic offshore oil pipeline systems was framed with respect to the project basis. The hazard frequency estimates were representative probabilities based on the historical record of offshore pipeline system failures for single wall pipelines located outside an arctic environment in the Gulf of Mexico. The historical records were subjectively reinterpreted for consideration of the hazards and associated causal events appropriate to a buried offshore arctic pipeline to estimate the hazard frequencies (section 10.3.2). Increased arctic pipeline experience and a more comprehensive quantitative risk assessment, that includes risk uncertainty, may present a basis for redefining the currently proposed hazard recurrence rates.

For the study parameters investigated and the underlying assumptions considered to develop the inferred hazard statistics, the double wall alternative has a lower risk of containment failure (i.e. loss of product) compared with the single wall pipeline. This is primarily due to the combined probabilities associated with simultaneous girth weld failure of both the inner and outer pipelines, as well as combined corrosion failure of the double wall system. Conversely, the double wall pipeline system has an increased risk of functional failure, primarily related to serviceability. The failure probabilities for both pipeline systems, however, meet or exceed the current practice for the target safety levels recommended by DnV (1996).

From the perspective of environmental damage, the primary concern is the risk of containment failure and product loss. Although the annual system failure probability of the double wall pipeline system (6×10^{-4} system failures/year) is marginally lower than the conventional single wall pipeline (1×10^{-3} system failures/year), this cannot be considered in isolation or as a generalized conclusion for double wall pipeline systems. The comparative assessment must also be viewed in terms of the defined parameters and constraints of the overall risk analysis framework. The costs associated with reduction of the potential hazard frequency would typically be only a fraction of the costs of responding to a containment failure. In general terms, pipeline expenditure is best directed to reduction in hazard frequency rates (i.e. probability of an event occurrence) as opposed to mitigation of event consequence (i.e. severity of the event). Any one or a combination of engineering design considerations can reduce the probability of an event occurrence. Either a single wall pipeline or double wall pipeline can be designed to satisfy a target safety level. Optimization of the design requires consideration of several factors, including potential environmental loads, properties of the seabed, properties of the product, geotechnical conditions, transmission temperature and costs. For example, increasing the depth of burial can reduce the probability of an event due to ice scour.

Tensile strain limits are typically based on crack-tip opening displacement tests during the welding procedure qualification and control development. The tensile strain limit is defined by a complex relationship between material toughness, flaw acceptance criteria (size, shape and position) and tensile strain limits. The engineered critical assessment (ECA) determines the tensile strain limit. To establish a greater pipeline resistance to weld failure, the weld toughness needs to increase (considering the pipeline, heat-affected zone and weldment) and/or the maximum acceptable flaw size needs to decrease. Increasing toughness is generally synonymous with a lower pipeline grade and thus a greater wall thickness would be required in order to satisfy the specified strain limits. Decreasing the acceptable flaw size tends to increase pipeline construction costs by raising the welding and weld quality control standards.

Statistics for pipeline failures (Bea 1999, Farmer 1999) indicate corrosion to be the greatest single factor that accounts for pipeline failures. However, they reflect a spectrum of pipelines over a span of time where design protocols, construction technique and inspection procedures have not been of the same standard as applied today. One or more of several methods can be applied to mitigate corrosion so that with modern pipelines, it will very likely not dominate failure statistics.

If a given target safety level for containment failure is accepted, for example an annual failure probability of 10^{-4}, it can be met by proper engineering design that takes into account all significant factors including constructability and cost. For certain conditions a robust single wall pipe may be preferable to a double wall pipe. Alternatively, the probability of a containment failure may best be reduced to the target level by the proper design of a double wall pipe. For this study, a generic arctic offshore regime has been assumed. It is not linked to any specific project. Each pipeline must be designed for the specific potential loads, seabed conditions, product properties, environmental considerations, constructability and life cycle costs.

There are peripheral issues, related to the level of inspection, detection, integrity monitoring and maintenance of the outer wall pipeline as well as the associated risk uncertainty. These factors must be considered with respect to the objectives of the pipeline operators, regulatory authorities and the adopted risk evaluation/risk management procedures throughout the life cycle.

3.9 Advantages and Disadvantages

Selection of the most appropriate pipeline, whether it be single wall or double wall, will be influenced by several factors. There is no basis for a simple conclusion that one is better than the other as each has advantages and disadvantages. The only basis would be a project specific risk assessment that concluded that the risk of oil getting into the environment was lower for double wall pipe. Both robust single wall pipe and double wall pipe meet or exceed specified code requirements; for example DNV (1996).

The most compelling reason for a double wall pipe, instead of a robust single wall pipeline, is the containment of a product leak. The annulus can also be monitored for evidence of a leak (or even pipe degradation). In these respects it has advantages over a single wall pipe. However, a leak in a robust single wall pipe has a very low probability. The thicker wall than normally used provides greater strength to resist environmental loads and greater resistance to erosion and corrosion than is the case for most of the offshore pipes (if not all) that have experienced leaks or failures. The major advantages of a single wall pipe are simpler construction, lower construction costs, lower life cycle costs and greater inspection reliability. The major disadvantage is that any size of leak will release product into the environment. The major advantage of the double wall pipe is that the probability of a failure or leak in both pipes at the same time is very low. It has a lower risk of product release to the environment than a single wall pipe. The disadvantages of the double wall pipe include its relative complexity and potential difficulties with integrity monitoring of the outer pipe.

4. SCOPE

This program of study was conducted in 4 phases over a 6-month period and covered a number of activities that had been identified in the Request for Proposals. The phases and related activities are described below.

Phase		Activities
1	Collection of Background Information	1a & 1b
2	Design Considerations	2, 8 & 10
3	Construction & Installation Considerations	2, 4 & 5
4	Operational Considerations	3, 6, 7, 9 and 11

The work undertaken to achieve the project objectives reflected the combined capabilities of the participating organisations. Each of the study participants contributed to most aspects of the study. The overall technical direction and project management, including responsibility for ensuring that milestones are met according to the schedule and within the budget allocated, was provided by C-CORE. The other participants were AGRA Earth & Environmental (AGRA), Colt Engineering (COLT) and Tri Ocean Engineering (TOE), all of Calgary, Canada.

	Activity Description
1a	Literature review and background study
1b	Designed performance versus actual performance
2	Potential for construction and installation problems
3	Inspection
4	Risks associated with more complex design & construction requirements
5	Quality assurance and quality control
6	Corrosion
7	Leak detection
8	Costs versus perceived risk mitigation
9	Long term operations and maintenance
10	Structural integrity, and
11	Secondary containment in the event of a leak occurring

5. CONCLUSIONS

5.1 Background

The study included a detailed literature review of offshore pipeline design, construction and performance as well as interviews with a number of operators. In addition all known references to other double wall pipe use in the chemical and petrochemical industries were assembled and assessed. The report brings together a bibliography of 135 referenced reports, articles and documents that are considered relevant to the subject. At the outset a comprehensive Glossary of Terms, and definitions with over 100 entries, was assembled and widely distributed amongst known stakeholders.

Five proposed, existing or historical pipelines were reviewed in detail in terms of their design basis, characteristics, and rationale (section 6.2). In general, double wall pipe configurations are used for the following reasons, in order of decreasing importance: thermal insulation required for reasons of flow assurance; weight control for ease of construction / operational stability; and secondary containment.

Project specific considerations reported for using or not using a double wall pipe have included its increased composite resistance to bending and installation related factors. Apparently contradictory decisions have been made from these considerations due to the different application considered, for example a buried versus surface laid pipe system. The installation-related factors, relative to the available alternative installation methods include shorter schedule and lower associated risk; lower installation cost and lower associated risk; and reduced environmental impact.

Project specific reasons reported for using double wall pipe have included increased composite resistance to collapse from external pressure associated with design water depths; facility for leak detection; and increased mechanical protection of inner pipe(s) and cable(s).

Project specific reasons reported for not using pipe-in-pipe, and using a single wall pipeline instead, have included reduced maintenance related inspectability and installation related factors, relative to the available alternative installation methods.

5.2 Double Wall Pipe Configuration

Three alternative double wall pipe systems were studied, designated Cases B, C & D, and a robust single wall pipe, designated Case A. Case B and C considered fixed solid bulkheads and shear rings respectively. The third double wall pipeline concept (Case D) is simply one pipe within another with approximately 0.5" clearance between the outside diameter of the inner pipe and the inside diameter of the outer pipe. There are design, operating and monitoring difficulties associated with spacers and bulkheads or shear rings and there does not seem to be a compelling reason to use them for secondary containment application. The study team selected Case D for the base double wall case. This double wall system was then subjected to detailed analysis of costs and risks.

5.3 Comparative Structural Robustness (Section 7.6.1)

The structural response of a single wall versus double wall pipeline system was analyzed and compared on the basis of equivalent robustness. This term can be related to the comparable mechanical integrity in terms of the pipeline structural response:

- *Equivalent robustness:* Pipeline Integrity with respect to product containment; that is, the likelihood of failing the single walled or both pipes of the double walled pipeline from excessive tensile strain.

- A limiting tensile strain criterion was adopted since excessive tensile strain represents a significant threat in terms of pipeline rupture and loss of product containment integrity. The structural integrity analyses concluded that, a simple guided double wall pipeline system (Case D) would provide equivalent robustness to a single wall pipeline for the investigated parameters and basic assumptions.

5.4 Corrosion (Section 7.6.2)

- The double wall pipe and single wall pipeline configurations have similar corrosion related design considerations.

- The potential corrosion of the inside of the inner pipe of the double wall pipe is the same as the inside of the single pipe. The outside of the inner pipe and the inside of the outer pipe have low potential corrosion because of the nitrogen gas that will be used to fill the annulus. The outside of the outer pipe will have a slightly lower corrosion potential than the single wall pipe because of the somewhat lower skin temperature. It is assumed that the robust single wall pipe and the double wall pipe will have similar coating and cathodic protection.

5.5 Leak Detection and Containment (Section 7.6.3)

- The double wall pipe provides a potential leak detection advantage (before product is released to the environment) over a single walled pipeline should a leak occur. A pressure based annulus leak detection system can monitor the effectiveness of both the primary and secondary containment on a pass/fail basis.
- The double wall has an advantage over a single wall pipeline in that it has secondary containment provided by the outer pipe.

5.6 Constructability (Section 7.7)

- Construction of a double wall pipe is more complex than construction of a single wall pipe. The additional construction activities consist of inserting one pipe within the other, with the associated outer pipe tie-in welds, pressure testing the outer pipe and drying and charging the annulus following construction.
- The amount of pipe and the number of girth welds is double for the double wall system.

5.7 Construction Quality (Section 7.8)

- All welds of the double wall pipe can be inspected by radiography methods as for the single wall pipe with the exception of tie-in welds on the outer pipe. These tie-in welds can be adequately non-destructively examined by ultrasonic inspection.
- Split sleeves may be required for final tie-in welds on the outer pipe of the double wall pipe. Manual ultrasonic inspection of the associated longitudinal welds should be adequate.

5.8 Operations and Maintenance (Section 7.9)

- The double wall system has several maintenance disadvantages, relative to single wall pipelines. These include reduced outer pipe defect monitoring capability and more complicated commissioning requirements. Repair procedures would be more complicated and the increased complexity of the double wall system would increase the repair frequency.

5.9 Abandonment (Sections 7.10 and 8.6)

- For abandonment in place, which is the norm for subsea pipelines, the double wall and single wall pipelines have similar abandonment requirements and similar costs.

5.10 Comparative Cost Assessment (Sections 8.1-8.4)

- The costs of the double wall and single walled pipeline systems described by the project basis are compared. The cost components are estimated to an accuracy of +/- 25% based on the cost estimates for other existing projects off the North Slope.
- The cost estimates for construction are shown in Table 5.1:

Table 5.1 - Comparative Cost Estimate, $M

	Single Wall	Double Wall	Difference
Design	1.13	1.43	0.30
Materials	5.03	7.54	2.51
Construction(1)	17.56	21.12	3.56
Total:	23.72	30.09	6.37

(1) Does not include costs of excavation, backfill or ice road that is estimated at $28,000,000 for each system.

5.11 Operations and Maintenance Cost (Section 8.5)

- Double wall pipe configurations have a potentially lower lifecycle cost for “containment failure”, relative to single wall pipelines, due to the secondary containment capability offered by the outer pipe. Containment failure cost includes lost product, service interruption / lost production, cost of repair and recommissioning, environmental restoration and intangible costs.

- Double wall configurations have a potentially higher lifecycle cost for functional failure, relative to single wall pipelines, due to the inability to readily inspect, evaluate, monitor and control outer pipe defects. Functional failure cost includes service interruption / lost production, and cost of repair and recommissioning.

- Double wall and single wall pipeline configurations have similar operating and maintenance costs, for operations (operational monitoring, leak detection, application of corrosion and chemical inhibition) and for maintenance (corrosion control, inspection, defect evaluation and defect control).

- The estimated operating and maintenance costs are shown in Table 5-2:

Table 5-2 - Estimated Operations & Maintenance Cost for 20 Year Life, $M

	Single Wall	Double Wall	Difference
Total Estimated Present Value	25.71	26.61	0.90

5.12 Comparative Risk Assessment (Section 9.1-9.4)

- The configuration of a double wall pipeline is more complex than a single wall pipeline; it has more material and more welds and it is more difficult to monitor. Hence it has a greater risk than a single wall pipeline for operational problems. However, a leak in a single wall pipe results in loss of product to the environment. It is unlikely that simultaneous failure of inner and outer pipe would occur with the double wall system. The risk of loss of product to the environment is lower for double wall system.

5.13 Comparative Life Cycle Cost and Risk (Section 10)

- Life cycle costs of a double wall pipeline and single wall pipeline are estimated in 1999 values. Operations and maintenance and civil works costs are dominant and are approximately equal for both systems.

- Life cycle costs estimated are shown in Table 5-3.

Table 5.3 - Life Cycle Costs $M

	Single Wall	Double Wall	Difference
Design	1.1	1.4	0.3
Materials	5.0	7.5	2.5
Construction	17.6	21.0	3.4
Civil Works	28.0	28.0	0.0
Operations & Maintenance	25.7	26.6	0.9
Abandonment	0.8	0.9	0.1
	78.2	**85.4**	**7.2**

(1) All costs to nearest $0.1M

(2) Repair costs not included. The probability of a containment failure is so low (less than 1 in 1000 years) that assignment of a cost would unrealistically distort estimated life cycle costs.

The analysis of hazard frequency estimates for buried arctic offshore oil pipeline systems was framed with respect to the project basis. The hazard frequency estimates were representative probabilities based on the historical record of offshore pipeline system failures for single wall pipelines located outside an arctic environment in the Gulf of Mexico. The historical records were subjectively reinterpreted for consideration of the hazards and associated causal events appropriate to a buried offshore arctic pipeline to estimate the hazard frequencies, as discussed section 10.3.2. Increased arctic pipeline experience and a more comprehensive quantitative risk assessment, that includes risk uncertainty, may present a basis for redefining the currently proposed hazard recurrence rates.

An important conclusion that was drawn from the hazard frequency analysis for the single wall and double wall pipelines (Table 10.3-2), is that the failure probabilities for both pipeline systems meet or exceed recommended target safety levels, DnV (1996) (Section 10.3-1).

Although difficult to quantify and partially subjective, based on inference of the historical data for failure rates of single wall pipeline systems, the double wall alternative would reduce the system failure probability by a factor of approximately 0.5. This is reflected in the hazard frequency estimates summarized in Table 5-4. The hazard frequency estimates indicate that the double wall pipeline system has a greater propensity for functional failures and reduced probability for containment failure, in comparison with the single wall pipeline system.

Table 5.4 - Hazard Frequency Estimates for Buried Offshore Single Wall and Double Wall Pipeline Systems for an Arctic Environment Based on Inferred Statistics from the Gulf of Mexico Database (Table 10.3-2).

Hazard	Annual Failure Probability			
	Single Wall Pipeline	Double Wall Pipeline		
		Inner Pipe	Outer Pipe	System
Girth Weld	1.3×10^{-4}	1.3×10^{-4}	5.0×10^{-4}	7×10^{-8}
Buckling	1.3×10^{-4}	1.7×10^{-4}	4.6×10^{-4}	2×10^{-4}
External Corrosion	2.4×10^{-4}	— (a)	2.4×10^{-4}	6×10^{-8}
Internal Corrosion	2.4×10^{-4}	2.4×10^{-4}	— (a)	
Annular Corrosion	—	0.1×10^{-4} (b)		0.1×10^{-4}
Accidental	1.1×10^{-4}	1.1×10^{-4}		1×10^{-4}
Erosion	0.1×10^{-4}	0.1×10^{-4}	—	0.1×10^{-4}
Material / Structural	0.8×10^{-4}	0.8×10^{-4}		0.8×10^{-4}
Unknown / Other	0.7×10^{-4}	0.7×10^{-4}	1.4×10^{-4} (c)	2×10^{-4}
Total	1×10^{-3}	0.8×10^{-3}	2×10^{-3}	0.6×10^{-3}

<u>Notes:</u> *A hazard frequency of 1´10^{-3} is equivalent to the occurrence rate of 0.001 failures/year or 1 failure event in 1000 years.*

[a] *– external corrosion of inner pipe and internal corrosion of outer pipe is covered in annular corrosion probability.*

[b] *– assumed annular corrosion failure rate of 1.00´10^{-5}*

[c] *– assumed factor of 2*

The risks of pipeline system failure is concluded to be 1×10^{-3} failures/year for single wall pipe and 6×10^{-4} failures/year for the double wall pipe. The risk of functional failure alone is higher for the double wall pipe than that for the single wall pipe. The risk framework was established on the basis of statistics presented by Bea (1999) and Farmer (1999). These statistics include a number of pipelines built to lesser standards than those now being applied to arctic pipelines.

5.14 Advantages and Disadvantages of Double Wall Pipe Relative to Single Wall Pipe

Both robust single wall pipe and double wall pipe meet or exceed all known codified safety levels. The environmental impact of construction, repairs and loss of containment will all have a bearing on the decision as to which is the most suitable system. These were not examined as parts of this study. Table 5.5 summarises the relative advantages for each of the single and double wall pipe systems.

Table 5.5 - Relative Advantages of Single Wall v. Double Wall Systems

	Single Wall	Same	Double Wall Pipe
Design and Construction Risks	X		
Construction Schedule	X		
Composite Resistance to Bending		X	
Corrosion of Product Pipe			X
Weld Integrity		X	
Leak Detection			X
Risk of Containment Failure			X
Risk of Functional Failure	X		
Repair Complexity	X		
Inspection	X		
Initial Costs	X		
Life Cycle Costs	X		

Note: X indicates the system having the advantage.

6. BACKGROUND

Pipe in pipe systems and pipe bundles have been used in a variety of different applications. The literature related to these previous applications is reviewed in section 6.1. There are also several proposed and existing offshore pipeline projects that were considered pertinent to the study. These projects include a number of arctic pipeline projects involving both single wall pipelines, cased pipelines and pipe bundles. These projects are reviewed in section 6.2.

6.1 Literature Review

From over 200 articles, those most relevant to this review are summarised in Appendix 6.1-1. The article numbers are cited in the following review for ease of reference to these summaries. For example, article # AP0123 is referred as [123]. The other articles not summarised are included in the main report bibliography.

Pipe-in-pipe (PIP) configurations have been adopted for both onshore and offshore industrial applications. These applications include thermal insulation, leak containment and protection of flowlines. The PIP configurations may involve single or multiple inner pipes. For example, multiple flowlines and other service lines are often bundled together inside one outer pipe in a pipe bundle for ease of installation, [3, 17].

For thermal insulation, in cold ambient waters such as deepwater developments, pipes carrying hydrocarbon fluids are insulated and even heated to prevent the formation of paraffin and hydrate [101, 102]. An example is Britannia in the UK North Sea where a hot water heated bundle prevents hydrate and paraffin formation in its inner subsea flowline [33]. Flowlines carrying gas or oil, both onshore and offshore, and district heating transmission pipelines are often operated at high pressures and temperatures (HP/HT) [9]. Offshore pipe-in-pipe systems have been used for such HP/HT operations [10]. Such pipe-in-pipe systems are used from the Shell ETAP reservoirs in the UK North Sea [26]. PIP applications for thermal insulation are further reviewed in section 6.1.1.

No PIP systems were identified for leak containment in an offshore environment. PIP systems have been used for leak containment of hydrocarbons for the Colville River crossing, section 6.2. A 1.2km long PIP system was also installed in 1987 by horizontal drilling for BP between Furzey Island and Goathorn Peninsula, UK in an area of extreme environmental sensitivity. PIP systems are frequently used for leak containment in the chemical industry (section 6.1.2). The US Environmental Protection Agency (EPA) regulations require secondary containment for piping and storage of hazardous fluids. A common solution is to use a PIP system with the outer pipe for leak containment and equipped with a leak detection system.

PIP applications for flowline protection include pipe bundles (section 6.1.3), and cased crossings. Cased crossings of pipelines have been used for several decades under highways and railroads (section 6.1.4). These crossings were developed to protect the inner pipe from the external loading on the outer pipe experienced during installation and operation under the highway or railroad. The outer pipe also provides a convenient means for removal or replacement of the inner pipe. In recent years, some such cased crossing have been noted to accelerate corrosion of the pipelines.

INTEC, Inc. (1998) presented a report on the double-wall pipe alternative evaluation of Northstar Development Project. This document presents an evaluation of the relative merits of a single thick walled pipe in preference to a pipe-in-pipe system for the offshore section of the Northstar project. The comparison is restricted to significant design and construction aspects, including structural design, pipe string make-up, construction and the effect on schedule and risk, quality assurance and quality control, corrosion, leak detection, operation, maintenance and repair. Their major conclusion is that the single thick-walled pipe design, as proposed for the Northstar project, is a superior design to an equivalent pipe-in-pipe approach. The pipe-in-pipe was considered to not provide superior structural integrity for product containment.

6.1.1 Thermal Insulation

Thermal insulation is currently the most common application of single or multiple (pipe bundle) PIP systems. This application is considered in more detail in [163]. Hot water and chilled water, heat transfer fluids, hot oils, liquefied gases (cryogenic service) and molten sulfur are typical service types common to industrial and commercial construction.

In transporting liquid sulfur through a piping system, it is imperative to keep the temperature of the sulfur above its freezing point. If the sulfur freezes in the pipe, reliquefying the sulfur may be more expensive than replacing the transport piping. PIP systems are used with the annulus containing an active thermal insulation system necessary to keep the sulfur molten. Such a pipeline is the Shell Canada liquid sulfur pipeline between Caroline and Schantz, Alberta [141]. The 42km long buried line comprises an 8.75" O.D. inner pipe inside a 12.75" O.D. outer pipe. The annular space is used to circulate pressurized hot water that is required primarily to prevent excessive cooling of the liquid sulfur. The outer pipe is insulated and equipped with an electrical resistance based leak detection system. This line has operated successfully since 1992.

For cryogenic service, PIP systems are used to keep liquid gases below their boiling point through a combination of high pressure and thermal insulation.

There are many types of passive insulation materials used in the annulus of PIP systems. The key parameters (i.e., strength and thermal conductivity) of several widely used insulation materials are listed in [163], together with a description of other accessory materials, such as coatings.

PIP systems have been used extensively offshore for thermal insulation of flowlines. Langner (1999) provided an overview of such PIP flowline installations in the Gulf of Mexico. Applications worldwide are listed in Table 6.1-1. Examples of these projects include the Hero Cluster of Shell ETAP field in the UK North Sea, [7] for HP/HT oil and gas transmission. A PIP system was used for the hot natural gas stainless steel pipeline from the platform K8-FA-3 in the Netherlands North Sea, [40] to prevent the formation of hydrates. Insulated CRA (corrosion resistant alloy) pipe-in-pipe flowlines are used in Mobile Bay development, [103]. The Texaco Erskine multiphase pipe-in-pipe system carried gas and condensate, [72].

The different temperatures of the inner and outer pipe cause thermal loads on the PIP system. In pipe-in-pipe riser design the thermal expansion of the hot inner pipe is constrained by the cold outer pipe, [8]. Other failure modes of PIP systems due to thermal expansion and pressure containment are examined in [10], which also identifies the benefits of strain-based design and the use of a limit state approach in PIP design. An analytical method has been developed [11] to consider the combined effects of temperature gradient, internal pressure, soil resistance, lateral deviation of the pipe-in-pipe system, and the interaction force between the outer pipe and inner pipe in a PIP system.

There are continuing improvements in the effectiveness of the thermal insulation systems. For examples, Polyurethane Foam (PUF) is now used as part of a cost-effective insulation sandwich construction of bonded pipe-in-pipe systems [92]. The Hydrotherm insulation, developed by British Steel, comprises a granular insulation material, held around the inner pipe by the outer pipe, [105]. The system combines durable thermal insulation with mechanical performance, and provides excellent lay capacity, impact resistance and upheaval buckling resistance.

The Rocky Flowline project in the Gulf of Mexico, [25] used a reeled pipe-in-pipe system. The project is significant for deep-water oil development and the transportation of waxy crudes. Reeled PIP systems are increasingly common. Other examples of such installations include the Seahorse and Tarwhine projects in Bass Strait [19] and the Gullveig project in the Norwegian North Sea [35].

Table 6.1-1 Pipe-In-Pipe Used For Insulation Purposes

Field	Operator	Area	More Info	Length (ml)	Inner Pipe OD/WT	Outer Jacket Pipe OD/WT	Insul'n	Instal'n Method	Install. Contract.	Year	Depth ft
King	Amoco	Gulf Of Mexico		18	8	12	Water Heated			New	
Nakika	Shell	Gulf Of Mexico		3	8	12	Electric Heat	J-Lay		New	
Europa	Shell	Gulf Of Mexico		18	8	12		J-Lay		1999	
Macaroni	Shell	Gulf Of Mexico		12	6	10		J-Lay		1999	
Etap	Shell	North Sea	AP0007, AP0026	22km	10"	16"	Yes			1998	95m
Arnold	Marathon	Ewing Bank		8	6	10	PUF			1997	1750
Gfsat		Norway North Sea	AP0035	11 km	6"	10"	Yes	Reel Method		1997	135 m
Troika	Bp/Maratho n/Shell	Gulf Of Mexico	AP0029	2x14 ml	10"	24"	Yes	Bottom Tow		1996	2700 ft
Rocky	Shell	Green Canyon 110	AP0025	4.3	3.5	6	Yes	Reel Method		1995	1785
Erskine	Texaco	UK North Sea	O.O.G.I.	30	16"	24"	Yes	CDTM	Rockwater	1994	300
Caroline	Shell	Alberta, Canada		24.6	8 / .323	12 / .252	Hot Water / PUF			1994	ONSH ORE
Du Pont Facilities	Du Pont	Del.	AP0022 Onshore		3"	6"	N/A			1993	n/a
Mobile Bay	Exxon	Alabama	AP0061	4	4	8	PUF	Laybarge		1992	up to 50 ft
Tarwhine	Esso/Bhp	Bass Strait	AP0100	10.8	10		HDPU	Reel Method		1989	
Seahorse	Esso/Bhp	Bass Strait	AP0100	7	10		HDPU	Reel Method		1989	
Vega	Montedison			1.5		16	PUF	Laybarge		1987	230
Ravenna	Sone	Ravenna Italy		5	22	28	PUF	Bottom Tow		1986	82
Bouri Field	Agip	Offshore Libya		5	DUAL 12.75	26 / .406	PUF	Laybarge		1986	588
Ravenna, Italy	Sone	Adriatic Sea		5 (dual)	22	28	PUF	Laybarge		1986	82
Balmoral	Sun	North Sea		3	3 (ID)	Neopren e	PVC	Reel Method		1985	475
Cormorant	Shell	Northern North Sea		2.1 (dual)	3 (ID)	PU	PVC	Reel Method		1985	558
Rolf	Maersk	Offshore Denmark		10.56	8	PE	PUF	Laybarge		1985	126
West Delta	Mesa	Gom		2.0 (dual)	3 (ID)	PE	PUF	Bottom Tow		1984	120
Revenna	Sone	Italy		16.2	26 26	PE PE	PUF	Bottom Tow		1983	
Cormorant	Shell	Northern North Sea		4.3 (dual)	8.265/ .25	14 / .31	PUF	Mid-Depth Tow		1982	492
Lucina	Shell	Offshore Gabon		1.24 (dual) 2.0	10 10	PE	PUF	Laybarge		1982	115

Skjold	Danbor	Denmark		6.83	6	PE	PUF			1982	110
Udang "B"	Conoco	South China Sea		2.9 (dual)	12.74/.5	18	PUF	Laybarge		1980	300
Ancona	Api	Adriatic Sea		2.2	24	12	PUF & Heat Method	Bottom Tow		1980	46
Magellan Strait	Enap	Offshore Chilie		56	8	PE	PUF	Laybarge		1979	60
Udang "A"	Conoco	South China Sea		1.1 (dual)	8.625/ .375	12.75	PUF	Laybarge		1978	300
Arabian Gulf	Amerada Hess	Arabian Gulf			4 6 8	22 22	PUF	Laybarge		1978	50
Tokyo Bay	Tokyo Gas	Tokyo Bay		15		24				1977	
Jatibarang	Pertanina	Offshore Indonesia		8	36"	40"	Glass Fiber	Laybarge	Korishio	1973	
Java Sea	Iiapco	Java Sea		5.2 22.6	18 18	14	Puf	Laybarge		1973	150
Oyster	Marathon	Ewing Bank		3	3.5	6	PUF				1220
Tahoe II	Shell	Viosca Knoll		12	4.5	8	Yes	Reel Method			
Dulang	Petronas	Malaysia			6 10	10 14					
Iosca Knol	Oryx	Gom		4	4.5	6	Yes				1720
K8-FA-3 Platform	Netherlands Oil	North Sea	AP0040	9 km	12.75"	18"	PUF				

Note: Table developed from Intec (1999)

Note: OOGI may be found on the World Wide Web at http://www.offshore-technology.com/projects/index.html

6.1.2 Chemical Industry Application

Chemical process facilities handle a variety of chemical substances and compounds at various temperatures and pressures. The piping system for transporting the fluids must be compatible with the intended service conditions. The selection of piping materials of construction depends on the specific application. Petroleum refinery piping is generally characterized as large-diameter metallic piping, operated at elevated temperature and pressure, [162]. Chemical plant piping is typically characterized by relatively small diameter pipes (2 in or smaller), with lower operating pressure and temperature, and corrosive fluids. The use of exotic alloy materials, thermoplastics, and thermoset resin materials is common for the pipe construction. Many chemical plant pipes transport flammable and toxic substances.

Pipe-in-pipe (or more commonly jacketed pipe) systems are used in petrochemical industries mainly for containment and thermal insulation. Jacketed pipelines are commonly used to carry certain fluids in process facilities. Process fluids that require temperature control (i.e., molten sulfur) are good candidates for the applications of jacketed pipes. For molten materials (i.e., polymers) where high temperature is required, jacketed pipelines can also be used. Some advantages of jacketed pipelines are stated in [162] as

1) uniformity of heat input around circumference of process pipe;

2) tighter temperature control over entire pipeline length; and

3) elimination of cold spots that may cause degradation or localized freezing of process fluids.

Pipe bundles comprising several inner pipes in a single containment casing are also used for economic advantage. The advantages and design considerations of multiple pipe containment bundles are described by [143].

In jacketed pipe systems, various heating media (liquid phase and vapor phase fluids) can be used for temperature control of process fluids. Jacketed piping systems where the annular space is evacuated are often used to convey cryogenic temperature process fluids. The vacuum minimizes heat gain from the atmosphere to the cryogenic fluids. The annulus of the system can also be used for passive thermal insulation by the addition of insulation materials.

The heat from the flowing fluids makes the outer pipes expand. Measures are available for reducing the thermal stresses in the jacketed pipes, [22]. These measures were implemented on two jacketed piping systems in Du Pont's Wilmington, Del., chemical process facilities. The lines are made from fiberglass-reinforced vinyl ester, with 3-in. diameter carrier pipes and 6-in. diameter containment pipes. They carry fluids with temperatures from 60ºF

The US Environmental Protection Agency (EPA) regulations now require secondary containment for piping and storing hazardous fluids. The Health & Safety at Work Act has also imposed exacting standards for transporting dangerous chemicals through piping to prevent spillage or leak. A common solution is to use a jacketed pipe with the inner pipe within a containment casing equipped with leak detection. Chemical Pipe & Vessel Co Ltd. has developed such a containment system. The inner pipe is normally within a size from 0.5 to 18 in (13 to 450 mm). The outer pipe is approximately two nominal sizes larger than the inner pipe.

Jacketed pipes have also been used in the chemical process industries as basic shell-and-tube heat exchangers. Different fabrication techniques for the jacketed pipes are employed to meet the different applications (e.g. thermal insulation, containment and heat exchange), [87].

Two different examples of the application of jacketed pipelines are given below for active thermal insulation and containment.

In 1986 Shell Canada discovered a large reservoir of sour gas in the Rocky maintains area near Caroline, Alberta. A buried pipeline was chosen to carry 5,100 tons of liquid sulfur extracted from the sour gas per day from the Caroline Field to a railhead 41 km away, [141]. Sulfur is difficult to handle by pipeline as it remains solid up to 118.9ºC. The pipeline is built from two coaxial pipes. The inner pipe with a diameter of 219 mm carries liquid sulfur while the annular space carries circulating hot water under pressure. The outer pipe with a diameter of 323.9 mm has 80 mm of high density urethane foam insulation.

A fiberglass reinforced plastic (FRP) pipeline system is used for transporting contaminated groundwater extracted from 43 wells at the site of a former chemical manufacturing plants in Toms River, New Jersey through seven miles of pipeline to a treatment plant, [46]. The acidic groundwater (pH 4 to 5) would be corrosive to carbon steel. The FRP pipe has a moderate capital cost and is corrosion resistant. Offsite, the 14-inch inner pipe is jacketed and buried. Leak detection devices are installed below ground in manways alongside the buried pipe route. The pipe system was finished in 1996.

In summary, pipe-in-pipe systems are applied in petrochemical industries mainly for containment and thermal insulation. The containment is required by some regulations for safe transportation of hazard liquid and for prevention of leakage. Conveying molten sulfur is a good example for the application of jacketed pipes where hot water is circulated through the annular space between the carrier pipe and the jacket.

6.1.3 Pipe Bundles

Pipeline bundles are used widely in offshore applications, mainly for thermal insulation, flowline protection or for convenience of pipeline installation. Table 6.1-2 lists a number of such pipe bundle projects worldwide. The Canadian Panarctic Drake F-36 Subsea Flowline, described in section 6.2, is an example of such a pipe bundle. Some offshore considerations for pipeline bundles follow.

Pipeline bundle installation by bottom tow is gaining acceptance for deepwater developments, where insulation is needed to prevent paraffin and hydrate formation. Approaches have been developed to mitigate the problems associated with deepwater bundles, such as potential leakage into the outer casing and the pressurization of the casing include bulkheads and foam filling [101]. Other potentially viable systems, design techniques, emerging technologies, feasible materials, and technical limitations for deepwater development are discussed by [102].

The bottom tow method was used to install a 6.5 km long submarine bundle in the Gulf of Thailand [3], and the submarine pipeline bundle connecting Yongjong airport site to Inchon, Korea [17]. The bottom tow was also used for the installation of the Troika flowline bundle [29]. The Troika project is considered in more detail in section 6.2. Considerations have also been given to the installation of bundled offshore pipelines using the reel method, [6] which imposes certain limitations on the number and size of the flowlines.

The Controlled Depth Tow Method (CDTM) of installation requires that the bundle is thermally insulated after the bundle has been installed on the sea floor. A new thermal insulation for CDTM bundles comprises a gelling but non-setting slurry of hollow, high-strength silica spheres and seawater which is pumped into the annulus [98]. Analytical methods are available for evaluating the thermal behaviour of flowline bundles, and to define their response in terms of fluid temperature drops, end movements, and stresses in the flowlines and bulkheads [90]. Analyses have also been developed for modelling the temperature induced buckling behaviour within the pipe bundles transporting high pressure and high temperature products [41].

Two failures of pipe bundles under construction were observed in the Hamilton Argyll field about 1982, when the bundles sank while under tow, Palmer (2000).

Corrosion control is a key consideration for some projects, see for example [33] and [61]. Britannia is a large sour gas condensate field in the North Sea with a 25 year field life. A hot water heated bundle with corrosion protection was used to prevent hydrate and paraffin formation in the 15 km long subsea flowline [4]. For 200 miles of offshore pipelines in Mobile Bay, the corrosive, high temperature, high pressure gas required special consideration of thermal insulation, corrosion protection and pressure resistance of the pipeline bundles [61]. This project also involved the construction of four directionally drilled pipe bundle crossings. Similar directionally drilled crossings were used to cross the Colville River are described in section 6.2.

Table 6.1-2 - Towed Bundle Configurations

FIELD	Operator	Area	More Info	Length ml	Inner Pipe Config	Outer Jacket Pipe OD	Insulated	Tow Method	Contractor	Year
Albacora Leste	Exxon	Brazil		3.11	2x8 + 1x6 WI + 1x6 GL	34"	Yes Syntactic Foam			
Girasol	Elf	W Africa Blk 17	OOGI	2.49	2x6 + 2x2, 4 SL	32	Yes Syntactic Foam		AMG	
Buckland	Mobil	UK North Sea		3.12, 3.73	8, 12 WL 4 GL 8, 6 WL 4 GL	40.5 28.5	Yes	CDTM	Rockwater	1999
Elgin/ Franklin	Elf	UK North Sea	O.O.G.I.	3.23	2 X 12 HTHP	40		CDTM	Smith Land & Marine	1999
Aagard As02	Statoil	Norway North Sea	O.O.G.I.	4.23	1x10 1x28 G 1x10 1x28 G	43.5	Yes	CDTM	Rockwater	1999
Bruce Ph2	BP	UK North Sea	O.O.G.I.	3.73	1x18 1x8 1x10 GI + umb	44	Yes	CDTM	Rockwater	1998
Gullfaks (2 Bundles)	Statoil	Norway North Sea	O.O.G.I.	4.04 2.17	2x6, 1x8, 1x3, 2x2 Inside 1x6, Umbilical 2x6, 2x2 1x3 Inside 8 1x2 Umbilical	40/28.5 34/30	Yes	CDTM	Rockwater	1998
Troika 4 Lines	BP	GOM		7	1x10, 1x28 G	24	Yes	BOTTOM TOW	KRJBA	1997
Aagard As03	Statoil	Norway North Sea		2.36	3x10, 3x2 Inside 28 sleeve pipe	44.5	Yes	CDTM	Rockwater	1997
Gannet - E,F	Shell Expro	UK North Sea		4.42 4.33 2.55	2X8, 1X3.5G 2X8, 1X3.5G 1X8, 1X3.5G	32 32 24	Yes	CDTM	Rockwater	1997
Britannia	Conoco	UK North Sea	O.O.G.I. AP0004	4.66 4.66	1X14, 1X12, 1X6, 3 MeOh		Yes + Hot Water Circ.	CDTM	Smith Land & Marine	1997
Esso	Bream	Bass Strait		3.11	8 oil IN 14 CARRRIER	14	No	Bottom Tow	Rockwater	1996
Esso	Tuna	Bass Strait		2.17	8 OIL w 4 Gas piggyback	None	No	Bottom Tow	Rockwater	1996
Thelma	Agip UK	UK North Sea		3.17 4.01		33.5 33.5	YES Hydrotharm	CDTM	Rockwater	1996
Garden Banks 967	Enserch	GOM		3	6x4 + umbilical	28	Yes	BOTTOM TOW	KRJBA	1996
Garden Banks 72	Flextrend	GOM		4	4x3.5	18	Yes	BOTTOM TOW	KRJBA	1996
Cyrus	BP	UK North Sea		4.05	1x10 clad 9x5hyd + umb 2x4.5, 2	28	Yes	CDTM	Rockwater	1995
Heidrun	Conoco Norway	Norway North Sea		1.23 1.87 1.87	1x16 gas exp, 1x16 oil exp, 1x16 oil exp	27 26 26	No	CDTM	Rockwater	1994
Cercina	Tunisian British Services	Offshore Sfax, Tunsia				4		CDTM		1994
Embia	Phillips	Norway North Sea		3.16	1X14	24	No	CDTM	Rockwater	1992

Miss Canyon 441	Enserch	GOM		2.90 5.90	6x3.5 + umb 6x3.5 + umb	22 22	Yes	BOTTOM TOW	RJBA	1992
Piper/ Sallire	Elf	UK North Sea		4.16 1.33	4x8, 10, 16 3x6 + umb	40 26.5	No	CDTM	Rockwater	1992
Gannet C	Shell Expro	UK North Sea		2.24 5.10 1.62 1.37	15x2, 4, 6 15x2, 4, 6 8x2, 4 8x2, 4	37 37 29 29	Yes	CDTM	Costain/ Heerema	1991
Osprey	Shell Expro	UK North Sea		2.01 2.01	3x6, 10 + umb 3x6, 10 + umb	36 36	Yes	CDTM	Rockwater	1990
Green Canyon 29	Placid	GOM		1.00 7.30 7.60	3x3.5 +umb, 3x3.5 +umb	16 16 16	No	BOTTOM TOW	RJBA	1988
East Frigg	Elf	Norway North Sea		1.00 1.00	2x4, 10 +umb	24 24	No	CDTM	Rockwater	1988
Scapa	Occidental	UK North Sea		2.73 2.73	5x3, 6, 10 5x3, 6, 10	28 28	Yes	CDTM	Rockwater	1986
Central Cormorant	Shell Expro	UK North Sea		5.49 5.49	1x8	26 26	Yes	CDTM	Rockwater	1984
Central Cormorant	Shell Expro	UK North Sea		2.08 2.08 2.06 2.06	1x8 1x8 2x4 2x4	26 26 24 24	Yes	CDTM	Rockwater	1982
Claymore	Occidental	UK North Sea		1.28 1.99	1x8 +umb 3x6, 10	14 26	Yes	CDTM	Rockwater	1981
Murchison	Conoco UK	UK North Sea		1.25 .077 0.50	2x3 +umb 2x3 +umb 2x3 +umb	18 18 18	Yes	CDTM	Rockwater	1980
Drake F76	Panarctic	Canadian Arctic		0.76	2x6 +umb	18/24	Yes	Bottom pull	RJBA	1977
Petchburi	PTC	Gulf Of Thailand	AP0003	6.5km	3x16" bundle	?	No	Bottom pull	HHI, Korea	1996
Troll Field		Norway North Sea	AP0015		up to 12 lines, J-tube section	620 mm OD	Yes	Mid-depth tow		
Yongjong Airport		Korea	AP0017	2.4 km	1x52"+1x30"+1x20"	n/a	No	Bottom pull		1998

Note: OOGI may be found on the World Wide Web at http://www.offshore-technology.com/projects/index.html

Note: Table developed from Intec (1999)

6.1.4 Cased Pipelines Crossings of Highways and Railroads

In the early 1940's during World War II, thousands of miles of pipelines were built in the U.S. to provide natural gas to munitions plants [28]. Due to restrictions imposed by the railroad companies, these pipelines crossed under railroads through casings. Casings also provided the ability to remove or replace pipes under railroads and roadways without taking them out of service. Highway agencies adopted the same requirement that pipelines crossings highways must be cased. Cased pipeline crossings under roads and railroads has been common practice in the pipeline industry [79].

Initially the cased crossings were made with the inner pipe in direct contact with the casing (or outer pipe). Later for corrosion protection, coatings were used and insulating spacers were used to prevent electrical contact between the casing and the inner pipe. The current practice for cased pipe has not changed significantly. The casing supports the external loads. End seals of the casing are used to prevent mud and water from entering the annular space. Vent pipes to atmosphere are usually installed on one or both ends of the casing. Consideration is often given to placing dielectric filler in the annular space to mitigate corrosion.

The National Association of Corrosion Engineers (NACE) prepared a State of the Art Report on Steel Cased Pipeline Practices in 1992, [78]. The report includes the details of design factors and considerations, installation and construction, maintenance and repair, criterion and monitoring, and typical casing filling procedures. The report concluded that cased crossings should only be installed when necessary; and that consideration be given to using a thicker pipeline with no casing rather than a cased pipeline.

Tenneco is a pipeline operator with existing pipeline crossings under water-bodies, roads, and railroads. They prepared a risk management study, [28] that considered

1) the rationale of why and how the cased crossing method was used for many major crossing in the 1980's;
2) concerns about shorted casings that arose with the passage of the National Gas Pipeline Safety Act in 1968;
3) the response and process adopted by Tenneco to mitigate shorted casings and uncased crossings;
4) the rehabilitation of pipelines, including internal inspection;
5) Tenneco's preferred design method for future crossings, and
6) monitoring of water-bodies crossings.

The risk management study concluded that casings are no longer preferred.

Research on cased and uncased pipeline crossings of railroads is summarised by [79] in four major areas:

1) a review of the design and construction recommendations of various professional and regulatory institutions, and the performance records of pipeline crossings beneath railroads;
2) construction techniques for installing the pipelines, and the soil and traffic loads acting on the pipelines;
3) general methods for corrosion protection; and
4) a summary of current analytical practices for modelling stresses and deformations of buried pipelines.

API has prepared Standard 1102 - Steel Pipelines Crossing Railroads and Highways for the recommended practice of cased and uncased steel pipelines crossing railroads and highways, [44]. This standard covers the type of crossing, crossing cover, design aspects, loads, stresses, installation and construction, inspection and testing, cathodic protection and adjustment of in-service pipelines. The casing seals, casing vents and insulators are also described. The stresses imposed on uncased pipelines and the potential difficulties associated with protecting cased pipelines from corrosion are considered the prime factors in selecting either a cased or uncased crossing. For cased crossings, the minimum diameter, wall thickness and cover depth of casing are recommended.

The American Railway Engineering Association (AREA) also has Standards for Pipeline Crossings. These include design requirements for uncased crossings, which recommend a minimum of 10 feet of cover from the base of rail to top of pipe. The standards were developed according to GRI's sponsored research at Cornell University.

By 1989, the DOT Office of Pipeline Safety (OPS), NACE and the pipeline industry had concluded that cased crossings increase the possibility for corrosion. This conclusion was independent of whether the casing was isolated from, or shorted to, the inner pipe. In the past five decades of operation, Tenneco has had three leaks in pipes inside of a casing. Since 1970's, Tenneco has recommended that all crossings be installed without casings, based on the following:

1) New techniques and the application of cathodic protection eliminate the historic purpose of casings.
2) Casings can shield the carrier pipe from receiving adequate cathodic protection and create environments conductive to atmospheric corrosion.
3) Safe pipeline crossings can be designed and installed with less cost.

6.1.4.1 Corrosion protection

Coatings and cathodic protection (CP) are used for the corrosion control of pipeline crossings. The GRI research at Cornell University showed that the presence of a casing can reduce the effectiveness of cathodic protection to guard against subsurface corrosion, [79]. Moreover, casings may also expose the inner pipe to atmospheric corrosion and make corrosion inspection more difficult.

The most significant problem with casing is the shorted casing: a casing which is in direct metal contact with the carrier pipe. A common definition of a shorted casing is that the pipe-to-soil to casing-to-soil potential is 100 mV or less, [78]. In some cases the inner pipe settles and comes in contact with the bottom of the casing pipes. This contact causes the cathodically protected inner pipe to be electrically shorted to the casing. Approximately 6 % of Tenneco's 6,700 cased crossings have been found shorted in the 5 years to 1996.

For shorted casings, the CP current travels through the casing resulting in less cathodic protection for the inner pipe. If the carrier pipe has damaged coating or poor coating, a greater opportunity for corrosion exists since the CP current is not protecting the inner pipe. When the casing is bare, large amounts of CP current are wasted on the casing pipe. Most pipes inside of casings are not, and can not be, cathodically protected. An effective measure against corrosion is a good coating that is well bonded to the carrier pipe.

Many highway and railroad crossings with casings have been used for over 50 years without any major problem, [63]. Smart pigging and continual visual inspection has permitted some case studies. Gibson concluded that whether shorted or isolated, casings have no significant bearing on the presence or absence of corrosion on the inner pipe.

There is an alternative method for the corrosion protection of cased pipeline crossings, [75]. Normally, the casing annulus is open to the atmosphere. This permits moist oxygenated air to collect around the inner pipe providing an environment for corrosion. The alternative is to seal the annulus from the atmosphere to prevent oxygen and moisture from entering the casing. Test results of Conoco Pipe Line Company demonstrated that while capping vents was beneficial, an even more effective way to reduce the oxygen levels was required. One way to do this is to use inert gas (Argon) as a casing filler in conjunction with capped vents. With its proven effectiveness, low cost, compliance with the Department of Transportation (DOT) regulations, and acceptance by NACE and the pipeline industry, the inert gas procedure has proven a good choice of the methods available for the corrosion protection of cased pipeline crossings.

6.1.4.2 Structural integrity

For a cased pipe crossing roads or railroads, the external soil and vehicular loads are applied only to the casing pipe; the inner pipe is stressed primarily by internal pressure. The inner pipe is properly supported within and outside the casing to prevent contact with the casing.

The U.S. and Canadian pipeline regulations and design codes were reviewed to determine the guidelines for allowable stress caused by pipe movement in cased pipes, [30]. An analytical procedure was developed for structural analysis of cased pipeline crossings to determine tolerable stress levels for maintenance of a settling casing. The controlling parameter in the design of casings is the ovalisation of the casing due to imposed soil and vehicular loads. This change in pipe diameter on buried casing can be calculated using the Iowa formula and should not exceed 3%, [79].

In summary, cased pipes have been used widely for crossing roads and railroads, especially in the infancy of the pipeline industry. The industry has concluded that cased crossings increase the possibility for corrosion. Single thicker walled pipes are now generally preferred to cased pipes for such crossings.

6.1.5 US DOT Position on Use of Double Walled Pipelines

A literature search on the US DOT position on the use of double walled pipelines, including a search of the United States Department of Transportation (DOT), Research and Special Programs Administration, Office of Pipeline Safety, Code of Federal Regulations, Parts 190-199, has been carried out. Whether or not double walled pipelines should be used is not concluded in the DOT publications reviewed.

6.1.6 Offshore Pipe-In-Pipe And Bundle Statistics

Pipe-in-pipe and bundle systems have been used in offshore oil and gas industry for decades. Some statistics are presented from the 70 offshore projects presented in Tables 6.1-1 and 6.1-2.

The number of pipe-in-pipe and bundle pipelines has increased significantly in the past three decades from 7 in the 1970s, to 25 in the 1980s, to 32 in 1990s, Figure 6.1-1. Approximately 87% of all pipelines were insulated. The installed length of these pipelines was 110 miles in the 1970s, 157 miles in the 1980s, and 229 miles in 1990s, increasing about 45% each decade, Figure 6.1-2.

These projects are geographically distributed as follows: North Sea: 178 miles (39.3%); North America: 84 miles (18.6%), including 83 miles in Gulf of Mexico area; Asia and Pacific Rim: 64 miles (14.1%); South America: 59 miles (13.0%); Australia: 23 miles (5.1%); Mediterranean and Adriatic: 12 miles (2.6%); and Africa and Middle East: 12 miles (2.6%), Figure 6.1-3. Approximately 60% of the pipe-in-pipe and bundle pipelines installed are in North Sea and Gulf of Mexico.

To put these lengths in context, the total length of pipelines installed in North Sea is 11,000 miles, of which the length of pipe-in-pipe and bundle pipelines is only 178 miles (1.6%). In Gulf of Mexico, the total length of pipelines installed is 23,000 miles, of which the length of pipe-in-pipe and bundle pipelines is only 83 miles (0.4%).

The offshore pipe-in-pipe and bundle pipelines are in water depths of: 0-200 m: 13 (32%); 200-400 m: 8 (20%); 400-600 m: 7 (18%); 600-800 m: 1 (3%); and 800 m or deeper: 11 (27%), Figure 6.1-4. More than 50% of the pipelines are installed in a water depth of less than 400 m. These pipelines are mainly installed using towed, lay barge or reel methods. About 65% of the pipelines were installed using towed method, 24% using lay barge method and 11% using reel method, Figure 6.1-5. Towing is the most widely used method for the installation of offshore pipe-in-pipe and bundle pipelines.

The inner pipe diameter is generally less than 5". About 53% of the inner pipe diameters are in the range between 2 to 5 inches, 36% between 5 to 12 inches, and only 11% have sizes greater than 12 inches, Figure 6.1-6. The outer pipe diameter ranges from 4 inches to 44 inches. About 39% of the pipes are in the range of 22 to 30 inches, 38% are smaller than 20 inches, and 23% are greater than 30 inches, Figure 6.1-7.

The Erskine double walled pipe system failed during the writing of this report, releasing its product to the environment. The cause of this failure is not yet known. This is the first known failure of an offshore double walled pipe system. The 33 offshore double walled pipe systems listed in Table 6.1-1 have been installed for more than 440 years. This implies that offshore double walled pipe systems have a failure rate of about $2x10^{-3}$/yr.

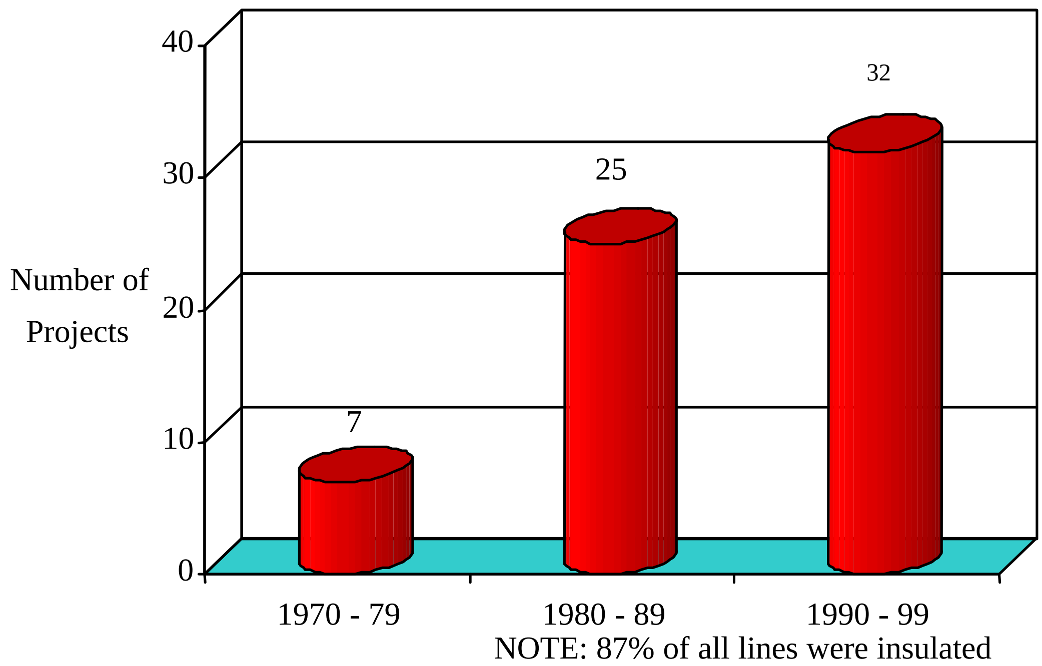


Figure 6.1-1 Chronological Development of Pipe-in-Pipe and Pipe Bundle Projects

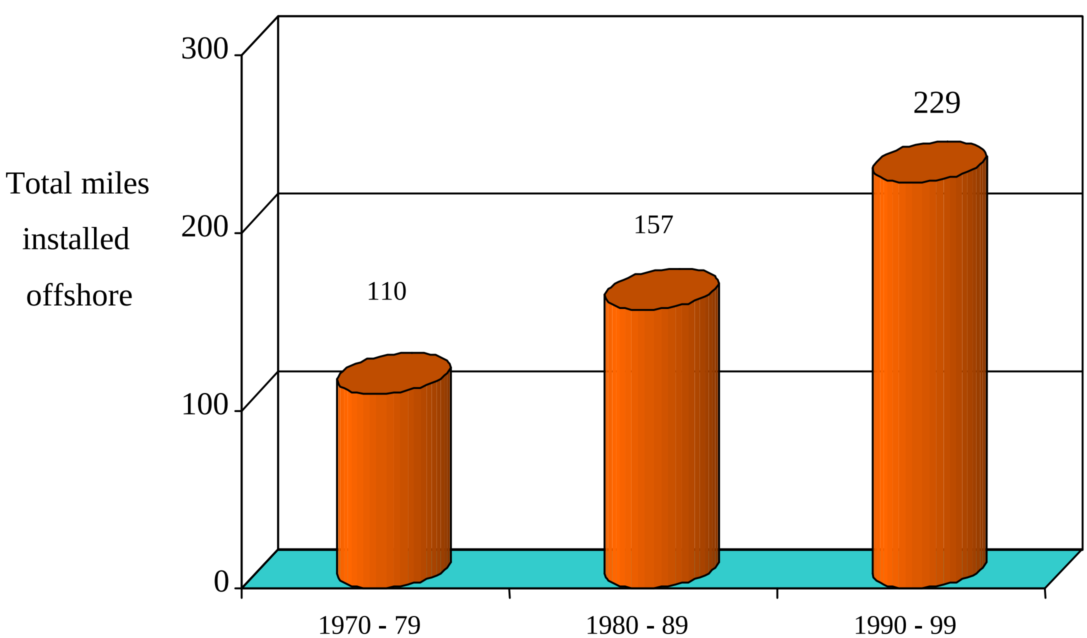


Figure 6.1-2 Chronological Development of Installed Lengths of Pipe-in-Pipe and Pipe Bundles

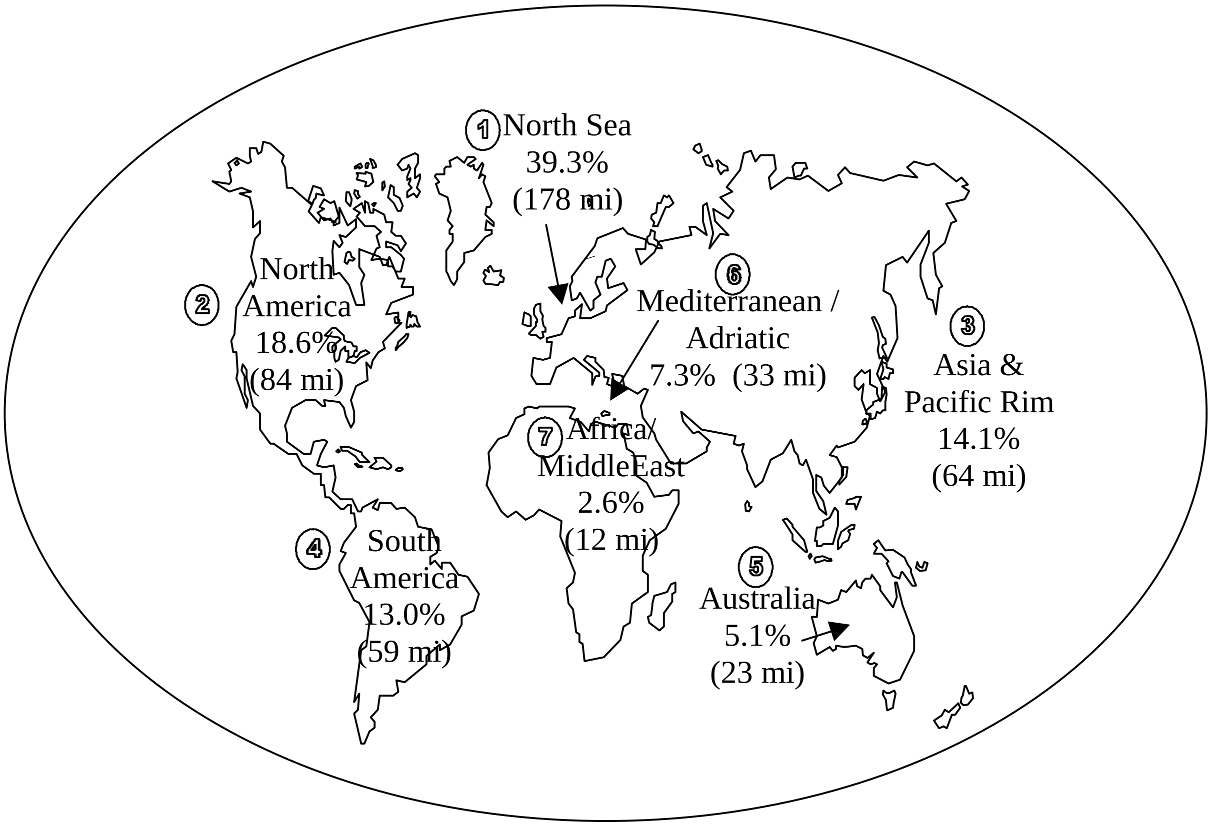


Figure 6.1-3 Geographical Distribution of Pipe-in-Pipe and Pipe Bundles

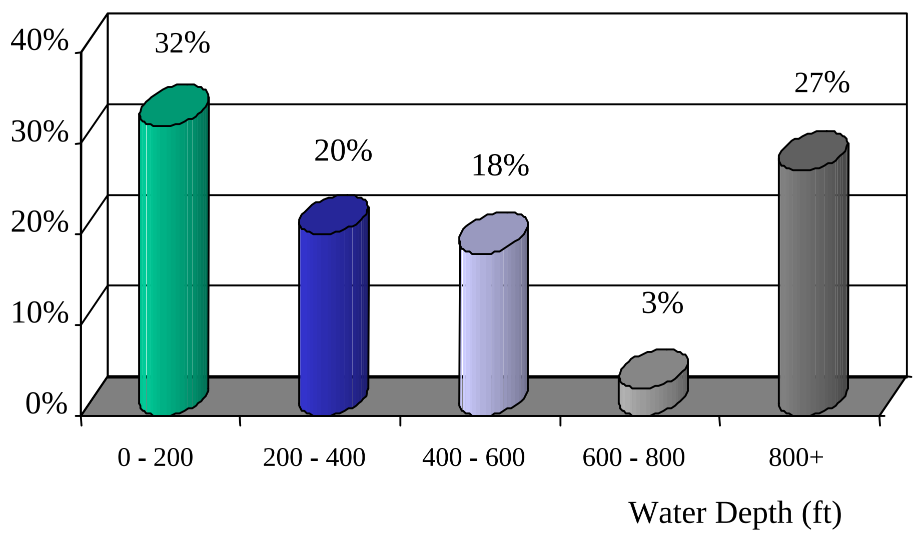


Figure 6.1-4 Water Depths of Pipe-in-Pipe and Pipe Bundle Projects

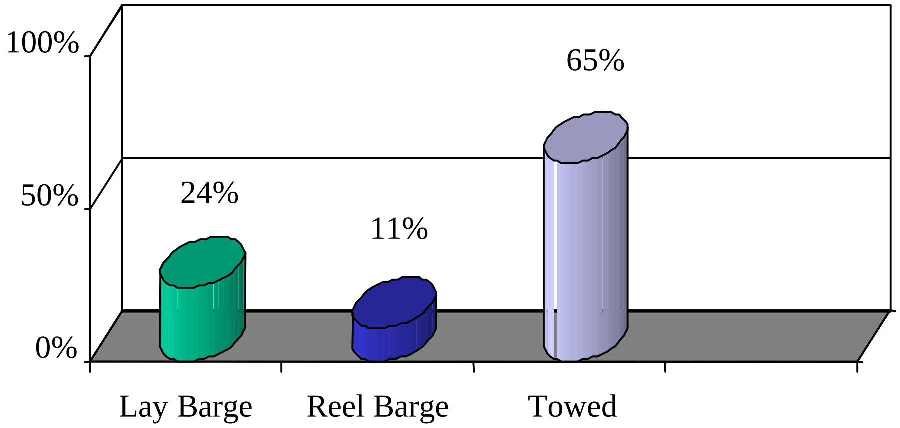


Figure 6.1-5 Installation Methods of Pipe-in-Pipe and Pipe Bundle Projects

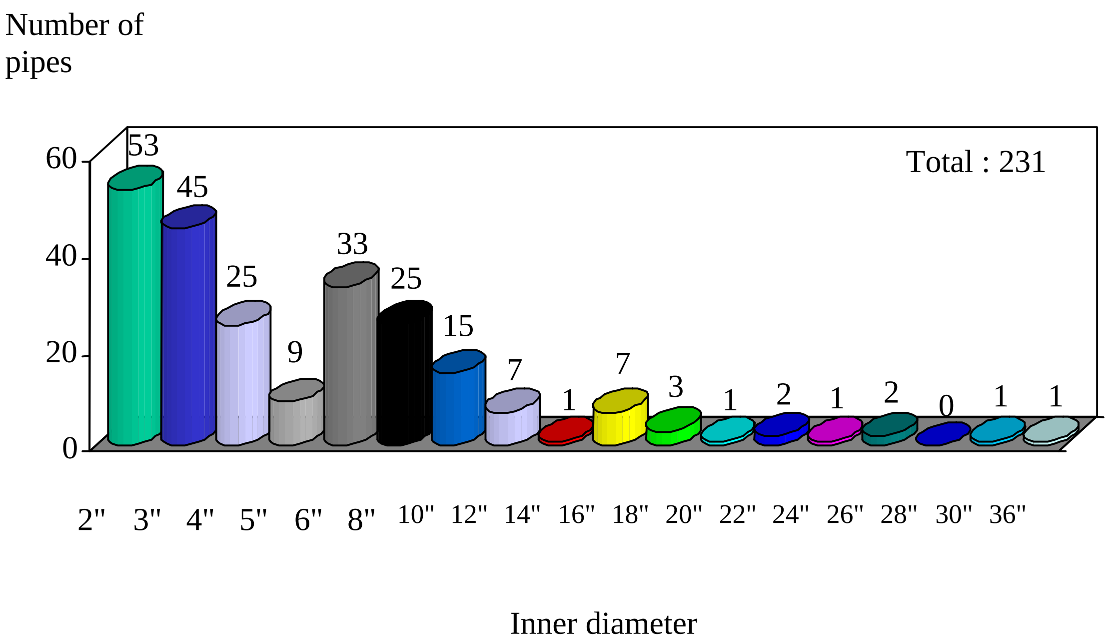


Figure 6.1-6 Inner Pipe Diameters of Pipe-in-Pipe and Pipe Bundle Projects

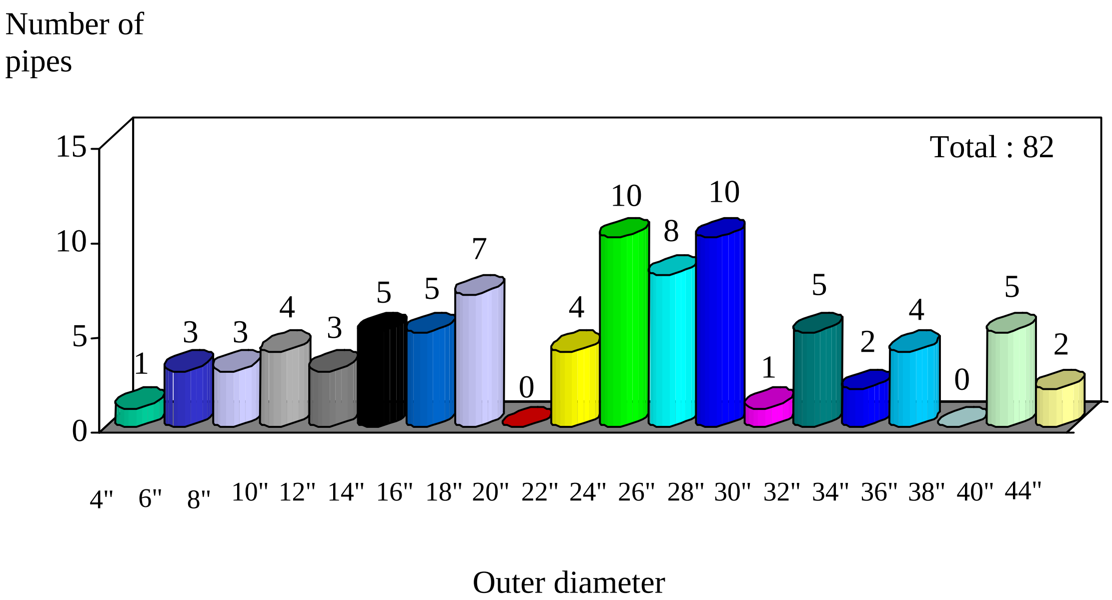


Figure 6.1-7 Outer Pipe Diameters of Pipe-in-Pipe and Pipe Bundle Projects

6.2 Designed Performance vs. Actual Performance

The following sections provide summary descriptions of the design, design rationale and operational performance of proposed, existing or historical single wall and pipe-in-pipe oil and gas pipelines.

6.2.1 Subsea Pipeline Design Review and Rationale

Based on a review of available historical information, this section presents design related data and design rationale for five proposed, existing or historical single wall or pipe-in-pipe subsea oil and gas pipelines, as follows:

- pipeline design basis summaries, i.e., information used to develop the pipeline design, including:
  - applicable design codes and standards
  - process design criteria and requirements
  - structural design criteria and requirements
  - corrosion design criteria and requirements
  - environment design criteria

- pipeline design characteristics summaries, i.e., information describing specific features final design, including:
  - inner pipe
  - outer pipe, for pipe-in-pipe designs only
  - corrosion mitigation and monitoring
  - pipeline stability
  - quality assurance and control
  - Installation

- qualitative rationale for pipeline design characteristics, i.e., explanations and reasons for key design elements, including:
  - configuration
  - pipe
  - corrosion
  - stability

Design basis and design characteristic summary tables for each of the above pipelines are included in the text of this section.

Design basis, characteristics and rationale are presented only for the "offshore" segment of the subject pipelines. Specialized design requirements associated with the shore approach / shore crossing, or the island / structure approach, e.g. shoreline erosion, dropped item protection, etc., are not considered in this review.

Also, specific conclusions or recommendations relative to "best practice" are not part of this scope of this review.

Though published information for eighteen relevant subsea pipelines were reviewed, only five were found to have published engineering information sufficient in kind and quality to be included in this review. The five selected pipelines, and their status as of the writing of this report, are as follows:

- ARCO Alpine Colville River Crossing; status - existing
- Panarctic Drake F-76 Subsea Flowline; status - historical
- BP Exploration Troika Towed Bundle Flowline; status - existing
- BP Exploration Alaska Liberty Island Oil Pipeline; status - proposed
- BP Exploration Northstar Subsea Pipeline; status - proposed

Each of the above pipelines is reviewed in the following sections 6.2.1.1 through 6.2.1.5.

6.2.1.1 ARCO Alpine Colville River Crossing

The design basis of the Alpine Colville River Crossing is given in Table 6.2.1.1-1. The major design characteristics of this crossing are given in Table 6.2.1.1-2.

Table 6.2.1.1 - 1: Design Basis Summary for the Alpine Colville River Crossing

Parameter	Unit	Inner Pipe	Outer pipe
General:			
geographic location	-	Colville River, Alaska	-
design life	years	25	-
Applicable Design Codes:			
pipeline	-	ASME B31.4	-
cathodic protection	-	NACE RP0169-96	-
leak detection	-	-	-
Design:			
Method	-	-	-
Stress / Strain Criteria:			
stress	psi	-	-
strain, compressive	%	85% of critical compressive buckling strain of outer pipe	100% of critical compressive buckling strain of outer pipe
strain, tensile	%	85% of critical tensile fracture strain of outer pipe	100% of critical tensile fracture strain of outer pipe
Pipeline Fluid Properties:			
flowrate	bopd	190,000	-
specific gravity	-	-	-
wax formation temperature	F	89	-
Pipeline Pressures:			
normal operating	psi	-	-
maximum operating	psi	2064	-
Pipeline Temperatures:			
maximum operating	F	165	-
Environmental Conditions:			
Water:			
depth	ft	-	-
current speed	ft / s	7.5	-
Temperature:			
minimum	F	-	-
maximum	F	-	-
installation	F	-	-
Soil:			
Characterization:			
silt / silty sand / sand	% length	78%	-
gravel / cobbles / rock	% length	22%	-
permafrost	% length	near entry / exit only	-
Temperature:			
minimum	F	17.4	-
maximum	F	63.4	-
installation	F	-	-
Air:			
Temperature:			
minimum	F	-17.5	-
maximum	F	47.7	-

Table 6.2.1.1 - 2
Key Design Characteristics Summary for the Alpine Colville River Crossing

Parameter	Unit	Inner Pipe	Outer pipe
Pipeline:			
configuration	-	pipe-in-pipe	-
length	ft	4,300	-
Pipe:			
Specification	-	API 5L	API 5L
SMYS	psi	65,000	65,000
Type	-	ERW	ERW
Dimensions:			
outside diameter	inch	14.000	20.000
wall thickness	inch	0.438	0.500
External Coating:			
type	-	FBE + AR	FBE + AR
thickness	inch	-	-
Insulation:			
type	-	-	polyurethane
thickness	inch	-	4.0
Spacer:			
type	-	polypropylene	-
spacing	ft	10	-
Bulkhead:			
type	-	-	-
spacing	ft	-	-
Cathodic Protection:			
type	-	-	impressed current
spacing	ft	-	-
Leak Detection:			
type	-	-	-
accuracy	%	-	-
Installation:			
method	-	HDD	-
depth of cover	ft	23.0	-
Testing:			
Requirements:			
pipe	-	CTOD	CTOD
weld	-	API 1104	API 1104
NDT	-	-	-
hydrotest	psi	2580, i.e., 1.25 x MOP	-
Acceptance Criteria:			
Pipe flaw	-	-	-
Weld flaw	-	API 1104, modified	API 1104, modified
hydrotest	hours	-	-
Operations and Maintenance:			
Monitoring Procedures:			
corrosion	-	-	-
deformation	-	-	-
leak	-	-	-
Mitigation Procedures:			
corrosion, internal	-	-	-
corrosion, external	-	-	impressed current
Repair Method	-	-	-

Based on the available information, qualitatively the design rationale for the Alpine Colville River Crossing is as follows:

- the primary reasons for using the pipe-in-pipe configuration for this pipeline are:
  - compatible with the horizontal directional drilling (HDD) installation method that was selected to achieve the following:
    - i. minimum disturbance of the environment during construction.
    - ii. installation of multiple parallel pipelines.
    - iii. reduced construction schedule and lowest overall installed cost, including the cost of abandonment, relative to other possible installation methods.
  - secondary containment of oil in the event of a loss of containment of the inner pipe.
  - facilitates leak detection in the event of a loss of containment of the inner pipe.
  - significantly increased the pipelines overall resistance to bending, i.e, the composite resistance to bending of the pipe-in-pipe configuration is greater than for a single wall pipeline.
- the primary reason for using spacers for this pipe-in-pipe configuration is:
  - the inner pipe is isolated from the outer pipe bending stresses, i.e., the outer pipe may bend without the inner pipe doing so. The result being that the strain on the inner pipe is less than the strain on the outer pipe by a ratio of the pipe diameters.
- the primary reason for pipe diameter criteria used for this design is:
  - to achieve a conservative composite pipeline bending resistance the outer diameter was selected to be the inner pipe diameter plus six inches.

6.2.1.2 Panarctic Drake F-76 Subsea Flowline

The design basis of the Panarctic Drake F-76 Subsea Flowline, which is described by Palmer et al (1979), is given in Table 6.2.1.2-1. The major design characteristics of Panarctic Drake F-76 Subsea Flowline are given in Table 6.2.1.2-2.

Table 6.2.1.2 - 1
Design Basis Summary for the Panarctic F-76 Subsea Flowline

Parameter	Unit	Inner Pipe	Outer pipe
General:			
geographic location	-	Sabine Peninsula, Melville Island, Canadian Arctic	-
design life	years	-	-
Applicable Design Codes:			
pipeline	-	CSA Z-184 “Gas Pipeline Systems”	CSA Z-184 “Gas Pipeline Systems”
cathodic protection	-	-	-
leak detection	-	-	-
Design:			
Method	-	-	-
Stress / Strain Criteria:			
Stress	psi	-	-
Maximum combined effective stress	%	considerably less then 90%	90%
Pipeline Fluid Properties:			
Flowrate	MMSCFD	60	-
specific gravity	-	-	-
wax formation temperature	F	-	-
Pipeline Pressures:			
normal operating	psig	-	-
maximum operating	psig	1750	-
Pipeline Temperatures:			
maximum operating	F	-	-
Environmental Conditions:			
Water:			
current speed	ft / s	-	-
Depth:			
minimum	ft	-	-
maximum	ft	181.4	-
Temperature:			
minimum	F	-2	-
maximum	F	-	-
installation	F	-	-
Soil:			
Characterization:			
silt / silty sand / sand	% length	97.5	-
gravel / cobbles / rock	% length	-	-
permafrost	% length	2.5	-
Temperature:			
minimum	F	-	-
maximum	F	-	-
installation	F	-	-
Air:			
Temperature:			
minimum	F	-	-
maximum	F	-	-

Table 6.2.1.2 - 2
Key Design Characteristics Summary for the Panarctic F-76 Subsea Flowline

Parameter	Unit	Inner Pipe	Outer pipe
Pipeline:			
configuration	-	pipe-in-pipe	-
length	ft	3937	-
Pipe:			
Specification	-	API 5XL, Charpy Impact Tested to – 50 C	API 5XL
SMYS	psi	42000	42000
Type	-	-	ERW, longitudinal seam
Dimensions:			
outside diameter	inch	6	18
wall thickness	inch	f1 = 0.432, f2 = 0.375	0.375
External Coating:			
type	-	f1 = zinc rich epoxy + vinyl/urethane top coat f2 = zinc rich epoxy + insulation + PE jacket	PE
thickness	inch	-	0.06
Insulation:			
Type	-	f2 = PE	PE
Thickness	inch	1	1
Spacer:			
Type	-	-	-
Spacing	ft	-	-
Bulkhead:			
Type	-	-	-
Spacing	ft	-	-
Cathodic Protection:			
Type	-	-	-
Spacing	ft	-	-
Leak Detection:			
Type	-	-	-
Accuracy	%	-	-
Installation:			
Method	-	1200 m bottom pull from shore, 55 m lateral pull to wellhead	- -
depth of cover	ft	4.9	
Testing:			
Requirements:			
Pipe	-	-	-
Weld	-	-	-
NDT	-	-	-
Hydrotest	psi	-	-
Acceptance Criteria:			
Pipe flaw	-	-	-
Weld flaw	-	-	-
Hydrotest	hours	-	-
Operations and Maintenance:			
Monitoring Procedures:			
corrosion	-	-	-

deformation	-	-	-
leak	-	-	-
Mitigation Procedures:			
corrosion, internal	-	pigging loop using the two 6 NPS flowlines	-
corrosion, external	-	-	sacrificial anode
Repair Method	-	-	-

Based on the available information, qualitatively the design rationale for the Panarctic Drake F-76 Subsea Flowline is as follows:

- the primary reasons for using the pipe-in-pipe configuration for this pipeline, listed in order of decreasing importance, are:
  - to test the feasibility of using this design and installation method for 1000 to 1200 foot subsea pipeline depths.
  - to control the submerged weight of the pipeline for ease of construction
  - to provide mechanical protection during installation.
  - to protect electrical and instrumentation cables and thermal insulation from water over the operational life of the pipeline.
  - to protect the pipe and cable bundle from external corrosion over the operational life of the pipeline.

6.2.1.3 BP Exploration Troika Towed Bundle Flowline

The design basis of the BP Exploration Troika Towed Bundle Flowline is given in. Table 6.2.1.3-1. The major design characteristics of the BP Exploration Troika Towed Bundle Flowline are given in Table 6.2.1.3-2.

Table 6.2.1.3 - 1
Design Basis Summary for the British Petroleum Troika Towed Bundle Flowline

Parameter	Unit	Inner Pipe	Outer pipe
General:			
geographic location	-	Gulf of Mexico	-
design life	years	20	-
Applicable Design Codes:			
pipeline	-	ANSI B31.8	ANSI B31.8
cathodic protection	-	-	-
leak detection	-	-	-
Design:			
Method	-	-	-
Stress / Strain Criteria:			
stress	psi	-	-
strain, compressive	%	-	-
strain, tensile	%	-	-
Pipeline Fluid Properties:			
flowrate(s):	bfpd	60,000	-
	MMSCFD	75	-
specific gravity	-	-	-
wax formation temperature	F		
Pipeline Pressures:			
normal operating	psig	-	-
maximum operating	psig	8,000	-
Pipeline Temperatures:			
minimum installed	F	40	-
maximum operating	F	160	
Environmental Conditions:			
Water:			
current speed	ft / s	1.7	-
Depth:			
minimum	ft	1,350	-
maximum	ft	3,200	-
Temperature:			
minimum	F	-	-
maximum	F	-	-
installation	F	-	-
Soil:			
Characterization:			
silt / silty sand / sand	% length	-	-
gravel / cobbles / rock	% length	-	-
permafrost	% length	-	-
Temperature:			
minimum	F	-	-
maximum	F	-	-
installation	F	-	-
Air:			
Temperature:			
minimum	F	-	-
maximum	F	-	-

Table 6.2.1.3 - 2
Key Design Characteristics Summary for the British Petroleum Troika Towed Bundle Flowline

Parameter	Unit	Inner Pipe	Outer pipe
Pipeline:			
configuration	-	pipe-in-pipe	-
length	ft	147,840	-
Pipe:			
Specification	-	-	-
SMYS	psi	70,000	70,000
Type	-	seamless	DSAW
Dimensions:			
outside diameter	inch	10.75	24
wall thickness	inch	0.860	0.375
corrosion allowance	inch	0.0	0.0
External Coating:			
type	-	FBE	FBE + ½ AR
thickness	inch	-	-
Insulation:			
type	-	open cell foam	-
thickness	inch	3	-
Spacer:			
type	-	polypropylene	-
spacing	ft	35	-
Bulkhead:			
Type	-	bulkhead, annulus pressure = 1435 psu	-
spacing	ft	2,000	-
Cathodic Protection:			
type	-	-	-
spacing	ft	-	-
Leak Detection:			
type	-	-	-
accuracy	%	-	-
Installation:			
method	-	bottom towed (400 miles, approx.) in two equal length sections	-
depth of cover	ft	-	-
Testing:			
Requirements:			
pipe	-	-	-
weld	-	-	-
NDT	-	-	-
hydrotest	psi	1.25 x MAOP	-
Acceptance Criteria:			
Pipe flaw	-	-	-
Weld flaw	-	-	-
hydrotest	hours	24	-
Operations and Maintenance:	-	scheduled MFL or UT	-

Monitoring Procedures:	-	inspection	-
corrosion	-	-	-
deformation			
leak	-	scheduled pigging,	-
Mitigation Procedures:		chemical inhibitor	
corrosion, internal		injection	
	-	-	sacrificial anode
corrosion, external			
Repair Method	-	-	-

Based on the available information, qualitatively the design rationale for the BP Exploration Troika Towed Bundle Flowline is as follows:

- the primary reasons for using the pipe-in-pipe configuration for this pipeline are:
  - pipe-in-pipe is required to ensure thermal insulation characteristics which in turn are required to ensure multiphase flow, i.e.,:
    1. minimizes the potential for paraffin deposition.
    2. minimizes the potential for hydrate formation for a 24 hour period following an unplanned shut-down.
  - the annulus is pressurized with nitrogen to:
    1. resist pipeline collapse, due to external pressure resulting from the water the depth.
    2. resist potential annulus corrosion. Nitrogen is used since it is inert and dry.
    3. provide an additional means by which to control pipeline bouyancy for ease of installation.
  - bulkheads are used for the following reasons:
    1. to limit loss of thermal insulation characteristics in the event the integrity of the outer pipe is lost and the annulus is flooded.
    2. to resist pipeline collapse, due to the external pressure resulting from the water the depth, in the event of a loss of annulus pressure.
    3. to minimize the potential impact on the bottom tow installation method of the possible flooding of one annular compartment.
  - the design achieves a reduced construction schedule, a lower overall installed cost, and a reduced risk to both, relative to the alternative deep water installation method.
- the primary reasons for pipe characteristics used for this pipeline are:
  - the outer pipe diameter and wall thickness both are used to control pipeline weight for ease of installation.

6.2.1.4 BP Exploration Alaska Liberty Island Oil Pipeline

The design basis of the BP Exploration Alaska Liberty Island Oil Pipeline is given in Table 6.2.1.4-1.

Table 6.2.1.4 - 1
Design Basis Summary for the British Petroleum Liberty Island Subsea Oil Pipeline

Parameter	Unit	Pipe
General:		
geographic location	-	Liberty Island, Alaska, Approx. 5 miles offshore, NNW of the Kadleroshilik River
design life	years	20
Applicable Design Codes:		
pipeline	-	ASME B31.4
cathodic protection	-	DnV RP B401
leak detection	-	-
Design:		
Method	-	-
Stress / Strain Criteria:		
Stress	psi	-
strain, compressive	%	-
strain, tensile	%	-
thaw settlement	%	1.2
ice keel	%	1.8
strudel scour	%	1.2
island settlement	%	1.2
Pipeline Fluid Properties:		
Flowrate	bopd	65,000
specific gravity	-	0.9
wax formation temperature	F	-
Pipeline Pressures:		
normal operating	psig	-
maximum operating	psig	1,415
Pipeline Temperatures:		
minimum installed	F	25
maximum operating	F	150
Environmental Conditions:		
Water:		
current speed	ft / s	0.66
Depth:		
minimum	ft	-
maximum	ft	22
Temperature:		
minimum	F	-
maximum	F	-
installation	F	-
Soil:		
Characterization:		
silt / silty sand / sand	% length	predominantly soft silts

gravel / cobbles / rock	% length	-
permafrost	% length	none
Temperature:		
minimum	F	-
maximum	F	-
installation	F	-
Air:		
Temperature:		
minimum	F	-
maximum	F	-

The major design characteristics of the BP Exploration Alaska Liberty Island Oil Pipeline are given in Table 6.2.1.4-2.

Table 6.2.1.4 - 2
Key Design Characteristics Summary for the British Petroleum Liberty Island Subsea Oil Pipeline

Parameter	Unit	Pipe
Pipeline:		
configuration	-	single wall
length	ft	32,200
Pipe:		
Specification	-	API 5L
SMYS	psi	52,000
Type	-	seamless
Dimensions:		
outside diameter	inch	12.75
wall thickness	inch	0.688
corrosion allowance	inch	0.0
External Coating:		
type	-	FBE x 2 layers
thickness	mil	-
Insulation:		
type	-	n.a.
thickness	inch	n.a.
Spacer:		
type	-	n.a.
spacing	ft	n.a.
Bulkhead:		
type	-	n.a.
spacing	ft	n.a.
Cathodic Protection:		
type	-	Galvalum III
spacing	ft	240
Leak Detection:		
type(s)	-	mass balance, pressure monitoring/analysis
accuracy	%	1% of 24 hr volume
Installation:		
method	-	through-the-ice trenching, on-the-ice construction
depth of cover	ft	7
Testing:		

Requirements:		
pipe	-	-
weld	-	-
NDT	-	-
hydrotest	psi	1.25 x MAOP
Acceptance Criteria:		
Pipe flaw	-	-
Weld flaw	-	-
hydrotest	hours	8
Operations and Maintenance:		
Monitoring Procedures:		
corrosion	-	scheduled MFL or UT inspection
deformation	-	scheduled caliper and 3 D geometry pigging
leak	-	continuous, automated pressure monitoring, oil flow measurement
Mitigation Procedures:		
corrosion, internal	-	scheduled pigging
corrosion, external	-	sacrificial anode
Repair Method	-	-

Based on the available information, qualitatively the design rationale for the BP Exploration Alaska Liberty Island Oil Pipeline is as follows:

- the primary reasons perceived by its designers for using the single wall pipe configuration for this pipeline are:
  - superior capacity for bending without collapse, relative to pipe-in-pipe.
  - superior leak detection capability, relative to pipe-in-pipe.
  - superior metal loss inspection / detection capability, relative to pipe-in-pipe, i.e., it is not possible to determine the condition of the outer pipe in pipe-in-pipe.
  - pipe-in-pipe thermal insulating characteristics are not required for the single phase flow design.
  - reduced risk to construction schedule and a significantly lower total installed cost, relative to pipe-in-pipe.
  - inability to effectively repair pipe-in-pipe configurations
- the primary reasons for the pipe wall thickness used for this pipeline are
  - to increase containment failure resistance in the event of an extreme ice scour event (maximum design strain of 1.8%).
  - to control pipeline weight such that it will sink when submerged.

6.2.1.5 BP Exploration Northstar Subsea Pipeline

The design basis of the BP Exploration Northstar Subsea Pipeline is given in Table 6.2.1.5-1. The major design characteristics of the BP Exploration Northstar Subsea Pipeline are given in Table 6.2.1.5-2.

Table 6.2.1.5 - 1
Design Basis Summary for the British Petroleum Northstar Subsea Pipeline

Parameter	Unit	Pipe
General:		
geographic location	-	Point McIntyre/Point Storkersen, Alaska
design life	years	20
Applicable Design Codes:		
pipeline	-	ASME B31.4
cathodic protection	-	DnV RP B401
leak detection	-	-
Design:		
Method	-	-
Stress / Strain Criteria:		
stress	psi	-
strain, compressive	%	-
strain, tensile	%	-
Pipeline Fluid Properties:		
flowrate	bopd	65,000
specific gravity	-	0.79
wax formation temperature	F	54
Pipeline Pressures:		
normal operating	psig	850
maximum operating	psig	1,480
Pipeline Temperatures:		
maximum operating	F	100
Environmental Conditions:		
Water:		
current speed	ft / s	1.7 to 3.4 average 5.0 to 6.7 design
Depth:		
minimum	ft	-
maximum	ft	37
Temperature:		
minimum	F	-
maximum	F	-
installation	F	-
Soil:		
Characterization:		
silt / silty sand / sand	% length	100
gravel / cobbles / rock	% length	-
permafrost	% length	-
Temperature:		
minimum	F	-
maximum	F	-
installation	F	-
Air:		
Temperature:		
minimum	F	-59
maximum	F	78

Table 6.2.1.5 - 2
Key Design Characteristics Summary for the British Petroleum Northstar Subsea Pipeline

Parameter	Unit	Pipe
Pipeline:		
configuration	-	single wall
length	ft	-
Pipe:		
Specification	-	API 5L
SMYS	psi	-
Type	-	-
Dimensions:		
outside diameter	inch	10.75
wall thickness	inch	0.594
corrosion allowance	inch	0.375
External Coating:		
type	-	FBE
thickness	mil	28
Insulation:		
type	-	n.a.
thickness	inch	n.a.
Spacer:		
type	-	n.a.
spacing	ft	n.a.
Bulkhead:		
type	-	n.a.
spacing	ft	n.a.
Cathodic Protection:		
type	-	-
spacing	ft	-
Leak Detection:		
type(s)	-	mass balance, pressure monitoring/analysis
		1% of 24 hr volume
accuracy	%	
Installation:		
method	-	on-ice assembly
		through-the-ice pipelay
depth of cover	ft	7
Testing:		
Requirements:		
pipe	-	-
weld	-	-
NDT	-	-
hydrotest	psi	1.25 x MAOP
Acceptance Criteria:		
Pipe flaw	-	-
Weld flaw	-	-
hydrotest	hours	-
Operations and Maintenance:		
Monitoring Procedures:		
corrosion	-	scheduled MFL or UT inspection
		scheduled caliper and
deformation	-	3 D geometry pigging

leak	-	continuous, automated pressure monitoring, oil flow measurement
Mitigation Procedures:		
corrosion, internal	-	scheduled pigging
corrosion, external	-	sacrificial anode
Repair Method	-	-

Based on the available information, qualitatively the design rationale for the BP Exploration Northstar Subsea Pipeline is as follows:

- the primary reasons perceived by its designers for using the single wall pipe configuration for this pipeline are:
- superior capacity for bending without collapse, relative to pipe-in-pipe.
- superior leak detection capability, relative to pipe-in-pipe
- superior metal loss inspection / detection capability, relative to pipe-in-pipe, i.e., it is not possible to determine the condition of the outer pipe in pipe-in-pipe.
- pipe-in-pipe thermal insulating characteristics are not required for the single phase flow design.
- reduced risk to construction schedule and a significantly lower total installed cost, relative to pipe-in-pipe.
- inability to effectively repair pipe-in-pipe configurations
- the primary reasons for the pipe wall thickness used for this pipeline are
- to increase containment failure resistance in the event of an extreme ice scour event (maximum design strain of 1.8%).
- to control pipeline weight such that it will sink when submerged.
- to provide an allowance for corrosion of 0.375 inch.

6.2.2 Subsea Pipeline Operational Performance Review

Based on a literature review and a telephone survey of oil and gas operating companies this section was intended to present the following:

- an assessment of the operational performance of the existing arctic pipe-in-pipe pipeline designs, i.e., information describing performance of the final design, including:
  - Reliability,
  - Availability, or Operational Readiness
  - Operability, or Operational Suitability
  - Maintainability

6.2.2.1 Literature Search Results

The literature search did not yield any published information on the subject of operational performance of arctic subsea pipelines, either single wall or pipe-in-pipe. Where operational performance data may once have existed, e.g., Drake F-76, it was found to have been recently destroyed.

6.2.2.2 Operator Survey Results

The following operating companies were surveyed:

- TransCanada Pipelines Ltd.
- ESSO Imperial Oil
- Shell Canada Ltd.
- Petro-Canada
- Gulf Canada Resources Ltd.
- WestCoast Energy Inc.
- Mobil Oil Canada

The results of the telephone survey indicated that none of the companies contacted were aware of any operating pipe-in-pipe pipelines, or any proposed designs for arctic applications. As a result no operational performance information was collected.

7. COMPARATIVE ASSESSMENT OF SINGLE AND DOUBLE WALLED PIPELINES

The comparative assessment of single and double walled pipelines presented in this study does not include the process of decision making that would lead to the selection of one over the other. Moreover there has been no optimization study done to determine the best combination of wall thickness, operating pressures and through put for either pipeline. The size of the product pipe was a given and the single wall pipe that was chosen was similar to that currently being used for the Northstar project. Rather than simply take the same diameter product pipe and double wall pipe and surround it with a large diameter pipeline, it was considered appropriate to provide a comparison for pipelines of equivalent robustness in terms of structural capacity. The two alternatives cannot be compared directly or precisely but a project basis was established and circulated to stakeholders at the outset and was agreed upon as the two specific pipelines for comparison.

This section presents considerations relevant to the comparison of single and double wall pipelines with respect to conceptual design, design, corrosion, constructability, construction quality, operations and maintenance and abandonment.

7.1 Project Basis

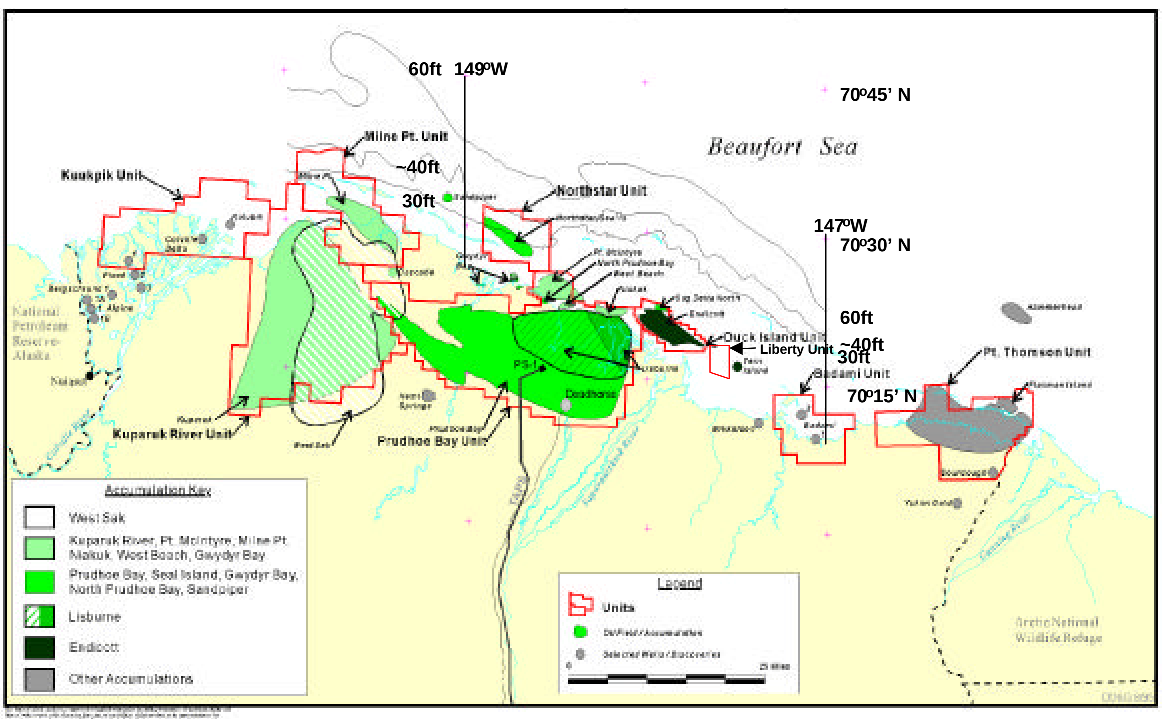
A project basis was formed based on anticipated generic conditions for offshore pipelines situated in the Alaskan Beaufort Sea west of 147°W to 149°W and northward from coastline to 40ft water depth, Figure 7.1-1. This general area encompasses the majority of the potential Northslope offshore oilfields including Sandpiper, Northstar, Port McIntyre, Duck Island Unit, Liberty, Tern Island and Badami. The project basis is shown in Table 7.1-1 as approved by the sponsors of the study. This basis was developed at the kick off meeting of 29 July 1999.

The parameters selected for this study and indicated in Table 7.1-1 are generic, and do not represent any specific site conditions within the study area. While the detailed results of the study are sensitive to some of the parameters selected, the general conclusions of the study remain valid. The selected study area (item 21 of Table 7.1-1) implied the base values for the water depth and the pipeline length, items 16 & 8. The soil and subsea permafrost conditions (items 22 and 23) were chosen from a review of the general conditions within the study area, section 7.1.1.3. The environmental load basis (item 24) is discussed in sections 7.1.2 and 7.6.1.2.4.

The pipe configurations, item 1 were defined by the objectives of this study. The inner pipe diameter, item 2, was considered representative of planned pipeline developments in the study area. Three variants of the pipe in pipe configuration were used to define the geometry and spacers (items 5 & 6) as illustrated in Figure 7.1-2. A discussion on the conceptual designs of the single wall and double wall configurations is presented in Sections 7.2 and 7.3.

Case A, is the conventional single, steel wall pipeline configuration. Two structurally similar double, steel wall pipeline systems, with a centrally located inner pipe, as illustrated for Case B and Case C. Case B considers a bulkhead type design where structural loads are transferred between the outer and inner pipelines through a transverse bulkhead. Case C represents a permeable transverse restraint that serves to center the inner pipe within the outer pipe and transfer loads between the two pipelines. The third variant, Case D considers a double, steel walled pipeline system with a floating inner pipe.

Figure 7.1-1: Study Area for Comparative Assessment, after ADNR (1999)



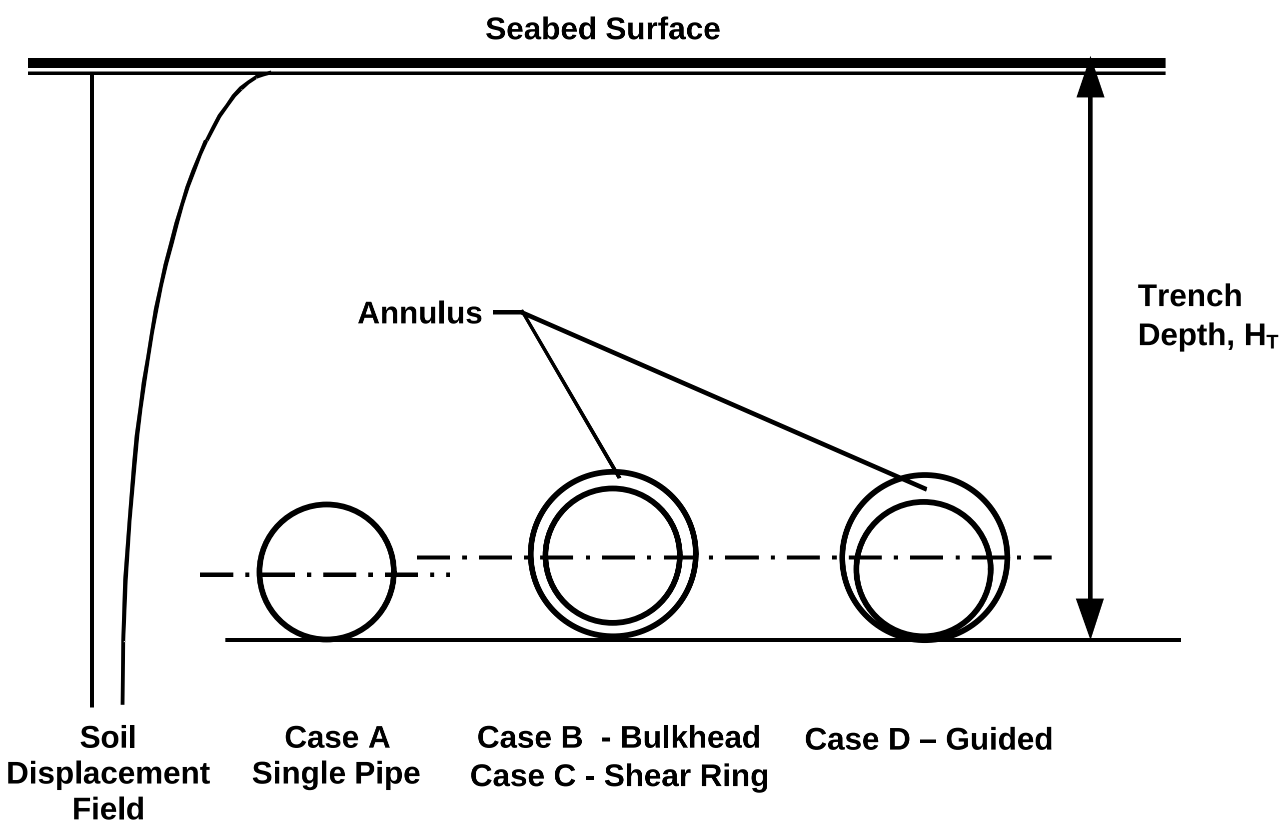


Figure 7.1-2. Schematic Illustration of the Baseline Pipeline Configurations Considered for the Structural Integrity Analysis.

Double walled systems have been adopted elsewhere for both onshore and offshore industrial applications for thermal insulation, leak containment and protection of flowlines, as described in section 6.1. The project basis assumed the primary reason to use a double wall system, in place of a robust single wall pipeline, buried offshore in an Arctic environment is for leak containment.

Table 7.1-1 - Project Basis

	Item	*Base Values*	*Parameters to be considered*
1	Pipe Configurations	Single walled Double wall	 Robust and light outer pipe
2	Diameter, inner	12" nominal for single wall pipe & inner pipe	Nominal Pipe Size between 8"&16"
3	Diameter, outer	Next larger constructable size	
4	Wall thickness	Determined by environmental and operating conditions	
5	PiP geometry	Inner pipe centred within outer pipe	Freedom for inner pipe to find its own profile within outer pipe
6	PiP Spacers	Fixed, solid bulkheads	Shear rings that transfer axial and radial loads between 2 pipes, and allow flow through the annulus. Guides that are free to slide and allow flow through the annulus.
7	Annulus pack	Inert gas at atmospheric pressure and ambient temperature	Engineered fluid
8	Length	12 miles	Effect of longer and shorter lengths (5 to 20 miles) on design and length constructable per spread per season.
9	Pipe material	X52	Grades up to X65
10	Product	Sweet crude oil	Multiple streams
11	Max Allowable Operating pressure	1440psi	500 to 3000psi
12	Product temperature	110^{o} F	90^{o} F to 180^{o} F
13	Design type	Strain based	Strain limits
14	Design codes and specifications	- API RP 1111 (1999) - ASME B31.4a (1994) - DoT 49 CFR Part 195 (1999)	Other codes and guidelines as appropriate
15	Pipe system	Girth welded standard pipe lengths. No subsea fittings. No branch connections	None
16	Water depth	40ft maximum	The influence of deeper water depths will only be commented on.
17	Construction	Pipeline in backfilled trench	Select backfill material Comment on need for backfill
18	Construction method	Winter construction from the ice	Ice thickness. Other possible methods of construction will be commented on
19	On-ice season	3 months, winter (for construction)	Comment on seasonal variations
20	Open water season	3 months, summer (for repair & maintenance)	Comment on seasonal variations
21	Study Area	Westward from 147.W to 149.W. Northward from coastline to 40ft water depth, Figure 7.1-1	
22	Soil conditions	Sand to medium stiff cohesive silt	
23	Subsea permafrost	Sporadic	
24	Environmental loads based on	Northstar EIS Liberty EIS API RP 2N (1995) API 2a (1993)	

The pipeline systems outer diameter and the pipe wall thicknesses (items 3 & 4) were determined from considerations of construction and environmental and operating conditions. Values for these items are presented in section 7.6.1.2.

External coatings are applied to mitigate the potential for metal loss corrosion in corrosive or potentially corrosive environments. Given that the annulus of double wall configurations is potentially low corrosive environment, only the outermost wall of all four pipeline study case configurations will require an external corrosion coating. Several external corrosion coatings are available for subsea pipelines. Factors affecting the selection of a coating include pipe diameter, maximum operating temperature, minimum ambient temperature, coating cost and availability, and the impact on the cost of pipeline cathodic protection. For the conditions and parameters outlined in the study basis a Fusion Bonded Epoxy (FBE) external corrosion coating is selected on the basis of coating performance and overall cost effectiveness. The following table documents the application of pipe coatings assumed in the study.

Table 7.1.2
Summary of Pipe Coating[1] Assumed for Each Pipeline Study Case

Pipe Wall	Study Case A	Study Case B	Study Case C	Study Case D
	Single Wall	PIP-Bulkhead	PIP-Shear Ring	PIP- Simple
Outer pipe, outer wall	FBE	FBE	FBE	FBE
Outer pipe, inner wall	none	none	none	none
Inner pipe, outer wall	-	none	none	none
Inner pipe, inner wall	-	none	none	none

Notes: 1. The Fusion Bonded Epoxy coating is typically 14 to 28 mil thick. If the pipe us coated externally with concrete, an additional 3 mil thick anti-slip coating will be applied. If required, an additional anti-abrasion coating of up to 25 mils thickness may also be applied.

The product and the associated maximum pipeline operating pressure and temperature (items 10 to 12) were based on the planned pipeline developments in the study area. The design type, codes and specifications (items 13 and 14) are appropriate for offshore pipelines subject to deformation controlled loading events. The construction (item 17) considers ice scour and pipeline upheaval buckling. The on-ice and open water seasons (items 19 and 20) were based on issues discussed in section 7.1.1.4.

Environmental loads and the physical environment, including geotechnical conditions and the ice regime, are important considerations for the design, construction, operation and maintenance of pipeline systems. The general conditions for the study area are presented in Appendix 7.1.

7.1.1 Project Basis Parametric Considerations

Table 7.1.1 presents the base values for the parameters considered in this study. The variations considered for some of these parameters are discussed elsewhere in this report, for example seasonal variations for items 19 and 20 are discussed in section 9.6.1. Considerations on variations in pipe material (item 9) and product temperature (item 12) are presented below.

7.1.1.1 Pipe Material

The base cases, used for comparison of pipe in pipe and the single walled system, utilised a relatively low grade pipe (X52) since the stress component of the internal pressure was not the major design requirement. The pipe material's ability to deform or strain without failure requires ductile steel normally associated with lower grades of pipe.

As grades increase from X52 toward X65 and X70 materials, the strength is achieved either through alloying with other metals or through a temperature modifying working process. However, modern steels have achieved better ductility and high toughness even at low temperatures. Either a single wall or a pipe-in-pipe system, when in use as an oil pipeline, could benefit from higher strength steels to resist deformation and bending stresses at operating temperature.

Weldability of higher grade steels, both to code requirement and to the ECA flaw size design criteria for a strain based pipeline, is becoming more commonplace. The matching of welds to the parent metal has, however, given concern for more exacting quality control of welding procedures and consumables, both in manufacture and in use during construction. Automated welding, although not practical on such small pipe as the 12.25, has been proposed and is currently being used for 16" pipe. Current testing procedures in the codes governs the acceptance of the welds and the allowable strain to which the pipe can be subjected. It is these weld defects which are of concern for large strain values. The higher grades allow higher operating temperatures

Considering the use of plastic pipe for the outer pipe of a double wall system was part of the study's original scope. It was agreed at the kick-off meeting that this be dropped from the scope since it would be adequately addressed in an Intec study. As a result, this option was not considered in detail in this report. Readers are referred to the Intec study report PS 19: Pipeline System Alternatives - Liberty Development Project Conceptual Engineering of November 1999, and reviews of that report, for some considerations on the use of plastic pipe for the outer pipe in a double wall system. Langner (1999) stated that an HDPE outer pipe would not provide effective secondary containment because of its inadequate resistance to the fluid jetting that may accompany the escape of a high pressure fluid from the inner pipe.

7.1.1.2 Product Temperature

An initial base temperature was chosen to focus the comparative nature of the study. This base temperature was assumed as 110°F operating temperature to reflect typical consideration for offshore production to be transported onshore. It is, however, prudent to discuss the effects of increased operating temperatures that may be considered for different products. The maximum temperature to be considered was suggested to be approximately 180°F with 140°F to 150°F being the median range. The following discusses the comparative effects of a single walled pipeline and a pipe-in-pipe mode such that discussion and issues can be more clearly understood.

The temperature of installation of either system during the construction phase is expected to be near 32°F in seawater offshore. Since the pipeline in either configuration is similarly buried, it is considered fixed or axially restrained during the lay operation near 32°F. The operating temperature will then introduce compressive stresses on the pipe configuration, which in turn, will act to induce the pipe to want to grow and bend in areas to move or strain in an upward or lateral direction. It is interesting to note here that wrinkling failure is dependent upon the yield strength versus the wall thickness, and although an identified failure mechanism, in small diameters and relatively thick walled pipe considered for this study, it is not a significant concern.

It is intuitive that if the pipeline is buried in relatively competent materials, the direction of least restraint is upwards and therefore consideration of uplift buckling is an issue of concern. The force with which this uplift buckling is imparted to the soil is a function of the differential temperature between the operating temperature and the construction lay temperature and the cross-sectional area of the steel in the pipe system. By this criteria, the force exerted by a pipe-in-pipe configuration is approximately one-third greater than that exerted by a single walled 12.75" O.D. by 0.500" W.T. pipe. This force is resisted by the overburden weight of the soil above the pipe (which is a function of the diameter of the pipe exposed to the soil), the weight of steel, and to a much smaller extent the weight of the products carried by the system and the stiffness of the pipe system cross-section. In the case of the pipe-in-pipe configuration, the resistance to uplift buckling is about one-quarter greater than the single walled system for a similar differential temperature. The fact that the outer pipe in such a configuration runs somewhat cooler than the internal pipe also reduces the contribution of the outer pipe to uplift forces. None of the above factors is significant at a maximum differential temperature of 78°F (110°F-32°F).

Several factors tend to decrease the operational concerns related to this uplift issue; namely both systems are buried, whereby the backfill imparts the largest restraint; and secondly that the systems are laid without bends because they are offshore. These two criteria tend to minimize the concerns at higher temperatures and the concern for uplift buckling to the extent that both configurations are essentially identical in their reaction to such forces. Obviously the higher the differential temperature (or essentially the operating temperature), the greater the forces which must be restrained, but these considerations are similar for either system.

An issue for the pipe-in-pipe system however is the differential compression force between the inner and outer pipes due to different temperatures of the two lines, which tends to increase contact between the two pipes. Again, the base case of a 12.75" O.D. inside a 14" O.D. pipe, both of 3/8" W.T., tends to confine the profile of the inner pipe such that only consideration of axial buckling need be considered as a possible failure mechanism. This is a relatively simple calculation and a well-known result and not of significance for a 12.75" O.D. in a 14" O.D. pipe-in-pipe configuration. For larger pipe sizes, the outer pipe would not economically, be specifically fabricated in a diameter that continues to similarly confine the compression profile of the inner pipe. Full scale bending tests will readily prove the ability of the inner pipe to withstand the differential compression force of being confined and restrained by the outer pipe.

The forces are transferred to the outer pipe at either end of the pipeline where transition to an above grade mode or a significant change in direction is anticipated. Design will need to consider suitable flexibility at the entry and exit of the pipeline to allow transitions. As operating temperature is increased toward 180°F the end forces will increase accordingly and become more dependent on the design of the fittings and the soil properties (for example, frozen/unfrozen).

An increasing temperature of the pipe which carries the product will tend, in the case of the single walled pipeline, to increase the rate of corrosion substantially, while in the case of the pipe-in-pipe, the effect on the outer pipe is somewhat reduced due to presence of the annular space. The corrosion concern associated with the annular space itself is relatively unaffected since no sustainable corrosion mechanism exists within a pressurised inert gas filled annulus to initiate such corrosion. Since corrosion of the outer wall of the system is a major risk concern for failure, the single wall pipe is somewhat disadvantaged at higher temperatures due to this phenomenon.

7.2 Single Walled Pipeline – Conceptual Design

The single walled pipeline assumed for this study is constructed from 12.75" O.D. x 0.500" wall thickness Grade X-52 API linepipe. The single walled pipeline is labeled Case A in this study. It is roughly patterned after the design adopted for the BPA Northstar project and is considered to embody the positive attributes associated with tough steel, excellent weldability and low diameter to wall thickness (D/t) ratio. These characteristics provide a high level of confidence in the ability of the pipeline to tolerate high strain levels without loss of pressure containing integrity.

7.3 Double Walled Pipeline – Conceptual Design

One requirement of this study is to develop a conceptual design for a double walled pipeline of "equal strength" or "equivalent robustness" to the single walled pipeline described above. The design intent of the double wall is simply to provide secondary containment of the oil in the inside pipe. No additional functional use is made of the annular space. This simplifies the required analysis of the double walled system but may in some cases impose a greater than necessary economic burden on the concept. Development of a dual use double walled pipeline concept is outside the scope of this study.

There is no simple means of establishing "equivalent strength" of a double walled system with a single walled pipeline. For example, equivalent strength with respect to bursting requires that the D/t ratios be the same. If both inner and outer pipes in a double walled pipeline had the same D/t ratio as the single walled pipeline, all pipes involved in the comparison would have essentially the same strength in the sense of tolerance for internal overpressure, a concept which is typically stress based. The individual pipes would also have a similar tolerance for wall loss due to corrosion. This basis for comparison however fails to properly recognize the different possible operating loads on the inner and outer pipes of a double walled system. This is particularly significant with respect to hoop stress. A double walled system has the particular advantage of allowing the resistance of the inner and outer pipes to bending strain to be variable by controlling the pressure in the annulus. At high annulus pressure, the hoop stress on the inner pipe would be low. In fact, at the normal operating pressure of the inner pipe, the pressure in the annulus could be higher than the internal pressure; this would generate compressive hoop stress in the inner pipe, which would increase its tolerance for tensile strain at the expense of increasing the compressive strain. Conversely, at low annulus pressure, the hoop stress on the outer pipe would be minimal. In the absence of hoop stress, a pipe can tolerate greater axial stress and bending stress. By virtue of the resistance to heat transfer provided by the annulus, the outer pipe in a double walled system would normally be subjected to a lower thermal stress. Further, for pipes all having the same D/t ratio, the double walled pipeline system would be flexurally stiffer when exposed to large soil displacements of the type that could be caused by thaw settlement or ice scour. Its increased section modulus would yield a stiffer pipe and generally result in lower bending strain for any given soil displacement field. The benefit of increased section modulus is offset to a significant extent by the increased outside diameter of the double walled system.

For an arctic offshore pipeline exposed to significant bending strain from large soil displacements, a strength comparison between single and double walled systems should be based upon consideration of the design margin with respect to loss of containment for design conditions of pressure, temperature and soil displacement. This means attention should be focussed on a strain based design approach and specifically on tensile strain levels. It is noteworthy that establishing design soil displacement is itself a challenging task that has a complex effect upon the comparative strength of single and double walled pipeline systems. The width as well as the depth of the ice keel causing the ice scour or the length of the thaw settlement feature defining the design soil displacement field significantly influences the response of a pipeline exposed to the design geotechnical load. The displacement of the soil orthogonal to the pipe centerline, the length of the displacement field parallel to the pipeline, the outside diameter of the pipeline exposed to the soil displacement and the stiffness of the soil all influence the resulting bending strain. To further complicate the establishment of a basis for strength equivalence, it should be noted that for any given set of load combinations that include a significant soil displacement field, the outer pipe of the double walled system will always experience greater bending strain than the inner pipe.

Given the designer's ability to manage the combined stress and resultant strain in a double walled pipeline, consideration must be given to the importance of tensile and compressive strain. It is suggested that the failure mode associated with compressive overstrain is generally section collapse. This would result in loss of functionality of the pipeline but is less unlikely to cause a loss of containment. Tensile overstrain, however, if high enough, would result in rupture of the pipe. High tensile strain coincident with a material defect, such as a weld flaw, results in failure at a lower strain level than would otherwise be the case. Material defects have little influence on the tolerance of a pipe to compressive overstrain.

It is suggested that the design basis for a double walled pipeline system should be based on functional analysis and risk management considerations rather than any measure of strength equivalence with a comparative single walled pipeline. The mandate given the study team, however, includes developing a conceptual design of a double walled pipeline with the same strength as a robust single walled pipeline since tensile overstrain can cause rupture. It is suggested that matching the calculated tensile strain of the inner pipe of the double pipe system with the tensile strain observed in the single walled pipe is the criterion most suitable for establishing the strength equivalence of the two systems. The comparison is made for systems operating at design temperature and pressure and exposed to the design ice scour. While this set of simplifying assumptions is necessary to make a comparative assessment of single and double walled pipelines at a generic level, the writers caution that more detailed assessments for an actual project may result in different weightings between the two pipeline concepts. Different load combinations, soil types and operating requirements could reasonably be expected to result in significantly different wall thicknesses, steel grades, or both, hence changing the costs for a well designed double walled pipeline. Further, it seems inevitable that a double walled pipeline would have a cost premium compared to a single walled pipeline. It is beyond the scope of this study to consider whether that cost premium, if judged to be warranted on the basis of reducing the risk of loss of containment, might be more effectively spent on alternate integrity enhancing measures. For example, further increasing the wall thickness or burial depth of a single walled pipeline could also increase the design integrity of an Arctic offshore pipeline.

Strain is the response of the pipe to the combined loads from internal and external pressure, thermal stress and bending. It can be thought of as the change in length of an element of steel when loaded, divided by its original length. The loading is expressed in terms of stress, the combined load per unit area of steel resisting the load. The relationship between stress and the strain it produces is illustrated by the stress – strain curve, which is unique for each different steel. The grade of steel reflects its specified minimum yield strength (SMYS). Grade 52 steel, for example, has a SMYS of 52 thousand psi. Allowable stresses are expressed as fractions of SMYS in the B31.4 oil pipeline code. Different stress levels are allowed for various types of stresses and combinations of stresses.

The B31.4 code does not provide any guidance for the designs of buried pipelines regarding the handling of load combinations that include bending. It is generally accepted that hoop stress be kept within the 0.72 times the SMYS stress limit allowed by the B31.4 code. For a 12.75” O.D. pipeline designed for a maximum operating pressure of 1440 psi and constructed from grade 52 line pipe, this imposes a minimum wall thickness requirement of 0.25”. API RP 1111 Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit States Design) provides an accepted basis for the use of lower wall thickness for this service. For buried pipelines designed to accommodate large geotechnical loads such as thaw settlement, strain based design methods are generally adopted, as was the case for buried portions of the TAPS and Badami pipelines. For loads that are effectively restrained by the soil surrounding the pipe (thermal stress and bending, but not internal pressure) design strain limits are effectively established in much the same way as stress based codes like B31.4 prescribe stress limits. This is understood to be part of the design basis for the Northstar pipelines. The strain limits and design ice scour event adopted for Northstar have been employed in this study and are essential to the assessment of strength equivalence for the double walled pipeline with the single walled pipeline described in the previous section of this report.

As developed in section 7.6.1, strains are considered in terms of global tensile, global compressive and local strains. Local strains are associated with loads transferred between the inner and outer pipes of a double walled system by bulkheads, shear rings and spacers. In comparing the strains in single and double walled pipelines, local strains are included as appropriate with global strains in the case of the double walled system.

Double walled pipelines have been used in deep water offshore applications, particularly in the Gulf of Mexico and the North Sea. The application has been limited primarily to insulated pipelines. The outer pipe is used primarily to maintain the heat transfer resistance of conventional pipeline insulation when used in a high-pressure marine environment. Another application of pipe-in-pipe double walled pipelines is the Shell Canada liquid sulfur pipeline between Caroline and Schantz Alberta. It is an 8.75” O.D. inner pipe inside a 12.75” O.D. outer pipe. The annular space is used to circulate pressurized hot water that is required primarily to prevent excessive cooling of the liquid sulfur. The outer pipe is insulated and equipped with an electric resistance based leak detection system. The liquid sulfur pipeline is thought to provide a possible design analog for a double walled arctic offshore pipeline since it addresses many of the issues and is of a similar size (8" in 12"). Figures 7.3-1 to 7.3-4 illustrate how the design attributes of the liquid sulfur pipeline might be adapted to an arctic offshore pipeline.

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Double walled pipelines are generally expected to utilize a series of bulkheads or shear rings and spacers to transfer loads between the inner and outer pipes and centralize the inner pipe within the outer pipe. Bulkheads are pressure containing, load transferring structural attachments between the inner and outer pipes. The bulkhead system is labeled Case B in this study. Shear rings are essentially bulkheads that contain ports that allow communication (fluid flow) between adjacent annular segments. The shear ring system is labeled Case C in this study. Figures 7.3-2 and 7.3-4 illustrate bulkheads and shear rings. Bulkheads and shear rings would be custom manufactured from low alloy steel very similar to the steel used in the line pipe. Spacers are generally non-metallic bands manufactured as half cylinders and bolted to the outside of the inner pipe. Each spacer has a series of longitudinal ribs that fit snugly inside the outer pipe. They serve to position the inside pipe within the outer pipe, allow more even annular space and allow less restricted movement of the inner pipe. Spacers are commercially available manufactured items. A typical spacer is illustrated in Figure 7.3-3. If specific dimensions are required, spacers can be customised. As indicated in Figure 7.3-1, typical shear ring or bulkhead spacing is about three thousand feet; typical spacer spacing is about thirteen feet. This amounts to one or two bulkheads or shear rings per typical day's pipeline production and three spacers per forty foot long joint of pipe. Neither represents a large cost item either in terms of materials or construction effort.

Bulkheads isolate the annulus into a series of annular segments. Bulkheads have the potential advantage over shear rings of isolating a leak from the inside pipe from defective segments of outside pipe. There is no known inspection method for monitoring the overall condition of the outer pipe, however. Consequently, bulkheads are not considered to afford adequate advantage to compensate for the lost opportunity of utilizing the annulus to continuously monitor the pressure containing integrity of both the inner and outer pipes. Hence in principle, the study team favors shear rings over bulkheads. Conversely, however, for the unique case of a 12" inner pipe, shear rings would necessitate the use of a "two sizes over" 16" outer pipe in order to have adequate annular space for communications ports. By comparison, bulkheads could be designed for a 12" pipe inside a 14" pipe. (Up to and including 12", pipe size is nominal inside diameter; for 14" and larger pipe, nominal size is outside diameter. Consequently, the annular space between a 12" pipe within a 14" pipe is about ½ inch, whereas for all other combinations of a pipe within the next larger nominal pipe size, it is about 1-1/2 inches, adequate for the manufacture of shear rings.) As indicated above, there is a performance penalty associated with increasing the outside diameter in terms of bending under the influence of large geotechnical loads. This makes the increased outside diameter of a shear ring system a very undesirable design requirement relative to the bulkhead system, in addition to its increasing the relative cost of the double walled pipeline alternative.

There are several disadvantages of either bulkheads or shear rings. The transfer of loads between pipes, particularly bending loads, could create local strains large enough to render the double walled pipeline less tolerant of bending than a comparable single walled pipeline. It is felt that the use of three piece bulkheads or shear rings as illustrated in Figure 7.3-2 solves this problem. Such tapered fittings avoid local stress and strain concentration and the increased section modulus of the bulkheads or shear rings diminish the bending strain associated with geotechnical loads. Bulkheads and shear rings design has been used routinely for pipeline projects elsewhere, such as in pipe bundles. Bulkheads or shear rings can be designed to operate at lower stress and strain levels than the adjacent straight run pipe sections, hence global loads away from the bulkheads or shear rings, not local strains at the bulkheads or shear rings control the design integrity.

Bulkheads and shear rings have a generally recognized quality burden associated with the increased complexity. For the relatively few, relatively simple bulkheads or shear rings that would be required, this is not considered to be a major concern, despite the unconventional weld proposed between the two segments of the outer portion of the bulkheads or shear rings.

Bulkheads and shear rings present challenges for pipeline integrity monitoring by magnetic flux or ultrasonic internal inspection devices. As has been noted above, there is no known inspection method capable of monitoring the overall condition of the outer pipe. Interpreting magnetic flux fields recorded by magnetic flux instruments cannot be as reliable for the double walled pipeline as for single walled pipelines. There should be little, if any problem, however, obtaining reliable ultrasonic measurements of wall thickness of the inner pipe from ultrasonic internal inspection tools for the bulkhead configuration considered herein. The presence of the communications ports in the shear rings would complicate interpretation of ultrasonic inspection records but it is within the capability of ultrasonic inspection technology to monitor the inner pipe of the shear ring system.

As discussed in sections 7.4 and 7.6.2, at least for normal oil pipeline operating temperatures when the only functional requirement of the outer pipe is containment, there does not appear to be any design imperative for the use of bulkheads, shear rings or spacers for double walled pipelines. This would reduce the fabrication and constructability issues of double walled pipelines significantly. The only caveat on this statement is that the overall condition of the outer pipe can only be monitored on a pass/fail basis with respect to its ability to contain a leak. This would be done by means of maintaining the annulus at a pressure above or below the ambient pressure and monitoring this pressure.

The double walled concept selected for this study is Case D. It is simply one pipe inserted within the next larger standard pipe size. The inner and outer pipes would be suitably attached at each end by means of a bulkhead like device. Side outlets suitable for filling and purging the annulus and instrument connections would be installed on the outer pipe at each end to provide operating and maintenance access to the annulus.

Several design rationalizations were made with the decision to eliminate the bulkheads or shear rings and spacers in the conceptual design developed in this study as compared to the design that was adopted for the liquid sulfur pipeline and the Alpine crossing of the Coleville River. There seems to be no significant structural advantage to the use of a centered inner pipe. (Some pipe bundles in the Gulf of Mexico do not have centralizing spacers to locate the flowlines.) There does not seem to be a requirement to avoid contact between the inner and outer pipes to control corrosion, as is the case with cased crossings where the annulus is vented to atmosphere. To practically eliminate corrosion in the annulus, it is suggested that following construction, the pipeline be placed in service and allowed to warm up to some temperature significantly above 32^{o}F to melt whatever ice and snow was trapped in the annulus during construction. The annular space can then be vacuum dried. Once dried, the annulus could be evacuated or filled with nitrogen. To provide an extra measure of insurance against corrosion in the annulus in case the drying is incomplete, a volatile amine vapor phase oilfield corrosion inhibitor could be injected into the annulus with the nitrogen to elevate the pH anywhere moisture is present.

Based on the following reasons, the simple double wall system should be at lower risk from corrosion than a single walled pipeline. Internal corrosion would be the same for both systems. There should be virtually no corrosion in the annulus. Pipe corrosion barrier coating and cathodic protection would be as effective in protecting the outside of a double walled pipeline as they are for a single walled pipeline. The outer pipe of a double walled pipeline operates at lower temperature than a comparable single walled pipeline by virtue of the heat transfer resistance provided by a vacuum or inert gas-filled annulus. It would therefore experience a lower rate of external corrosion in the event that external corrosion is not effectively mitigated. As a general rule, corrosion rate doubles for every 20 ^{o}F increase in system temperature. The maximum temperature of the outer pipe is estimated to be 80 ^{o}F for a design product temperature of 110 ^{o}F. Such a temperature reduction would result in a reduction in the corrosion rate on the outer pipe compared to that of the single walled pipeline.

The simple (no spacers, bulkheads or shear rings) double walled pipeline identified as Case D in this study is the selected design of the 3 PiP concepts used by the study team for comparison with the single wall system, as it is the simplest and most viable. The wall thickness suggested for both inner and outer pipes is 0.375 inches. The study team feels that this design would provide a suitable compromise between increasing cost and enhancing containment for the double walled pipeline alternative to a 0.50-inch wall thickness single walled pipeline. As discussed above, it would be an oversimplification to declare this to be a double walled pipeline that has the same strength as the 12.75” O.D. by 0.50” wall thickness single walled pipeline represented as Case A. As discussed below, however, it is believed that the risk of an accidental release from the double walled pipeline would be lower than the single walled pipeline, against which it is being compared, but that its cost would be greater. The simple double walled pipeline, Case D, is the double walled design referred to in the remainder of this report, except as noted.

7.4 Functional Requirements of Inner and Outer pipes in Double Walled Pipelines

It is suggested that to design a double walled pipeline, each pipe should be designed to meet a set of project specific performance requirements rather than attempting to match the strength of a single walled design alternative. The performance requirements should be based on functional analysis. Depending on burial depth, there may be no requirement that the outer pipe be designed for large bending strains. In that case, if the outer pipe were designed only to provide containment of releases from the inner pipe due to corrosion and material or workmanship defects in the inner pipe, its wall thickness could be less than what was used in this study. If a pressure relieving system were installed on the annulus, it may be possible to justify a lower design pressure for the outer pipe than for the inner pipe. Conversely, risk analysis may indicate that the most economic design of a double walled pipeline is to increase the structural strength of one or both pipes and decrease the burial depth. Presumably any such reduction in burial depth would be based on burial beneath the expected scour depth but in a zone where the design geotechnical loads are greater. It is expected that the optimum design basis for a double walled pipeline would depend to some extent on the line size. Caution and good judgement should be exercised in applying the conclusions reached in this study to pipelines of significantly different size, design pressure or operating pressure.

Tensile strain limits are generally established on the basis of assuring the survival of a weld with the largest flaw size (allowed by the welding quality control standard) being located at the point of maximum tensile strain. Risk analysis may establish that it is unnecessary to design a double walled pipeline for large weld flaws in both pipes coincident with high tensile strain. This would decrease the relative cost of the double walled system without significantly changing the risk of an accidental release, particularly if a conservative burial depth is used.

It may be adequate, for example, to design a double walled pipeline, for one or the other, but not necessarily both pipes, to survive an extreme ice scour event. The conceptual design proposed in this study essentially provides an inner pipe of similar integrity to the single walled pipeline alternative but a lower level of integrity of the outer pipe in the case of extreme bending. Depending on burial depth, this design may be either unnecessarily conservative or unconservative. Functional analysis would identify the means by which risk from ice scour would be mitigated, at which point the performance requirements of each pipe would become clear. This could lead to either reduced pipeline costs or enhanced integrity.

Functional analysis, done early in the project development, is likely to be helpful in establishing the design basis for the most economic development scheme that satisfies the economic, environmental and permitting requirements of the project.

7.5 Non-conventional Double Walled Design Opportunities

Pipeline bundles are sometimes used for offshore pipeline systems that require multiple lines, simply based on economics and construction preferences. If secondary containment is warranted, it may be economically attractive to use multiple lines of coiled pipe within an outer pipe. Coiled pipe can be practically handled in sizes up to four inch nominal diameter. Its use could significantly reduce the construction labor cost for a double walled pipeline system configuration.

The more complicated the pipeline system requirements, the more attractive a pipe-in-pipe design is likely to become. For example, if thaw subsidence, uplift buckling or process constraints such as wax deposition were a major design concern, it may be attractive to insulate the pipeline. In that case a pipe-in-pipe design may be economically attractive.

This study considered only low alloy steel as the construction material for both pipes. Functional analysis may indicate advantages to the use of an alternate material such as high-density polyethylene or fiberglass for the inner pipe of a double walled pipeline. In this scenario, the inner pipe would not be susceptible to corrosion. The outer steel pipe would be designed for pressure containment and structural strength.

7.6 Design Considerations

A comparative assessment of a single wall single wall versus double wall (i.e. pipe-in-pipe) pipeline system is presented for the Alaskan North Slope region. The investigations are focused on the structural response of both pipeline systems, in terms of equivalent robustness, subjected to the same extreme design ice gouge (i.e. 100-year event). Sections 7.6.2 and 7.6.3

compare the corrosion, leak detection and containment design aspects of the single and double wall pipelines.

7.6.1 Structural Integrity

7.6.1.1 Rationale

7.6.1.1.1 Introduction

The primary objective for considering a double wall pipeline system is based on reducing the potential for accidentally releasing oil product from an Arctic offshore pipeline into the environment. From this viewpoint, the analytical investigations on comparative pipeline integrity, between single wall and double wall systems, were conducted.

Structural integrity issues are concerned with pipeline response and performance due to the imposed operational and environmental loads. General considerations for issues on pipeline structural response are summarized in Table 7.6-1. The two parameters that define the present analysis scope with respect to comparative structural robustness issues are:

- Pipeline Integrity – excessive tensile strain that represent risk of pipeline rupture
- Pipeline Stability – excessive compressive strain that would most likely represent collapse but not loss of product containment

Table 7.6-1.
Structural Integrity Issues for Pipeline Design.

Parameter		Structural Integrity Issues
Working Stress	MAOP	Maximum allowable internal operating pressure (MAOP)
	Temperature	Thermal stress load
	Stress	Membrane (i.e. in-plane) stress due to internal and external pressure
Strain Limit State	Rupture	Membrane tensile strain limit due to primary and secondary loads
	Combined Strain	Membrane strain due to combined differential displacements and/or rotations
Stress Limit State	Burst (Yield)	Maximum internal pressure limit
	Combined Stress	Membrane stress due to differential loads, pressure distributions or moment couples
Stability	Buckling	Loss of global or local structural stability due to bending moment, internal or external pressure, excess temperature differential
	Ovalisation	Local sectional collapse due to effects such as overburden pressure, or interaction between carrier and outer pipe
Integrity	Weld CTOD	Interaction of weld defects with tensile strain and accumulated plastic strain

Acceptable stress or strain limits are established as a function of a number of parameters including operating pressure and temperature, pipeline diameter, wall thickness, material grade. Basis for the adopted framework will be developed throughout this section.

7.6.1.1.2 Governing Design Rules and Standards

The analysis conducted in this report will be in accordance with the following engineering codes and recommended practice:

- API RP 1111 (1999).

  Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)

- API RP 2N (1995).

Planning, Designing, and Constructing Fixed Offshore Structures in Ice Environments

- ASME B31.4 (1994)

Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia and Alcohols

Typically, the design of onshore and offshore pipeline systems has been based on working stress or allowable stress design criteria. ASME B31.4 (1994) is a stress based engineering code for the design of liquid pipeline transportation systems.

In general terms, the philosophy is to define an allowable stress as a fraction of the specified minimum yield stress (SMYS) in terms of design factors. The design or "safety" factor accounts for variation in material properties, applied loads, structural defects and model uncertainty. For particular scenarios, the allowable stress criteria may be conservative. This issue has been addressed by API RP 1111 (1999) with respect to the maximum allowable hoop stress of high-pressure pipelines with a low diameter to wall thickness ratio (*D/t*).

Stress based design in accordance with ASME B31.4a (1994), however, is impractical for large magnitude, deformation controlled mechanisms (e.g. ice gouge, thaw settlement). Several northern pipelines, including the buried portions of Badami and Trans–Alaska Pipeline System (TAPS) and the Norman Wells pipeline in Canada, were designed to strain limits instead of stress limits for the displacement controlled (geotechnical) loads such as thaw settlement. Geotechnical loads imposed on the pipeline due to the subgouge soil displacement field from ice gouging would logically be treated in the same way. Loads such as internal pressure is considered in terms of conventional stress based design limits. This approach was considered for the Northstar pipeline system (INTEC, 1998b) and a similar methodology was adopted for the current study.

Consequently, additional guidance from recognized international codes, such as CSA Z662 (1999) and PD 6493 (1991), which consider strain limit design issues, will be referenced. The importance of adopting a limiting strain criteria, in engineering practice and standards, has gained wider acceptance among the pipeline industry (INTEC, 1999a, 199b), engineering research community (Dinovitzer et al., 1999; Walker and Williams, 1995; Zimmerman et al., 1995) and design guidelines (API RP 1111, 1999; CSA, 1999; DNV, 1996).

Limit states is a reliability based design methodology that specifies the factored resistance to be greater than the factored loads with incorporation of a limited plastic response. A number of national pipeline codes, including the British, Norwegian, Dutch and Canadian, provide specific guidance on strain based, limit states design. Many years of successful pipeline operation in the North Sea validates this design approach. To illustrate the difference between allowable stress and limit states design, the respective stress-strain regimes for a typical pipeline stress-strain response is schematically illustrated in Figure 7.6-1. The three zones (A, B, C) can be defined as

A *Allowable stress* – maximum level for conventional analysis with typical design factors ranging from 0.72-0.90

B *Limit states* – upper limit for loads governed by stress based mechanisms (e.g. wave, current)

C *Limit states* – upper limit for loads governed by strain based mechanisms (e.g. frost heave, ice gouge) A typical tensile strain limit is about 1.5%.

7.6.1.1.3 Structural Robustness

One of the main objectives for the current assessment study is to evaluate the relative structural response between single wall and double wall pipeline systems with comparable structural robustness or equivalent strength. For the engineering community, however, there is a considerable difference in opinion in defining equivalent robustness between the single wall and double wall pipeline system alternatives. For example, comparable robustness could be defined as a function of:

- Equivalent wall thickness for the inner and/or outer pipelines of the double wall alternative in comparison with the single wall pipeline
- Equivalent diameter to wall thickness ratios (D/t) for all pipelines of the single wall and double wall systems
- Equivalent bending stiffness (EI) between the single and double wall pipelines, which is proportional to the pipeline diameter and wall thickness ($EI \mu D^3t$),
- Comparable pressure containing integrity under design load conditions

The first three criteria have merit with respect to stress based load events, such as burst limits due to hoop stress arising from internal pressure, or wall thickness requirements, such as corrosion allowance. For buried arctic marine pipelines that are potentially subjected to significant relative soil displacements, due to strain based mechanisms such as thaw settlement, frost heave, ice gouge, these formulations do not adequately reflect a consistent basis for an assessment of equivalent structural robustness. This has been addressed in Section 7.6.1.2 and illustrated in Figure 7.6-1. Consequently, the comparable pressure containing integrity criterion has been developed and adopted for the current study.

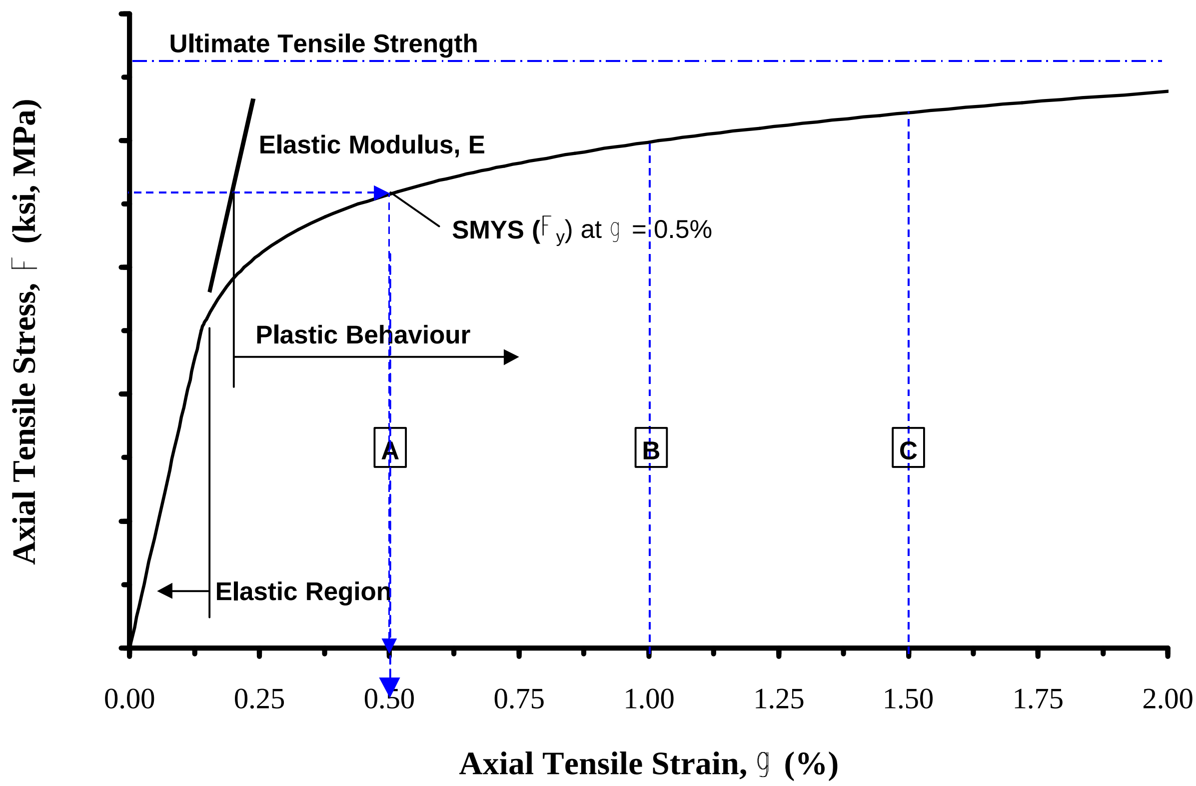


Figure 7.6-1. Typical Pipeline Stress–Strain Response and Characterisation of Upper Limits for Design Methods.

The key issue is the significant axial pipeline strains that would develop due to the imposed relative soil displacement field, which can be characterized by large deformations and inelastic strains. This constraint would be in addition to the effects of internal pressure and thermal stress. Consequently, the proposed equivalent robustness is specified as comparable mechanical integrity in terms of the pipeline structural response:

- Equivalent robustness ≡ Pipeline Integrity with respect to product containment; that is, the likelihood of failing the single walled or both pipes of the double walled pipeline from excessive tensile strain.

The basis is defined with respect to satisfying the limit tensile strain criteria governing the structural response of the respective pipelines, which comprise the single wall and double wall systems. A limiting tensile strain criterion was adopted since excessive tensile strain represents a significant threat in terms of pipeline rupture and loss of product containment integrity. Although excessive compressive strain levels (i.e. pipeline stability) must also be considered for design, the consequence would most likely only result in local wrinkling or sectional collapse due to ovalisation. This event would be of economic significance to the pipeline operator, but would not likely result in accidental product release. Excessive compressive strains are therefore considered to lead to functional failure, rather than a containment failure of the pipeline system.

7.6.1.1.4 Tensile Strain Limits – Structural Integrity

Pipeline systems should have adequate resistance to prevent propagating fracture, which can lead to loss of pressure containment integrity and release of product into the environment. The development of propagating fracture is primarily due to high stress/strain levels and the presence of local metallurgical flaws, in general, but not necessary for girth weld defects or brittle microstructures. Three characteristic mechanisms can be associated with the initiation of fracture events:

- Pipeline body flaw propagation due to bending strain
- Axial girth weld flaw propagation due to internal pressure (i.e. hoop stress)
- Circumferential girth weld flaw propagation due to pipeline bending strain

Tensile strain limits are normally established based upon consideration for the potential growth of the largest weld defect that satisfies the weld acceptance criteria. This dictates the requirement for crack-tip opening displacement (CTOD) tests during welding procedure development. Engineering critical assessment (ECA) methods, essentially fitness-for-purpose analysis, can be employed to evaluate pipeline integrity based on the adopted welding procedure. The ECA investigation focuses on crack tip opening displacement (CTOD) testing and analysis. Parameters such as weld toughness and ductility, tensile strain limits as well as maximum acceptable flaw size, shape and location are established by ECA methods to provide the specified level of pipeline integrity with respect to the combined tensile loads imposed on the pipeline. The weld toughness requirement increases and/or the maximum acceptable flaw size decreases with increasing applied tensile strain levels. In general, loss of product containment and pipeline integrity due to tensile failure would probably be associated with the growth of a small planar defect, in either the pipe body or more likely in a girth weld.

Material toughness, flaw acceptance criteria (size, shape and position) and tensile strain limits are engineering parameters that characterize a coupled, complex relationship. A number of design alternatives exist for any required level of pipe integrity with respect to the limit tensile strain. For example, if a high design tensile strain is considered then some combination of increased toughness of the pipeline material and decreased acceptable flaw size is required. The specified level of toughness would apply to the pipeline, the weld material and the heat-affected zone (HAZ), which can be defined as the pipeline material in the vicinity of the weld. The HAZ influences local mechanical properties of the pipeline and typically the toughness is reduced, due to the heating and cooling associated with the welding process.

In practical terms, a high design strain limit increases the tolerance of a pipeline to large bending deformation but tends to also increase the pipeline material cost. Increasing toughness is generally synonymous with a lower pipeline grade and thus a greater wall thickness is required to satisfy the specified strain limits. Decreasing the acceptable flaw size tends to increase pipeline construction costs by raising the welding and weld quality control standards. Strain based design should invoke a requirement for crack tip opening displacement (CTOD) testing of both the pipe and girth welds to verify the design integrity with respect to potential tensile failure from the uncontrolled growth of a flaw in the material. The procedure which links toughness, flaw size and tensile strain limit is generally called engineered critical assessment (ECA). The British Standard PD 6493 (1991) provides valuable guidance in this area for engineering analysis.

For the comparative pipeline assessment study, tensile strain limits were based on the parametric analysis conducted by INTEC (1998e), which considered the ultimate tensile strain to be 3.6% and selected lower design strain limits.

7.6.1.1.5 Compressive Strain Limits – Structural Stability

For combined loading due to internal pressure, external pressure and external displacements (i.e. geotechnical loads), the pipeline should also resist local sectional collapse and global buckling instability. The critical strain (i.e. curvature limit) is a function of pipeline geometry (i.e. diameter, wall thickness, initial pipe out-of-roundness), material properties (i.e. stress-strain response) and applied loads (i.e. axial and transverse geotechnical loads, internal and external pressure). Pipeline stability limits are typically based on coupled empirical and analytical studies.

7.6.1.2 Basis of the Pipeline Response Analysis

7.6.1.2.1 Structural Parameters

The baseline structural parameters defining the single wall pipeline (Case A) and double wall pipe-in-pipe systems (Case B, Case and Case D) are summarized in Table 7.6-2. The pipeline mechanical properties were adopted from Walker and Williams (1995) and the stress-strain response characteristics were defined by the Ramberg-Osgood formulation.

7.6.1.2.2 Internal Pressure

The positive working fluid pressure ($p = 1440psi = 10MPa$) imparts a hoop or circumferential stress (s_{22}) on the single wall pipeline and inner pipeline of the double wall system. The net effect is to cause a diametral expansion of the single pipeline or inner pipeline in proportion with the expression

$$s_{22} = \frac{p\, r_i}{t} \qquad (7\text{-}1)$$

where p is the internal pressure (psi, Pa), r_i is the internal pipeline radius (in, m) and t is the pipeline wall thickness (in, m).

Table 7.6-2.
Parameters Defining the Single Wall and Double Wall Pipeline Configurations.

Parameter		Case A	Case B	Case C	Case D
		Single Steel Wall	Double Steel Wall (Bulkhead)	Double Steel Wall (Shear Ring)	Double Steel Wall (Guide)
Modeled Length	L	0.6miles (1km)			
Steel Grade		API 5L X52			
Elastic Modulus	E	30,000ksi (205GPa)			
Yield Stress	σ_y	52ksi (358MPa)			
Plastic Yield Offset	α	1.86			
Hardening Exponent	n	17.99			

Carrier Pipeline		Case A	Case B	Case C	Case D
		Single Steel Wall	*Double Steel Wall* (Bulkhead)	Double Steel Wall (Shear Ring)	Double Steel Wall (Guide)
Outside Diameter	D_o	NPS-12[a], 12.75″ (323.9mm)			
Operating Pressure	p	1440psi (10MPa)			
Operating Temperature	T	110°F (43°C)			
Wall Thickness	t_w	1/2″ (12.7mm)	3/8″ (9.525mm)		

Outer pipeline		Case A	Case B	Case C	Case D
		Single Steel Wall	Double Steel Wall (Bulkhead)	Double Steel Wall (Shear Ring)	Double Steel Wall (Guide)
Outside Diameter	D_o	N/A[b]	NPS-14 (355.6mm)	NPS-16 (406.4mm)	NPS-14 (355.6mm)
Annulus Pressure	p	N/A	1440psi (10MPa)	15psi (101kPa)	
Operating Temperature	T	N/A	110°F (43°C)	Ambient	
Wall Thickness	t_w	N/A	3/8″ (9.525mm)		

[a] NPS ≡ Nominal Pipe Size
[b] N/A ≡ Not Applicable

7.6.1.2.3 Thermal Stress

The single pipeline and inner pipeline experiences thermal stress due to the differential temperature gradient between the product and external environment. The product working temperature was defined as *110°F* (*43°C*) and the reference environmental lay-in temperature was considered to be *32°F* (*0°C*). The corresponding differential temperature was (*DT = 78°F = 43°C*). Thermal strains are developed due to the temperature differential,

$$e = a \, \Delta T \qquad (7\text{-}2)$$

where a is a material constant termed the coefficient of linear expansion (in/in/°F, m/m/°C). In terms of pipeline response, the deformation is realized as an imposed axial thermal stress on the pipeline due to axial restraint (e.g. frictional resistance, structural boundary condition).

7.6.1.2.4 External Loads

Historical records have established that the two most significant factors, which have caused accidental product release from offshore pipelines, are external trauma due to natural hazards and corrosion (Bea, 1999; Farmer 1999). For buried offshore pipelines in the North Slope region of the Alaskan Beaufort Sea, strudel scour (e.g. unsupported span, vortex shedding), and ice gouging are generally considered the greatest risk to pipeline integrity in terms of loading severity. Alternate environmental loads are also recognized and these project specific factors can include thaw settlement, frost heave, stamukha grounding, direct ice contact as well as rare events such as an earthquake or tsunami.

Strudel scour results in the formation of seabed depressions where unsupported pipeline lengths span and bridge the scour holes. Except for the low risk of pipeline fatigue failure due to vortex shedding, strudel scour expresses itself similarly to a large subgouge soil deformation in potentially exposing a pipeline to bending strains high enough to compromise its integrity. Ice gouge events impose large soil deformations (movement) beneath the ice keel (subgouge) that can subject a buried pipeline to high strain levels. Details of the ice gouge process are presented in a number of sources including C-CORE (2000), INTEC (1998d), C-CORE (1998) and API RP 2N (1995). Consideration of pipeline integrity subject to relative soil deformation, from an extreme gouge (i.e. 100-year design event), forms the basis for defining the external load on the pipeline systems.

The extreme design load case was based on the statistical analysis of ice gouge events conducted by INTEC (1998d) for the Northstar development project. The 100-year load event, adopted for the current comparative assessment study, was defined by a peak transverse horizontal displacement of 5ft (1.5m), imposed at the pipe springline, and distributed over a 50ft

(15m) pipeline length. The soil displacement field is illustrated in Figure 7.6-2, which was based on empirical relationships that defined the subgouge displacement field (Nixon et al., 1996; Woodworth-Lynas et al., 1996).

The selected design scenario for the geotechnical loads imposed on the pipeline due to an ice gouge event, of the current study, represents a more severe loading condition than either strudel scour or thaw settlement.

7.6.1.3 Numerical Model for Pipeline Response

The response of a buried arctic marine pipeline subject to an ice gouge event is analysed by the finite element method. Three coupled components define the numerical model: soil/pipeline interaction; ice gouge/soil relationships; and finite element formulation.

Further details are presented in Kenny et al. (2000) and Woodworth-Lynas et al. (1996). A schematic illustration of pipeline response due to an imposed soil displacement field is presented in Figure 7.6-3. The soil response is idealized and represented by a series of springs. The soil load-displacement response functions (t_u-x_u, p_u-y_u) presented in Table 7.6-3, were defined using the guidelines of the ASCE (1984) guidelines for the seismic design of oil and gas pipeline systems. They assumed an undrained, cohesive soil strength ($C_u = 1045psf = 50kPa$) with an axial adhesion reduction factor of 10%.

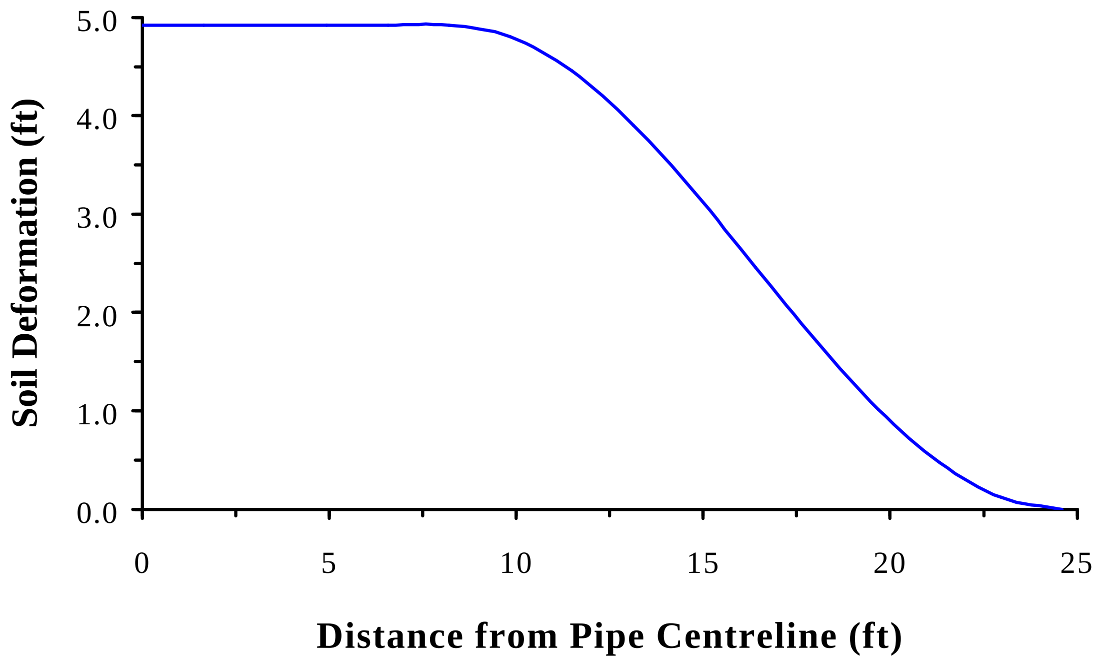


Figure 7.6-2. Imposed Soil Deformation Profile for Structural Integrity Analysis.

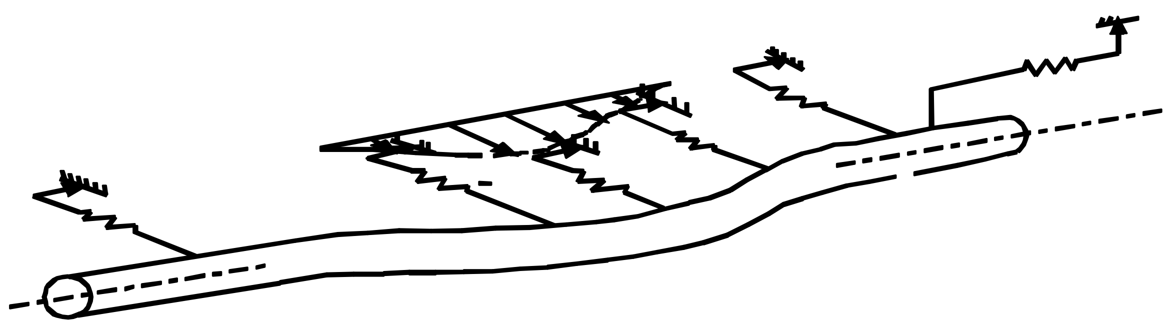


Figure 7.6-3. Schematic Illustration of the Soil/Pipeline Interaction Model Employed for Global Structural Integrity Analysis.

Table 7.6-3. Soil Characteristics and Yield Response Functions.

System	Parameter		Magnitude	
			Imperial	SI
All Cases	Unit Weight	γ	120lb/ft^3	19kN/m^3
	Maximum Subgouge Deformation	u_c	4.9ft	*1.500m*
Soil Response (NPS-12)	Yield Axial Load	t_u	0.3kips/ft	4.5kN/m
	Yield Axial Displacement	x_u	0.3in	7.62mm
	Yield Horizontal Load	p_u	5.4kips/ft	78.6kN/m
	Yield Horizontal Displacement	y_u	3.2in	80mm
Soil Response (NPS-14)	Yield Axial Load	t_u	0.3kips/ft	4.9kN/m
	Yield Axial Displacement	x_u	0.3in	7.62mm
	Yield Horizontal Load	p_u	5.9kips/ft	85.8kN/m
	Yield Horizontal Displacement	y_u	3.2in	80mm
Soil Response (NPS-16)	Yield Axial Load	t_u	0.4kips/ft	5.6kN/m
	Yield Axial Displacement	x_u	0.3in	7.62mm
	Yield Horizontal Load	p_u	6.6kips/ft	97.0kN/m
	Yield Horizontal Displacement	y_u	3.2in	80mm

The yield load displacement relationships, as a function of pipeline diameter, are summarized in Table 7.6-3.

The finite element analyses was conducted using ABAQUS/Standard version 5.7. The soil/pipeline interaction was discretized by two-dimensional beam elements (PIPE22) and one-dimensional spring elements (SPRINGA). The finite element model, which accounted for longitudinal symmetry, is illustrated schematically in Figure 7.6-4. The pipeline response is based on Timoshenko beam theory and accounts for the effects of internal pressure and temperature gradient. The numerical model and procedure has been subject to peer review and recognized; see for example Kenny et al. (2000). The finite element solution accounted for fully nonlinear behaviour (i.e. geometric and material) with large displacement and strain.

7.6.1.4 Structural Robustness Analysis

7.6.1.4.1 Introduction

Preliminary pipeline response analysis, due to an ice gouge event, was conducted with Cases A, B, C and D. These are summarized in Table 7.6-2 and illustrated schematically in Figure 7.6-5. The two main considerations developed through the analysis were:

- The structural response of the inner and outer pipeline for the double wall system could be effectively and accurately modelled as having the same radius of curvature. This was due to the small annular clearance and the large magnitude of the imposed relative soil displacement field due to the design ice gouge event.

- Stress concentrations developed during the interaction between the inner and outer pipelines through the spacers and bulkheads could be resolved through project specific design details; for example see Section 7.3 on pipeline conceptual design.

Consequently, the analysis presented for the comparative structural robustness assessment was conducted with consideration of only the single wall pipeline (Case A) and the guided, double wall pipeline system (Case D). The structural integrity analysis was conducted by investigating the pipeline response subject to internal operating pressure, differential thermal gradient and imposed soil deformation field, identified in Section 7.6.2, and summarized as:

- Internal working pressure (p = 1440psi = 10MPa)

- Differential temperature (ΔT = 110°F - 32°F = 78°F = 43°C)

- Soil displacement field (δ_{max} = 5ft = 1.5m)

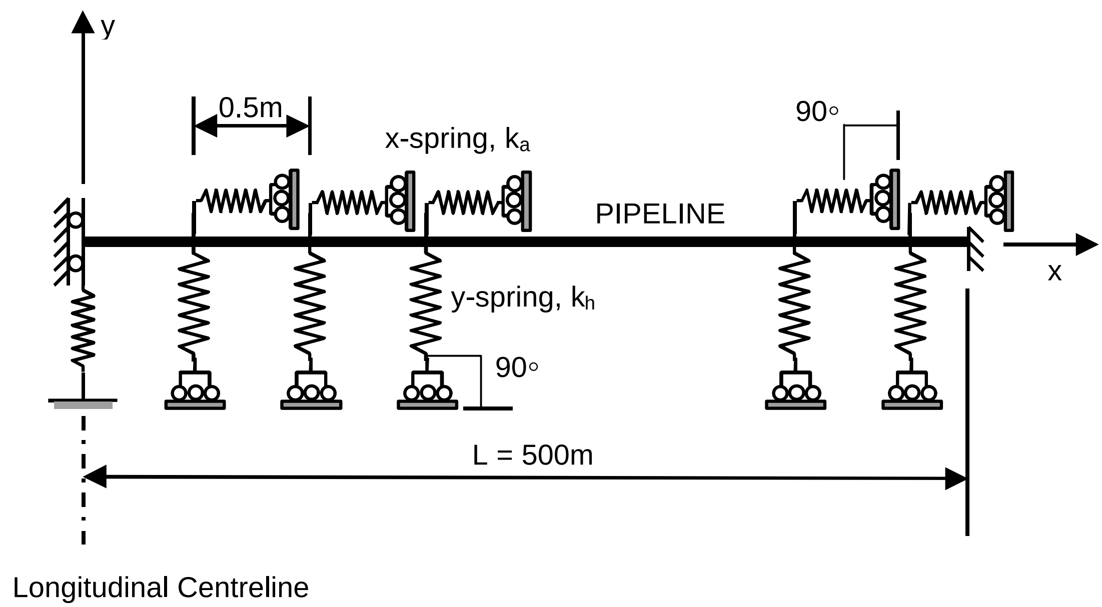


Figure 7.6-4. Schematic Illustration of Finite Element Model and Geometric Boundary Conditions.

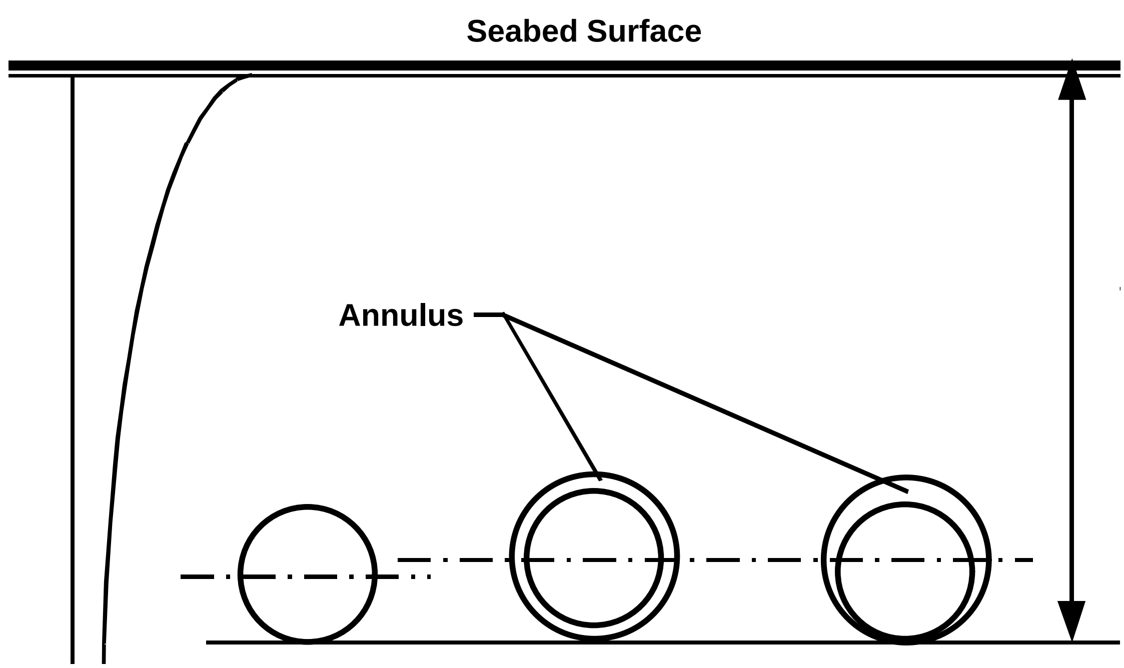


Figure 7.6-5. Schematic Illustration of the Baseline Pipe Configurations.

- The matrix defining the baseline and variant load case scenarios for the comparative assessment of the single wall versus double wall pipeline systems is summarized in Table 7.6-4. The parameters varied during the investigations were increased wall thickness of the inner pipeline and material grade of both the inner and outer pipeline. The numerical model, based on the finite element method discussed in Section 7.6.3, was employed to consider these factors.

Table 7.6-4.
Parameters Defining the Baseline and Variant Load Case Scenarios for the Finite Element Analysis Investigating Comparative Structural Robustness.

Baseline Load Case Scenarios							
Scenario	Single / Inner Pipe			Outer pipe			Comments
	D_o	t_w	Load	D_o	t_w	Load	
1	12.75″	1/2″	ΔT, p, δ	NA			Single Wall, Case A
2	12.75″	3/8″	ΔT, p	14″	3/8″	δ	Double Wall, Case D

Variation on Baseline Double Wall Load Case Scenario			
Scenario	Inner Pipe	Outer pipe	Comments
3	T_w = 1/2″	API 5L X52	Double Wall, Case D
4	T_w = 1/2″; API 5L X65	API 5L X52	Double Wall, Case D
5	T_w = 1/2″; API 5L X65	API 5L X65	Double Wall, Case D

NA Not Applicable
NC No Change
ΔT Differential Temperature (ΔT = 78°F = 43°C)
p Internal Pressure (p = 1440psi = 10MPa)
δ Soil Displacement (δ_{max} = 5ft = 1.5m)

7.6.1.4.2 General Response Characteristics

- The resultant deformed profiles for the baseline systems investigated, single wall (Case A, Scenario 1, Table 7.6-4) and double wall (Case D, Scenario 2, Table 7.6-4), is illustrated in Figure 7.6-6. The imposed relative soil displacement field, due to the ice gouge, is also shown for comparison. The greater resistance of the double wall system (Case D) demonstrates the influence of increased bending stiffness, where the displacement response was moderated in comparison with the single wall pipeline (Case A). The computed pipeline response data is only presented from the pipe centreline

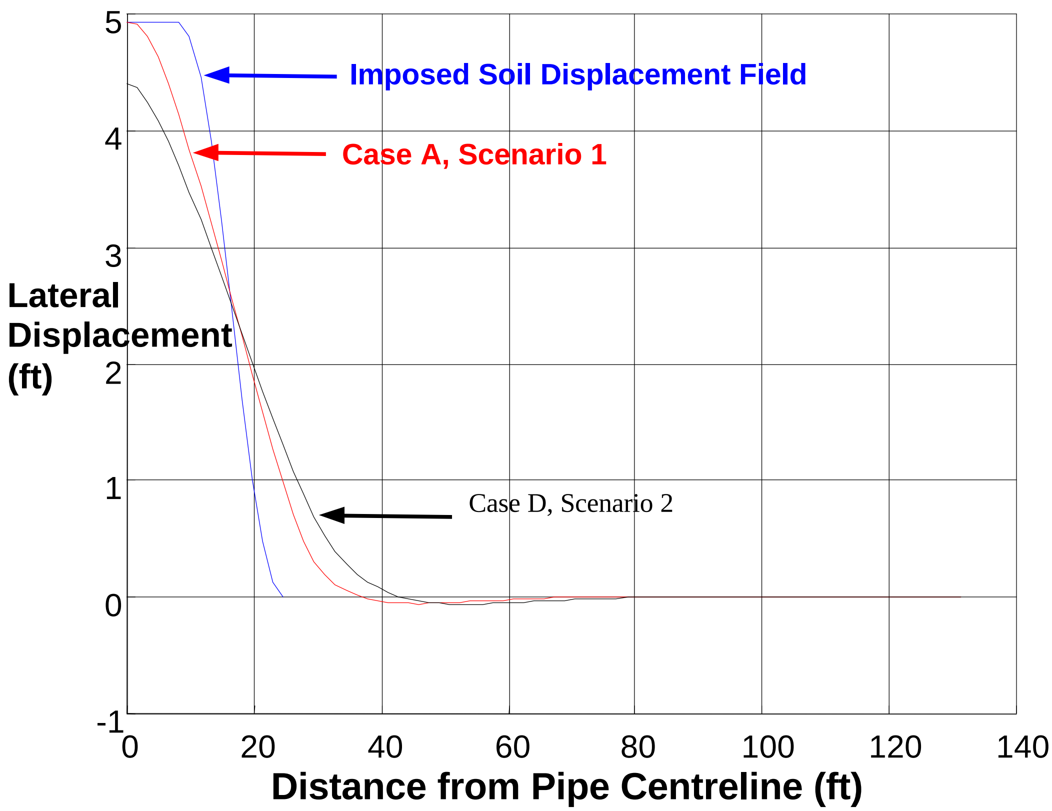


Figure 7.6-6. Imposed Soil Displacement Field and Pipeline Deformational Response Profiles for the Single (Case A, Scenario 1) and Double (Case D, Scenario 2) Wall Pipeline Systems.

due to axial symmetry. The greater structural resistance to transverse, bending deformation exhibited by the double wall pipeline system can be attributed to the greater cross-sectional area of steel and the increased diameter of the outer pipeline. In relatively simple terms, the pipeline bending stiffness (*EI*) is proportional to the diameter and wall thickness (EI μ D^3t).

One of the primary disadvantages for employing a larger diameter, outer pipeline is that, for the same radius of curvature (i.e. bend deformation profile), a greater longitudinal strain would develop in comparison with the single wall or inner pipeline due to the moment–curvature relationship. Furthermore, a larger diameter pipe would "attract" a greater geotechnical load due to the increased projected surface area. For a buried Arctic marine pipeline, subject to an ice gouge event, the structural response is a complex interaction between the defining pipeline characteristics (e.g. geometry, mechanical parameters), soil properties (e.g. strength, yield response functions) and subgouge displacement field.

7.6.1.4.3 Pipeline Integrity

Tensile strain limits are an important factor to address to prevent pipeline rupture and mitigate the propagation of local flaws or defects.

For applied longitudinal pipeline tensile strain levels less than 0.5%, the tensile strain capacity of girth welds can be determined by standard API 1104 (1999). The workmanship based standard specifies weld acceptance criteria as a function of the pipe diameter, pipe wall thickness, crack-tip opening displacement (i.e. fracture toughness), weld misalignment and applied strain levels.

Typically, extreme design events for deformation based mechanisms, such as ice gouging, subject the pipelines to significant tensile strains greater than 0.5%. Consequently, alternative methods must be incorporated to develop appropriate tensile strain limit criteria. The procedure is based on employing principles of fracture mechanics and conducting an engineering critical assessment (ECA). The design standards CSA Z662 (1999) and PD 6493 (1991) present a proposed methodology for the acceptance criteria for weld defects. The CSA Z662 (1999) code defines an analytical procedure to conduct a preliminary assessment of critical defect size that is parallel with a Level 1 treatment presented by PD 6493 (1991).

For the comparative pipeline assessment study, the tensile strain limits were based on the analysis conducted by INTEC (1998e), which employed a Level 2 assessment in accordance with the British Standard PD 6493 (1991). A parametric analysis was conducted by INTEC (1998e) to determine the critical weld flaw geometry assuming a range of crack-tip opening displacement (CTOD) values for a pipeline subject to an ultimate tensile strain limit of 3.6%.

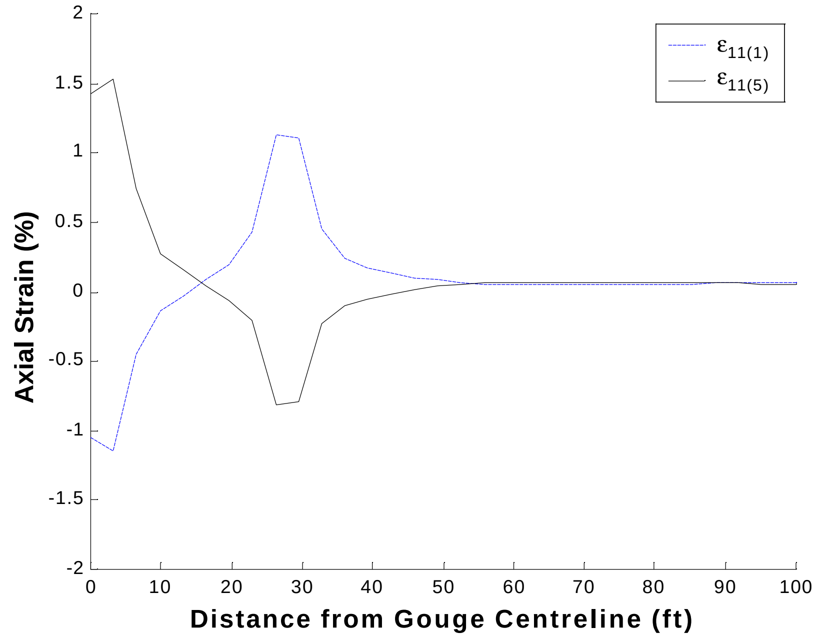
Typical, longitudinal distributions of axial strain for the single wall pipeline (Case A, Scenario 1, Table 7.6-4) and the outer pipeline for the double wall system (Case D, Scenario 2, Table 7.6-4) are illustrated in Figure 7.6-7. The inner pipeline for Case D exhibited a similar longitudinal distribution to the outer pipeline but with a lower strain magnitude. Although the peak strain magnitude for the double wall system ($e = 1.95\%$) was greater than the single wall pipeline ($e = 1.54\%$), the greater flexural rigidity of the double wall pipeline was exhibited by the moderated strain response with increasing distance from the pipe centreline.

The computed maximum tensile strain response magnitudes for the single walled pipeline and double walled pipeline systems, for the load case scenarios listed in Table 7.6-3, are summarized in Table 7.6-5. For the double wall pipeline systems considered, the inner and outer pipes will adopt the same radius of curvature in response to large relative soil deformation. Consequently, due to the inherent moment–curvature relationship, the strain levels developed in the larger diameter outer pipe would necessarily exceed those of the inner pipe. The strain magnitudes demonstrate that increasing pipe wall thickness and/or material grade has a beneficial influence on the double wall pipeline response with respect to decreasing strain levels.

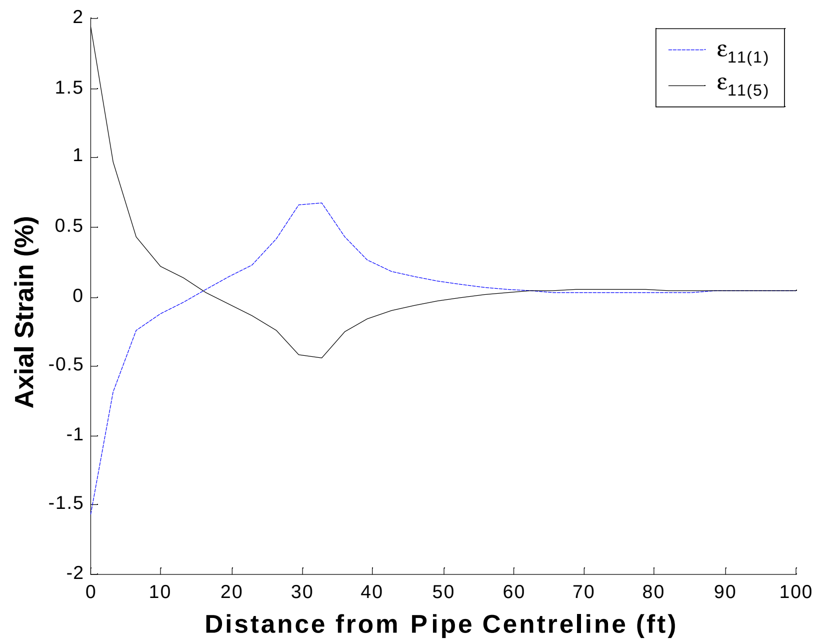
Table 7.6-5. Summary of Computed Tensile Strain Response for the Single Wall (Case A) and Double Wall (Case D) Pipeline Systems.

Single Wall Pipeline (Case A)	
Scenario	Computed Strain (%)
	Finite Element
1	1.54

Double Wall Pipeline (Case D)		
Scenario	Computed Strain (%)	
	Finite Element	
	Inner	Outer
2	1.79	1.95
3	1.67	1.85
4	1.51	1.66
5	1.37	1.50



(a)



(b)

Figure 7.6-7. Longitudinal Distribution of Axial Strain (a) Single Wall Pipeline (Case A, Scenario 1, Table 7.6-4) and (b) Outer Pipeline of Double Wall System (Case D, Scenario 2, Table 7.6-4).

For the adopted ultimate tensile strain limit (3.6%), the analysis demonstrates that the various double wall alternatives represent equivalent structural robustness with respect to the single wall pipeline based on the proposed comparative measure (Section 7.6.1.3) in terms of pipeline integrity and product containment.

For pipeline integrity issues, girth weld flaws are of significant concern. The exhibited characteristic pipeline response with respect to localized peak strain magnitude is advantageous for the double wall pipeline system. The pipeline configuration could be designed such that the girth welds for the inner and outer pipeline are stationed at staggered locations, offset by as much as one half the construction joint length, thereby further reducing the risk of simultaneous pipeline failure. The strain distribution (Figure 7.6-7) was determined for the extreme ice gouge event (i.e 100-year design).

In terms of pipeline failure due to tensile rupture, the probability of a significant defect existing in both the inner and outer pipelines, as well as located within the same peak tensile strain regime, is very remote, Figure 7.6-8. For the double wall pipeline system, loading mechanisms that cause the outer pipe to reach a design strain limit is unlikely to result in the failure of either, let alone both pipes, in the double walled case. Matching the tensile strain levels for the outer pipeline with the single wall case would constitute excessive conservatism in terms of comparable mechanical integrity of the double walled pipeline. Thus, the logic for defining equivalent, comparable robustness is to match the strain level ratios for the inner pipeline of the double walled case with the single wall pipeline.

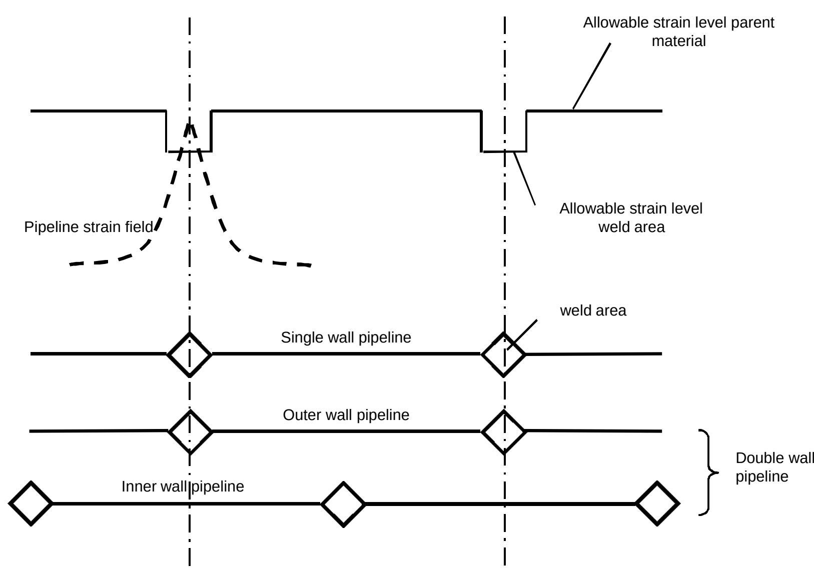


Figure 7.6-8: Assumed location of peak tensile strains with respect to pipe welds and allowable strain levels.

As previously discussed in Section 7.6.1.4, specific limits for the critical flaw geometry (i.e. defect length, depth, location) and weld misalignment (i.e. eccentricity) cannot be determined prior to the welding procedure qualification and determination of the material fracture toughness (i.e. CTOD). In addition, pipeline material grade selection and welding procedure can be selected to accommodate the tensile strain through considerations of the weld metal and heat affected zone (HAZ).

7.6.1.4.4 Pipeline Stability

For combined loading due to internal pressure, external pressure and external forces or displacements, the pipeline should resist local sectional collapse and global buckling instability. The critical strain (i.e. curvature limit) is a function of pipeline geometry (i.e. diameter, wall thickness, initial ovality), material properties (i.e. stress-strain response) and applied loads (i.e. axial and bending loads, internal and external pressure). Pipeline stability limits are typically based on coupled empirical and analytical studies, and for the current investigations are based on the compressive strain limits defined by the recommended practice API RP1111 (1999).

The critical compressive strains limits defined by API RP 1111 (1999) and the maximum axial compressive strain for the computed pipeline response (finite element method) are presented in Table 7.6-6. Also listed is a normalized strain ratio (Computed/Critical Strain Ratio) which relates the maximum compressive strain response (Computed Strain) to the compressive strain limit (Critical Strain). The data was evaluated for the load case scenarios summarized in Table 7.6-4.

Analysis of the computed strain ratios for the double wall pipeline system (Scenario 2 through 5) demonstrates that the inner pipeline satisfies the stability limit for all loading events. The only significant concern would be with respect to localized denting of the outer pipeline and the effects on the structural integrity of the inner pipeline. Although this should be viewed in context of the conservatism for compressive strain limits (INTEC, 1998e) and the significant compressive plastic strains imposed during the Northstar pipeline bend tests (Lanan, 1999). Furthermore, excessive compressive strains are primarily restrictive on serviceability conditions (e.g. flow rates, pigging operations).

Table 7.6-6.
Summary of Critical Compressive Strain Limits, Computed Compressive Strain Response and Strain Ratio the Single Wall (Case A) and Double Wall (Case D) Pipeline Systems.

Single Wall Pipeline (Case A)			
Scenario	Critical Strain (%)	Computed Strain (%)	Computed/Critical Strain Ratio
	API RP 1111 (1999)	Finite Element	
1	-2.74	-1.15	0.42

Double Wall Pipeline (Case D)						
Scenario	Critical Strain (%)		Computed Strain (%)		Computed/Critical Strain Ratio	
	API RP 1111 (1999)		Finite Element			
	Inner	Outer	Inner	Outer	Inner	Outer
2	-2.74	-1.16	-1.40	-1.56	0.51	1.34
3	-2.74	-1.16	-1.45	-1.62	0.53	1.40
4	-2.66	-1.16	-1.32	-1.48	0.50	1.28
5	-2.66	-1.16	-1.19	-1.33	0.45	1.15

7.6.1.5 Pipeline Structural Design Sensitivity

For the current study on comparative structural robustness, the effort has been limited to a single, extreme, combined design load case. A parametric investigation conducted by C–CORE (C–CORE, 2000) has demonstrated that ice gouge/soil/pipeline interaction is a coupled, complex and nonlinear process. The longitudinal distribution of axial strain and peak strain magnitude was dependent on a number of factors including:

- Pipeline Characteristics (e.g. D/t ratio, material grade)
- Soil Properties (e.g. strength, yield response functions)
- Ice Gouge (e.g. gouge geometry, ice feature bearing stress)

Alternate ice gouge and other environmental load events can be postulated that might change the required parameters for an equivalent double walled pipeline system. The structural response computations presented in the current document should not be considered definitive across the board generalizations considering the narrow focus of the design scenario parameters. The key issue to be recognized is that the investigation has demonstrated an equivalent structural robustness between the single wall and double wall pipeline systems.

7.6.2 CORROSION

The following sections 7.6.2.1 through 7.6.2.3 present subjective assessments and qualitative comparisons and of the following corrosion related design considerations:

- material selection
- cathodic protection
- chemical corrosion inhibition

Assessments made are subjective and, based on engineering judgement, rated as either minor, moderate or significant in impact. Corrosion is considered to be a relatively minor issue in a well-designed and monitored pipeline system.

There are a number of perceptions and concerns commonly raised for potential for corrosion in the annulus of the pipe in pipe system. Such concerns are indeed more fiction than fact and stem largely from the comparison to a cased road crossing where many failures have been attributed to a shorted casing.

No mechanism exists in the pipe in pipe annulus, in an environment that does not have oxygen or an electrolyte present to transfer the current between the pipes. The two pipes are continuously bonded or in contact along their entire length and therefore should not develop an electrical differential. This zero differential can be assured by periodically connecting the inner and outer pipes with earth straps as the double wall system is fabricated.

There are several solutions to mitigate the concern should it exist as presented in section 7.3. These would include a pressurized inert gas fill typically with either argon or nitrogen, and corrosion inhibitors prior to start up. No insulation or coatings are recommended on the inner pipe outer wall prior to pipe make up during construction, section 7.1. Such coverings would only tend to isolate the two pipes that could lead to differences in potentials. The steel pipe in pipe system can be adequately protected with sacrificial aluminum anodes

Gibson (1994) supports the above position on permitting contact between the inner and outer pipes. The DOT regulations regarding cathodic protection are relevant for casings or insulated double walled pipelines. Relief from these regulations should be considered, as this is a conformance issue, not a pipe integrity issue. In the case of cased crossings, the current is impressed on the inner, not the outer pipe and the corrosion protection coating is on the inner, not the outer pipe, as would be the case in our design. In the case of insulated double walled pipelines, cathodic protection is applied to the outer pipe and because the inner pipe is insulated, the regulation is naturally satisfied, hence it is not an issue but maintaining the isolation is not essential to the corrosion protection system.

7.6.2.1 Material Selection

This section presents a subjective assessment of characteristic differences and a qualitative comparison of the study case pipelines for the following corrosion related material selection considerations:

- service conditions
- operating conditions
- corrosiveness / erosiveness of the fluid carried
- expected forms of corrosion
- external corrosion coatings

Assessment

Based on the comparison of study case pipelines presented in Table 7.6.2.1-1 differences are assessed as follows:

- PIP configurations B and C have additional metallic pipeline components to consider such as bulkheads and shear rings, relative to single wall pipelines. This is a manageable and relatively minor concern, assuming galvanically similar steels are used for all components.

- PIP configurations must deal with the corrosion environment present within the annulus. During normal operation this is a manageable and relatively minor concern, assuming chemical corrosion inhibition in the form of an inert gas and / or chemical inhibitor is used. However, in the event of an integrity failure of the outer pipe, a potential for local accelerated corrosion within the annulus will develop. Due to PIP configuration geometry, even with the assumption of “best practice” repair and commissioning, a completely clean, vacuum dried and chemically inhibited and “oxygen scavenged” annulus will be difficult to ensure. Consequently this potential for corrosion in the annulus cannot be entirely eliminated. However, localized accelerated corrosion will only continue however until residual water and oxygen are depleted. From a design perspective this is a manageable and relatively minor concern, that can be addressed by adding a corrosion allowance to the PIP pipeline components.

- The corrosiveness of sweet crude oil is typically very low for water contents of less than 30% and flow velocities greater than 1 m/s, approximately. If water content is greater and / or flow velocities are lower chemical corrosion inhibition and / or a pipe corrosion allowance will be required. All study case pipelines will be equally affected by these requirements and so the effect of product fluid corrosiveness is not considered to be a source of difference(s) between the study case pipelines.

- The erosiveness of sweet crude oil is typically very low for flow velocities in the typical design range of 1 m/s to 3 m/s, approximately. The presence of erosive solids is not indicated in the design basis and is not typically present in sweet crude oil. If flow velocities are higher than 3 m/s, approximately, and / or erosive solids are present a pipe erosion allowance will be required. All study case pipelines will be equally affected by these requirements and so the effect of product fluid erosiveness is not considered to be a source of design difference(s) between the study case pipelines.

Comparison

Table 7.6.2.1-1 presents a qualitative comparison of the corrosion related material selection considerations for the four study cases. The issues for the double walled systems Cases B, C and D, that is for bulkheads, shear rings and guides, are the same:

Table 7.6.2.1-1
Qualitative Comparison of Study Case Pipelines for Material Selection for Corrosion

Material Selection Consideration	**Study Case A**	**Study Cases B, C & D**
	Single Wall Issues	**PIP Issues**
service conditions: - environmental corrosiveness - design stress limits - cathodic protection details	Standard design practice applies to all pipeline components., i.e.; saltwater corrosion resistance, galvanically similar materials, yield strengths less than 420 MPa, approx..	Standard design practice applies to all pipeline components., i.e.; saltwater corrosion resistance, galvanically similar materials, yield strengths less than 420 MPa, approx..
operating conditions: - maximum operating pressure - maximum operating temperature - minimum ambient temperatures	No special requirements; standard design practice applies to all pipeline components.	No special requirements; standard design practice applies to all pipeline components.
corrosiveness of fluid transported: - presence and concentration of: • hydrogen sulphide • carbon dioxide • oxygen • chlorides	Sweet crude oil is not typically corrosive. With no other corrosive components present there are no special requirements; standard design practice applies to all pipeline components	Sweet crude oil is not typically corrosive. With no other corrosive components present there are no special requirements; standard design practice applies to all pipeline components

• water		
potential for erosion: - presence and concentration of solids - density and velocity of fluids carried	Sweet crude oil is not typically erosive. Erosive solids are not indicated in the design basis nor are they typically present in sweet crude oil. Therefore there are no special requirements; standard design practice applies to all pipeline components.	Sweet crude oil is not typically erosive. Erosive solids are not indicated in the design basis nor are they typically present in sweet crude oil. Therefore there are no special requirements; standard design practice applies to all pipeline components.
potential for types of corrosion (see note 1.): - galvanic - pitting - crevice - intergranular - stress cracking - fatigue	For normal operation, assuming selection of galvanically similar materials and yield strengths less than 420 MPa, approx., there are no special requirements; standard design practice applies to all pipeline components.	No special requirements arise for normal operation, with materials as described for Study Case A., and an inert or otherwise chemically corrosion inhibited annulus. However, a corrosion allowance may be required for all pipeline components to address local accelerated corrosion that may occur within the annulus as a result of an integrity failure in the outer pipe.
external corrosion coating (see note 2.) characteristics: - cathodic disbondment - surface wetting - chemical adhesion - oxygen and water-transmission - water absorption	Typical requirements and design practice for selection of an external pipe coating for protection of the exterior of the single wall pipe for marine service applies.	Typical requirements and design practice for selection of an external pipe coating for protection of the exterior of the outer pipe for marine service applies. The exterior of the inner pipe is protected by chemical corrosion inhibition rather than by a combination of external coating and CPS.

Notes:

1. NACE corrosion classifications are listed. Other methods of classifying corrosion exist.
2. In general internal coatings are not used for the purpose of corrosion protection because of the inability to completely avoid discontinuities in, and thus ensure the effectiveness of, the coating.

7.6.2.2 Cathodic Protection

This section presents a subjective assessment of characteristic differences and a qualitative comparison of the study case pipelines for the following cathodic protection considerations:

- pipe material specifications
- overall pipeline characteristics
- environmental conditions
- external corrosion coatings
- CPS anode type
- operations and maintenance requirements

Assessment

Based on the comparison of study case pipelines presented in Table 7.6.2.2-1 differences are assessed as follows:

- Relative to single wall pipelines PIP configurations have approximately 36% additional exterior pipeline surface area to cathodically protect. However, this exterior surface will operate at a lower temperature due the insulating effect of the annulus. While a greater surface area will increase the requirement for anode material, a lower operating surface temperature will decrease this requirement, approximately 25% for each 10 degrees C of temperature reduction to a minimum operating temperature of 30 degrees C.. The approximate net effect of these factors is cathodic protection requirements will be similar for PIP and single wall pipelines. Consequently this is a relatively minor design difference between the study case pipelines.

Comparison

Table 7.6.2.2-1 presents a qualitative comparison of the cathodic protection considerations for the four study cases. The issues for the double walled systems Cases B, C and D, that is for bulkheads, shear rings and guides, are the same:

Table 7.6.2.2-1

Comparative Assessment of Study Case Pipelines for Cathodic Protection

Cathodic Protection Consideration	**Study Case A**	**Study Cases B, C & D**
	Single Wall Issues	**PIP Issues**
pipe component material characteristics: - steel type - steel grade	Assuming HIC resistant steel with yield strengths less than 420 MPa, approx., standard design practice selection applies for all pipeline components.	Assuming HIC resistant steel with yield strengths less than 420 MPa, approx., standard design practice selection applies for all pipeline components.
pipeline characteristics: - length - diameter - depth of burial - operating temperature - design life - access	No special requirements, standard design practice applies.	The exterior surface areas of PIP configurations are larger than equivalent single wall pipelines but, other than this, they have no special requirements; standard design practice applies.
environment characteristics: - sea water properties: • ambient temperature • current speed • turbulence - soil properties: • ambient temperature • resistivity	No special requirements, standard design practice applies.	No special requirements, standard design practice applies.
corrosion coating characteristics: - type - application effectiveness - design life	No special requirements, standard design practice applies.	The exterior surface areas of PIP configurations are larger than equivalent single wall pipelines but, other than this, they have no special requirements; standard design practice applies.
anode characteristics: - material type	Assuming HIC resistant steel with yield strengths less than 420 MPa, approx., standard anode material selection applies.	Assuming HIC resistant steel with yield strengths less than 420 MPa, approx., standard anode material selection applies.
operation and maintenance: - inspection requirements - seasonal access restrictions - monitoring requirements	No special requirements, standard design and operating practice applies.	No special requirements, standard design and operating practice applies.

7.6.2.3 Chemical Corrosion Inhibition

This section presents an assessment of characteristic differences and a qualitative comparison of the study case pipelines for the following chemical corrosion inhibition considerations:

- Product fluid characteristics
- potential for solids deposition
- pipeline configuration

Assessment

Based on the comparison of study case pipelines presented in Table 7.6.2.3-1 differences are assessed as follows:

- Due to their configuration, PIP pipelines differ from single wall pipelines in that corrosion inhibition will be required in the annulus. While this is a significant physical difference, it is a manageable and relatively minor concern for chemical corrosion inhibition given that inhibiting the annulus using a dry and inert gas, such as nitrogen, and / or chemical inhibitors is based on standard design and operating practice. E.g.,"cased crossing" design and operating practice can be adapted to study cases C and D. Similarly "Troika" design and operating practice can be applied to study case B.

Comparison

The following Table 7.6.2.3-1 presents a qualitative comparison of chemical corrosion inhibition considerations for the four study cases. The issues for the double walled systems Cases B, C and D, that is for bulkheads, shear rings and guides, are the same:

Table 7.6.2.3-1

Comparative Assessment of Study Case Pipelines for Chemical Corrosion Inhibition

Chemical Corrosion Inhibition Consideration	**Study Case A**	**Study Cases B, C & D**
	Single Wall Issues	**PIP Issues**
Characteristics of fluid transported: - pressure and temperature - velocity / flow regime - corrosivity, i.e. presence and concentration of: • hydrogen sulphide • carbon dioxide • oxygen • chlorides • water	For typical sweet crude oil (see “material selection” assessments above) corrosion and erosion rates in oil pipelines will be low. Corrosion inhibition will not be required to protect the inner wall of the single wall pipe.	For typical sweet crude oil (see “material selection” assessments above) corrosion and erosion rates in oil pipelines will be low. Corrosion inhibition will not be required to protect the inner wall of the inner pipe.
potential for solids deposition of fluid transported	Deposition of solids is not expected. No special design requirements exist for the single wall pipe.	Deposition of solids is not expected. No special design requirements exist for the inner pipe.
pipeline configuration:	None.	PIP configurations must address the potential for corrosion in the annulus.

7.6.3 LEAK DETECTION AND CONTAINMENT

A double walled pipeline that contains bulkheads (as further discussed in section 9.5) affords no apparent leak detection advantages relative to the single walled alternative. To attempt to devise and install a monitoring system in a segmented annulus would entail the development of state-of-the-art technology and would introduce significant construction complexity and potential performance risk. It seems more reasonable to use the LEOS leak detection system, Jax (1999) for a double walled pipeline with bulkheads. LEOS is based on the installation of a semi-permeable tube alongside the pipeline. Inert gas is circulated through the tube on a daily basis and analyzed for the presence of trace hydrocarbons. This system is complimentary with a conventional leak detection system to monitor for leaks that are below the detection limit of the leak detection system. (Conventional leak detection systems utilize flow meters that typically are subject to errors of at least 0.1% of the rated capacity of the meter. In practical terms, this means that leaks of hundreds or thousands of barrels per day cannot be reliably detected by conventional leak detection systems. It is understood that the LEOS system will be installed on the Northstar project.

A double walled pipeline with shear rings and the simple double walled pipeline developed in this study provides a significant leak detection advantage over a single walled pipeline or a double walled pipeline with bulkheads. The annulus can be charged with gas at a pressure that is distinctly different from both the operating pressure of the inner pipe and the ambient pressure of the water over the pipeline, or left as a vacuum. Redundant pressure monitors on the annulus, integrated into a SCADA system, would provide reliable continuous leak detection monitoring of both inner and outer pipes. An annulus pressure monitoring leak detection system could be installed and maintained at nominal cost. Since the annulus is a confined space, a vessel in fact, and does not flow even small changes in pressure can be detected. If the annulus is maintained at a pressure above the maximum operating pressure of the inner pipe, the annulus leak detection system would also provide continuous integrity monitoring of both the inner and outer pipes. This would ensure its ability to contain a release from the inner pipe, except in the event of an extreme loading event that ruptures both pipes. Given the inability to monitor the wall thickness of the outer pipe, this is thought to be a distinct advantage.

An inherent disadvantage of a double walled pipeline is the absence of any known technology upon which the wall thickness of the outer pipe could be periodically monitored, except at fixed locations. A distinct disadvantage of a double walled pipeline with bulkheads is that there is no way of monitoring the integrity of the outer pipeline. As a consequence, with this design there is risk associated with the effectiveness of the outer pipe to provide the secondary containment that is the sole reason for its existence. For a double walled pipeline with shear rings, or a simple double walled pipeline that requires neither spacers nor shear rings, periodic or continuous pressure testing of the annulus would be required to monitor that effective containment is being provided by the outer pipe. There is some operational and economic risk associated with the lack of a monitoring system that is predictive but there is negligible environmental performance risk associated with the outer pipe, since it can be pressure test monitored on a pass-fail basis, as discussed above.

7.7 Constructability

It is suggested that the best manufacturing strategy for a double walled Arctic offshore pipeline would be to perform nearly, if not all welding in a large, heated temporary welding shop near shore. This construction strategy was implemented with good results on the PanArctic Oils Drake Point F-76 offshore pipeline. The proposed welding fabrication (fab) shop would house separate welding lines for each of the two pipe sizes, and an insertion and tie-in area, all with the requisite welding non-destructive examination (NDE) stations. Pipe would be handled on roller systems within the welding fab shop. Powered rollers are routinely used in pipe mills and pipe coating plants to move pipe in a manner similar to that required for these operations. A finished double walled pipeline would emerge from the fab shop on a roller system that could conceivably be long enough to produce the entire pipeline in a single segment, or in relatively few, fairly long segments that would require field tie-ins. Either linear winches or tractor-mounted winches could be used to move the pipe assembly along the roller system on the right-of-way. (Rotary winches were used on Drake F-76.)

The individual welding lines would produce multiple joint length segments up to several hundred feet long in a manner similar to that utilized for deepwater double walled pipelines, except that the segment length could be greater than the nominally 160 feet long “quads” typically used in deepwater offshore applications. The inner pipe would be “tied-in” to the inner pipe of the previously made-up portion of the pipeline in relatively conventional fashion. Fit-up would be simple and reliable by virtue of the roller handling system. Linear winches and hydraulic line-up stations would logically be used to set the gap and provide final line-up. Segments of the outer pipe would be lined up with the inner pipe, supported on rollers, and winched over the inner pipe. The same linear winches and hydraulic line-up stations as used for the tie-in welds on the inner pipe would set the gap and provide final line-up for the tie-in welds on the outer pipe. The only compromise with the tie-in weld of the outer pipe is that normal radiographic NDE girth weld QC would not be practical. Ultrasonic inspection, like that used on the buried portions of the Badami pipelines, would be required. Logically, the separation between girth welds on the inner and outer pipelines would be offset as much as practical to maximize the system integrity in the presence of high tensile bending strain.

The base case inner and outer pipe sizes, considered in section 7.6.1.2, provide limited clearance. There are several reasons why the fit is possible. The pipe considered is an ERW pipe, which has more consistent wall thickness, and during system make-up the 14" outer pipe is in fact installed over the already completed inner pipe. Pipe ovality could be an issue. If ovality tolerances for both pipes are at their allowable maximums and the orientation is at its most unfavorable, there could be significant interference between the pipes. Several potential solutions are available. Reduced mill tolerances on ovality could be considered. Ovality measurements could be made before the pipe segments are fabricated to ensure that interference associated with excessive ovality is avoided. (This may require selective location or orientation of the most out of round pipe joints.) Construction procedures could be established to require offending sections of pipe to be removed and replaced as required during the construction step of sliding the one pipe over the other. A custom outer pipe diameter could be specified to increase the clearance enough to eliminate this concern. Depending on the size of the order, there would be little or no cost impact from using a non-standard size for the outer pipe. The cap welds on the inner pipe may need to be controlled to minimise the risk of interference between the pipes.

Should the pipe in pipe concept be seriously considered for a project, it may be advisable to purchase enough pipe during the design stage to conduct meaningful constructability testing. This would logically include welding and NDE as well as proving out the methodology for inserting one pipe within the other and making the tie-in welds.

For any size combination other than 12" inside 14" pipe, standard pipe sizes produce an annular clearance of about 1-1/2 inches. This would eliminate the interference issue but would adversely effect pipe strain. For any given inner pipe size, increasing the outer pipe size increases the bending strain. It seems unlikely that "next larger size" would be the most economical size of the outer pipe for any other inner pipe size.

The double walled pipeline has two more construction steps than the alternative single walled pipeline. The annulus must be dried to eliminate the risk of corrosion in the annulus. This can best be accomplished by vacuum drying. Following construction, some ice and snow would inevitably be contained in the annulus. Once the pipeline is placed in service, it will warm the annulus enough to melt the ice and snow. To purge that moisture from the annulus, as necessary to eliminate any risk of corrosion, vacuum pumps should be installed on the annulus to reduce temporarily its pressure below the boiling point of water at the minimum operating temperature of the annulus. Following evacuation of the annulus, the annulus would be charged with nitrogen.

The other construction step unique to the double walled pipeline alternative is leak and pressure testing of the outer pipe. This could be done by means of relatively conventional hydrostatic testing in a heated fabrication shop but that would present unusual and difficult dewatering challenges. It is suggested that a more suitable pressure test medium would be air. Pneumatic testing of pipelines is a familiar concept in Canadian pipeline testing whenever extreme elevation differences or cold ground make hydrotesting with water impractical. This too can become impractical if very high pressures and/or large volumes are required.

The construction strategy described above for double walled pipelines, in combination with the elimination of the extra complexity associated with spacers and bulkheads or shear rings, is thought to eliminate constructability considerations as a significant disadvantage of double walled pipelines. With most, if not all welding done in a temporary construction fabrication shop, workmanship quality should actually be greater than it is on normal cross-country pipeline construction. Since the fab shop welding and roller pipe handling construction method is similarly applicable to single walled pipelines, any advantages associated with this construction method are irrelevant on a comparative basis.

The amount of pipe to be handled and the number of girth welds to be performed would double for a double walled pipeline. This imposes additional infrastructure and construction execution planning burdens but does not add constructability issues relative to the single walled pipeline alternative. The additional construction activities, such as inserting one pipe within the other, with the associated outer pipe tie-in welds, pressure testing the outer pipe and drying the annulus following construction are not expected to add significant complexity or risk. The fit-up of the outer pipe for tie-in welds on each segment would be more complicated than normal and the occasional pup or cut off may be required to maintain the desirable large separation between the welds on the inner and outer pipes. Both pneumatic testing and vacuum drying involve equipment and construction procedures not normally used on the North Slope. To that extent, they add constructability issues. The techniques have been proven elsewhere and the necessary equipment exists in the North American rental equipment fleet. If a double walled pipeline is not produced as one long segment, a limited number of final tie-in girth welds would be required. The tie-in welds on the inner pipe would be a relatively conventional operation. It is suggested that split sleeves be used for the tie-in welds on the outer pipe, although conceivably, linear winches could be used to shift the outer pipe over the inner pipe as necessary to establish a proper weld gap. The methodology is similar to that used when adding split tees to reinforce pipelines when retrofitting branch connections onto existing lines. Split sleeves were used successfully for outer pipe tie-ins on the Shell Caroline liquid sulfur pipeline. The split sleeves would have an outer profile similar to a girth weld and therefore be a candidate for similar joint coating procedures and materials as the main line.

For double walled pipelines that use a spacer and bulkhead or shear ring design, however, there are a few unique welds and installation steps involved. Given the simplicity of the designs developed for bulkheads or shear rings in this study, however, and how few bulkheads or shear rings are required, this is not thought to be a significant constructability penalty. The installation of spacers, while itself a simple process, results in added complexity in terms of inserting the outer pipe over the inner one. It increases the burden associated with imperfect alignment of girth welds and adds risk in terms of the possibility of the spacers sliding on the inner pipe during construction and becoming misplaced hence failing to function as intended. The weld attachment proposed for the mid-point weld on the outer portion of the bulkheads or shear rings developed in this study are unconventional welds. These considerations add to the undesirability of the double walled pipelines that use spacers and bulkheads or shear rings relative to either the simple double walled pipeline or the single walled alternative.

7.8 Construction Quality

Quality consists of various components and applies to every stage of the design, procurement and construction phase of a project. A good project should have a quality management system in place before detailed design that defines the procedures by which quality is managed. Properly implemented, a comprehensive quality management system will ensure that the quality objectives of the project are met and that an auditable permanent record exists to prove that the requisite quality standards were consistently achieved. It is important that the engineering design itself and the procurement procedures be subject to an effective quality plan. The design and procurement activities should define the acceptance standards for each component and every construction activity involved in building the pipeline. They should also define the inspection, quality control (QC) and quality assurance (QA) requirements.

For a strain based design pipeline, it is important that the quality management system produce a permanent QA record that verifies that the pipe and all welds are capable of tolerating the design strain limits without failure. This typically imposes considerably higher quality standards on construction than are routinely employed on stress based design pipelines. Because of the critically important role of weld flaws in the tolerance of a pipeline to high tensile strain, strain based pipelines should require complete non-destructive examination (NDE) of all girth welds. Typically, premium inspection methods such as X-Ray radiography (RT) and automated ultrasonic (UT) methods are adopted to generate permanent records of weld defects adequate for the implementation of the ECA analysis discussed above in Section 7.3. In order to ensure the requisite weld toughness, some codes and project quality plans require the qualification of welding procedures for every unique combination of welding consumable batch and heat of steel in the line pipe. Typically, stringent controls are placed on preheat and interpass temperatures, electrode size, travel speed, weave width and heat input, and on cooling rate, both in terms of the welding procedure and the QC procedures to ensure that production welds have adequate toughness to satisfy the design requirements.

None of the above discussion is in any way more or less applicable to the construction of the inner or outer pipes of the simple double walled or to the single walled pipeline alternatives. The only quality penalty associated with manufacturing a simple double walled pipeline as described herein is the inability to use RT inspection on tie-in welds of the outer pipe. It is suggested that the NDE of those welds by means of automated UT is perfectly adequate. The use of automated UT for the NDE of girth welds, although widely used in various parts of the world and well accepted in Canada, is not well established in the United States. It has been used in Alaska , however, on the strain based portions of the Badami pipelines. The use of split sleeves for final tie-in welds on the outer pipe, if they must be used, are undesirable because the longitudinal weld does not lend itself to conventional pipeline NDE methods and hardness issues exist, particularly where the longitudinal welds intersect the girth welds. Manual UT inspection should be adequate for the NDE of the longitudinal welds. Full-scale bend tests would be required to prove the performance of the tie-ins under high strain conditions.

There are exceptions to the previous statement that would apply to a double walled pipeline with spacers and bulkheads or shear rings. Provided the design attributes identified herein are embodied in the bulkheads or shear rings, the center welds of the outer sleeve of the bulkheads or shear rings should not be subject to large bending loads, hence normal welding acceptance standards and QC procedures should be adequate for those welds only. There is a quality control burden associated with verifying the proper location and condition of spacers in double walled pipelines. Since spacers are not thought to be a design requirement of double walled pipelines for the design conditions specified for this comparative study, no effort was placed on developing a conceptual QC procedure for this construction activity.

7.9 Operations and Maintenance, General:

The following sections 7.9.1 and 7.9.2 present an assessment and qualitative comparison of operations and maintenance related considerations for the study case pipelines. Assessments made are subjective and, based on engineering judgement, rated as either minor, moderate or significant in impact.

7.9.1 Operation

This section presents an assessment of characteristic differences, and a qualitative comparison of the study case pipelines for the following operating considerations:

- definition of operating conditions
- monitoring of operating conditions

- leak detection methods
- chemical inhibition application
- contingency response to failure detection

Assessment

Based on the comparison of study case pipelines presented in Table 7.9.1-1, differences are assessed as follows:

- PIP configurations offer the potential for secondary containment. Advantages of this, relative to single wall pipelines, include:

  - potential containment of spills resulting from the loss of integrity of the inner pipe. Study case B offers the greatest potential for secondary containment. Since this capability offers the potential to eliminate, or reduce the size of, a spill to the environment this represents a significant operating difference between study case B PIP and single wall configurations.

  - potential reduction of the size of spills resulting from the loss of integrity of both the inner and outer pipes. Since this capability offers the potential to reduce the size, and thus the associated consequence of a spill this represents a significant operating difference between all PIP study cases and single wall configurations.

  Disadvantages of PIP configurations, relative to single wall pipelines include:

  - The operating condition of the annulus must be monitored. Except for study case B where this is impractical, the incremental requirements for scheduled and / or automated monitoring of the operating condition of the PIP annulus are relatively minor. As a result this represents a relatively minor operating difference between study case C and D PIP and single wall configurations. For study case B this limitation means the operational condition of the annulus cannot be readily monitored and evaluated for current "fitness for service". As a result this represents a significant operating difference between study case B PIP and single wall configurations.

  Locally, the condition (thickness) of the outer pipe can be monitored using ultrasonic transducers that are permanently bonded to the pipe and monitored remotely throughout the operating life. Such transducers do not provide information however on the overall condition of the outer pipe.

Comparison

Table 7.9.1-1 presents a qualitative comparison of operation considerations for the four study cases:

Table 7.9.1-1
Qualitative Comparison of Study Case Pipelines for Operation Considerations

Operations Consideration	Study Case A	Study Case B	Study Case C	Study Case D
	Single Wall Issues	**PIP-Bulkhead Issues**	**PIP-Shear Ring Issues**	**PIP- Guide Issues**
definition of operating conditions: - normal - alarm - shutdown	None; standard practice applies.	The conditions of the PIP annulus must be defined but otherwise standard practice applies.		
monitoring of operating conditions: - pressure - temperature - flow rate - density - chemical composition - facilities: • pumps • control valves • instruments/ meters	None; standard practice applies	Standard practice applies to the inner pipe.		
		Isolated annulus compartments make monitoring of the operating condition of the annulus impractical.	Communication between annulus compartments make monitoring of the operating condition of the annulus practical.	No annulus compartments make monitoring of the operating condition of the annulus practical.
leak detection methods (see Appendix 7.9-1): - visual surveillance - hydrocarbon / water sensing tape, cable or tube - flow deviation - pressure deviation - flow difference deviation - volume / mass balance - transient modeling - statistical analysis - tracer chemicals - acoustic pig	All available internal leak detection methods apply. If used, external systems such as hydrocarbon sensing tape, cable or tube must be placed adjacent to the pipeline.	All available internal leak detection methods apply.		
		If used, external systems such as hydrocarbon sensing tape, cable or tube must be placed adjacent to the pipeline. Isolated annulus compartments make monitoring of the operating condition of the annulus impractical.	If used, typically external systems such as hydrocarbon sensing tape, cable or tube could be placed in the annulus.	
			Communication between annulus compartments make monitoring of the operating condition of the annulus practical.	No annulus compartments make monitoring of the operating condition of the annulus practical.

chemical inhibition application: - continuous injection - batch application	Internal chemical inhibition is not required but standard practice applies if desired.	Internal chemical inhibition of the inner pipe is not required but standard practice applies if desired.		
		Isolated annulus compartments make annulus chemical inhibition application impractical.	Communication between annulus compartments make annulus chemical inhibition application practical.	No annulus compartments make monitoring and maintenance of annulus chemical inhibition application practical.
contingency response: - loss of function - loss of containment	Single wall pipe has no “secondary containment” capability. As a result, any loss of containment requires immediate Operations response / shutdown in order to reduce the size of the spill.	The “secondary containment” capability of this PIP configuration may potentially eliminate spills resulting from a failure of the inner pipe. As a result, a loss of containment of the inner pipe may or may not require immediate Operations response / shutdown, depending on the severity of the failure.	The “secondary containment” capability of these PIP configurations may potentially eliminate, or more likely reduce the size of, spills resulting from a failure of the inner pipe. As a result, a loss of containment of the inner pipe may still require immediate Operations response / shutdown.	

7.9.2 Maintenance

This section presents an assessment of characteristic differences, and a qualitative comparison of the study case pipelines for the following maintenance considerations:

- scheduled maintenance activities
- metal loss monitoring

- geometric anomaly / strain monitoring
- contingent monitoring
- defect assessment
- contingency response to defect detection
- defect repair

Assessment

Based on the comparison of study case pipelines presented in Table 7.9.2-1, differences are assessed as follows:

- Disadvantages of PIP configurations, relative to single wall pipeline, include:

- The annulus cannot be pigged. For normal operation the annulus will be clean and thus should not require pigging. As a result this represents a relatively minor maintenance difference between PIP and single wall configurations.

- For study case B the condition of the annulus, i.e., pressure, chemical composition, chemical inhibition, or response to a hydrotest, cannot be readily monitored. Since this eliminates a significant inspection, monitoring and evaluation capability this represents a significant maintenance difference between study case B PIP and single wall configurations.

- The majority of existing defect inspection, monitoring and associated assessment methods and technologies cannot be applied to the outer pipe wall of PIP configurations. This limitation means the condition of the outer pipe cannot be readily inspected and evaluated for “fitness for service”. As a result this represents a significant maintenance difference between PIP and single wall configurations.

- The two pipe walls, with or without bulkheads, shear rings, guides and inert gas annulus “packs”, are physically more difficult to repair relative to a single wall pipeline. Commissioning PIP configurations for return to service will also be more difficult potentially requiring an annulus flush, vacuum drying and the application of chemical inhibitors and oxygen “scavenger”. As a result this represents a moderate maintenance difference between PIP and single wall configurations.

Comparison

Table 7.9.2-1 presents a qualitative comparison of maintenance considerations for the four study cases:

Table 7.9.2-1

Qualitative Comparison of Study Case Pipelines for Maintenance Considerations

Maintenance Consideration	Study Case A	Study Case B	Study Case C	Study Case D
	Single Wall Issues	PIP-Bulkhead Issues	PIP-Shear Ring Issues	PIP- Guide Issues
scheduled maintenance: - pigging - CPS testing and monitoring - CPS maintenance - chemical inhibition monitoring and maintenance	None; all standard practice / methods apply.	Standard practice / methods apply to CPS testing, monitoring and maintenance and pigging of the inner pipe. The annulus can not be pigged.		
		Isolated annulus compartments make monitoring and maintenance of annulus chemical inhibition condition impractical.	Communication between annulus compartments make monitoring and maintenance of annulus chemical inhibition condition practical.	No annulus compartments make monitoring and maintenance of annulus chemical inhibition condition practical.
metal loss monitoring (see Appendix 7.9-1): - MFL pig - Ultrasonic pig - Fixed monitors; TLA, NA, FS, UT - corrosion coupons - probes; resistance / electrochemical - chemical analyses - cut-out and inspect	None; all standard practice / methods apply.	Standard practice / methods apply to the inner pipe. Only “cut out and inspect” and possibly FS methods of metal loss monitoring apply to the outer pipe.		
geometric anomaly / strain monitoring (see Appendix 7.9-1): - caliper pig: • ovality • denting - inertial mapping pig / strain gauge: • buckling: lateral, upheaval • thaw settlement	None; all standard practice / methods apply.	Standard practice / methods apply to the inner pipe.		

		Caliper pig will not detect outer pipe ovality / denting except for extreme defects that also affect the inner pipe. To the extent that the inner and outer pipes are constrained to move together, the inertial mapping pig and strain gauge monitoring methods may apply to the outer pipe.		Except for extreme defects that affect both the inner and outer pipes the following monitoring methods do not apply to the outer pipe; caliper pig, inertial mapping pig, strain gauge.
contingent monitoring (see Appendix 7.9-1): - visual surveillance - fixed point leak detection - distributed leak detection - acoustic pig - hydrotest	None; all standard practice / methods apply.	Standard practice / methods apply to the inner pipe. Isolated annulus compartments make the use of distributed leak detection systems and the hydrotesting of the annulus impractical. Secondary containment capability can work to “mask” the existence of an inner pipe containment failure from a fixed point leak detection system.	None; with minor adaptions to account for the presence of an annulus, standard practice / methods apply. .	

Defect assessment: - characterization / assessment - evaluation methods: • ASME B31G • AGA/Battelle "Modified Criterion" • RSTRENG	None; standard practice / methods apply.	Standard practice / methods apply to the inner pipe. The condition of the outer pipe cannot be inspected with available technologies. Consequently existing "predictive" evaluation methods cannot be readily applied to the outer pipe.
Defect repair (see Appendix 7.9-2): - installation methods: • surface • subsurface, dry • subsurface, wet - connection methods: • spool • string • clamp	None; standard practice / methods apply.	Due to more complex geometry, assembly and commissioning requirements, the majority of PIP repair work must be performed on the surface.

7.10 Abandonment

This section presents a comparative assessment, and a qualitative comparison of the study case pipelines for the following abandonment activities:

- decommission:
  - removal and disposal of associated surface facilities or projections, if any
  - clean and isolate subsurface segments
- abandon:
  - location verification survey
  - clearance verification survey

Assessment

Based on the comparison of study case pipelines presented in Table 7.10-1 differences are assessed as follows:

- Historically, subsea pipelines in water depths greater than approximately 15 feet are abandoned in place (more than 90%, approx.) so that any damage to the environment is minimized. It is assumed single wall and PIP pipelines would have similar minimum in situ abandonment requirements, as follows:
- location must be verified by survey

- must be cleaned of hydrocarbon / combustible content
- must be filled with seawater or an inert material, e.g., solidified sand slurry
- ends must be capped, plugged or otherwise sealed, and buried
- surface facilities, or projections, if any must be cut and removed to below the seabed so that the abandoned pipeline does not present a hazard to navigation, or other users
- hazard clearance must be verified

Comparison

Table 7.10-1 presents a summary comparison of abandonment issues for the four study design cases.

Table 7.10-1
Comparison Summary of Abandonment Issues for Study Case Pipelines

Abandonment Design Consideration	Study Case A	Study Case B	Study Case C	Study Case D
	Single Wall Issues	**PIP-Bulkhead Issues**	**PIP-Shear Ring Issues**	**PIP- Guide Issues**
Decommission: - clean - fill / inert - cap / remove	None; standard practice applies.	Not significant; cleaning the annulus prior to abandonment may be slightly more difficult but otherwise standard practice applies. Differences arise with respect to the type of end caps or connectors can be used on PIP but this is a minor issue.		
Abandon: - survey: i. location ii. clearance - future issues: i. monitoring ii. corrosion control	None; standard monitoring and future liability applies. Future corrosion control is not applicable if pipeline is abandoned and not suspended			

8. COMPARATIVE COST ASSESSMENT

8.1 Method

Design costs are estimated at 5% of the estimated total cost of materials and construction for each pipeline alternative.

Materials costs are almost entirely the cost of pipe. Pipe costs are the same on a cost per ton basis for the sizes, grades, wall thicknesses and quantities involved in the two pipelines being compared in this study. The pipe costs were estimated on the basis of the weight of linepipe required for each alternative times the cost per ton from the Northstar estimate.

Construction costs were estimated for only the offshore pipeline fabrication of the single walled and simple double walled pipeline alternatives. No consideration has been given to the civil works portion of the offshore pipeline construction. It is felt that the ice platform construction, trenching and backfilling costs should be substantially the same for the single and double walled pipeline alternatives.

The construction cost estimate is based on the cost estimate for the Northstar project, which was kindly made available for use in this study by BP Pipelines. The study team is grateful to BP Pipelines for their cooperation and support. Being able to use the Northstar cost estimate as a basis for cost estimating allowed the study team to develop relatively accurate comparative costs for single and double walled pipeline alternatives constructed generally in accordance with the construction strategy developed for Northstar. The construction costs developed in this study are considered to be plus or minus 25% in accuracy.

Sections 8.5 and 8.6 present a comparative assessment of single and double wall pipelines for the cost elements relating to Operations, Maintenance and Abandonment. Assessments made are based on experience and engineering judgement, and rated as minor, moderate, or significant.

8.2 Design

The extra engineering and procurement effort associated with the simple double walled pipeline concept, as compared to the single walled pipeline alternative, is relatively small. A second pipe would need to be designed, specified and procured. The tasks are all substantially the same as for the single walled alternative, hence they do not represent a significant engineering burden. With the elimination of spacers and bulkheads or shear rings from the double walled pipeline design, the challenging task of modeling the pipe to pipe interactions at spacers and bulkheads or shear rings has been avoided. It is thought that the incremental engineering burden on the double walled pipeline alternative can be conservatively estimated at 5% of the estimated incremental cost of materials and construction. This works out to $303,000 based on the estimated costs developed in this study.

8.3 Materials

Based upon Northstar unit costs for pipe and coating, the materials costs for the single and double walled pipelines are as follows:

ITEM	DOUBLE WALL	SINGLE WALL	DIFFERENCE
Pipe, Coated, F.O.B. Deadhorse	7,174,710	4,681,055	2,493,655
Misc. Fittings	21,000	10,500	10,500
CP Anodes	51,500	46,000	5,500
Pig traps	293,700	293,700	0
TOTAL, MATERIALS	**7,540,910**	**5,031,255**	**2,509,655**

8.4 Construction

8.4.1 Estimate Basis

The design basis is for twelve statute miles of 12.75” O.D. Arctic offshore pipeline in the Beaufort Sea, Alaska. The maximum water depth of 40 feet allows trenching to be done by backhoe working from the ice surface, as planned for Northstar and Liberty. The double walled pipeline alternate employs a 14.00” O.D. outer pipe around the 12.75” O.D. inner pipe. The double walled pipeline is the “simple double walled pipeline” (no spacers and bulkheads or shear rings) conceptual design developed in this work. In preparing this comparative cost estimate, the study team has made extensive use of the Northstar pipelines construction cost estimate. This enabled the study team implicitly to harmonize the execution and methodology of construction for the single walled alternative, as well as to benchmark direct and indirect construction costs, and to establish the expected productivities resulting from local conditions. This provides the study team with a high level of confidence in the accuracy of the relative cost comparison provided herein.

8.4.2 Construction Method

Construction of both the single and double walled pipelines would utilize the full winter construction season during which heavy construction equipment can work directly off a strengthened ice surface. An obvious challenge to constructing from the ice is to efficiently schedule and safely maintain adequate productivity such that all construction activity is complete before break-up occurs, and the ice surface becomes unfit to work upon. This challenge is greater for the construction of the double walled pipeline design, which has twice the welding of the single walled pipeline and involves the extra step of inserting one pipeline within the other. This added activity introduces some minor scheduling concerns. Ice surface preparation and maintenance, cutting access to the sea bed through the ice surface, excavation of the trench, and final backfill operations are expected to be substantially the same for the single and double walled pipeline alternatives and have therefore been excluded from the scope of this comparative cost estimate. For both designs, it has been assumed that 60 foot long joint lengths of pipe would be hauled from stockpile and strung directly onto the ice surface. To achieve the necessary welding productivity for the double walled pipeline, the proposed welding process involves separate pipe gang and firing line crews for each pipe size, welding together pipe segments of approximately eight joints in length. Positioning and tying in the pipe segments will be done by a separate tie-in crew. Fabrication of the segments of 12 and 14 inch pipe could be done either near shore in a temporary welding shop as described in Section 7.7 of this report, or along the right-of- way as assumed for this cost estimate. The 12 inch pipeline segments would be welded in place on pipe rollers along the centerline of the final pipe string, one segment length ahead of the made-up pipeline string. The 14 inch segments would be welded a few feet off of the final pipe string centerline, also one segment length ahead of the made-up pipeline string. The tie-in crew would first line up and tie in a 12 inch segment to the made up pipe string. The tie-in weld would be non-destructively examined. To start the pipe insertion process, a 14 inch segment would be moved into position, on rollers along the final pipe string centerline. The under side of the 12 inch pipe would be lubricated and the 14 inch pipe would be winched over the 12 inch pipe. The outer pipe will move relatively freely on the rollers. The winching load should be less than the weight of the fixed inner pipe segment that is sliding inside the moving outer pipe segment. It has been assumed that a hydraulic powered fit-up system would be used to set the gap for the tie-in welds. Once the tie-in weld has been made on the outer pipe, it would be ultrasonically inspected. This process would be repeated for each pipe segment until the full 12 mile pipe string is completed.

All other activities are normal construction activities for Arctic offshore pipelines and are the same, except for quantities, for both the single and double walled pipeline alternatives. Given the similarity of the section modulus of the single and double walled pipeline alternatives, the sideboom spacing and the equipment count should be substantially the same for the lowering-in operation of the single and double walled pipeline alternatives.

8.4.3 Construction Cost Estimating Method

To establish the estimated construction cost, specific construction and construction support crews were conceptualized and estimated for each major activity involved in the pipeline construction. Each construction crew was equipment and manpower loaded to meet the productivity required by the length of the construction season. The crew sizes, the equipment lists and the construction schedules were based upon the Northstar estimate, except for those activities unique to the double walled alternative. The costs associated with all the necessary construction and support crews result in the basic cost of construction.

Additional activities and materials costs not captured in the basic construction estimate outlined above were then estimated, utilizing information obtained from the Northstar estimate. Costs such as stockpile preparation were factored on the basis of the required stockpile area. Pipe handling costs were factored on a joint count basis. Costs like skid deployment, lowering in and clean-up were factored on a unit length basis. Welding costs were factored on the basis of weld length times the number of welding passes. Costs for activities like procurement, construction management and support for running instrumented internal inspection tools were assumed to be the same in all cases. Support activities like night support and yard support were factored based on the estimated field supervision requirement. Profit was estimated as a percentage of the estimated total construction and materials cost.

Cost estimate summaries are attached in Appendix 8.4-1.

8.4.4 Estimate Assumptions

- Pipe and coating costs were factored from the Northstar estimate, and are Free on Board the North Slope.
- Pipe was assumed to be supplied in average 60 foot joint lengths.
- Pipe was assumed to be stockpiled at the Duck Island Gravel Mine, a 40 mile haul distance from the right-of-way.

- Construction activity is based on 7 day work weeks, 10 hours a day, with 8 hours at straight time. All overtime has been assumed to be at 1.5 times the straight time rate. In certain instances crews have been scheduled at 12 hours a day to meet required productivities, or support construction activities.

- Rates for manpower and equipment have been based on the Northstar estimate.

- Pipe haul and string was assumed as 1,500 feet per day for 12 inch, and 1,260 feet per day for 14 inch.

- An average welding productivity of 30 to 35 joints per day has been assumed for both line sizes.

- For the double walled pipeline scenario, line up of pipe joints for segment fabrication will be by internal pneumatic clamp. Line up of fabricated sections for tie in will be by external mechanical clamp. All single walled pipeline line up will be by internal pneumatic clamp.

- On all 0.375 w.t. pipe, 4 weld passes have been assumed: root, hot, 1 fill, and cap. On 0.500 w.t. pipe, 5 weld passes have been assumed: root, hot, 2 fill, and cap.

- Pipe Gang to do root and hot passes. Firing line to do fill and cap passes.

- For the double walled pipeline, it has been assumed that 4 segments of 8 joints of each size can be fabricated and tied in to the main pipe string per day.

- NDE was assumed to be 100% automated ultrasonic plus X-ray to code. UT costs are included in the basic construction costs. RT included in the miscellaneous cost section.

- The same proportions of shallow and deep water lower as for the Northstar Project have been assumed. Because of the increased length of the pipelines in this study relative to Northstar, however, the deep water lower in crew has been double shifted for both alternatives to acheive the required productivity.

- It has been assumed that the 12 inch pipeline will be integrity tested by way of water/glycol hydrotest; a pneumatic test of annular space will be undertaken to test the outer pipe of the double walled system.

- Bracelet type sacrificial anodes have been assumed for cathodic protection.

- No allowances have been made for ice roads or other infrastructure. It has been assumed that all ice pad work, trenching the ditch in the sea floor, and final backfill will be by others. It is expected that these costs would be substantially the same for the single and double walled pipeline alternatives, therefore no costs for these items have been included.

- Subsistence at $65.00 per day has been included for each worker.
- No allowances have been made in this estimate for down days due to extreme weather or conditions beyond the control of the contractor, other than those embedded in the Northstar estimate.

8.4.5 Estimated Total Installed Cost

Detailed construction cost estimate summaries are provided in Appendix 8.4-1. The comparative cost estimate results are as follows. All of these construction costs are accurate to +/-25%.

ITEM	DOUBLE WALL	SINGLE WALL	DIFFERENCE
DESIGN	**1,432,343**	**1,129,572**	**302,771**
MATERIALS	**7,530,410**	**5,031,245**	**2,499,165**
Direct Construction	5,958,813	4,220,887	1,737,926
Indirect Construction	1,292,408	1,182,715	109,693
Construction Administration	2,118,662	1,929,530	189,132
Maintenance	1,440,166	1,314,694	125,472
Subtotal, Basic Construction	10,810,049	8,647,826	2,162,223
Support	1,591,000	1,408,000	183,000
Trends	3,637,000	3,218,000	419,000
Other	2,171,700	1,994,100	177,600
Subtotal, Misc. Construction	7,399,700	6,620,100	779,600
Anchorage G & A	1,158,307	913,463	244,844
Profit	1,748,400	1,378,821	369,579
Total Construction Cost	**21,116,456**	**17,560,210**	**3,556,246**
TOTAL INSTALLED COST	**30,079,209**	**23,721,028**	**6,358,182**

8.5 Operation and Maintenance

This section presents a subjective assessment and comparison of operations and maintenance related costs for the following categories:

- Operations:
  - Operational monitoring
  - Leak detection
  - Application of corrosion chemical inhibition
- Maintenance:
  - Corrosion control
  - Inspection

  - Defect evaluation
  - Defect control
- Failure:
  - Defect repair and pipeline recommissioning:
    - “Loss of Function” failure
    - “Loss of Containment” Failure
  - Service interruption / lost production
  - Lost product
  - Environmental restoration
  - Intangibles, e.g.:
    - Adverse public relations and Damage to reputation

Based on the comparison of study case pipelines presented in Tables 8.5-1 through 8.5-3 differences are assessed as follows:

- Based on available historical data for single wall pipelines in Alaska, cost elements and approximate average magnitudes are as follows:

Operations and Maintenance Cost Element	Percent of Total O&M Cost [% , approx.]
- Operating and Maintenance (O&M)	66 %
- Ad Valorum Taxes	14 %
- Partnership Fees	9%
- Miscellaneous	5%
- Fuel and Power	4%
- Environmental Monitoring	1%
- Right of Way fees	0.6%
- Legal, FERC and Regulatory fees	0.4%
Total =	100.0%

The observed historical range of variation of the above costs is of the order of +85% / -40%. Incremental O&M costs for PIP configurations will be expected for the following operating and maintenance activities:

- operational condition monitoring of the annulus, whether scheduled and/or automated

- monitoring and maintenance of annulus chemical inhibition, whether scheduled and/or automated, including inert gas and/or chemical inhibitors

Note: PIP incremental costs associated with inspection, evaluation, and monitoring of the outer pipe are assumed to be zero given that no technology currently exists to accomplish this (see 7.9 "Operations and Maintenance " assessment).

Qualitatively, the above activities will increase O&M costs, but have no effect on remaining cost elements, i.e., taxes, fees, fuel and power, and miscellaneous. Assuming an O&M cost increase in the range of 10% to 20%, total operating and maintenance costs will increase by 7% to 13%. For arctic oil pipelines in general, relative to typical oil revenues over life, this is not a significant increase and is well within the observed historical variation in total operating and maintenance costs. For any given PIP pipeline, however, the increased annual operating and maintenance cost will be real and, depending upon project specific economics, may serve to reduce its economic life. Consequently, with the qualifier that the economic life of PIP pipelines will be reduced relative to single wall pipelines, this does not in general represent a significant cost difference between PIP and single wall configurations.

- "Containment failure" is defined as a failure of the pipeline resulting in a release of oil to the environment. Relative to single wall pipelines, over the life of the pipeline, a PIP "containment failure", i.e., is:

- more expensive to repair, due to their more complex geometries and recommissioning requirements

- potentially more likely to contain or reduce the size of spills, and associated consequences, due to their secondary containment capability

The relative costs of "containment failure" for the study case pipelines are qualitatively assessed in the following Table 8.5-1:

Table 8.5-1

Qualitative Assessment of Relative Costs of Containment Failure for Study Case Pipelines

Failure Cost Consideration	Study Case A Single Wall Costs	Study Case B PIP-Bulkhead Costs	Study Case C PIP-Shear Ring Costs	Study Case D PIP- Guide Costs
Lost product	Highest	Lowest	Moderately Low	Moderately Low
Service interruption/ lost production	Lowest	Highest	Moderately High	Moderate
Repair and recommission	Lowest	Highest	Moderately High	Moderate
Environmental restoration	Highest	Lowest	Moderately Low	Moderately Low
Intangible costs	Highest	Lowest	Moderately Low	Moderately Low

Based on the above assessment, the pipelines are listed below in order of increasing cost of "containment failure":

- study case D, PIP with guides
- study case B, PIP with bulkheads
- study case C, PIP with shear rings
- study case A, single wall pipeline

Thus, relative to single wall pipelines, and assuming a spill event occurs the total "containment failure cost" of PIP configurations is potentially lower.

- "Functional failure" is defined as a failure of the pipeline resulting in a degradation or loss of function of the pipeline, but with no release of oil to the environment. Relative to single wall pipelines, over the life of the pipeline, a PIP "functional failure", i.e., an integrity failure of the PIP outer pipe, is:

  - less predictable, because the existence of defects in the outer wall of PIP cannot be readily detected, inspected, evaluated or monitored

  - less controllable, because the size and growth of any defects in the outer wall of PIP cannot be controlled and monitored until is has been detected, inspected and evaluated

  - potentially more costly, for the following reasons:

    i. because PIP functional failures are more likely to occur they will, as a result, cost more over the life of the pipeline.

ii. PIP repairs, when they occur, will have a higher cost relative to single wall pipelines, due to more complex geometries and recommissioning requirements

The relative costs of "functional failure" for the study case pipelines are qualitatively assessed in the following Table 8.5-2:

Table 8.5-2

Qualitative Assessment of Relative Costs of Functional Failure for Study Case Pipelines

Failure Cost Consideration	Study Case A	Study Case B	Study Case C	Study Case D
	Single Wall Costs	**PIP-Bulkhead Costs**	**PIP-Shear Ring Costs**	**PIP- Guide Costs**
Service interruption/ lost production	Lowest	Highest	Moderately High	Moderate
Cost of repair and recommission	Lowest	Highest	Moderately High	Moderate

Based on the above assessment, the pipelines are listed below in order of increasing cost of "functional failure":

- study case A, single wall pipeline
- study case D, PIP with guides
- study case C, PIP with shear rings
- study case B, PIP with bulkheads

Thus, relative to single wall pipelines, assuming a loss or degradation of function event occurs, the total "functional failure cost" of PIP configurations is potentially higher.

Repair costs in general are discussed in terms of what the cost drivers would be and what issues have the greatest impact on these costs. The practical repair of either system must consider:

- type of failure which has occurred (eg. pinhole corrosion, cracked weld, buckled or wrinkled pipe wall, etc.)
- location of the failure (onshore, near-shore, offshore, depth of water, depth of burial, etc.)
- time of year (summer, winter, transition)
- requirement for materials

- requirement for specialized resources (eg. diving bells, divers, ditching or excavation equipment, etc.)
- mobilization and logistics to site
- clean-up, mitigation of effects of repair, demobilization
- direct cost of the repair itself

Experience with pipeline repairs has shown that by far the largest cost factor is related to clean-up of product released from the system. This cost is so large that it has not been included in this study and was determined to be similar for either system. The second major cost factor is loss of production during the period that the system is shut-in awaiting repair. The next largest is the logistics and resources which must be assembled for repair of either system and the least significant cost of the repair itself and materials required to effect that repair.

It is expected that either system could be repaired by divers in summer since water depths are less than 40' and would probably require excavation and lift to surface during winter months to effect repair on ice. It becomes readily apparent that although the cost to repair a more complex pipe-in-pipe system would be higher, these costs are quickly and significantly overshadowed by an opportunity to better choose the time of repair.

This endorses the above argument then that there is a significant difference between a 'functional failure,' and a 'containment failure'. After a 'functional failure', the regular operation of the pipeline is affected and changes may need to be implemented. However after a 'containment failure' product is released to the environment and the system 'must be' immediately shut-in and clean-up operations must immediately be implemented.

It is estimated that the cost of a repair to an offshore system could easily be $5 to 10 million. The cost of lost production could be about $1M per day. The cost of clean-up of an accidental release of oil could be much higher than either the repair cost or the value of the lost production.

Comparison

Tables 8.5-3 through 8.5-5 present qualitative comparisons of operating and maintenance cost considerations for the four study cases:

Table 8.5-3

Qualitative Comparison of Fixed and Variable Operating Costs for Study Case Pipelines

Cost Consideration	Study Case A Single Wall Issues	Study Case B PIP-Bulkhead Issues	Study Case C PIP-Shear Ring Issues	Study Case D PIP- Guide Issues
operating costs: - operational monitoring - leak detection - corrosion control application - emergency response capability - taxes - fees - fuel and power	None; typical fixed and variable operating costs apply	Due to the isolated annulus compartments, fixed and variable operating costs will potentially be the same as single wall pipelines.	Fixed operating costs, associated with operational monitoring of the annulus, will potentially be higher than single wall pipelines.	

Table 8.5-4
Qualitative Comparison of Fixed and Variable Maintenance Costs for Study Case Pipelines

Cost Consideration	Study Case A Single Wall Issues	Study Case B PIP-Bulkhead Issues	Study Case C PIP-Shear Ring Issues	Study Case D PIP- Guide Issues
maintenance costs: - corrosion control monitoring and evaluation - inspection - defect evaluation - defect control	None; typical fixed and variable maintenance costs apply	Due to the isolated annulus compartments, fixed and variable maintenance costs will potentially be the same as single wall pipelines.	Fixed maintenance costs, associated with monitoring and maintenance of the annulus, will potentially be higher than single wall pipelines.	

Table 8.5-5
Qualitative Comparison of Failure Costs for Study Case Pipelines

Cost Consideration	**Study Case A**	**Study Case B**	**Study Case C**	**Study Case D**
	Single Wall Issues	**PIP-Bulkhead Issues**	**PIP-Shear Ring Issues**	**PIP- Guide Issues**
failure costs: - defect repair (see also App. 7.9-2) - lost product - service interruption - environmental restoration - intangibles e.g.; • adverse public relations • damaged reputation	Defect repair costs will be marginally lower relative to PIP configurations. Spill sizes, and associated service interruptions and consequences, will be greater, relative to PIP pipelines, due to an absence of secondary containment capability.	Defect repair costs will be marginally higher relative to single wall pipeline configurations.		
		Spill sizes, and associated service interruptions and consequences, may be significantly less, relative to single wall pipelines, due to the secondary containment capability of this PIP configuration		Spill sizes, and associated consequences, may be less, relative to single wall pipelines, due to the secondary containment capability of this PIP configuration.

An estimate of the operating and maintenance costs for a single walled pipeline and a double walled pipeline system is required for consideration of their comparative life cycle costs in Section 10.1. These estimates at present value are presented in Table 8.5-6 based on the cost assumptions presented above. The oil production rate is assumed to be constant at 65,000 BOPD for 10 years and then declining by 20% per year for a further 10 years.

Table 8.5-6 : Estimate of Operations & Maintenance Life Cycle Costs for Single Wall and PiP Systems

						Single Wall Annual O&M Cost			PIP Annual O&M Cost		Present Value	
	Production					Dollars As-Spent			Dollars As-Spent		O&M Cost	
	Rate		Present Value Factors		Fixed	Variable	Total	Fixed	Variable	Total	SW	PIP
year	[BOPD }	**Escalate**	**Discount**	**Total**	$US x 1000	$US x 100]	$US x 100]	$US x 10]	$US x 100]	$US x 100]	$US Million	$US Millio]
1	65,000	1.00	1.00	1.00	2,000	989	2,989	2100	989	3089	2.99	3.09
2	65,000	1.02	0.89	0.90	2,000	989	2,989	2100	989	3089	2.70	2.79
3	65,000	1.03	0.79	0.82	2,000	989	2,989	2100	989	3089	2.44	2.52
4	65,000	1.05	0.70	0.74	2,000	989	2,989	2100	989	3089	2.20	2.28
5	65,000	1.06	0.63	0.67	2,000	989	2,989	2100	989	3089	1.99	2.06
6	65,000	1.08	0.56	0.60	2,000	989	2,989	2100	989	3089	1.80	1.86
7	65,000	1.09	0.50	0.54	2,000	989	2,989	2100	989	3089	1.62	1.68
8	65,000	1.11	0.44	0.49	2,000	989	2,989	2100	989	3089	1.47	1.52
9	65,000	1.13	0.39	0.44	2,000	989	2,989	2100	989	3089	1.33	1.37
10	65,000	1.14	0.35	0.40	2,000	989	2,989	2100	989	3089	1.20	1.24
11	52,000	1.16	0.31	0.36	2,000	835	2,836	2100	835	2936	1.03	1.06
12	41,600	1.18	0.28	0.33	2,000	706	2,706	2100	706	2806	0.88	0.92
13	33,280	1.20	0.25	0.30	2,000	596	2,597	2100	596	2697	0.77	0.80
14	26,624	1.21	0.22	0.27	2,000	504	2,504	2100	504	2604	0.67	0.69
15	21,299	1.23	0.20	0.24	2,000	426	2,426	2100	426	2526	0.58	0.61
16	17,039	1.25	0.17	0.22	2,000	360	2,360	2100	360	2460	0.51	0.54
17	13,631	1.27	0.15	0.20	2,000	304	2,304	2100	304	2404	0.45	0.47
18	10,905	1.29	0.14	0.18	2,000	257	2,257	2100	257	2357	0.40	0.42
19	8,724	1.31	0.12	0.16	2,000	217	2,217	2100	217	2317	0.36	0.37
20	6,979	1.33	0.11	0.14	2,000	183	2,184	2100	183	2284	0.32	0.33
					Total Estimated Present Value O&M Cost =						**25.71**	**26.61**

Notes: 1. The calculations in Table 8.5-6 are based on the following:

1.1 Re oil production forecast:

production flat life =	10 years	
production decline	20.0%	per year after flatlife

1.2 Re time value of money:

Discount rate =	11.0%
Escalation rate =	1.5%

2. Based on the following:

2.1 single wall and inside PIP pipe size	12 NPS
2.2 outside PIP pipe size =	14 NPS
2.3 pipeline length [miles] =	12
2.4 Fixed Opcost ratio (PIP / SW) =	1.05

8.6 Abandonment

This section presents a comparative assessment of characteristic differences, and a qualitative comparison of the study case pipelines for the following abandonment costs:

- cost to decommission:
- removal and disposal of associated surface facilities or projections, if any
- clean and isolate subsurface segments
- cost to abandon:
- location verification survey
- clearance verification survey
- future liabilities

Assessment

Based on the comparison of study case pipelines presented in Table 8.6-1 differences are assessed as follows:

- For abandonment in place, which is the norm for subsea pipelines, PIP and single wall pipelines have similar costs.

Comparison

Table 8.6-1 presents a summary comparison of abandonment costs for the four study design cases. The costs for the double walled systems Cases B, C and D, that is for bulkheads, shear rings and guides, are the same

Table 8.6-1

Comparison Summary of Relative Abandonment Costs for Study Case Pipelines

Abandonment Cost Consideration	Study Case A Single Wall Costs	Study Cases B, C & D PIP Costs
Decommission: - clean - fill / inert - cap / remove	Cost is Low.	Cost is low. In the event the inner pipe has leaked, or liquid chemical inhibition has been used, the cleaning cost may be marginally higher than case A, but the difference is not significant.
Abandon: - survey: i. location ii. clearance - future issues: i. monitoring ii. corrosion control	Cost is Low.	Cost is Low.

9. COMPARATIVE RISK ASSESSMENT

The risks related to both single wall and double wall pipelines are considered for activities related to design, construction, scheduling, quality, integrity monitoring and repair. Each is discussed with specific focus on the single wall pipe as compared to Case D, the selected pipe-in-pipe configuration because of lesser risks and complexity. A comparison of the components for the two pipelines is contained in Table 9.7.1

9.1 Design Risk

There is a design risk associated with double walled pipeline designs that involve bulkheads or shear rings and spacers. The exact nature of the pipe to pipe interaction would need to be quantified. With bulkheads or spacers designed essentially as indicated in Figure 7.3-2 and 7.3-4, it is thought that this represents a design development cost rather than a design risk. The greatest uncertainty is associated with development of a suitable welding procedure for the unconventional weld between the two segments of the outer portion of the assembly. This is not seen as a significant design integrity issue because the single piece inner portion of the assembly can be designed for adequate structural strength without support from the outer portion of the assembly. There is one design issue with shear rings that has a potential design integrity concern. It is getting the geometry correctly specified such that local strain concentration is avoided without compromising the constructability of the assembly or increasing the required size of the annular space. This is thought to be a design cost, rather than a design integrity risk that could readily be resolved by engineering analysis.

The spacer design would need to be thoughtfully considered for the design of a double walled pipeline with a centralized inner pipe. Various parameters would need to be optimized to minimize the local stresses imposed on the inner and outer pipes. These include contact area, compressive strength and spacing. Local stress issues on the inner pipe could be overcome by the same design approach as was used in the conceptual design of the bulkheads and shear rings. It is not apparent that a similar design opportunity exists to eliminate the issues associated with local stress on the outer pipe. This represents a design risk that could diminish the effectiveness of the outer pipe to provide secondary containment in the presence of extreme bending loads.

To eliminate the complexities associated with the spacers and bulkheads or shear rings on the double walled pipeline concept, the design solution developed in this study was to eliminate them altogether. This was based on the application of the principles of functional analysis. For the conceptual double walled pipeline design represented by Case D of this study, the design risk is thought to be no greater than for the single walled pipeline design alternative. Basic principles of piping stress analysis can be applied to handle the pipe interaction forces associated with the bulkheads required at each end. The only remaining pipe to pipe interaction is the line contact that would exist between the inner and outer pipes. Given the lack of restraint on the inner pipe, the force necessary to produce Euler (elastic) buckling of the inner pipe within the annulus is so low that the associated design risk is thought to be insignificant. Only in the case of extreme bending over relatively short lengths would the pipe to pipe interaction forces require significant engineering analysis. It would likely be necessary and sufficient to employ Finite Element Modeling (FEM) with the pipe interaction forces modeled in the same way as soil loads are handled in non-linear analysis. It is expected that any such design would be verified by full scale bend testing as was done on the Shell Caroline liquid sulfur (double walled) pipeline and the BPA Northstar (single walled) pipeline design. In that way, the design risk associated with the simple double walled pipeline design is thought to be insignificantly greater than the design risk associated with a corresponding single walled pipeline.

Probably the greatest perceived risk associated with the simple double walled pipeline concept (Case D) is associated with concern for corrosion in the annulus. A dry annulus does not present a corrosion risk. Evacuating the annular space then charging it with nitrogen provides one method of preventing corrosion. This is the design solution developed in the conceptual design developed in this study for a double walled pipeline. The risk of corrosion in the annulus is therefore thought to be a construction and/or a repair risk and, as such, is discussed in the next section.

It is possible that making up one long double walled pipeline on rollers is not practical, and a winching system cannot be devised to shift the outer pipe segments over the inner pipe to allow conventional girth welding of the final tie-in welds on the outer pipe. In that case split sleeves, like those used on the liquid sulfur pipeline, would be required for final tie-ins of the outer pipe. Adequate performance of those sleeves at high strain levels cannot be taken for granted. This would introduce an additional element of design risk to the double walled pipeline alternative. It should be possible, if necessary, to transition each end of the outer pipe segments to a higher wall thickness such that the strain experienced by the split sleeves is sufficiently low to provide a successful design.

There is always risk associated with innovation. Because the simple double walled pipeline is an unusual design concept for which there is no known operating history, some allowance for increased design risk should be recognized. Because any double walled pipeline is more complex than its single walled alternative, the double walled concept will necessarily involve greater design risk. It is thought, however, that the design of a simple double walled pipeline involves no additional, or more difficult, design challenges than does the design of its single walled counterpart. Provided that premise is valid, it is expected that risk analyses would reveal acceptably low differences in the design risk associated with the two concepts.

9.2 Construction Risk

Unfamiliar construction activities, increased complexity and increasing the construction schedule all impose a certain level of incremental construction risk on the double walled pipeline relative to its single walled counterpart. It is axiomatic that the simpler the double walled pipeline design, the lower the related incremental construction risk. This is a significant advantage of the simple double walled pipeline design developed in this study over the more familiar designs that use bulkheads or shear rings and spacers.

Bundled offshore pipelines in the Gulf of Mexico and the North Sea, some of which have considerably greater complexity than the simple pipe-in-pipe design, have been very successful. It was reported at the MMS sponsored pipeline workshop in Anchorage in November 1999, that there were no known failures on any bundled offshore pipelines in operation.

In terms of risk to pipeline integrity, welding is by a considerable margin the greatest construction risk. Within the welding activities, the elements of greatest impact on weld integrity are the root and hot pass, the first two welding passes. It is therefore suggested that the construction risk due to welding be thought of on a ”per weld inch” basis, independent of wall thickness. (This simplification slightly favors the single walled alternative.) Because the double walled pipeline alternative has more than double the total weld length than the single walled alternative, the risk of a weld failure is expected to be more than double that of a single walled pipeline. On the positive side, however, simultaneous weld failures on both inner and outer pipes would be required to result in loss of containment. Hence the economic risk from welding goes up but the environmental risk goes down for the double walled pipeline relative to the single walled alternative.

The only increased construction risks with the simple double walled pipeline are the tie-in welds of the outer pipe. Normal radiographic NDE girth weld QC would not be practical; ultrasonic inspection, like that used on the buried portions of the Badami pipelines, would be required. If split sleeves are used for final tie-in welds on the outer pipe, additional risk is involved in that either manual ultrasonic testing (UT) or adapting UT inspection techniques from long seam pipe mills would be required to inspect the longitudinal welds.

The temporary welding fabrication shop and roller pipe handling system construction strategy should produce welding quality and productivity advantages but would increase the construction infrastructure costs relative to conventional pipeline construction methods. With this fabrication method, the increased construction risk associated with the increase in construction complexity associated with the double walled pipeline alternative should be significantly outweighed by the increase in pipeline integrity associated with secondary containment, relative to a single walled pipeline.

Given the similarity of section modulus between the single and double walled alternatives, there should be little change in either construction method or risk during lowering in, aside from the increased dry weight of the double walled system.

The double walled pipeline has two additional construction steps, each involving some increase in construction risk over the alternative single walled pipeline. The annulus must be dried to eliminate the risk of corrosion. This can best be accomplished by vacuum drying. Following construction, some ice and snow would inevitably by contained in the annulus. Once the pipeline warms up after it is placed in service, that ice and snow would melt. This would provide the electrolyte necessary for a corrosion mechanism in the annulus to exist in the unlikely event of significant local variation in electromotive potential between or within the inner and outer pipes at a location where water is present. To purge moisture from the annulus, vacuum pumps should be installed on the annulus to reduce the pressure to below the boiling point of water at the minimum operating temperature of the annulus. Following evacuation of the annulus, the annulus would be charged with nitrogen. To protect against corrosion in the unlikely occurrence of residual free water in the annulus, a volatile amine oilfield corrosion inhibitor could be injected into the nitrogen to elevate the pH of any residual water to above 9.5. This has been found effective in inhibiting the corrosion of steel oilfield tubulars in an aqueous environment.

The other construction step unique to the double walled pipeline alternative is leak and pressure testing of the outer pipe. This could be done by means of relatively conventional hydrostatic testing but that would present unusual and difficult dewatering challenges. It is suggested that a more suitable pressure test medium would be air. Pneumatic testing of pipelines is a familiar concept in Canadian pipeline testing whenever extreme elevation differences or cold ground make hydrotesting with water impractical. The uniformity of seabed temperature would be advantageous for a pneumatic test. The main difficulty with pneumatic testing is that small leaks do not generate as dramatic a pressure response as occurs with a liquid test medium, hence a longer test period is advisable.

None of the design or construction challenges associated with the double walled concept involve the increased construction risks associated with the application of unproven technology. Every additional construction activity involves a certain amount of construction risk, however, and the double walled pipeline inevitably increases the construction activity, hence it increases proportionally the associated construction risk relative to the single walled pipeline alternative. In the absence of detailed risk analysis, it is suggested that the increased risk with the double walled pipeline is likely to be roughly proportional to the increase in its cost relative to the single walled alternative.

9.3 Schedule

As outlined in Section 8.0 (the Comparative Cost Assessment) a reasonable construction strategy is available that allows a double walled pipeline to be fabricated and installed in essentially the same construction period as a single walled pipeline. This eliminates any increased relative risk associated with the double walled pipeline alternative.

It is not expected that the fabrication of a pipe in pipe system would require a longer construction period. With the construction strategy described in this study, there would be a requirement for increased resources (construction manpower and equipment) but the construction period would be the same. Alternately, to make more efficient use of smaller pipe fabrication crews, it may also be possible to prefabricate pipe segments onshore or in the near-shore area where shallow water depths should allow an early start of pipe fabrication, before the construction period that is available for the bulk of offshore construction. For the relatively short lengths involved in this study, ice platform construction, excavation and backfilling, not pipe fabrication are most likely to control the construction schedule.

9.4 Quality

With the elimination of the extra complexity associated with the spacers and bulkheads or shear rings from the double walled pipeline design, there is little incremental risk associated with the double walled pipeline alternative aside from that associated with the increment in material quantity and construction activity. The only significant exception to this is the inability to employ conventional radiographic inspection techniques to the tie-in girth welds on the outer pipe. As previously discussed, well-proven ultrasonic inspection alternatives exist which substantially eliminate any associated incremental risk. This reduces the incremental quality risk from the double walled pipeline alternative to being roughly proportional to its increased capital cost, relative to the single walled pipeline alternative. Given the need to have simultaneous failure of both inner and outer pipelines to produce an unintentional release from the double walled pipeline, this manifests itself in project increased cost risk but decreased environmental risk.

9.5 Integrity Monitoring

Integrity monitoring (IM) embraces a number of both passive and active components related to construction and operations. These are considered qualitatively for the four alternatives for the following components:

- Defects: materials and installation
- Damage: installation, environmental, third party interaction, corrosion and operation
- Error: organizational and individual

Based on the comparison of study case pipelines presented in Table 9.5-1 through 9.5-3 differences are assessed as follows:

- PIP configurations, relative to single wall pipelines, have a higher risk in that the integrity of the outer pipe and / or bulkheads and shear rings cannot be readily inspected, evaluated or monitored for defects or damage during operation.

- PIP configurations require additional components, relative to single wall pipelines, the integrity of which cannot be readily inspected, evaluated or monitored for defects or damage during operation.

- PIP configurations require additional shop and field welds, relative to single wall pipelines, the integrity of which cannot be readily inspected, evaluated or monitored for defects or damage during operation. The weld count, per joint, for the study case pipelines are presented in Table 9.5-1:

Table 9.5-1

Comparison of Weld Count per Pipe Joint for Study Case Pipelines

Defect Related Risk	Study Case A Single Wall Weld Quantity	Study Case B PIP-Bulkhead Weld Quantity [2]	Study Case C PIP-Shear Ring Weld Quantity	Study Case D PIP- Guide Weld Quantity
Shop weld [1]	0	4	4	0
Field weld	2	4	4	4

Notes: 1. For simplicity a "double, or more, jointing" fabrication strategy is not assumed.

2. A minimum weld quantity is indicated. Depending on design details the weld count may increase to 10 (6 shop welds and 4 field welds).

Based on the weld count presented in the above table, weld-associated IM risks, whether defect or damage related, will be higher for PIP configurations, relative to that of single wall pipelines, due to their two to four fold increase in total weld count and their two fold increase in field weld count.

PIP configurations, relative to single wall pipelines, have a higher risk of minor weld flaws going undetected due to the presence of the annulus. By providing a physical separation between the inner and outer pipes, the annulus can mask or hide a functional failure of a weld in the outer pipe caused by damage not significant enough to have also damaged the inner pipe. Also, by providing a secondary containment capability, the annulus can mask or hide a containment failure of a weld on the inner pipe that is not large enough to be detected by the leak detection system(s).

Tables 9.5-1 through 9.5-3 present qualitative comparisons of integrity monitoring relative risks for the four study design cases.

Table 9.5-1

Qualitative Comparison of IM Defect [1] Related Relative Risks for Study Case Pipelines

<table>
<tr><th rowspan="2">Defect
Related Risk</th><th>Study Case A</th><th>Study Case B</th><th>Study Case C</th><th>Study Case D</th></tr>
<tr><th>Single Wall
Issues</th><th>PIP-Bulkhead
Issues</th><th>PIP-Shear Ring
Issues</th><th>PIP- Guide
Issues</th></tr>
<tr><td>materials:
- pipe
- external coating
- cathodic protection
- other:
• bulkhead
• shear ring
• guide</td><td>No bulkheads, shear rings or guides are required. Risk of material related defects is typical.</td><td colspan="3">The additional PIP components, i.e., outer pipe, guides, shear rings, and bulkheads, increases the potential risk for material related defects.</td></tr>
<tr><td>installation:
- weld
- trench depth</td><td>The potential for weld flaw defects and incorrect trench depth related risks is typical.</td><td colspan="3">Additional welded components, i.e., outer pipe, guides, shear rings, and bulkheads, increases the potential for weld flaw defects related risks.</td></tr>
</table>

Note: 1. "Defect" is defined as a deviation from an intended, specification, level or state.

Table 9.5-2

Qualitative Comparison of IM Damage[1] Related Relative Risks for Study Case Pipelines

Damage Related Risk	Study Case A Single Wall Issues	Study Case B PIP-Bulkhead Issues	Study Case C PIP-Shear Ring Issues	Study Case D PIP- Guide Issues
installation: - collapse / ovality - buckle - dent	Assuming this damage is not detected and corrected during construction, the risk of not detecting it during operation is low.	Assuming this damage is not detected and corrected during construction, the risk of not detecting it during operation, for the outer pipe only, is high.		
environmental: - ice scour - strudel scour - thaw settlement - frost heave - wave action - sediment transport / movement - seismic	The risk of not detecting damage resulting from these sources during operation is low.	The risk of not detecting significant damage resulting from these sources, i.e., where both the inner and outer pipes are affected, during operation is low. The risk of not detecting damage caused to the outer pipe only is high.		
third party interaction: - fishing - dropped objects - other CPS - AC interference	The risk of not detecting damage resulting from these sources during operation is low.	The risk of not detecting significant damage resulting from these sources, i.e., where both the inner and outer pipes are affected, during operation is low. The risk of not detecting damage caused to the outer pipe only is high.		

corrosion: - galvanic - pitting - crevice - intergranular - stress cracking - fatigue	The risk of not detecting damage resulting from these sources during operation is low.	The risk of not detecting damage resulting from these sources during operation, for the outer pipe and bulk heads only, is high.	The risk of not detecting damage resulting from these sources during operation, for the outer pipe and shear rings only, is high.	The risk of not detecting damage resulting from these sources during operation, for the outer pipe only, is high.
		The risk of not detecting damage caused to the inner pipe only is low.		
operating: - hydraulic surge	The risk of not detecting damage resulting from this source during operation is low.	The risk of not detecting damage resulting from this source during operation is low.		

Note: 1. "Damage" is defined as an effect that causes a reduction in the capability of the pipeline to perform its required function.

Table 9.5-3

Qualitative Comparison of IM Error [1] Related Relative Risks for Study Case Pipelines

Error Related Risk	Study Case A Single Wall Issues	Study Case B PIP-Bulkhead Issues	Study Case C PIP-Shear Ring Issues	Study Case D PIP- Guide Issues
organizational: - design - manufacture - construction - operation - maintenance	Risk to IM from organizational error is low.	Due to more complex geometry and a greater number of pipeline components the risk to IM from organizational error is low to moderate.		
individual: - design - manufacture - construction - operation - maintenance	Risk to IM from individual error is low.	Due to a more complex geometry, a slightly more complex operating requirement, and a greater number of pipeline components the risk to IM from individual error is low to moderate.		

Note: 1. "Error" is defined as an action, or inaction, that results in a failure of, or a degradation in the ability of, the pipeline to perform its required function.

9.6 Repair

A subjective assessment and qualitative comparison of repair related risks for the alternative pipelines is considered in three subsets:

- Defects: materials and installation
- Damage: installation
- Error: organizational and individual

Based on the comparison of study case pipelines presented in Tables 9.6-1 through 9.6-3 differences are assessed as follows:

- For repairs significant enough to require a replacement spool or string, the additional components required for PIP configurations, relative to single wall pipelines, increase the risk of introducing material defects.

- PIP configurations are potentially more vulnerable, relative to single wall pipelines, to corrosion in the annular space in the event of an integrity failure of the outer pipe. Due to the geometries of PIP configurations, ensuring complete removal all water and oxygen from the annulus during recommissioning is difficult. Even with vacuum drying and the introduction of oxygen scavenging chemical some water and oxygen may remain, trapped in low spots and crevices. As a result some degree of local accelerated corrosion may be expected to occur until the trapped water and oxygen are depleted.

Tables 9.6-1 through 9.6-3 present qualitative comparisons of repair risk issues for the four study design cases.

Table 9.6-1

Qualitative Comparison of Repair Defect [1] Related Relative Risks for Study Case Pipelines

Repair Defect Related Risk	Study Case A Single Wall Issues	Study Case B PIP-Bulkhead Issues	Study Case C PIP-Shear Ring Issues	Study Case D PIP- Guide Issues
materials: - pipe - spool - string - clamp - external coating - cathodic protection	Risk of material related defects is low.	The additional PIP components, i.e., outer pipe and bulkheads, increase the potential risk for material related defects.	The additional PIP components, i.e., outer pipe and shear rings, increase the potential risk for material related defects.	The additional PIP components, i.e., outer pipe, increase the potential risk for material related defects.
installation [2]: - mechanical connector - weld	The risk of weld flaw defects is low.	Additional welded components, i.e., outer pipe and bulkheads, increases the potential for weld flaw defect related risks.	Additional welded components, i.e., outer pipe and shear rings, increases the potential for weld flaw defect related risks.	Additional welded components, i.e., outer pipe, increases the potential for weld flaw defect related risks.

Note: 1. "Defect" is defined as a deviation from an intended, specification, level or state.
2. Assumes that the repaired pipeline depth of cover is restored to a state equal to the original installation.

Table 9.6-2

Qualitative Comparison of Repair Damage[1] Related Relative Risks for Study Case Pipelines

Repair Damage Related Risk	Study Case A Single Wall Issues	Study Case B PIP-Bulkhead Issues	Study Case C PIP-Shear Ring Issues	Study Case D PIP- Guide Issues
installation: - collapse / ovality - buckle - dent	For diameter / wall thickness ratios in the range of 10 to 40, approx., the risk of collapse and buckling is low. For the study diameters and wall thicknesses the risk of denting is low.	For diameter / wall thickness ratios in the range of 10 to 40, approx., the risk of collapse and buckling is low. For the study diameters and wall thicknesses the risk of denting is low.		

Note: 1. "Damage" is defined as an effect that causes a reduction in the capability of the pipeline to perform its required function.

Table 9.6-3

Qualitative Comparison of Repair Error [1] Related Relative Risks for Study Case Pipelines

Repair Error Related Risk	**Study Case A**	**Study Case B**	**Study Case C**	**Study Case D**
	Single Wall Issues	**PIP-Bulkhead Issues**	**PIP-Shear Ring Issues**	**PIP- Guide Issues**
organizational: - design - manufacture - construction	Risks to repair from organizational error are low.	Due to more complex geometry and a greater number of pipeline components the risks to repair from organizational error is low to moderate.		
individual: - design - manufacture - construction	Risks to repair from individual error are low.	Due to more complex geometry and a greater number of pipeline components the risk to repair from individual error is low.		

Note: 1. "Error" is defined as an action, or inaction, that results in a failure of, or a degradation in the ability of, the pipeline to perform its required function.

9.6.1 Open Water Season Variation Effects on Repair

This section presents assessments of the impact of variations in duration of the open water season on the following elements of repair:

- connection type
- installation method

The potential impact on environmental clean-up and remediation work that may or may not be required is not assessed.

9.6.1.1 Open Water Season Variation Assessment

The impact of open water season duration on typical repair connection systems is assessed as follows:

A typical open water season may vary in duration from approximately 2 to 5 months. The impact of the variation in open water season duration on typical repair connection systems is assessed in Table 9.6.1-1.

Table 9.6.1-1 Impact [1] of Seasonal Variation on Repair Connection Systems

Connection System [2]	**Impact of Indicated Open Water Duration**	
	Short Season (two months **)**	**Long Season (** five months **)**
Sleeve	None.	None.
Spool	None [4].	None [4].
String	None [3, 4].	None [4].
Clamp	None [4].	None [4].

Note:

1. This impact is based on the technical scope of repair work and does not include environmental clean-up and remediation work that may or may not be required, based on the specifics of the pipeline failure.

2. For more information describing these connection systems see Appendix A "Subsea Pipeline Repair Summary"

3. Depending on the length of "pipe string" required to effect a repair, a short season may not allow sufficient time for a tow-type installation (see Table 9.6.1-2) .

4. This table assumes that spools, strings and clamps of the correct size have been prefabricated / manufactured and are available for immediate use.

This study concludes that, unless the subject components are prefabricated / manufactured and held in reserve for immediate deployment, the short open water season may preclude the use of string and clamp connection systems due to the short duration in which to effect a repair.

- The impact of the range of variation on the open water season duration on the repair installation method is assessed in Table 9.6.1-2.

Table 9.6.1-2

Impact [1] of Seasonal Variation on Repair Installation Methods

Installation Method [2]	**Impact of Indicated Open Water Duration**	
	Short Season (two months **)**	**Long Season (** five months**)**
Surface, Barge / Vessel: Pipe Lay Pipe Tow Subsurface, dry: Coffer dam Subsurface, wet: Diver assisted ROV assisted	Depending upon the actual ice conditions, ice management and icebreaker support systems may be required. Depending upon the severity of the pipeline failure, and thus the actual repair duration required, this installation method may not be applicable.	Depending upon the actual ice conditions, ice management and icebreaker support systems may be required.
Subsurface, dry: Hyperbaric chamber Subsurface, wet: PRS	Depending upon the actual ice conditions, ice management and icebreaker support systems may be required. Depending upon the severity of the pipeline failure, and thus the actual repair duration required, this installation method may not be applicable. Depending upon when the pipeline failure is detected, due to the specialized nature of the construction equipment required for this installation method, the time required to mobilize the required equipment to site may not permit a repair to be performed in that season.	Depending upon the actual ice conditions, ice management and icebreaker support systems may be required.

Note:

1. This impact is based on the technical scope of repair work and does not include environmental clean-up and remediation work that may or may not be required, based on the specifics of the pipeline failure.

2. For more information describing these installation methods see Appendix A "Subsea Pipeline Repair Summary".

This study concludes the short open water season may preclude the use of hyperbaric chamber, ROV and PRS dependent installation methods, based on the time required to mobilize the specialized construction equipment to the site of the repair.

9.6.1.2 Open Water Season Assumptions

A typical seasonal variation for the study area is presented in Table 9.6.1-3.

Table 9.6.1-3
Seasonal Variation Basis

Description	Range of Variation	
	Early Start	**Late Start**
Break-up	May	July
Open water, average	July (late)	October (late)
Open water, minimum	July (late)	August (late)
Open water, maximum [1]	June (late)	November
Freeze-up	October	December

Note: 1. This duration assumes ice management and ice breaker support systems are used.

Assumptions regarding the total repair duration required are presented in Table 9.6.1-4.

Table 9.6.1-4

Assumed Repair Schedule Duration

Description	Assumed Repair Schedule Durations		
	Mobilization [1] [month]	Repair [4] [month]	Total [month]
Surface, Barge / Vessel:			
Pipe Lay [2]	0.5	0.6	1.1
Pipe Tow [2]	0.5	0.6	1.1
Subsurface, dry:			
Coffer dam [2]	0.5	0.5	1.0
Hyperbaric chamber [3]	1.2	0.6	1.8
Subsurface, wet:			
Diver assisted [2]	1.2	included	included above
ROV assisted [3]	1.2	above	-
PRS [3]	1.2	note 5.	-
		note 5.	

Notes:
1. Duration is for mobilization. Demobilization duration will be the same.
2. Assumes mobilization / demobilization from Seattle, a one way distance of 5,200 km, approx.. Although the availability of floating equipment is severely restricted in the region, e.g, Pt. Barrow, Prudhoe Bay, Cook Inlet, a duration of 0.2 month may be possible if the necessary marine equipment is available when required.
3. Assumes mobilization / demobilization from the Gulf of Mexico, a one way distance of 14,700 km, approx..
4. Repair duration will vary widely with the magnitude of the pipeline failure and the connection system used. For the purpose of this table a "spool" repair by pipelay barge is assumed. Includes excavation and backfill durations. PIP repair durations will be marginally longer.
5. This table assumes that these installation methods would not be considered for the assumed failure.

9.7 Summary of Comparative Risks

Table 9.7-1 Summary of Comparative Risk Assessment
Double Wall Pipeline (Case D) Compared to Single Wall Pipe

	Same	Slightly Greater	Moderately Greater	Much Greater
Design		✔		
Construction			✔	
Schedule			✔	
INTEGRITY				
Defect			✔	
Damage		✔ inner pipe		✔ outer pipe
Error Related		✔		
REPAIR				
Defects			✔	
Damage		✔		
Error Related			✔	

Table 9.7-1 reflects the fact that the pipe-in-pipe is more complex with more material, more welds and more difficult to monitor. Hence it will have a greater risk than a single wall pipeline for potential problems related to these aspects. However, a breach or leak in a single wall pipe results in definite loss of product to the environment. It would be very unlikely that such an event would affect both pipes in the pipe-in-pipe system at the same time. The risk of loss of product to the environment is therefore much lower for the pipe-in-pipe. By making a number of assumptions and by taking account of the data available for performance of offshore pipelines, it is possible to come up with a reasonable approximation for the risk of loss of product for both pipeline systems.

10. Comparative Life-Cycle Cost and Risk

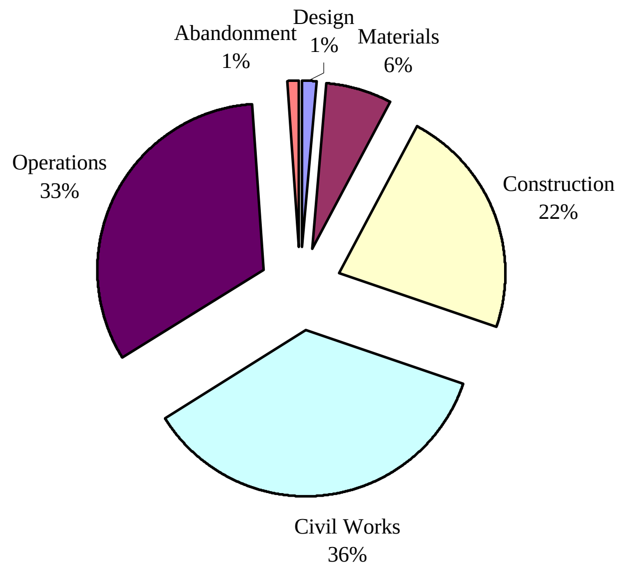
A coupled framework in defining life-cycle cost with risk analysis is important for the comprehensive assessment and management of novel technologies and/or large scale projects (e.g. double wall pipeline systems). The strategy can encompass viewpoints from all stakeholders, in terms of hazards and event consequence, and direct focus on the key and significant elements. For the arctic environment, the ecological sensitivity further underscores the importance of adopting this approach.

10.1 Life-Cycle Cost

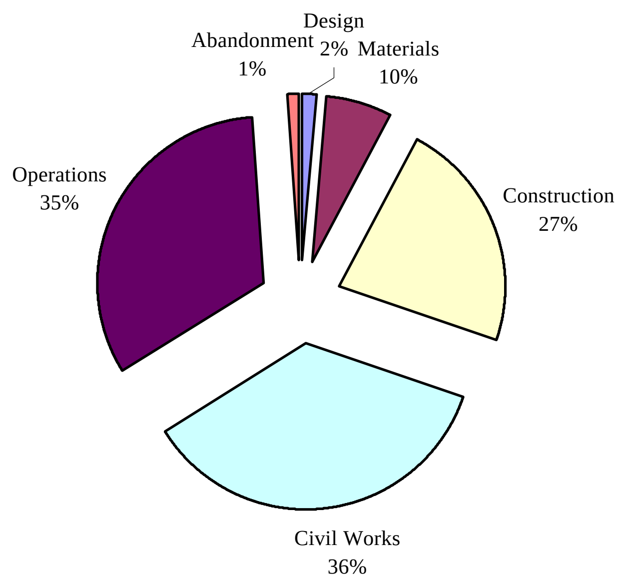
Life-cycle cost represents the total project value, in terms of capital and operating costs, from conception to abandonment. The major components of life-cycle cost are

- Engineering Design and Project Management
- Materials
- Construction (infrastructure and civil works)
- Operations (maintenance and monitoring)
- Repair (potential event that may also include environmental remediation)
- Abandonment

The estimated comparative life-cycle cost for a double wall pipeline, normalized with respect to the defined baseline case for the single wall pipeline system, is summarized in Table 10.1-1. The distributions for the single wall and double wall pipeline arctic offshore pipeline systems are illustrated in Figure 10.1-1. The normalized factors for design, materials and construction were based on the detailed cost analysis conducted in Chapter 8. The cost of civil works (e.g. trench excavation, backfill, ice road construction) was not assessed with the same level of detail but are based on recent pipeline construction experience. A cost of \$28 million (1999 US dollars) was estimated for both the single wall and double wall pipeline systems, Appendix 10.1. The other factors considered in the assessment (i.e. operations and abandonment) were subjective, but based on current knowledge, are considered reasonable and representative of arctic pipeline projects.



(a)



Total =110%
(b)

Figure 10.1-1. Distribution of Life-Cycle Cost for (a) Single Wall Pipeline System (b) Double Wall Pipeline System, with a Estimate Margin of ±25%, compared to that for a Single Wall Pipeline System.

Table 10.1-1. Comparative Life-cycle Cost for a Double Wall Pipeline Alternative Normalized with Respect to a Single Wall Pipeline System.

Activity	Single Wall	Double Wall	
	Life Cycle Cost (%)	Normalized Factor	Life Cycle Cost (%)
Design	1.4%	1.30	1.8
Materials	6.4%	1.50	9.6, up to 12.1
Construction	22.5%	1.20	27.0, up to 33.7
Civil Works	35.8%	1.00	35.8
Operations	32.9%	1.05	34.5, up to 43.1
Abandonment	1.0%	1.10	1.1
Total	100%	—	110%, up to 128%

The life cycle costs are dominated by the cost of civil works at the time of construction and the operation and maintenance costs, which make up over sixty percent. The estimate for the single wall pipe is comparable to the cost estimate for Northstar, which has been given significant detailed attention and is probably within about 10 percent. The double wall pipe for containment is novel technology. It is estimated that operation and maintenance, materials and construction costs for this system could vary by as much as 25 percent. The operations, civil works and abandonment costs are about the same for both the single wall and double wall pipeline systems. Taking these factors into account, for the specific pipelines studied, the life cycle costs of a double wall pipelines is estimated to be in the range of 1.1 to 1.3 times the life cycle costs of a robust single wall pipeline.

A logical basis for comparative risk of pipeline failure for a single wall and double wall system can be put forward and a reasonable estimate of alternative life cycle costs can be made with the exception of repair and environmental clean-up. For example, if both pipes fail for the pipe-in-pipe system (as has apparently happened for the Erskine pipeline) then the cost of repair could be greater, because of the increased complexity, but the cost of cleanup would be the same as for a comparable size single wall pipeline failure. If the inner pipe fails but the outer pipe contains the product the cost of repair could be less than a single wall pipe failure since it could be scheduled for the most favourable time to undertake the repairs without environmental damage and clean-up. Cleanup costs for a comparable failure of a single wall pipe may be greater if it occurs during challenging environmental conditions. Failure of either a single wall pipe or pipe-in-pipe has a very low probability of occurrence for the expected project life. Any attempt to include repair costs in life cycle costs for the two alternatives could distort the comparison of risk versus life cycle cost that is based on the information presented in Section 8 and 9. Qualitatively, the study team has concluded that repairs and cleanup costs would be less for a pipe-in-pipe than for a single wall pipe. This is because of the somewhat lower risk of failure that has been estimated the secondary containment offered by the double walled pipe and the ability to better schedule repairs for a pipe-in-pipe failure.

10.2 Risk Analysis Framework

10.2.1 Introduction

Regulatory authorities in several countries including the UK, Norway, The Netherlands and Canada require the application of risk assessment strategies for offshore projects. For example CSA Z662 (1999) and DNV (1996) provide guidelines on the risk assessment process for pipeline systems. The importance is highlighted by the development of industry regulations for the UK North Sea in 1992 after the Piper Alpha accident (Nesje et al, 1999).

Risk analysis is concerned with the development of risk estimates by evaluating the probability of occurrence and likely consequence of defined hazards. The procedure can be employed during any life-cycle phase to facilitate the decision making and can be considered a subset of the risk assessment and management process. A generalized risk analysis framework is illustrated in Figure 10.2-1 and the overall process will be discussed.

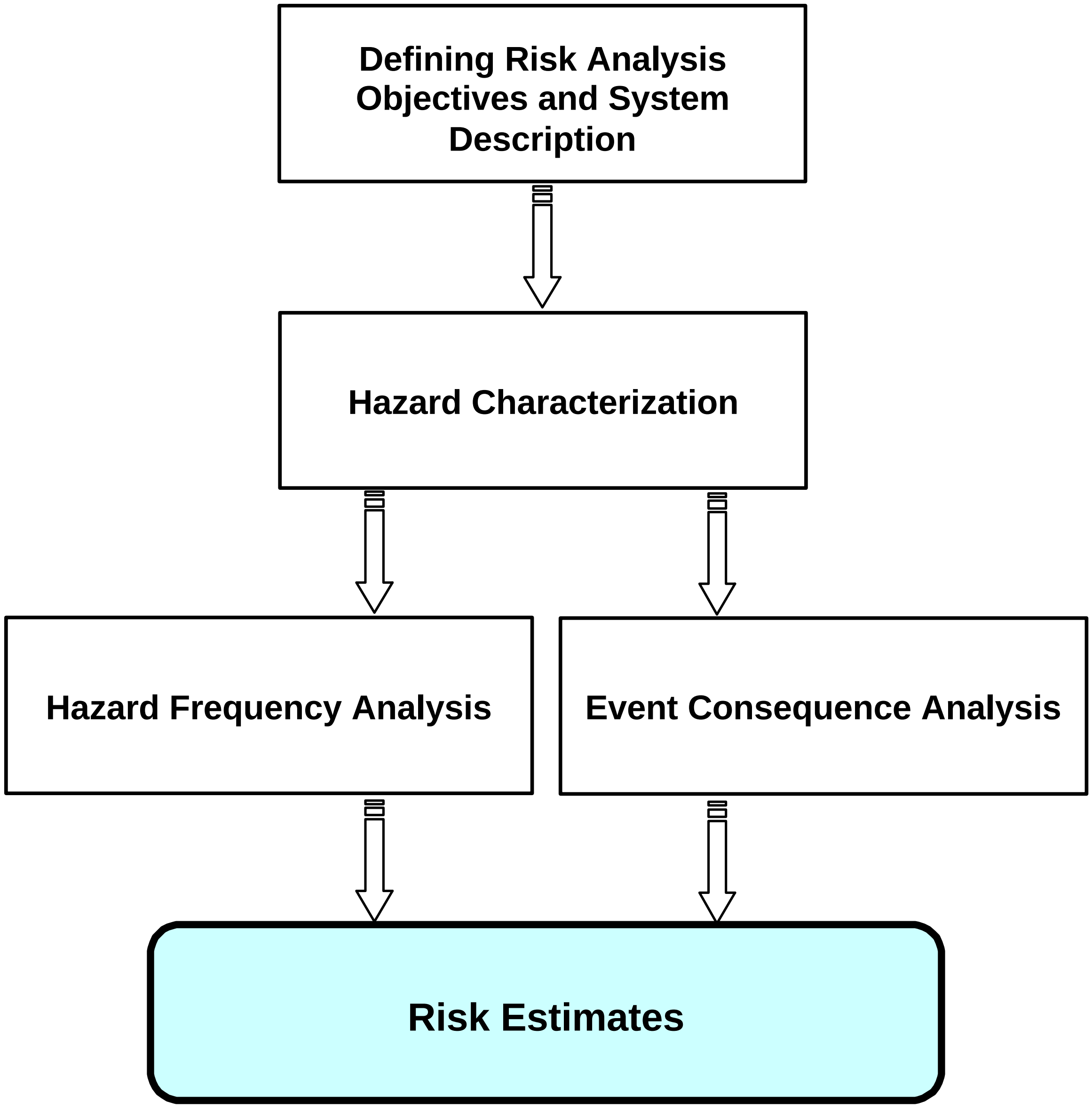


Figure 10.2-1. Illustration of Risk Assessment Framework.

10.2.2 Risk Analysis Procedure

There are three basic objectives for risk analysis:

- hazard characterization – identification and definition of potential events (i.e. what can go wrong?)
- hazard quantification – evaluation of the likelihood for an event to occur (i.e. what are the chances that it will go wrong?)
- consequence – assessment of the probable outcome for the perceived hazard (i.e. what is the impact if it does occur?)

10.2.2.1 Hazard Characterization

A systematic and comprehensive review should be conducted, for all life-cycle stages, to identify all potential system threats. Documented historical records, empirical, or *in situ* data provide the primary basis for identifying pipeline system hazards. Alternative comparative processes include generic checklists, based on experience with similar systems, or input from technical expertise, which is particularly relevant when the database has not been developed. Systematic and structured processes such as hazardous operations studies (HAZOP) and failure mode effect analysis (FMEA) can also be employed. In addition there are logical procedures such as event tree and fault tree analysis methods. These issues are illustrated in Figure 10.2-2. CSA Q634-M91 (1991) and API 750 (1990) provide guidelines on hazard characterization.

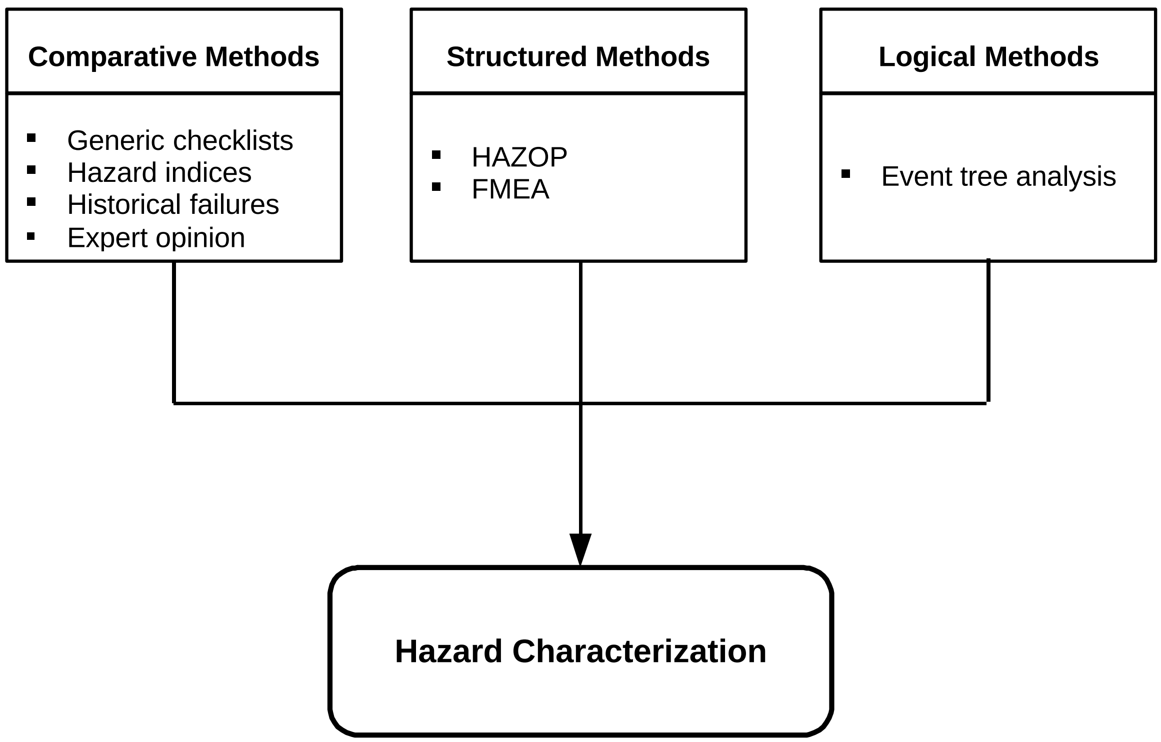


Figure 10.2-2. Hazard Characterization Process.

The fundamental concern is to identify all known risks, as well as hazards that have not been proven or bounded. The later issue can be defined as *uncertain risk* and is directly related to the present novel approach of considering a double wall pipeline system for the arctic offshore environment. The quantitative probabilistic risk analysis process will establish the significant hazards to be addressed, and a risk assessment framework, based on defined target safety levels, will determine acceptable risk levels.

Generally speaking, the significance of uncertain risks is recognized in hindsight, since the initial foundation of an accurate and reliable database for these hazards did not exist. The importance of addressing uncertain risks can be illustrated by a number of examples. Historically, consideration of cyclic fatigue and brittle failure of nominally ductile materials was not recognized. Catastrophic failures of the early Liberty ships, built during 1940's, did not account for stress concentrations and brittle failure in the design (Rawson and Tupper, 1983). In geotechnical engineering, problems with long term slope stability and failure of clay soils have been recognized (Skempton, 1964). The importance of addressing uncertain risks can be also appreciated for conventional engineering structures, such as the Tacoma Narrows suspension bridge failure (Amann et al., 1941; Lazer and McKenna, 1990).

Hazard uncertainty also has significant implications on quantification and consequence estimates. For emerging or novel technology, such as double wall pipeline systems in the arctic, the risk assessment framework is very important.

10.2.2.2 Hazard Quantification

Hazard quantification is concerned with defining the frequency of occurrence for the identified hazards with reference to the associated consequences. Recurrence rates can be estimated based on historical records, empirical data, mathematical models, event and fault tree analysis, as well as expert opinion. The analysis can be expressed in quantitative terms on a system basis (failures per year) or linear basis (failures per kilometre per year). Furthermore, qualitative or hybrid approaches can be employed (Bea, 1999; Muhlbauer, 1996).

The analysis must also consider parameter or model uncertainty, which influences source hazard quantification. Parameter uncertainty can be expressed as inherent variability in the actual process (e.g. random nature of component fatigue life) or in the estimation error, which can be related to database quality and reliability (e.g. ice gouge statistics and recurrence rates).

For engineering systems where the historical or scientific database does not exist, for example double wall pipelines as a product containment system, the risk analysis framework should employ a strategy encompassing:

- parametric distributions – direct quantitative data, inferred from historical and/or empirical records, numerical modeling

- nonparametric distribution – expert opinion modeling

The primary goal is to define input distributions of hazard frequency that can be incorporated within a quantitative risk analysis framework (e.g. Monte Carlo simulations). The mere process of defining and quantifying hazards to estimate risk levels implies uncertainty. In general terms, uncertainty can be equated with lack of knowledge and can be categorized as objective or subjective. Objective uncertainty is related to defined quantities, such as external pipeline corrosion rates or ice gouge recurrence rates. The parameters can be evaluated through sensitivity analyses, as well as assessment of data accuracy and reliability. Subjective uncertainty is related to technical expertise, perception and personal bias.

10.2.2.3 Consequence

Defining consequence is an integral component of the risk assessment process that addresses severity of the defined hazards in terms of potential loss of life, impairment of safety functions (e.g. structural integrity, evacuation systems), environmental damage (e.g. pollution, remediation) and/or economic impacts (e.g. production loss, delay).

10.2.3 Risk Estimates

Risk estimates represent the fundamental objective of the risk analysis and the primary throughput for the risk assessment process. The process considers hazard frequency and probable consequence to develop a level of risk, which is dependent on the hazard type, event mechanism and objectives of the risk assessment process. For example, peripheral issues could include the level of importance attached to system downtime for a defined level of pipeline damage (i.e. repair cost, lost revenue), potential environmental damage due to construction or loss of product containment integrity, as well as public perception and credibility. Qualitative, quantitative and mixed methods can be employed which include:

- Risk matrix method – hazard frequency and consequence are defined as a two-dimensional function. Although a relatively coarse assessment process, the procedure is often employed to identify potential high-risk events that could warrant a more detailed analysis. The method is easy to apply and visualize as illustrated in Figure 10.2-3.

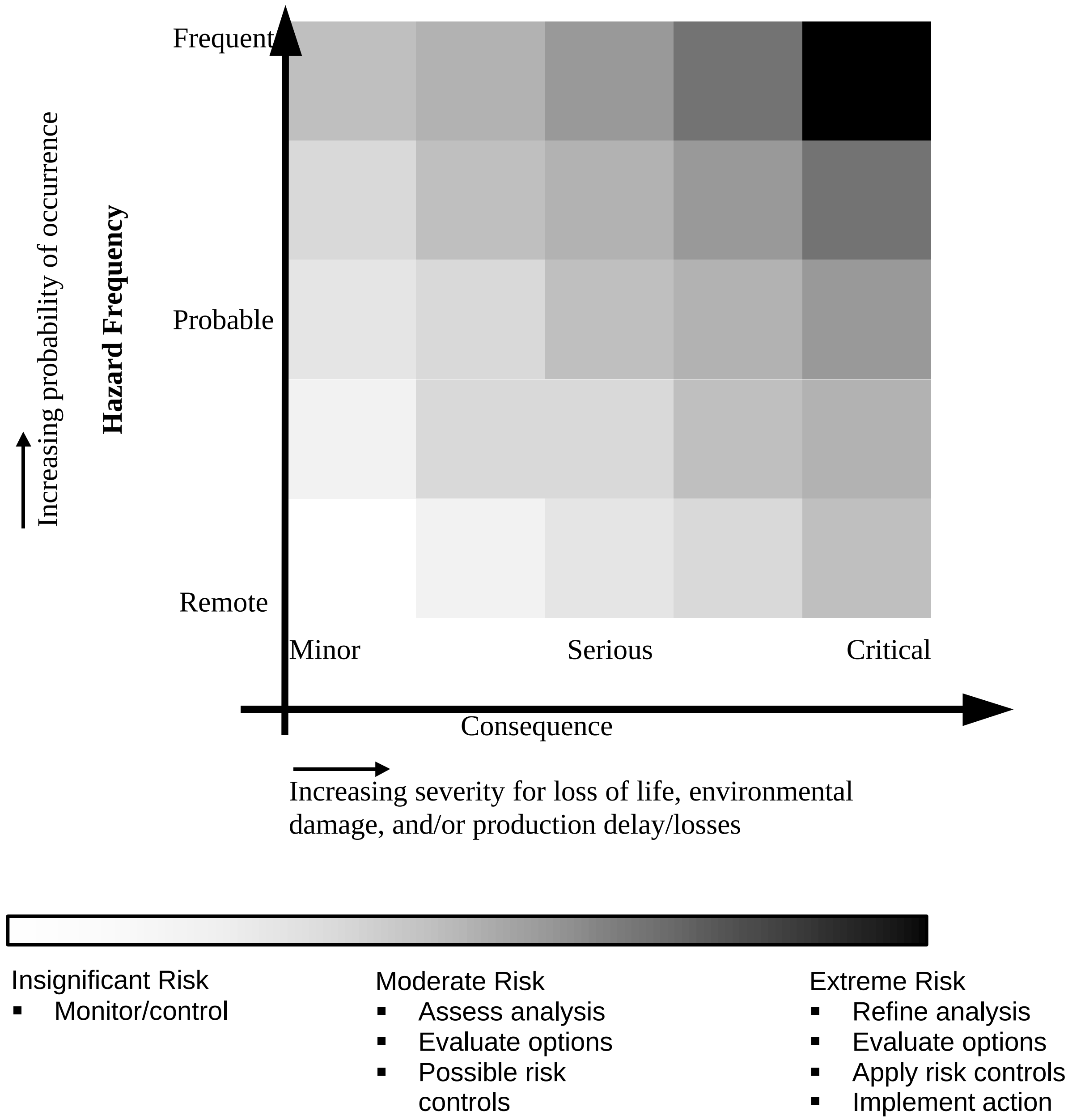


Figure 10.2-3. Qualitative Risk Estimates by Matrix Method (CSA Z662, 1999).

- Risk index method – the factors influencing hazard frequency and event consequences are rated in terms of numerical indices and evaluated mathematically.

- Probabilistic risk analysis – a comprehensive, quantitative analysis is conducted to determine risk estimates.

The matrix and index methods incorporate qualitative and quantitative characteristics in order to define a relative level of risk. The procedures are typically hybrid in nature and combine data from historical records, models, empirical data and/or technical knowledge and expert opinion. In general, probabilistic risk analysis determines an absolute measure of risk through a rigorous statistical evaluation of multiple input distributions, including possible cumulative effects, for hazard frequencies and event consequences. This latter method is the most demanding and time-consuming procedure to employ but can be considered more accurate and versatile for multivariate analysis.

10.3 Risk Issues for Arctic Offshore Pipeline Systems

The main factors that must be considered in conducting risk analysis have been outlined. A comprehensive quantitative probabilistic risk assessment for a conventional single wall pipeline is a demanding task. Application to double wall pipeline systems for the arctic offshore environment further increases the complexity. The key issues concerning pipeline risk for the single wall and double wall alternatives, in terms of the arctic offshore comparative assessment, are discussed.

Pipelines are an effective and economic means for the transportation of oil and gas in ice covered waters. Optimization strategies for pipeline design must weigh a number of factors including:

- Structural integrity
- Construction technology
- Economic development
- Public concern and perception
- Life-cycle cost
- Target levels of safety, and
- Risk and consequence

All of the above factors, except for public concern and perception, are readily quantifiable on the basis of experience. For example construction costs, or on the basis of established analytical protocols such as structural integrity and risk analysis, but there is no procedure or basis to quantify public concern or perception. This is a very important consideration in optimizing the strategies for pipeline design but at present the perceived risks of the public are made subjectively and may reflect the perception of only a small but very active constituency. Perceived risks by the concerned public are, nevertheless, legitimate concerns that need to be understood and decisions must reflect sensitivity to the public perception.

There are several factors that can influence public perception of risk, not the least of which is the media. For example aircraft accidents are publicized world wide both through television and newspapers when they occur. This engenders a certain nervousness or apprehension amongst even passengers that fly frequently and those people that are close to them. Yet statistics show that the most dangerous part of any trip is the drive from home to the airport which would not likely concern any of them. The risk of an accident on the ground in a car is over 100 times the risk of an accident flying.

An airline pilot has about 100 times the risk of a fatal accident as a passenger. Many view this as a hazardous occupation but it is not nearly as hazardous an occupation as that of a miner or a fisherperson. Perceived risk is influenced by many factors including personal bias, experience, received information or sometimes obsessive fear (phobias). Probability theory is not widely understood by the general public when assessing potential risk and statistical data may be ignored if it is not of interest to the media. Many people live in hope of winning a lottery but for all of the major lotteries there is a greater probability of being hit by lightening than winning the big prize.

Perceived risk or public concern cannot be quantified but there are manifestations that can indicate the level of concern. The most important activity that can lead to mitigation of an unrealistic perception of risks or to diminishing a concern that may not be warranted is open, honest and effective communication. Proponents, regulators and politicians must be sensitive to the reality of public perception and must respond in a manner that is meaningful to individual concerns.

The risk of product loss to the environment from either a robust single wall pipe or equally robust double wall pipe is about the same as the risk of being in a building that collapses in a non seismic area where there are rigorous building codes that are enforced. This is about one in ten thousand, $1x10^{-4}$. The same levels of safety standards are applied to design of structures where failure could lead to loss of life as are applied to design of offshore production facilities and pipelines where failure could lead to severe environmental damage. Building safety is accepted and taken for granted but pipeline safety, even though to the same or greater standard, has not had the same acceptance. There is no such thing as zero risk. Yet a shopper in major cities in North America never thinks about the building collapsing around them. This implies a faith in the designers, the regulators, the inspectors and most importantly the owners who commissioned the work and paid for it. Yet empirical models and mathematical models indicate that the same level of confidence should exist in relation to potential major loss of product occurring from offshore pipeline. Experience and effective communications can engender the same level of confidence and a realistic perception of risk of a pipeline failure as exists for buildings and bridges.

For the current study, the primary objectives of the risk analysis process, for buried arctic offshore marine pipelines, can be concerned with two scenarios:

- Functional Failure

– pipeline system damage without loss of product containment integrity
- Containment Failure

– pipeline system damage with loss of product containment integrity

The first issue is related to serviceability, while the latter represents an ultimate failure issue associated with a significant potential for environmental damage. In addition, both factors are also related to potential production delay and/or loss. For the double wall pipeline system, functional loss or product breach of the inner pipeline does not necessarily imply accidental product release into the environment.

10.3.1 Limit States and Target Safety Levels

In general, allowable stress design methods consider a load event based on a single fixed return period, typically 100-year event, for the entire pipeline system and incorporate safety factors. In contrast, a limit states approach typically considers a variable annual probability of exceedence per unit pipeline length or pipeline system depending on the safety class and limit state considered. For example, CSA Z662 (1999) specifies annual probability of exceedance levels for general environmental loads as 10^{-2} per kilometre and for rare events (e.g. earthquake, iceberg impact) or accidental loads (e.g. construction, fire/explosion) the exceedence limit is specified as 10^{-4} per kilometre. The target safety level represents a maximum acceptable failure probability for a defined limit state; that is the minimum acceptable level for a defined hazard. Sotberg et al. (1997) and DNV (1996) present annual target safety levels for offshore pipelines and recommend the following levels:

Limit State	Target Failure Probabilities	Reference Units
Serviceability	$10^{-2} – 10^{-3}$	/total pipeline length /year
Ultimate	$10^{-3} – 10^{-4}$	/total pipeline length /year
Fatigue	$10^{-3} – 10^{-4}$	/total pipeline length /life cycle
10.3.1.1 Ac cidental	$10^{-4} – 10^{-5}$	/unit pipeline length /year

10.3.2 Inference from the Historical Record

A database explicitly characterizing source hazards for single wall or double wall pipeline systems in an arctic offshore environment does not currently exist. Inferences can be made from the historical record, however, based on an engineering assessment of known offshore pipeline system failures located in other offshore environments. According to Bea (1999), corrosion and damage due to natural hazards have accounted for 83% of the pipeline system failures. The total source distribution is shown in Figure 10.3-1 for the years 1980–1996. Farmer (1999) presented a similar distribution for data spanning 1982–1998, illustrated in Figure 10.3-2, where corrosion and external loads accounted for 66% of pipeline failures.

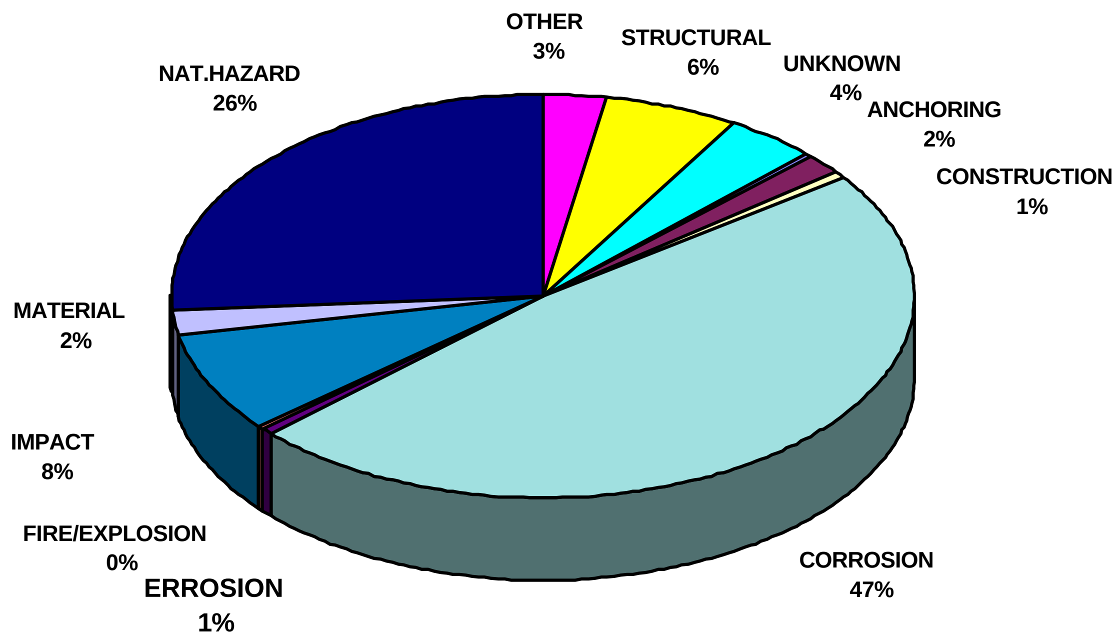


Figure 10.3-1. Source Distribution for Offshore Pipeline System Failures Based on Gulf of Mexico Data (Bea, 1999).

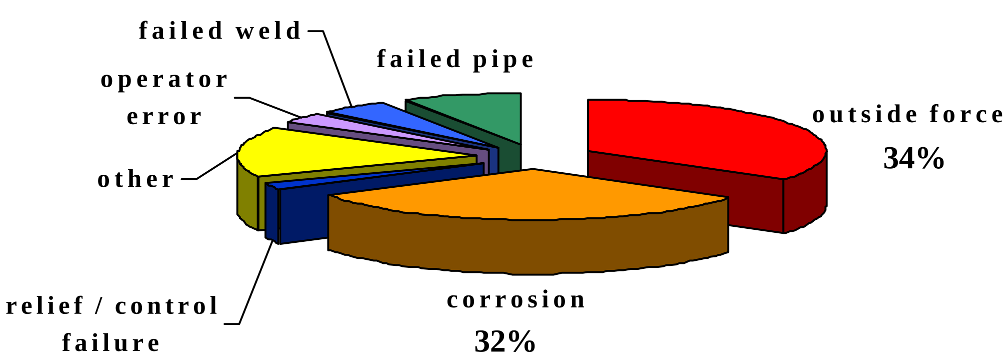


Figure 10.3-2. Source Distribution for Offshore Pipeline System Failures Based on Gulf of Mexico Data (Farmer, 1999).

For the present comparative pipeline assessment, the recognized and perceived hazards for pipeline failure, of a buried single or double wall arctic offshore pipeline system, can be categorized as:

- Girth weld
- Buckling
- External corrosion
- Internal corrosion
- Accidental
- Erosion
- Material / Structural
- Unknown / Other

To assess risk in terms of life-cycle cost it is necessary to have a source hazard distribution of single wall offshore pipeline system failures. The statistics presented by Bea (1999) and Farmer (1999), predominantly for Gulf of Mexico pipeline systems, are reinterpreted in consideration of these selected parameters for the arctic offshore environment and illustrated in Figure 10.3-1. Although defined on a subjective basis, the application of sound engineering judgment should provide order estimates for hazards to arctic offshore pipeline systems. The relative distribution of hazards for a single wall, buried arctic offshore pipeline system is illustrated in Figure 10.3-3. Characterization of hazards (i.e. failure mode) and causal event (i.e. mechanism) for buried single wall and double wall pipeline systems in an arctic offshore environment are summarized in Table 10.3-1. The comparative assessment considers both functional failure and product containment failure. The primary objective for a double wall pipeline system is containment in the event of product loss from the inner pipeline. Consequently, excessive pipeline strain has been separately characterized as girth weld (i.e. tensile) and buckling (i.e. compressive) source hazards. The division into two components is due to the fact that consequences for each event can be markedly different. Buckling can be generally associated with a loss of serviceability with relatively minor consequence, whereas girth weld failure represents loss of product and the severity is dependent on the spill magnitude. For buried arctic offshore pipelines, the hazards would be primarily associated with strain-based mechanisms that include ice gouge and strudel scour and time dependent thaw settlement. An underlying assumption has been made such that the natural hazard statistic (26% of Figure 10.3-1) was equally distributed between girth weld (13%) and buckling (13%).

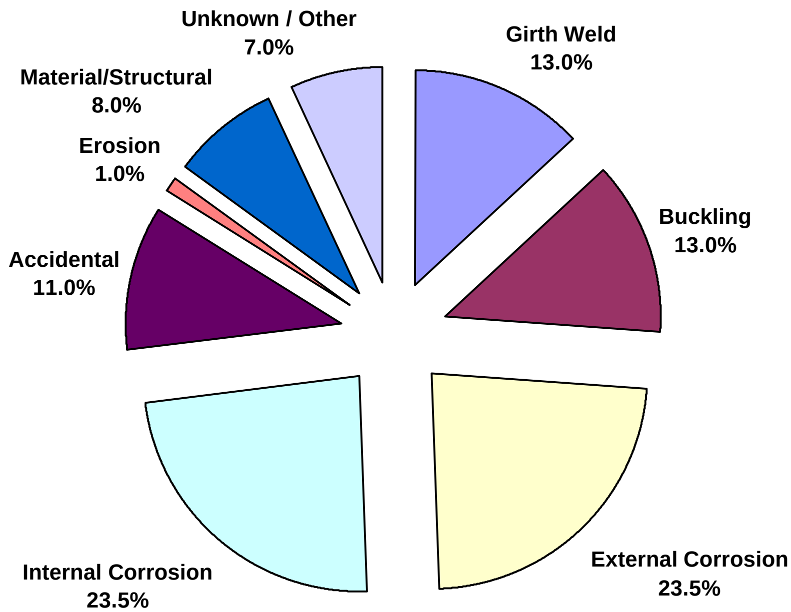


Figure 10.3-3. Inferred Source Hazard Distribution for Single or Double Wall Buried Arctic Offshore Pipelines Based on Historical Record of Single Wall Offshore Pipeline System Failure Distribution from Gulf of Mexico Data Presented in Figure 10.3-1.

Table 10.3-1. Hazard Characterization and Causal Event for Single Wall and Double Wall Pipeline Systems in an Arctic Environment.

Hazard (i.e. Response Mode)	Causal Event (i.e. Mechanism)
Girth weld failure	▪ Extreme environmental load (e.g. ice gouge, strudel scour) ▪ Operational over-pressure ▪ Faulty design or error in fracture analysis/ECA ▪ Faulty workmanship, NDE/RT/UT inspection procedures ▪ Pipe laying operations
Buckling	▪ Extreme environmental load (e.g. ice gouge, strudel scour) ▪ Upheaval buckling ▪ Faulty design practice, workmanship
External corrosion	▪ Natural environmental processes aiding corrosion (e.g. soil, water, burial depth, ambient temperature) ▪ Faulty procedures or failure with monitoring, maintenance and/or detection of the cathodic protection system ▪ For double wall pipeline system inability to MFL/UT inspect the outer pipe ▪ Faulty workmanship, design or degradation of the external corrosion coating inhibitor ▪ Potential annulus corrosion issues
Internal corrosion	▪ Corrosiveness of product (composition/water cut), “higher” pipeline operating temperature ▪ Faulty procedures or failure with monitoring, inspection and/or maintenance program ▪ Lack of effective corrosion inhibitor related to improper use or degradation with time ▪ Potential annulus corrosion issues
Accidental	▪ Unaccounted external loads, Fire/explosion ▪ Loss of control systems (e.g. tie-in locations, gates, valves) ▪ Incurred during construction, installation
Erosion	▪ Product quality (e.g. flow velocity, solids content) impairs single wall or inner pipe of double wall system
Material / Structural	▪ Deviation from intended design specification (e.g. improper cathodic protection, pipe mill spec) or configuration (e.g. mechanical connection)
Unknown / Other	▪ Faulty design ▪ Workmanship standards, technical expertise ▪ QA/QC controls ▪ Unidentified

Palmer (2000) observed that corrosion does indeed account for many pipeline failures. However, corrosion is mostly in lines that are poorly designed, poorly maintained, poorly monitored or operated with contents and at temperatures they are not designed for. Other factors causing corrosion have included stopping corrosion inhibition, coating damage, or operating beyond the intended design life. The corrosion statistics presented above therefore should overpredict the corrosion failures that can be expected for high profile and well-engineered and monitored Alaskan pipelines. Palmer holds the opinion that it is possible to design a pipe-in-pipe system to be safe against corrosion. In support of this, he points to the many North Sea bundles that have been in operation for 10 or 15 years. This overprediction was not accounted for in the following.

Corrosion (47% of Figure 10.3-1) was assumed equally weighted with respect to internal (23.5%) and external (23.5%) corrosion mechanisms. Arguments could be forwarded for a reduction in the source distribution for external corrosion (lower ambient temperatures) and internal corrosion (product type). Annual failure rate estimates, however, were based on the historical data. Data for anchoring (2%), construction (1%), fire/explosion (0%) and impact (8%), presented in Figure 10.3-1, was assessed as a single, accidental hazard (11%). For the arctic environment, the source distribution could be lowered to reflect the reduced level of general offshore activity (e.g. trawling, anchoring).

Failure statistics for erosion, material/structural, unknown/other were directly incorporated, from Figure 10.3-1, into the projected hazard distribution for arctic offshore pipelines, Figure 10.3-3.

Although difficult to forecast and quantify, the source hazard distribution (Figure 10.3-3) could be augmented and/or restructured due to unforeseen events or mechanisms as discussed in section 10.2.2.1. For example, there is uncertainty associated with novel technology (e.g. double wall pipeline systems for containment) or unique environments for conventional systems (e.g. single wall pipelines in an arctic environment).

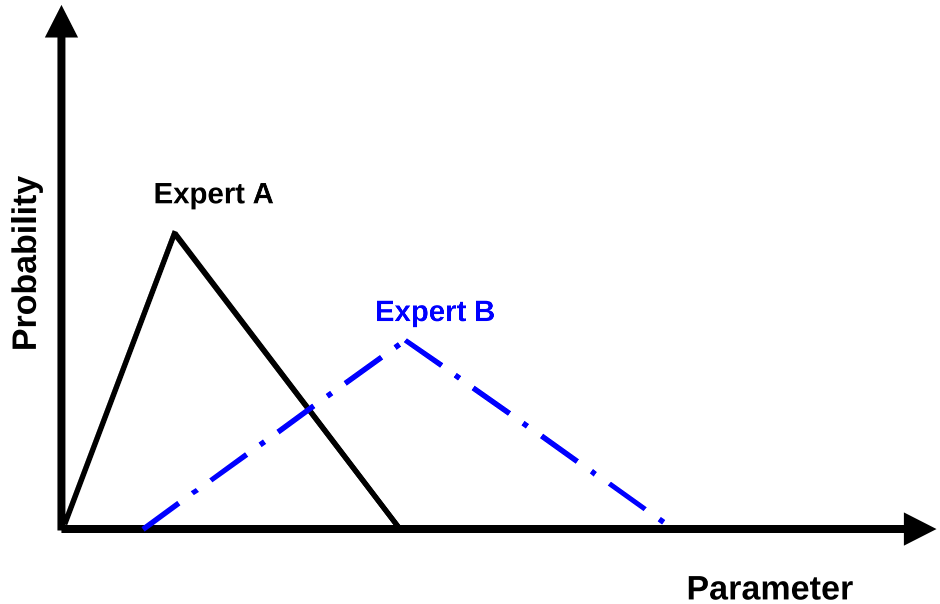
10.3.3 Hazard Frequency Analysis

For the years 1980–1996, annual failure rates of oil and gas pipelines systems in the Gulf of Mexico has been typically on the order of $1–2\times10^{-3}$/year and have not exceeded 1×10^{-2}/year (Bea, 1999). Although pipe-in-pipe systems have been employed for offshore environments, as summarized in Table 6.1-2 (e.g. Troika, Shell E-TAP), extrapolation of the hazard source and frequency to the arctic environment is not straightforward. The primary design issues were hydrostatic pressure and thermal protection, rather than the envisaged product containment function of a buried, double wall arctic offshore pipeline system that could potentially be subject to large differential ground movement. There are no statistics for the failure of double wall pipelines.

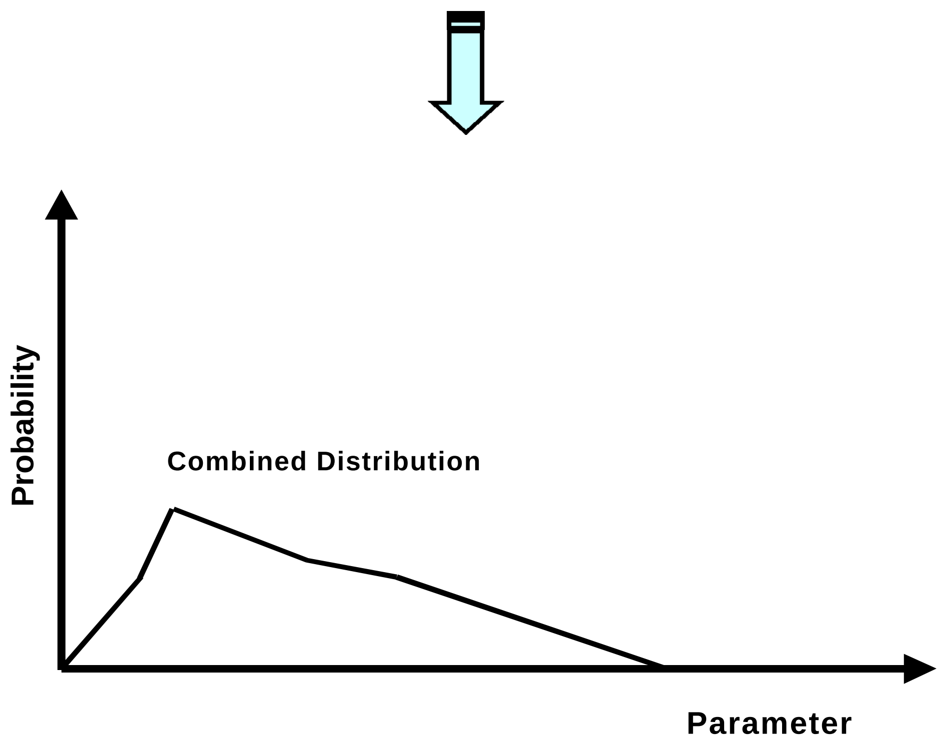
The main difficulty in establishing hazard source distributions and frequency estimates representative of an arctic environment lies in extrapolating the historical record (i.e. reinterpretation of Figure 10.3-1 to develop Figure 10.3-

3) and defining failure rates in lieu of a statistical database. The issue is further compounded by the associated uncertainty with respect to perceived risks and, in particular, for unknown hazards. For example, the influence of external activities (e.g. trawling, dropped objects and anchors) can be effectively ignored for buried arctic offshore pipelines, whereas other hazards (e.g. ice gouge, strudel scour) represent significant risks not included in the historical pipeline system failure database (Figure 10-3.1, Figure 10-3.2).

Expert opinion modeling, based on qualified engineering expertise and common sense, can provide an alternative basis for conducting a preliminary assessment of hazard characterization and frequency estimates where data is nonexistent or inconclusive. Invariably expert opinion, which represents subjective uncertainty, will be dissimilar due to assumptions, information, analytical method, level of expertise, perspective, and/or inherent bias. This could be illustrated by the variation in source hazard distribution statistics presented in Figure 10.3-1 and 10.3-2. The discrepancy, however, could also be attributed to the source of the data set, since the distributions represent marginally different time lines. The process for combining two dissimilar expert opinions, using an equal weighting function, is shown in Figure 10.3-4. Triangular distributions have been selected for illustrative purposes, although, the Beta distribution would be preferred since the response is less influenced by the potential systematic bias in terms of the mean and standard deviation parameters.



(a)



(b)

Figure 10.3-4. (a) Initial Distribution of Two Dissimilar Expert Opinion (b) Combined Distribution Using Equal Weighting Function.

Alternatively, quantitative analytical procedures could be employed to define hazard frequency estimates. For example, excessive pipeline strain (i.e. girth weld failure, buckling) due to external environmental loads due to ice gouge events could be determined by a coupled approach that considers site specific surveys, empirical investigations and numerical modeling. This is illustrated in Figure 10.3-5.

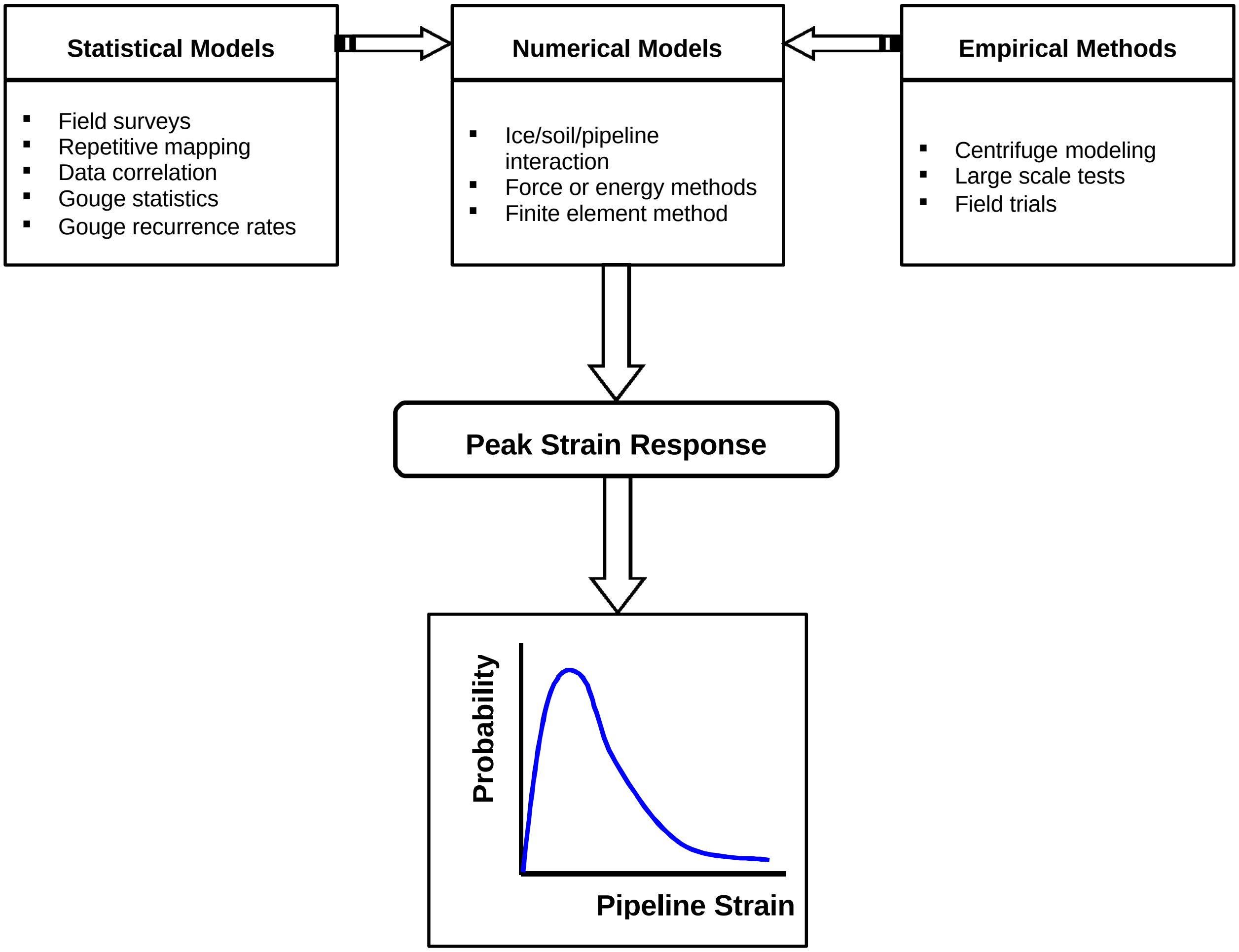


Figure 10.3-5. Illustrative Example of a Coupled Approach in Defining Hazard Frequency for Excessive Pipeline Strain due to Ice Gouging Process.

Failure probabilities based on the reinterpreted source hazard distributions (Figure 10.3-3) and assuming an average system failure rate of 1×10^{-3}/year as presented by Bea (1999) are summarized in Table 10.3-2. The data represents the hazard frequency estimates for a single wall, buried arctic offshore pipeline. The data should only be viewed as representative frequency estimates based on the historical record of offshore pipeline system failures for single wall pipelines located outside an arctic environment. A more comprehensive quantitative assessment may present a basis for redefining the tabulated hazard recurrence rates. Inference for the inner and outer pipelines for the double wall alternative is also presented. The rationale for defining the hazard frequency estimates, presented in Table 10.3-2, is addressed.

Table 10.3-2. Hazard Frequency Estimates for Buried Offshore Single Wall and Double Wall Pipeline Systems for an Arctic Environment Based on Inferred[e] Statistics from the Gulf of Mexico Database (Figure 10.3-3).

Hazard	Inference for Buried Offshore Arctic Pipeline Systems				
	Annual Failure Probability				
	Single Wall Pipeline	Double Wall Pipeline			
		Inner Pipe	Outer Pipe	System	
Girth Weld	1.3×10^{-4}	1.3×10^{-4}	5.0×10^{-4}	7×10^{-8} [a]	I [d]
Buckling	1.3×10^{-4}	1.7×10^{-4}	4.6×10^{-4}	2×10^{-4}	D
External Corrosion	2.4×10^{-4}	—	2.4×10^{-4}	6×10^{-8}	I
Internal Corrosion	2.4×10^{-4}	2.4×10^{-4}	—		
Annular Corrosion	—	1.0×10^{-5} [b]		1×10^{-5}	—
Accidental	1.10×10^{-4}	1.1×10^{-4}		1×10^{-4}	D
Erosion	1.0×10^{-5}	1.0×10^{-5}	—	1×10^{-5}	—
Material / Structural	8.0×10^{-5}	8.0×10^{-5}		8×10^{-5}	D
Unknown / Other	7.0×10^{-5}	7.0×10^{-5}	1.4×10^{-4} [c]	2×10^{-4}	D
Total	1×10^{-3}	8×10^{-4}	2×10^{-3}	6×10^{-4}	

<u>Notes:</u> *A hazard frequency of 1´10^{-3} is equivalent to the occurrence rate of 0.001 failures/year or 1 failure event in 1000 years.*

[a] – assumed single soil deformation event, localized tensile strain and staggered weld locations (see Section 10.3.3)

[b] – assumed annular corrosion failure rate of 1.00´10^{-5}

[c] – assumed factor of 2

[d] – independent or mutually exclusive event (I), dependent event (D)

[e] – annual failure rate taken from Gulf of Mexico data but source hazard distribution is inferred for an Arctic environment (Figure 10.3-3).

Girth Weld Failure

Based on the structural integrity analysis (Table 7.6-5), the girth weld failure probability of the inner pipeline for the double wall alternative should be on the same order as the single wall pipeline (i.e. 1.30×10^{-4} failures/year). For the double wall system the weld count would be two to four times greater than the single wall counterpart (Table 9.5-2). In addition, as discussed in

Section 9.2, there is an increased construction risk with the double wall systems due to the increased weld count and the difficulties associated with the tie-in welds of the outer pipe. Consequently, an increased girth weld failure probability for the outer pipeline of the double wall system (i.e. 5×10^{-4} failures/year) was considered.

For the double wall pipeline system, there are several underlying assumptions for the system failure probability estimate for the girth weld that must be addressed:

- The pipeline is subjected to a single soil deformation event. The influence of multiple spatial (e.g. multi-keeled ridges) or temporal (e.g. sequential deformation events) geotechnical loads applied to the pipeline was not considered.
- The excessive peak tensile strain developed in the pipeline would be localized to a finite section of the pipeline. This would be consistent with the consideration of a single event, strain based mechanism considered (i.e. ice gouging, thaw settlement).
- The application of staggered weld locations would thus confine the localized strain region to a single weld joint of either the inner or outer pipeline.
- On this basis, simultaneous girth weld failure of both the inner and outer pipeline was considered independent events.

Referring to Table 10.3-2, the probability of a simultaneous failure of both pipelines for a double wall system (P_{DW}) resulting in a total system containment failure, can be defined as,

$$P_{DW} = (1.30\times10^{-4})(5\times10^{-4}) \cdot (7\times10^{-8}) \text{ system failures/year.}$$

Buckling Failure

The buckling hazard frequency estimates for the inner and outer pipelines of the double wall alternative were based on a normalized factor with respect to the single wall pipeline. The assessment used the critical compressive strain ratios of the computed pipeline system response as summarized in Table 7.6-6. For the single wall pipeline, the compressive strain ratio was 0.42, whereas the inner pipe ratio was 0.51 and the outer pipe ratio was 1.34 for the double wall alternative. Estimates of the hazard frequency for components of the double pipeline system were considered by normalizing the compressive strain ratio of the inner and outer pipelines with respect to the single wall pipeline. On this basis, the inner pipeline hazard frequency would be increased by a factor ($0.51/0.42 \approx 1.25$) and the outer wall pipeline would be increased by a factor ($1.34/0.42 \approx 3.5$). The hazard frequencies for the pipeline systems are presented in Table 10.3-2.

The buckling hazard failure rates were based on structural analysis of the pipeline response, for the single wall and double wall systems presented in

Section 7.6. For the double wall system, the analysis demonstrated that the outer pipeline exceeded whereas the inner pipeline satisfied the compressive strain limits in accordance with code requirements for combined loads. Buckling of the inner and outer pipelines cannot be assessed as independent events where the system failure rate would be probably highly correlated. The annual system failure rate was estimated on the basis of the inner pipeline and rounded to 2×10^{-4}.

Consequently, in lieu of a documented historical record, the annual buckling failure rates for the double wall pipeline system can only be considered an approximate estimate. Further detailed engineering analyses through finite element methods and empirical investigations should clarify the potential significance of pipe-in-pipe interaction and the relative freedom of motion for the inner pipeline. Through this parametric analysis, a more complete database with respect to coupled interaction effects, failure modes and joint distributions can be assessed in defining annual failure rates.

In general terms, buckling failure for either pipeline systems can be primarily viewed as a functional failure (i.e. no containment loss) with the major implications related to serviceability, downtime and repair.

Corrosion

For the double wall pipeline system there are three corrosion issues (i) internal corrosion of the inner pipeline, (ii) external corrosion of the outer pipeline and (iii) annular corrosion of the inner and outer pipelines.

The internal corrosion failure rate of the inner pipeline and the external corrosion failure rate of the outer pipeline for the double wall system have been assumed to be equivalent to the hazard frequency estimates for the single wall pipeline system. The respective annual failure rates are presented in Table 10.3-2.

The major uncertainty is with respect to annular corrosion and an annual failure rate of 1×10^{-5} was assumed. The hazard frequency estimate for annular corrosion is not known *a priori*, however, based on the qualitative analysis presented in Section 9 the effects should be relatively minor and localized. Although difficult to quantify with certainty, the assumed estimate for annular corrosion is considered to be a conservative value due to the perceived limited corrosion potential. The annulus would not be subjected to the ‘negative’ effects of the product or the environment, and the presence of a nitrogen pack coupled with the amine oilfield corrosion inhibitor would virtually eliminate significant annular corrosion over the life of the pipeline.

Recent interpretation of the pipeline system failure rates (Smith, 2000) indicates that internal corrosion represents 69% of the corrosion failure statistic. For an arctic environment, the external corrosion rate of the outer pipe would most likely be reduced, in comparison with warmer environments, due to the lower temperature. For the present study, equal source distribution of internal and external corrosion was considered valid.

Accidental Event

Although the protective nature of the outer pipe should decrease the accidental failures of the inner product pipeline from external loads, with respect to the single wall pipeline, the annual failure rate was assumed equivalent.

Erosion

Variation in the erosion and material/structural pipeline system failure rates was not considered to be significant and the base values of the single wall pipeline were adopted for the double wall system alternative.

Unknown / Other

The added complexity and uncertainty for a double wall pipeline system suggests an increased frequency estimate for unknown hazards, inexperience associated with emerging or novel technology and uncertainty associated with integrity monitoring of the outer pipeline during operation. The inner pipeline was considered to be equivalent with the single wall pipeline and an arbitrary factor of 2 was assumed for the outer wall pipeline.

10.3.4 Event Consequence

For the present study, event consequences are defined in terms of functional failure and containment failure. Respective issues concerning environmental damage, production delay/loss, social impact and financial cost as a function of severity are summarized in Table 10.3-3. The events could be further divided into subcategories defining the spill magnitude in terms of the time frame required for recognizing the existence of a failure event and pipeline damage index. The severity assessment must also integrate the stochastic impact of an event, in terms of the physical environment (e.g. open water, spring break-up) and ecological environment (e.g. animal migration, mating patterns). For the present analysis, functional failure and containment failure was addressed in the context of the same event consequence.

Table 10.3-3. Event Consequence Characterization and Categories for Functional or Containment Failure.

Functional Failure	
Magnitude	Consequence
Minor	▪ Production impairment with time span of day(s) to weeks(s) ▪ ≤ $0.1million
Severe	▪ Downtime and/or minor production loss with time span of month(s) ▪ $1million – $5million
Critical	▪ Loss of total production with time span of year(s) ▪ ≥ $5million

Containment Failure	
Magnitude	Consequence
Minor	▪ Isolated leaks (i.e. processing, pumping stations) or minor damage to pipeline containment integrity ▪ Relatively minor and localized environmental damage ▪ Local community concern ▪ Production impairment with time span of day(s) to weeks(s) ▪ ≤ $0.1million
Severe	▪ Damage to pipeline containment integrity ▪ Considerable environmental damage ▪ Local and State concern ▪ Downtime and/or minor production loss with time span of month(s) ▪ $1million – $5million
Critical	▪ Significant damage to pipeline containment integrity, monitoring system failures and/or control systems ▪ Significant and widespread environmental damage that requires long term remediation and cost ▪ Local, State and Federal concern ▪ Loss of total production with time span of year(s) ▪ ≥ $5million

10.4 Comparative Risk Issues

Risk issues that consider hazard frequency and event consequence for single wall and double wall alternatives of buried arctic offshore pipeline systems are addressed. The comparative risk assessment is conducted on a qualitative basis, since there is no historical record for a buried arctic offshore pipe-in-pipe concept with respect to product containment integrity. Initial risk estimates evaluated using a semi-quantitative index method demonstrated that the analysis was sensitive to the selected parameters and associated numerical indices.

A semi-quantitative assessment of risk and life cycle cost for the arctic pipeline systems considered is presented. The analysis is based on a number of constraints that include:

- The analysis only considers parameters defined by project basis (Table 7.1-1).
- The hazard frequency estimates are representative probabilities based on the historical record of offshore pipeline system failures for single wall pipelines located outside an arctic environment. A more comprehensive quantitative assessment may present a basis for redefining tabulated hazard recurrence rates.

10.4.1 Functional Failure

The consequence of a functional failure, where the pipeline system is damaged but pressure containment integrity is maintained can be viewed as relatively benign when compared with a loss of product into the environment. From this perspective, the environmental impact can be considered minimal and the main issues are associated with a loss of serviceability, system inspection, repair, production downtime/loss, impact on economic return and/or environmental consequences of repair activities. A qualitative comparative risk assessment, between the double wall pipeline system and the single wall pipeline, for functional failure is summarized in Table 10.4-1. Failure issues with respect to girth weld, external or internal corrosion were not considered since these would most likely represent product loss for the single wall pipeline. The analysis suggests that the double wall pipeline has an increased risk of functional failure, which is primarily associated with the higher annual hazard frequency estimates for the outer wall pipeline (Table 10.3-2).

Table 10.4-1. Qualitative Assessment of Comparative Risks for a Double Wall Pipeline System with Respect to a Single Wall Pipeline System for Functional Failure.

Functional Failure			
Hazard	Probability	Consequence	Relative Risk
Buckling	>	≡	⇑
Accidental	≡	≡	⇑
Erosion	≡	≡	≡
Material / Structural	≡	≡	⇑
Unknown / Other	>	≡	⇑

<u>Legend:</u>

>	Greater failure rate	<	Lesser failure rate
≡	Equivalent failure rate, consequence severity or risk		
⇑	Increased risk (failure × consequence)	⇓	Decreased risk (failure × consequence)

10.4.2 Containment Failure

The more significant consequence to address is the pipeline system containment failure, that is a loss of product containment integrity for either the single wall or both pipes of the double walled pipeline. As defined in Section 7.6.1.3, this was the basis for defining equivalent robustness. An important point to recognize is that for the double wall pipeline system, failure of the inner pipeline does not necessarily correspond with a loss of product containment integrity. Although there is a degree of uncertainty associated with the hazard frequency estimates presented in Table 10.3-2, the double wall pipeline system offers the potential advantage for secondary containment of product leakage from the inner pipeline. This is illustrated in Table 10.4-2 and is directly related to the reduced probability (Table 10.3-2) for either simultaneous girth weld failure or corrosion failure of both the inner and outer pipelines of the double wall system. For pipeline rupture events associated with a girth weld failure and a major product spill, the double wall alternative should offer a potential reduction in the risk level in comparison with single wall pipelines.

Table 10.4-2. Qualitative Assessment of Comparative Risks for a Double Wall Pipeline System with Respect to a Single Wall Pipeline System for Containment Failure.

Containment Failure			
Hazard	Probability	Consequence	Relative Risk
Girth Weld	<<	≡	⇓
Buckling	<	≡	≡
External Corrosion	<<	≡	⇓
Internal Corrosion	<<	≡	⇓
Accidental	≡	≡	⇓
Erosion	≡	≡	⇓
Material / Structural	≡	≡	⇓
Unknown / Other	>	≡	≡

<u>Legend:</u>

> Greater failure rate   < Lesser failure rate

≡ Equivalent failure rate, consequence severity or risk

⇑ Increased risk (failure × consequence)   ⇓ Decreased risk (failure × consequence)

10.4.3 Summary

The double wall alternative appears to represent a reduction in risk due to containment failure (i.e. loss of product) for most of the major hazards considered. For localized strain based mechanisms (e.g. pipeline system response to ice gouge or thaw settlement), the probability of simultaneous system failure (i.e. both the inner and outer pipelines fail), assuming staggered girth weld, is reduced. The double wall alternative, however, has an apparent increased risk of functional failure (i.e. primarily related to serviceability).

Although difficult to quantify and partially subjective, based on the inference of historical data for failure rates of single wall pipeline systems, the double wall alternative would reduce the system failure probability by a factor of approximately 0.5. The hazard frequency estimates indicate that the double wall pipeline system has a greater propensity for functional failures and reduced probability for containment failure scenarios.

An important conclusion based on the parameters of the hazard frequency analysis conducted for the single wall and double wall pipelines (Table 10.3-2), is that the failure probabilities for both pipeline systems meet or exceed the recommended target safety levels (Section 10.3-1).

10.5 Factors Influencing Risk Assessment and Life Cycle Cost

Comparison of quantitative risk levels (risk estimate = hazard frequency × consequence index) for buried single wall and double wall pipeline alternatives for the arctic offshore environment with life cycle cost is a difficult task. The lack of a historical basis significantly hinders this process and consequently, engineering judgement was used to provide an indication of what potential benefits are associated with the increased life cycle costs for the double wall alternative.

The primary objective for a comparative assessment between a single wall pipeline and double wall system alternatives is based on reducing the risk of environmental damage due to containment failure and product loss in terms of life cycle cost. Although the analysis has suggested that the annual system failure rate of the double wall pipeline system will be lower than the conventional single wall pipeline, this information cannot be considered in isolation.

The comparative assessment must also be viewed in terms of the defined parameters and constraints of the overall risk analysis framework. For example, the girth weld and buckling hazard statistics were estimated by the structural integrity calculations, which were dependent on the parameters defined by the project work scope and basis. (Table 7.1-1). For large deformation events, such as ice gouge or thaw settlement, pipe/soil interaction is a complex, nonlinear process. Variations in the parameters defining the project basis (e.g. product characteristics, burial depth, loading event) would influence the pipeline structural integrity calculations and thus requirements to meet specified design criteria. For the variant scenarios, this would indirectly impact the risk estimates and life cycle cost.

Another factor to consider is the potential for functional failure and pipeline operations as well as risk evaluation, control and management procedures throughout the pipeline life cycle. From this perspective, the increased functional failure rate of the double wall pipeline system has the potential for higher incremental repair costs over the project life. The ability or inability of either a single or double wall pipeline system to operate under a defined functional state has significant implications on life cycle cost and the associated risk-benefit analysis. For the double wall pipeline system, the significant issue is uncertainty associated with integrity monitoring of the annulus, such as the level of inspection, detection, monitoring and maintenance of the outer wall pipeline. These factors can be considered within a risk assessment (i.e. analysis and evaluation) and risk management (i.e. controls, decision making, regulatory authorities) framework. In addition, unknown hazards and the risk associated with emerging or novel technology can be addressed with more confidence as greater experience with buried arctic offshore pipeline systems is acquired.

For example, as an individual event, a girth weld failure of only the outer pipeline of a double wall pipeline system can be viewed as a functional constraint. This would also have significant consequences with respect to pipeline operations and risk management process. These factors are inherently coupled to consequence and risk significance, which must address the time frame associated with recognition of a system failure, spill category (i.e. product volume lost), environmental damage and the ability to intercede with remedial action (i.e. ice season, open water).

To illustrate, for a single wall pipeline, a reduction of the risk for containment failure, due to excessive tensile strain and girth weld failure could be achieved by a combination of material selection, pipe geometry and/or greater burial depth. The advantage would be a relatively simple design with proven integrity monitoring technology offset by increased installation costs and potential for decreased hazard frequency rates.

A comprehensive assessment of risk and life cycle cost must consider risk evaluation and also recognize the available risk control measures. Risk evaluation is the process of judging the significance of the estimated risk level (i.e. hazard frequency $\times$ consequence index) and identifying options for risk management. Risk control is related to decision-making within the risk management process in terms of monitoring activities and implementation of objectives. A number of factors must be assessed, which include the frequency of occurrence, event severity, acceptable risk levels and the costs associated with an incremental reduction in the estimated risk level. For example, the significance of a functional failure at year one (Year 1) is considerably different than a functional failure at year twenty-five (Year 25) of a 30-year project life.

In general terms, it is more economical to invest in a reduction of the hazard frequency rates (i.e. probability of an event occurrence) as opposed to mitigation of event consequences (i.e. severity of the event). The analysis must consider the tradeoffs in terms of incremental cost/risk reduction, objectives of pipeline operators, regulatory authorities and the adopted risk evaluation/risk management procedures throughout the life cycle.

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APPENDIX B Glossary of Terms / Definitions

Note: Numbers following a definition corresponds to bibliography at the end of the section.

AAC Alaska Administration Code

Abrasion Resistant Coating (AR): A type of coating applied to the outside of an externally coated pipe to protect the coating from damage caused by abrasion.

AGA American Gas Association

Allowable Stress Design Method: A deterministic design method that limits pipe stresses to some fraction of the pipe materials Specified Minimum Yield Stress (SMYS) to keep the material entirely below its "elastic limit". ASME B31.4 is an example of a stress based pipeline code.

Annulus Pack **Any engineered material placed in the annular space between an inner pipe and an outer pipe. An example is a gelled non-electrolyte, which would reduce heat transfer and protect the outside of inner pipe and the inside of the outer pipe from corrosion. Other attributes such as non-toxicity could also be specified.**

Annulus The space between the inner and outer pipes in a double wall pipe system. Also sometimes referred to as the annular space.

ANSI American National Standards Institute

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASTM American Society for Testing and Materials

Availability: A measure of the probability that a pipeline system will perform its function, as intended by its design, at any given point in time.

Backfill Soil used to replace soil excavated during trench construction, after [1] and [6]

Big Inch Pipe A pipeline 24 inches (61 centimeters) in diameter which carries oil or gas, usually for great distances. – [1] Named after a 24" pipeline from Longview, Texas to Norris City, Illinois, built during WWII, [3].

Bolt on Weights, Saddle Weights Weights added to a pipe to provide negative buoyancy. Usually used instead of concrete coating.

Bulkhead See Pipe Bulkhead

Carrier Pipe See Outer Pipe. It is recommended that the term 'Carrier Pipe' is not used as it has been used by others in different contexts to denote either the inner or outer pipe.

Cathodic Protection System (CPS): A method of protecting the external pipe wall of a metal pipeline from galvanic corrosion by neutralizing the electrochemical reaction responsible. The reaction is neutralized through the introduction of an impressed current or, more typically for offshore pipelines, the use of sacrificial anodes.

CFR Code of Federal Regulations

Chemical Inhibition: A method of protecting the internal pipe wall of a pipeline from corrosion by the introduction of corrosion inhibiting chemicals.

Cleaning Pig: A pipeline pig used for physically cleaning the internal space of a pipeline.

Composite Pipe A pipe made up of two or more materials - e.g., stainless steel/ fibre reinforced plastic piping.

Concrete Cased Pipe A pipe with a continuous concrete coating, usually to provide negative buoyancy and/or provide mechanical protection to an external coating on the pipe.

Containment Failure A failure which involves pipeline system damage with loss of product containment integrity, that is product loss to the external environment.

Crack Tip Opening Displacement (CTOD) Test: A type of destructive testing for pipe and pipe weld material. The test is performed to characterize the materials fracture toughness and is especially appropriate to materials that change from ductile to brittle behaviour with decreasing temperature.

CSA Canadian Standards Association

Directional Drilling The technique of drilling at an angle from the vertical by deflecting the drill bit [3].

DnV Det Norske Veritas,

DOT Department of Transport

Double Submerged-Arc Weld (DSAW) Pipe: A pipe manufacturing process that produces pipe with a longitudinal butt weld produced by at least two weld passes, one of which is on the inside of the pipe, of a shielded electric arc. Filler metal is applied to the weld joint by electrode but no external pressure is applied to complete the weld.

Double Wall Pipe See Pipe in Pipe

Elastic Limit: The maximum stress beyond which a material will exhibit some plastic deformation and below which stress and strain are, within specified limits, directly proportional.

Electric Resistance Weld (ERW) Pipe: A pipe manufacturing process that produces pipe with a longitudinal, electric resistance heated butt weld, from coiled skelp. No filler metal is used, but external pressure is applied to the weld joint to complete the weld.

Encased Pipe, Cased Pipe A pipe contained within some type of casing, usually steel, to provide protection for short lengths such as under roads or railways.

Flexible Pipe: A pipe that has a high degree of compliance in contrast to conventional steel pipeline.

Functional Failure A failure which involves pipeline system damage without loss of product containment integrity, that is no product loss to the external environment.

Fusion Bonded Epoxy (FBE): A type of coating applied as a powder and fused, by the application of heat, to the outside of a pipe to protect it from external corrosion.

Geometry Pig: A pipeline pig used to measure pipe deformation, e.g., pipe diameter changes caused by dents or ovality, or pipeline curvature, e.g., pipeline settlement, lateral or upheaval buckling.

Guides A fixture around a pipe section used to guide or locate the pipe relative to its surrounding.

Heavy Wall Pipe: A pipe with a diameter to wall thickness (D/t) ratio of 30 or less.

High Density Polyethylene (HDPE): A plastic, which has been used commercially for piping. HDPE is not subject to electrolytic corrosion and is fairly tolerant of hydrocarbons. Individual lengths can be fused together by means of thermal butt welding to form a long pipe without potentially troublesome connectors.

Horizontal Directional Drill (HDD) Installation Method: A construction method whereby a pipeline is constructed by first drilling a horizontal hole, beneath a body of water to be crossed, from a fixed position at one end of the crossing. The pipeline is then constructed at a fixed point, usually on shore at the exit end of the hole, and is pulled by the drill rig into its final position within the drilled hole.

Hydrotest: The pressure testing of a pipeline to some factor above its maximum operating pressure using water as the test medium. Also referred to as hydrostatic testing.

Ice Gouge: See Ice Scour

Ice Scour: An ice scour is produced by the process of ice interaction with the seafloor, 1982 National Research Council of Canada workshop.

Inner Pipe: The inner pipe of a pipe-in-pipe system.

Jetted Pipe: A pipeline buried beneath the sea floor by a jet sled, an underwater trenching machine which straddles the pipeline and scours out the seabed material ahead and beneath the line with a series of high pressure jets of sea water [3].

Landfast Ice: A zone or belt where the formation of a relatively level ice field grows seaward from the coastline and remains static throughout the winter season. The ice may be bottom fast (≤ 2m contour) or freely floating (≤ 20m contour). During spring break-up the ice melts or drifts away.

Lateral Buckling: Horizontal displacement of a pipeline induced by axial forces resulting from the effects of internal pressure and temperature, and horizontal movement resulting from installation and / or accidental third party activity.

Lay Barge Installation Method: An “open water season” construction method whereby a pipeline is constructed on a barge on the surface of the water and is then lowered to its final position on the sea bottom.

Limit State Design: An alternative to stress based design in which individual stresses and combinations of stresses are based on defined fractions (design factors) of stresses that the pipe is specified to be able to withstand. This allows materials to be designed to exhibit a certain amount of non-linear (plastic) behavior. Limit state designs are typically used for offshore pipelines and pipelines buried in permafrost. API RP1111 defines recommended practices for the limit states design of offshore hydrocarbon pipelines.

Maintainability: A measure of the probability that a pipeline system will be restored to operational status, as intended by its design, within a specified period of maintenance related downtime.

MAOP Maximum Allowable Operating Pressure

MMS Minerals Management Service

Multi-year Ice: An ice feature that has survived from the previous winter season.

NACE National Association of Corrosion Engineers

Non Destructive Testing (NDT): A type of testing which does not impair the usability of the object tested. In the context of pipelines NDT typically refers to the testing of welds either by radiographic, i.e. x-ray, or ultrasonic methods.

NPS: Nominal pipe schedule.

Operability: A measure of the ability of a pipeline system to be operated as intended by its design.

OPS Office of Pipeline Safety

Outer Pipe: The outer pipe of a pipe-in-pipe system.

Pack Ice (Transitional Pack Ice, Seasonal Pack Ice) : Consisting of mainly first-year ice, the regime is highly mobile and located between the shear zone and polar pack ice zone. Isolated multiyear floes, pressure ridges, icebergs or ice islands can be can be encountered.

Permafrost (Relict): Permafrost reflecting past climate conditions differing from those of today [9]. Formed when the ground surface temperature was colder than at present (e.g., because of lower sea levels) and the permafrost is not in equilibrium with the present mean annual ground surface temperature.

Permafrost (Subsea): Permafrost occurring beneath the sea bottom [9]. Subsea permafrost either occurs in response to negative sea-bottom water temperatures, or it formed in now-submerged coastal areas that were previously exposed to air temperatures below 0C (relict permafrost). There is typically a significant transition zone of unfrozen (non ice-bonded) permafrost due to the saline pore fluid.

Permafrost: Ground (soil or rock) that remains at or below 0C for at least two years.[9] Since the definition is based on temperature, all permafrost may not be frozen, however, all perennially frozen ground is permafrost. It is possible, especially in marine (saline) environments, for some permafrost to be unfrozen due to the depressed freezing point of the porewater fluid.

Pipe Bulkhead: An interior wall between the inner and outer pipes of a pipe in pipe system that subdivides the annulus into a series of longitudinal compartments [7].

Pipe Bundle: A group of parallel pipes that have been fastened together [4].

Pipe Pull Installation Method: A construction method whereby a pipeline is constructed at a fixed point, either on a barge or on shore, and is then pulled by winch into its final position on the sea bottom from a fixed position at the other end of the pipeline, i.e. from the shore for barge construction, and from a barge for construction on shore. This method may be adapted for use during the "open water season" or during winter.

Pipe Spacer: An object which locates one pipe with respect to another. Typically pipe spacers are used to prevent contact between the inner and outer pipes of a double walled pipeline.

Pipe Strain: The physical deformation of a pipe as measured by changes in distance between two fixed points on the pipe.

Pipe Stress: The force applied to a pipe as measured by the magnitude of the force divided by the area across which the force is applied.

Pipe-In-Pipe: A pipe that consists of outer steel pipe containing an inner steel pipe.

Pipeline Design: The approach used by engineering disciplines to specify the what and the how of constructing and operating a pipeline.

Pipeline Pig: A mechanical device designed to be conveyed through the pipeline by the fluids being transported. In general, pipeline pigs can be of two types; cleaning or measurement.

Pipeline Stability: Generally refers to the stability of a pipeline with respect to soil strength and movement, buoyancy and hydrodynamic lift, and scour and other erosional forces.

Pipeline Weight : See Bolt-On Weight, Saddle Weight

Plastic Deformation: Permanent physical deformation resulting from imposed stresses greater in magnitude than the elastic limit.

Polar Pack Ice: Located on the seaward side of the continental shelf, the zone covers approximately two-thirds of the Arctic Ocean. Consisting of predominantly of multi-year ice, although incursions of first-year ice may occur due to the formation of leads or open water.

Pressure Ridge: A linear feature of broken, angular pieces of ice that are formed by the interaction of ice sheets or floes in a direction normal to the contact boundary. The undulating ridge profile can be characterised by ridge sail and ridge keel features.

Quality Control / Quality Assurance (QA/QC): The planned and systematic activities, performed to ensure conformance of a product or process to a required specification.

Quality Plan: The documented organizational structure, responsibilities, procedures, processes, and resources required to ensure quality.

Quality: The conformance, or degree of conformance, to which a product, or process meets a requirement specification.

Reel Barge Installation Method: An "open water season" construction method whereby a pipeline is constructed on shore, reeled onto a barge mounted spool, and then is unreeled from the barge as it is lowered, from the surface of the water, to its final position on the sea bottom.

Reliability: A measure of the probability that a pipeline system will perform its function, as intended by its design, for a specified period of time.

Sacrificial Anode: A metal, electrochemically dissimilar to that of the pipe, used to protect the pipe metal from galvanic corrosion by corroding itself preferentially.

Sacrificial Pipe: An outer pipe designed to protect the inner pipe or bundled pipe(s) system from damage due to environmental or other loads.

Seamless Pipe: A pipe manufacturing process that produces pipe by piercing a billet followed by rolling, drawing, or both.

Shear Ring: A permeable bulkhead that serves to center the inner pipe within the outer pipe of a dual walled pipeline and transfer loads between the two pipes but allows flow through the annulus between the two pipes.

Shear Zone: A highly dynamic and active boundary between the landfast ice and polar pack ice zones. Action of the mobile polar pack causes compression and shearing action of the ice features within the shear zone to create open leads, as well as the formation of pressure and shear ridges. Although not a definitive rule, the shear zone generally extends to approximately 100km offshore.

Shielded Pipe: A single wall pipe protected by an external casing over a limited length, see also cased pipe.

Shore Fast Ice (Bottom-Fast Ice, Floating Shore-Fast Ice): See Landfast Ice.

Sleeves A short length of tube that fits closely over a pipe section.

Specified Minimum Yield Strength (SMYS): A minimum value of yield strength specified in its purchase, upon which many codes base allowable loads. For example, X-56 pipe has a specified minimum yield strength of 56,000 psi; X-60, 60,000 psi, and so on.

Split Sleeves A 'sleeve' that has been split longitudinally into 2 parts to ease its placement around a pipe section.

Stamukha : A grounded ice hummock or pressure ridge.

Strain Based Design Method: A deterministic design method that limits pipe strains to some percentage to allow for the fact that pipe materials possess ductility and can undergo a certain amount of "plastic deformation" before failure occurs.

Stress – Strain Curve: A graphical representation of the strain (changes in displacement) produced in a material in response to different stress (applied loads) levels, see Figure. Strain (e) is generally reported as a percentage change in length (DL) from the original length (L_o) of an axially loaded test specimen (i.e. $e = 100\ DL/L_o$).

Stress Based Design: A pipeline designed on the basis of individual stresses and combinations of stresses limited to defined fractions (design factors) of the specified minimum yield strength (SMYS) of the pipe. ASME B31.4 is an example of a stress based pipeline code.

Strudel Scour: The formation of large scour craters on the seabed in shallow water (≤ 5m contour) due to a hydraulic vortex of water draining through cracks or openings in the landfast ice cover. Occurs during the annual spring breakup, near the mouths of river deltas, when the landfast sea ice is flooded by meltwater from rivers and inland drainage basins.

Technical Integrity: The state of a product, or process when under specified conditions there is no forseeable risk of a failure that will endanger safety of personnel, the environment, or asset value.

Thaw Settlement: Vertical displacement of a pipeline resulting from thermal degradation over time of the permafrost surrounding a pipeline operating at temperatures above ambient.

Thin Walled Pipe: A pipe with a D/t ratio of 100 or more. Typically a thin walled pipe has limited ability to withstand internal pressure and provides relatively little resistance to bending.

Through-the-Ice Installation Method: A winter construction method whereby a pipeline is constructed on the surface of "landfast" sea ice by conventional land pipeline techniques and equipment and is then lowered to its final position on the sea bottom through a slot cut through the ice.

Towed Bundle Installation Method: An "open water season" construction method whereby a pipeline is constructed on shore, then towed at some depth by tug to the site where it is lowered to its final position on the sea bottom.

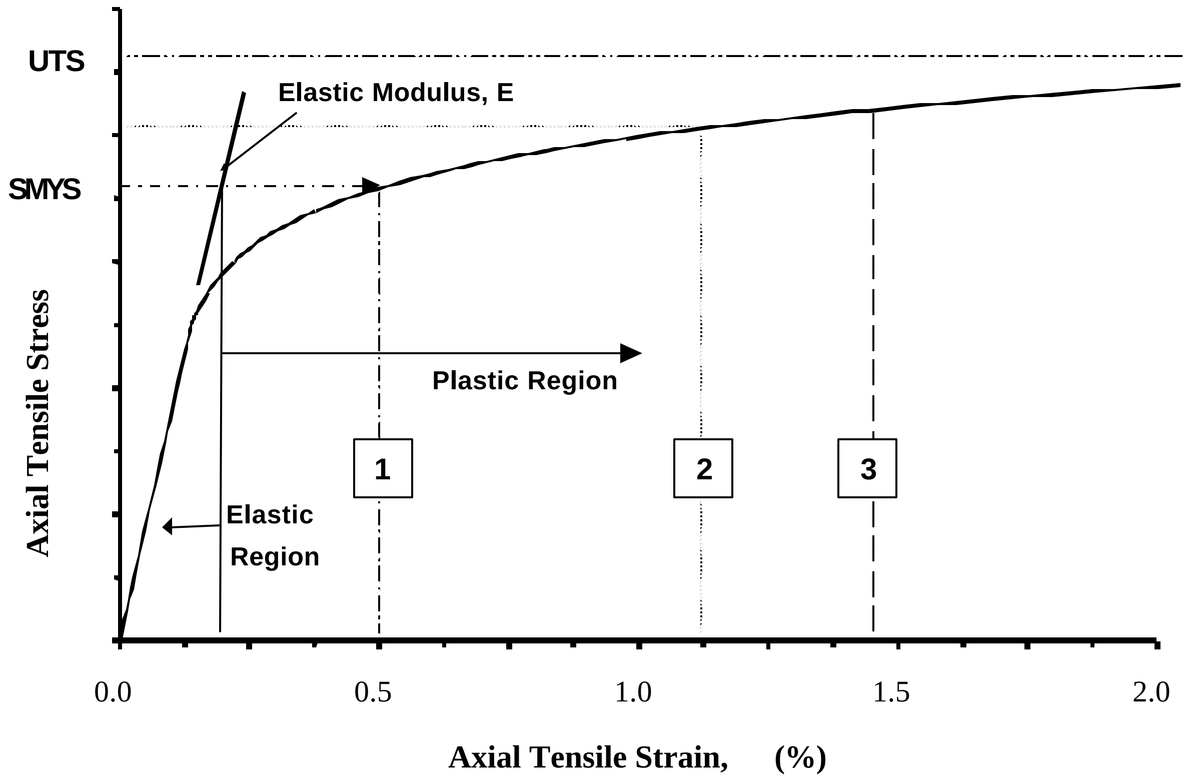
Towed Pipe: A pipe that is assembled away from its final position and then pulled into place below the water level.

Upheaval Buckling: Vertical displacement of a pipeline induced by axial forces resulting from the effects of internal pressure and temperature, and variations in vertical relief in the seabed profile.

Wall Thickness Measurement Pig: A pipeline pig used for detecting pipeline corrosion by measuring pipe wall thickness ultrasonically or by measuring pipe metal loss magnetically.

Welding: The joining of two pieces of pipe through the application of heat and filler metal.

Yield Strength: The stress level below which a material such as steel is considered to behave in a purely elastic manner, in which region the dimensions and strength of the material will return to their original values when forces on the material (pipe) are removed. Linepipe often exhibits actual yield strengths significantly in excess of the SMYS.



Notes:
UTS Ultimate Tensile Stress, typically about 20% larger than SMYS
Failure occurs typically around 25-30% elongation.
1 - Typical upper limit of conventional Stress Based Design
(Stresses limited to fraction of SMYS)
2 - Typical upper limit of Limit States Design based essentially on UTS
3 - Typical upper limit to Limit States Design for Displacement Controlled Systems
(Strain based design)

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Article #	Author(s)	Article Title	Source (citation)	Activity	Configuration	Focus	Project location	Cross refs	Summary/Review
AP0003	Ngiam, P.C. A., Brown, K.R.J., Jo, C.H., Uthaichandond, S., and Yong, K.K.	An Application of Bottom Pull Method to Bundled Submarine Pipelines	ISOPE '98-Vol. 2, pp. 53-59	Design & installation	Bundle of 3 pipes: 2 for diesel, 1 for mogas		Offshore: Petchburi, Thailand	AP0059	The design, construction and installation of a 6.5 km long submarine pipeline bundle are described. The pipeline bundle is pulled from an onshore stringing yard to a new jetty in the Gulf of Thailand using the bottom pull method. The bundle consists of three 16 inch pipelines coated externally with corrosion protection coating and concrete weight coating. Two of the three pipelines are used to transport diesel and the other is used to carry mogas.
AP0004	Smith, J.E.	Challenges of the Britannia Subsea Development	OTC '99-11016	Design	Bundles, PIPs	Thermal insulation, corrosion control	Offshore: Britania, North Sea	AP0033, AP0041, AP0096, AP0097	Britannia is a large gas condensate field in the North Sea, starting production in 1998. The corrosive nature of the Britannia fluids coupled with the turn up/down requirements of the gas sale contracts and the long 25 year life of the field provided a number of design challenges. The paper describes the logic behind the design and the work undertaken by the Britannia Subsea Team for a cost effective development. Hydrate formation is avoided by insulating the flow-lines and by externally heating the flowlines using water heated by platform generator turbines. Both pipe-in-pipe & bundle configura tions were considered, with the bundle being ultimately chosen.
AP0005	Williams, J.G., and Silverman, S.A.	Composites Technology Used Onshore With Synergy to Offshore Applications	OTC '99-11062	FRP application	HDPE, dual containment pipes, cased pipe	Corrosion, high pressure	Onshore & offshore: general		The use of Fiberglass Reinforced Plastic (FRP) composites on offshore platforms and piping is rapidly growing. The paper presents a study to review the status of FRP technology and consider how corrosion-resistant composite products could better be used in onshore petroleum industry. Applications include line pipe, tubing, casing, tanks, vessels and sucker rods. The use of FRP pipe for flowlines has proven to be cost-effective in onshore operations where corrosion is an issue.
AP0006	Nock, M.	Considerations in Reeling Bundled pipelines	OTC '95-7817, p.133-138	Installation	Bundles	General	Offshore - General		The paper presents considerations in the installation of bundled offshore pipelines using the reel method. Reel vessel configurations and the requirements of reeling in general are presented. The specific problems associated with simultaneous reeled installed of multiple pipelines are discussed. Limitations in the number and size of the flowlines in a bundle are also discussed.
AP0007	Sahota, B.S., Ragupathy, P., and Wilkins, R.	Critical Aspects of Shell ETAP HP/HT Pipe-in-Pipe Design and Construction	ISOPE '99-Vol. 2, pp. 64-73	Design and construction	PIPs	Thermal insulation; high-pressure resistance	Offshore: Shell ETAP, North Sea		The Shell ETAP reservoirs in the UK North Sea are high pressure and high temperature (HP/HT) reservoirs. The product pressure is 613 barg and the temperature is up to 160^{o}C at the wellhead. Due to the arrival temperature and the cool down criteria, the pipelines need to be thermally insulated. A pipe-in-pipe system was chosen as the preferred insulation for the design of the Hero Cluster, consisting of a 10"diameter production pipelined insulated inside a 16" outer jacket pipe. The paper presents in detail the critical aspects of the design and construction of the pipelines, particularly the production pipelines that are designed to cater for high pressures and temperatures.

AP0008	Delaskaran, M., and Demetriou, D.H.	Design and Analysis of High temperature, Thermally Insulated, Pipe-in-Pipe Risers	OTC '97-8543	Design & analysis - case study	PIPs, risers, sleeves	Thermal insulation ; high-pressure resistance	Offshore: UK north Sea	AP0098	The paper presents a case study of the work performed during the detailed design and analysis of high temperature of offshore platform risers in the UK North Sea, incorporating thermal insulation using the pipe-in-pipe concept. The results of the finite element analysis are presented. It is shown that the thermal expansion of the hot inner pipe is constrained by the cold outer pipe. An example of how a pipe-in-pipe riser may be designed for HP/HT applications using a steel sleeve pipe and microsphere thermal insulation is presented.
AP0009	Guijt, W.	Design Considerations of High-Temperature Pipelines	ISOPE '99-Vol. 2, pp. 683-689	Design analysis - Thermal stress & expansion	PIP, pre-insulated pipelines	Thermal insulation ; high-pressure resistance	Onshore & offshore: general		Flowlines carrying gas or oil, both onshore and offshore, and district heating transmission pipelines are often operated at high pressures and temperatures. This paper presents design considerations of high-temperature pipelines. Different pre-insulated pipelines and pipe-in-pipe systems are reviewed. The results of finite element analysis are presented. Measures such as pre-stressing of pipelines are highlighted. A limit state approach or strain based design is more adequate in design high-temperature pipelines, compared with an allowable stress design.
AP0010	Sriskandarajah, T., Anurudran, G., Ragupathy, P., and Wilkins, R.	Design Considerations in the Use of Pipe-in-Pipe for Hp/Ht Subsea Pipelines	ISOPE '99-Vol. 2, pp. 672-682	Design analysis - Integrity	HP/HT PIPs	Thermal insulation ; high-pressure resistance	Offshore: general	AP0002	The paper discusses the design and use of offshore pipe-in-pipe systems for transportation of HP/HT oil and gas. The integrity of the pipe-in-pipe systems due to thermal expansion and pressure containment is examined. The mechanism of force transfer between inner and outer pipes is discussed. Both stress based and strain based design of HP/HT systems are evaluated. With a pipe-in-pipe system, the failure may occur in more ways than in a single pipe, and different pipe-in-pipe systems will have different failure modes. The adoption of a limited state approach to the design can result in a more economical pipeline design and in some cases may lead to the only solution available. For pipe-in-pipe systems, finite element technique can be a good tool for the design, provided the results are assessed by experienced designers.
AP0011	Harrison, G.E., Kershenbaum, N.Y. , Choi, H.S.	Expansion Analysis of Subsea Pipe-in-Pipe Flowline	ISOPE '97-Vol. 2, pp. 293-298	Thermal expansion/stress analysis	PIPs	Thermal insulation	Offshore: general		The paper presents a new analytical method, investigation results and applications of thermal expansion of subsea, insulated pipe-in-pipe systems for carrying hot product. Temperature gradient, pressure, soil resistance, lateral deviation of the pipe-in-pipe system, and interaction force between the carrier pipe and jacket pipe are considered. The new simple analysis method has been applied in subsea pipeline design. The results show that the pipe-in-pipe system yield less longitudinal expansion, compared to single wall pipe systems.
AP0012	Sriskandarajah, T., Ragupathy, Anurudran, G., and Wilkins, R.	Fishing Gear Interaction on HP/HT pipe-in-Pipe Systems	ISOPE '99-Vol. 2, pp. 160-167	Design analysis - Integrity	HP/HT PIPs, fishing gear	Thermal insulation ; high-pressure resistance	Offshore: general		The paper presents some design aspects associated with the effect of fishing activity of on-bottom trawl gear on HP/HT pipe-in-pipe systems that are left on the seabed without trenching or burial. The effects of impact in terms of dent depth are investigated using both empirical formulae and the finite element method. The results from a non-linear dynamic FE analysis are compared to those obtained by considering the available energy of the trawl gear to the energy dissipated in forming the dent. It is shown that FE analysis represents

									the only viable method of assessing the effects of trawl gear interaction on pipe-in-pipe systems. The pipe-in-pipe systems give additional safety in protecting the flowlines from fishing gear interaction, compared to single-wall pipelines.
AP0013	Fyrileiv, O., and Venas, A.	Finite Element Analysis of Pipeline Bundles on Uneven Seabed	ISOPE '98-Vol. 2, pp. 46-52	Structural integrity - FEA	Bundles	Thermal and pressure effects	Offshore: general	AP0011, AP0020, AP0101	The paper presents different FE models for structural integrity analysis of pipeline bundles installed on uneven seabeds. The concept of pipeline bundles offers many advantages such as fabrication onshore, simplified installation, thermal insulation and protection of the flowlines. In the paper, the second order bending effects arising from the compression forces in bundles are addressed. The main non-linear effects arise from the total effective axial force, the frictionless sliding between the carrier pipe and the internal flowlines, the sagging into free spans and the frictional sliding against the seabed.
AP0015	Maten, G.J., and Hales, M.	J-Tube Pull-in Theory is Applied to North Sea's Troll Multiple Flowline Bundles	Oil and Gas J., Vol. 83, 1985, pp. 138-144	Structural integrity	Bundles, risers, J-tubes	Structural integrity	Offshore: Troll field, North Sea		Structural integrity of flowline bundles of the Troll filed in the Norwegian North Sea is presented. The flowline bundles contain uo to 12 conduits varying from 5 in. to 1 in. nominal ID running from subsea well templates and the platform in 340 m of water. The mechanics of the behaviour of flowlines in a J-tube during pull-in and the theoretical models available to forecast the pull-in forces are discussed. Calculations for primary bending load are presented.
AP0017	Jo, C.H.	Multi-Bundle Pipeline Installation Technique Applied to Yong-Jong Island	ISOPE '99-Vol. 2, pp. 89-95	Installation	Bundled pipelines		Offhsore: Yongjong airport, Korea	AP0003, AP0059, AP0099	The paper describes the design and construction of a submarine pipeline bundle connecting Yongjong airport site to Inchon, Karea. The bundle consists of three pipes of 52", 30" and 20" in diameter. The 2.4 km long pipeline bundle was installed using the bottom pull method for the three non-symmetric bundled pipelines. Construction period and project cost were significantly saved by installing three lines all together. The operation requires close coordination among all the parties involved.
AP0019	Mollison, M.I.	Pipe-in-Pipe Insulation System Passes Tests for Reel lay	Oil and Gas J., Vol. 90, 1992, pp. 52-57	Structural tests	PIPs	Thermal insulation	General		PIP systems used in the development of Seahorse and Tarwhine fields in Bass Strait, Australia consist of inner steel pipe coated with HDPU foam inside an outer steel carrier pipe. Laboratory tests were carried out to examine the behaviour of the insulation system during reeling. The PIP specimens of 12 m long were bent around a bending shoe to simulate the forces on the pipe when reeled. The tests show that PIP is suitable for installation by reeling. The polyurethane foam on the inner pipe was undamaged by the bending, and the heat-transfer coefficient was acceptable.

AP0021	Silva, R.M.C., and Patel, M.H.	A Preliminary Design Method for Double Walled Catenary Riser Pipes in Deep Water	OMAE '98-0615	Design - structural analysis	Single & double wall risers	External pressure resistance, buoyancy, damping to vibration	Offshore - deep water: general		The paper describes a simplified design method to investigate the mechanical behaviour of double walled pipe in a catenary configuration for deep water oil filed development. A quasi-static catenary analysis is developed and parametric calculations are carried out to show that the substantial top tension reductions available over a range of water depths and pipe size. The external pressure capacity of the pipes is also studied. It is demonstrated that a steel catenary riser constructed from a double walled pipe with structural filler material in the annulus offers a viable riser alternative for moderate to high water depths. The double walled construction yields greater collapse pressure capacity for the same weight of steel.
AP0022	N/A	Reducing Stress in Contained Pipes: Special Fitting and Loops Limit Expansion Effects	Chemical Engineering, Vol. 100, 1993, Page 149	Stress analysis of supports	PIPs, double wall plastic	Chemical leak protection	Onshore: Du Pont facilities, Del.		This one page note introduces the two installed contained piping systems in Du Pont's Wilmington, Del., chemical processing facilities. The lines are made from fiberglass-reinforced vinyl ester, with 3-in. diameter carrier pipes and 6-in. diameter containment pipes. They carry fluids with temperatures from 60^{o}F to 140^{o}F. The heat from the flowing fluids makes the carrier pipes expand. Analysis of stress in the pipes are stated for different supporting conditions of the pipes.
AP0025	Hoose, J.W., Schneider, D.R., and Cook, E.L.	Rocky Flowline Project-the Gulf of Mexico's First Reeled Pipe-in-pipe	OTC '96-8131	Design, fabrication & installation	PIPs	Thermal insulation	Offshore - deep water: Rocky Prospect, Gulf of Mexico		A review of the Rocky Flowline project in the Gulf of Mexico from preliminary design through detail design, testing, fabrication and installation of the reeled pipe-in-pipe system is presented. The paper focuses on the issues involved with deep water insulated flowlines. The design and installation of 21,000 ft of dual insulated 3-inch inside inside 6-inch flowlines in water depths up to 1785 ft are highlighted. The project is of significance for deep water oil development and the transportation of waxy crudes.
AP0026	Trout, S., and Sahota, B.	Shell etap High Pressure and Temperature Pipe-in-pipe Pipeline Design and Fabrication	OMAE '99-5038	Design and fabrication	HP/HT PIPs	Thermal insulation ; high-pressure resistance	Offshore: Shell ETAP, North Sea		The Shell ETAP reservoirs, Heron, Egret and Skua, in the UK North Sea are high pressure and high temperature (HP/HT) reservoirs. The product pressure is 613 barg and the temperature is up to 160^{o}C at the wellhead. All pipelines and umbilical are routed in parallel along a corridor from the Heron subsea manifold via the Egret and Skua manifolds to Marnock CPF. They consist of two 10" pipe-in-pipe lines for transporting production, one 6" pipeline for waste water, and one umbilical for communications and electrical power. The product pipelines are insulated in a pipe-in-pipe system. This paper discussed the design and fabrication of these pipelines, particularly the production pipelines that are designed to cater for the high pressure and temperature. The pipeline design is stress based and fully meets the design requirements of the BS8010 Part 3. It is concluded that the integrity of the pipelines meet the requirements of the upheaval buckling, lateral buckling, breakout from the rock dump profiles and agains

AP0028	Street, J.S., and Bowles, J.C.	Tenneco's Risk Management Approach to Pipeline Crossings	Proc. 1996 Specialty Conf on Pipeline Crossings, Burlington, VT, 1996, pp. 14-21	Risk management	Pipeline casings	Leak and corrosion protection	Onshore: railroad and highway crossings			This paper explains Tenneco's risk management efforts to maintain existing pipeline crossings of water-bodies, roads, and railroads. Those include (1) explanations of why and how the cased crossing method was used for many major crossing in the 1980's, (2) concerns of shorted casings that arose with the passage of the National Gas Pipeline Safety Act in 1968, (3) the response and process adopted by Tenneco to mitigate shorted casings and uncased crossings, (4) the rehabilitation of pipelines which includes internal inspection, (5) Tenneco's preferred design method for future crossings, and (6) monitoring of water-bodies crossings. It is explained that casings are no longer preferred.
AP0029	Beckmann, M.M., Riley, J.W., Volkert, B.C., and Chappell, J.F.	Troika - Towed Bundle Flowlines	OTC '98-8848	Design, fabrication & installation	PIPs	Thermal insulation	Offshore - deep water: Troika, Gulf of Mexico			This paper presents the design, fabrication and installation of the Troika flowlines. Troika is a deepwater (2,700 ft) oil development located in the Gulf of Mexico. The reserves are being recovered through an 8 slot manifold cluster subsea production system. Commingled flow from 5 initial wells is produced to Bullwinkle through two 14-mile long 10" diameter pipe-in-pipe insulated flowlines. The flowlines were installed by the bottom tow method in four 7 mile long segments. Connection to the Bullwinkle platform entailed lifting the riser end to the surface and securing it to the jacket leg in a catenary configuration. Insulated steel pipe jumpers were used to join the 7 mile sections at the mid and subsea manifold end points. The flowline bundle segments between the steel catenary riser at Bullwinkle and Troika subsea manifold include a pipe-in-pipe configuration with thermal insulation, spacers, bulkheads and anodes. The 24" casing is designed to provide the proper bundle submerged weight, in addition to pro
AP0030	Rosenfeld, M.J.and Maxey, W.A.	U.S., Canadian Design Codes Differ for Work on Cased Crossings	Oil and Gas J., 1994, pp. 87-91	Maintenance	Pipeline casings	Leak and corrosion protection	Onshore: railroad and highway crossings			U.S. and Canadian regulations and design codes for natural gas and liquid products pipelines differ for the allowable longitudinal stress levels during operations that require pipeline movement. Pipeline casing maintenance operations often require such movement. This paper provides a review aimed at determining a maximum allowable stress level for casing maintenance operations or any line movement.
AP0031	Zabaras, G.J., and Zhang, J.J.	Bundle-Flowline Thermal Analysis	SPE Journal, Dec., 1998, pp. 363-372	Thermal analysis & design	Bundles, PIPs,	Thermal insulation	Offshore: general			The paper presents a study of the thermal performance of insulated flowline bundles with a general-purpose, finite element, partial-differential equation solver. The steady-state and transient cooldown performance were analyzed for six different bundle configurations, with different heat transfer coefficients, insulation levels and pipe sizes. In order to expedite the calculation of overall heat transfer coefficients for bundle flowlines, simplified heat transfer calculations were developed as an approximation to the finite element solutions. Compared with pipe-in-pipe insulation, bundle flowlines reduce the cool down rate significantly. The results presented can be used to provide a thermal design base for field applications.

AP0032	Milliken, M., Schulte, R. and Chitwood, J.	Deepstar: Harsh Environment Flow Assurance Test Facility	OTC '99-11039	Maintenance operation	PIPs	Thermal insulation	Onshore: teapot Dome, Wyoming		DeepStar and the Rocky Mountain Oilfield Testing Center (RMOTC) provides test facility of full-scale, multi-phase flow loop at Teapot Dome Field, Wyoming. The field had the advantages of low ambient temperatures, terrain character, and existing oil filed infrastructure. RMOTC can simulate the harsh conditions typical of deep-water environments, where flow line hydrates pose risks to productivity and pipeline integrity. The highly automated facility allows high pressure, high rate, multi-phase flow testing at low temperature.
AP0033	Brown, L.D., Clapham, J., Belmear, C., Harris, R., Loudon, A., Maxwell, S., and Stott, J.	Design of Britannia's Subsea Heated Bundle for a 25 Year Service Life	OTC '99-11017	Design, installation & operation	Bundles	Thermal insulation, Environmental & corrosion protection	Offshore: Britania, North Sea		The paper presents the design, installation and operation of the Britannia's subsea heated bundle in the UK North Sea, which was brought into operation in 1998. A hot water heated bundle concept was used to prevent hydrate and paraffin formation in the 15 km subsea flowline. Corrosion control was a key factor to achieve a 25-year design life. The success should be attributed to the Britannia management team's focus on open, structured teams and support from the team's balance between technology, risk and cost.
AP0034	Suman, J.C., Karpathy, S.A., and Brown, J.	Design Method Addresses Subsea Pipeline Thermal Stresses	Oil & Gas J., Aug., 1993, pp. 85-89	Structural - thermal stress	PIPs	Thermal insulation	Offshore: Asia - general		The paper explores design methods for the analysis of thermal stresses of subsea pipe-in-pipe lines. Managing thermal stresses in subsea pipelines carrying heated oil requires extensive thermal-stress analysis to predict trouble spots and to ensure a design flexible enough to anticipate stresses and expansions. The methods introduced are based on recent work performed for a major Asian subsea pipeline project.
AP0035	Endel, G., Williams, K.A., Kvello, O., and Hammer, G.	The Gullfaks Satellite Project: Reel Installation of 6"/10" Pipe-in-pipe Flowline	OMAE '98-3903	Structural analysis	PIPs	Thermal insulation	Offshore: GFSAT, North Sea	AP0099, AP0100	The paper presents the main design aspects of the Gullveig 6"/10" pipe-in-pipe system in the Norwegian North Sea. It is an 11 km long multiphase flowline which was installed by reel method in 1997. The flowline was insulated using glass wool with negligible structural stiffness. Spacers were used to keep the inner pipe centrilised. Numerical analysis and full scale bending testing show that the reel installation imposes a large residual moment in the inner pipe. A spacer pitch of 2.5 m was necessary to control the configuration of the inner pipe during installation and operation in order to avoid unacceptable compression of the insulation material and localization of strain at he spacers. Fatigue tests proves that the steel pipe is able to accommodate the shut-down/start-up cycles during the lifetime.
AP0037	Nuttall, R.H., and Rogers, M.	Insulated Pipe-in-pipe Subsea Hydrocarbon Flowline	OMAE '98-0610	Thermal analysis	PIPs	Thermal insulation	Offshore: general		It is important to measure and mathematically model heat flow and other thermal properties of insulated flowlines. This paper presents the test equipment and methodology for the radial thermal transmittance of insulated pipe-in-pipe flowlines. The results of the performance and sensitivity of the equipment are also presented, together with an evaluation of the thermal characteristics of pipe-in-pipe specimens which are insulated with mineral wool or microporous insulation with the temperature range from 50^{o}C to 200^{o}C. The measured thermal conductivity parameters agree with the published data of the manufacturers. The fundamental validity of an in-house spreadsheet which adopts a relatively complex theoretical approach to calculating the Overall Heat Transfer Coefficient

									(OHTC) values of pipe-in-pipe systems has been confirmed.
AP0038	Tan, T., Orgill, G., Ahrabian, D., and Smith, I.	Subsea Malaysian Waxy Crude Line Uses Single-pipe Installation Coating	Oil & Gas J., Sept., 1995, pp. 84-90	Structural integrity	Coated pipelines	Thermal insulation, corrosion protection	Offshore: GuD, Malaysia		The evaluation of several insulation-coating systems for the 12" diameter, 14 km long Guntong D waxy crude pipeline by ESSO Production Malaysia Inc. led to the selection of a single-pipe coating. The coating system consists of a fusion-bonded epoxy (FBE) corrosion coating (0.45 mm thick) on the pipe, a syntactic polyurethane (SPU) insulation coating (38 mm thick) and an outer concrete weight coating (25 mm thick). The paper presents the critical design aspects of the structural integrity and the corrosion and insulation performance.
AP0039	Chin, Y.D., Bomba, J.G., and Brown, K.R.J.	Structural and Thermal Optimization of Cased Insulated Flowlines	OTC '99-11042	Structural & thermal analysis	PIPs	Thermal insulation	Offshore: general	AP1008, AP0092, AP0098, AP0101, AP0102	This paper introduce a theoretical model and the analytical results of insulated pipe-in-pipe systems for flow assurance in the exploitation of deepwater reservoirs. The model addresses the synergy between the design issues related to the structural integrity and the thermal behaviour of the pipelines. The structural design is governed by the buckling and collapse resistance of the pipes. Thermal insulation behaviour is controlled by the geometric parameters and the thermal conductivity of the insulation material. The cased insulated configurations can be used to combine a range of technologies to achieve the structural and thermal performance for particular applications.
AP0040	P&GJ Staff	X-52 jacket, Insulated Stainless Inner Pipe Sections Used on Hot Gas Pipeline: International pipeline construction report	Pipeline & Gas J., Sept., 1985, pp. 26-28	Fabrication & installation	PIPs	Thermal insulation	Offshore, K8-FA-3 platform, North Sea, Netherlands		The natural gas production from platform K8-FA-3 in the Netherlands North Sea requires insulation for the 9 km seabed transportation pipeline. The gas temperature, 65°C at the point of production cannot be allowed to drop below 22°C in order to prevent the formation of hydrates. The inner 12.75" O.D. pipe was insulated using polyurethane form in a pipe-in-pipe system. Some aspects on the fabrication and installation of the pipeline have been described.
AP0041	Dixon, M., Herd, B., Patel, M.H., Pearson, O.J., and Vaz, M.A.	On the Buckling Behaviour of Pipe Bundles with High Temperature Flows	Proc. 8th Intl. Conf. On the Behavior of Offshore Structures, 1997	Structural integrity	Bundles	Thermal insulation, and pressure resistance	Offshore - North Sea: general		High temperature offshore reservoirs in the North Sea are exploited using pipe bundles made up of several inner flowlines supported on spacers within a carrier pipe. This paper presents the techniques for modelling the buckling behaviour of the pipe bundles for transporting high pressure and high temperature products. An analytical method has been described for temperature-induced buckling effects and a finite element analysis demonstrates how it can represent realistic structural detail that has to be approximated in the analytical method. The application of both methods has also been introduced.

AP0042	American Petroleum Institute (API)	API 1111 Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (1999)	API Standards API 1111	Comprehensive	PIPs, Pipes		Offshore: general		This document presents the recommended practice of the design, construction, operation, and maintenance of offshore hydrocarbon pipelines using limit state design method. It describes the design details, materials and dimensions, safety systems, construction and welding, inspection and testing, operation and maintenance, and corrosion control.
AP0044	American Petroleum Institute	API 1102 Steel Pipelines Crossing Railroads and Highways	API Standards 1102	Design & installation	Cased pipelines	Containment, corrosion protection, structural integrity	Railroad & highway crossings	AP0059	This document presents the recommended practice of cased and uncased steel pipelines crossing railroads and highways. It describes the type of crossing, crossing cover, design aspects, loads, stresses, installation and construction, inspection and testing, cathodic protection and adjustment of in-service pipelines. The crossings may be cased or uncased. To select a cased or uncased crossing, the stresses imposed on uncased pipelines and the potential difficulties associated with protecting cased pipelines from corrosion.
AP0046	Maxey, R., and Pincince, R.	Surmounting Design Problems in a Complex Piping System for Groundwater Remediation	Environmental Progress, Vol.17(1), 1998, pp. 38-47	Design	Double walled pipe for contaminated groundwater		Onshore: A chemical plant, NJ		This paper presents the design of a fiberglass reinforced plastic (FRP) pipeline system for transporting contaminated groundwater extracted from 43 wells at the site of a former chemical manufacturing plants in Toms River, New Jersey through seven miles of pipeline to a treatment plant. The acid groundwater (pH 4 to 5) could be detrimentally corrosive to carbon steel. The FRP pipe chosen has a moderate capital cost and is corrosion resistant. All piping within the chemical plant boundary is above ground. Offsite piping of 14-inch diameter is installed below ground and is double walled. Leak detection devices are installed below ground in mainways along the buried pipe route. System designed commenced in 1993and system construction was finished in 1996. The carrier pipe is capable of withstanding the dead-head pressures of the pumps (250 psi).
AP0047	American Society of Mechanical Engineers	Liquid Transportation System For Hydrocarbons, Liquid Petroleum gas, Anhydrous Ammonia and Alcohols	ASME b31.4 1992 Edition	Design, construction, operation and maintenance	Pipelines		General	AP0059	This code includes the design, construction, operation and maintenance of liquid transportation system for hydrocarbons, liquid petroleum gas, anhydrous ammonia and alcohols. It presents the design conditions and criteria, design of piping components, materials, dimensional requirements, construction, welding, assembly, inspection and testing, operation and maintenance procedures, and corrosion control.
AP0050	American Petroleum Institute	Recommended Practice for Planning, Designing and Constructing Structures and Pipelines for Arctic Conditions	API 2N-2nd edition, 1995	Design, construction, operation and maintenance	Pipelines		Arctic - General		This document presents the recommended practice for the planning, designing, and construction structures and pipelines for arctic conditions. For the offshore pipelines, it presents the details of ice gouges, permafrost, shore crossings, pipeline fabrication, construction, installation, protection, operation, and maintenance and repair.
AP0060	Marx, C., El-Sayed, A.A.H.	Evaluation of Collapse Strength of Cememted Pipe-in-pipe Casing Strings	Proc. SPE Drilling Conference, New Orleans, 1985, pp. 91-94	Structural strength	PIPs		Offshore: general		Structural tests have been carried out to evaluate the collapse strength of cemented pipe-in-pipe casing strings. The tests include twelve pipes of 13-3/8" - 9-5/8" casing combination and other pipes. The cements were of G type. Test results and equations for calculating the collapse strength of cemented pipe-in-pipe casing strings are presented. For all the tests, a reinforcement factor larger than 1.2 was obtained.

AP0061	Arthur, T.T., Cook, E.L., and Chow, J.K.	Installation of the Mobile Bay Offshore Pipeline Systems	OTC '94-7572	Planning & installation	PIPs, bundles	Thermal insulation, corrosion protection, and pressure resistance	Offshore: Mobile Bay	AP0103	The paper presents the planning and installation of about 200 miles of offshore pipelines in Mobile Bay. The corrosive, high temperature, high pressure gas requires special consideration of thermal insulation, corrosion protection and pressure resistance of the pipelines. The unique aspects in the implementation of the multifaceted pipelines project are described, in cluding the field application of new welding, the construction of four directionally drilled and bundled crossings, and the installation of 1 11,000 psi, nikel alloy, insulated pipe-in-pipe flowline system and associated power cable.
AP0062	Hart, J.D., Powell, G.H., and Rinawi, A.K.	Experimental and Analytical Investigations of Sleeved Pipe Configurations	ASME Energy Sources Technology Conf, Houston, 1995	Structural study - experimental & numerical	Sleeved pipes		General	AP0059	The paper describes a series of buckling tests conducted on 60 ft long 48" diameter pipe specimens at Southwest Research Institute in San Antonio, Texas. The sleeve pipe behave in a ductile manner. The test specimens wrinkled locally, with a single large wrinkle. Analytical correlation is carried out. It is concluded that the program PIPLIN can be used with a substantial degree of confidence to analyze pipeline configurations up to the point of incipient of wrinkling, subject to some limitations.
AP0063	Gibson, W.F.	Are Shorted Pipeline Casings a Problem	Materials Performance Vol. 33 (11), 1994, pp. 18-21	Case studies	Cased pipelines	Corrosion protection	Railroad and highway crossings		This paper presents some case studies. Many highway and railroad crossings with casings have been used for over 50 years without any major problem. Smart pigging and continual visual inspection have shown that whether shorted or isolated, casings have no significant bearing on the presence or absence of corrosion on the carrier pipe.
AP0064	Rosenfeld, M.J., and Maxey, W.A.	Pipeline Casing Maintenance - Conclusion: Method Reveals Pipe Stresses During Movement to Clear Shorted Casing	Oil and gas J., Nov., 1994: pp. 84-89	Structural integrity analysis	PIPs (cased pipes)		General		This paper presents an analytical procedure for structural analysis of cased pipeline crossings to determine tolerable stress levels for casing maintenance involving moving a pipeline. The method follows a review of U.S. and Canadian pipeline regulations and design codes to determine the guidelines' allowable stress caused by pipe movement. The means to casing maintenance that meets all regulatory concerns are provided.
AP0068	Kaempen, C.E.	A Subsea Pipeline Comprising Secondary Containment and Leak Detection	ASME Conf. Proc., Book 3, Drilling and Production Economics: Houston, 1996, pp. 343-346	General	Composite double-wall pipeline	Containment and leak detection	Offshore: General		A Concept for a flexible FRP pipe is proposed which includes secondary containment and leak detection capability.

AP0071	N/A	Technology Assists in Assembly of Pipe-in-pipe joints	Offshore, 58 (6), Jun., 1998, pp. 62 & 142	General PIP technology	PIPs	Thermal insulation	Offshore: Gulf of Mexico - general		In deepwater offshore oil production, the low temperature of the sea water causes a number of problems, such as hydrate, paraffin, and wax formation in piping. It is claimed that pipe-in-pipe systems generate real reduction of cost of a development and solve the problem of insulating the pipes. The paper discusses the issues of pipe-in-pipe systems for deep water development, such as hydrotherm system, insulation materials, thermal performance and structural integrity.
AP0072	Welsch, S.J., Inglis, R., and Sanders, D.	The Hydrotherm Pipe-in-pipe System: A Case Study - the Erskine Multiphase Pipeline	Proc 12th Pipeline Protection Conf., Paris, 1997, pp. 277-294	Overview of the PIP system	PIPs	Thermal insulation, corrosion protection	Offshore: Erskine,		The paper presents an overview of the 30 km Texaco Erkine multiphase pipe-in-pipe system, installed to transport gas/condensate in the UKCS at a maximum temperature of 150°C. The pipeline was installed by MET using the DLB-1601 laybarge in 1996. The paper describes the pipeline system, the hydrothermal system and the system detailed design and testing. Close technical collaboration between Texaco, MET, the EIPC contractor, British Steel the manufacturer, and others involved, led to the development of an optimal pipe-in-pipe solution.
AP0074	Romagnoli, R.	Verification of Double Wall Pipes in Different Loading Environments	Proc. 2nd Intl. Pipeline technology Conf, 1995, Ostend Belgium, pp. 99-104	Structural analysis	Double-wall pipes	Corrosion protection	Gas reservoirs or chamical plants - General		The paper presents an FEM verification of double-wall pipes produced in Japan for sour gas transportation. For the new type of double-wall pipes, the inner and the outer parts are bonded mechanically by means of shrink-fitting and expansion. Based on some experimental data available in the literature, the double-wall pipes have been studied analytically under various loading conditions.
AP0075	Austin, R.	Cased Crossings: Corrosion Mitigation Measures	Proc. 1993 API Pipeline Conf., Dallas, pp. 253-256	Maintenance	Casing pipes	Corrosion protection	Railroad and highway crossings		This paper introduces a method for the corrosion protection of cased pipeline crossings. For a pipeline crossing roads inside a casing pipe with vents open to the atmosphere, Water builds constantly from the moisture-laden air, due to the lower ambient temperatures underground. This water, combined with oxygen, may results corrosion of the carrier pipe. One solution to this problem is to isolate vent openings from the atmosphere and prevent the oxygen and moisture from entering the casing. Test results of Conoco Pipe Line Company demonstrated that while capping vents as beneficial in reducing the oxygen content in most casings, a more immediate and effective way to reduce the oxygen levels was required. A good way is to use inert gas (Argon) as a casing filler in conjunction with capped vents. With its proven effectiveness, low cost, compliance with the Department of Transportation (DOT) regulations, and acceptance by NACE and the pipeline industry, the inert gas procedure is proven a good choice of the metho

AP0078	NACE - National Association of Corrosion Engineers	State of the Art Report on Steel Cased Pipeline Practices	NACE Publication No. 10A192 (1992), Houston, 12p	Design, installation, construction and maintenance	Cased pipelines	Corrosion protection, structural integrity	General, i.e. railroad and highway crossings		Steel casings are used in practice to install and maintain steel pipeline crossings, such as road and railroad rights of way. This technical report presents the state-of-the-art practices when casings are installed. It does not imply that the utilization of casings is mandatory, nor does it imply that cased crossings shorted or unshorted contribute to the corrosion of the carrier pipe. The report presents the details of design factors and considerations, installation and construction, maintenance and repair, criterion and monitoring, and typical casing filling procedures.
AP0079	O' Rourke, T.D., Ingraffea, A.R., Norman, R.S., and Burnham, K.B.	Evaluation of Cased and Uncased Gas Pipelines at Railroads	Proc. 1986 Intl. Gas Research Conf., Toronto, pp. 286-297	Design, construction and maintenance	Cased pipelines	Corrosion protection; structural integrity	Railroad crossings	AP0044	The paper presents a capsule view of the research on cased and uncased pipeline crossings of railroads. The four major areas of research are: (1) review of the design and construction recommendations of various professional and regulatory institutions, and the performance records of pipeline crossings beneath railroads; (2) construction techniques for installing the pipelines, and the soil and traffic loads acting on the pipelines; (3) General methods for corrosion protection; (4) summary of current analytical practices for modelling stresses and deformations of buried pipelines.
AP0081	Matthews, J.	Method for Installing Double-Walled Pipelines	Canadian Patent 968974, 1975	Installation method	PIP (double-walled pipeline)		Offshore: General		The invention provides an improved method for the laying of double-walled pipelines between offshore platforms which avoid many of the problems encountered before and makes the use of such lines feasible in deep water over reasonably long distance.
AP0082	Brown, R.W. and House, R.F.	Method of Preventing a Cased Pipeline From Corrosion	US Patent 4925616, 1988	Corrosion protection	Case pipeline	Corrosion	General		The invention provides a method of protecting cased pipelines from corrosion. Tall oil pitch is used as casing fillers and is pumped into the interstitial space between the carrier pipe and casing pipe. The tall oil pitch can be used per se or can be modified by increasing its specific gravity, increasing its pour point, increasing its viscosity, or decreasing its pumpability temperature.
AP0083	Wittgenstein, G.F.	Construction of Encased Pipelines	Canadian Patent 1016881, 1977	Construction method	Encased pipelines		General		The invention provides a method of constructing a pipeline having an inner pipe surrounded by an outer jacket.
AP0084	Wittgenstein, GF (inventor)	Construction of Encased Pipelines	US Patent 3951437, 1974	Construction method	Encased pipelines		General		The invention provides a method of constructing a pipeline having an inner pipe surrounded by an outer jacket.
AP0085	Intec, Inc.	Ice Keel Protection, TN410 Northstar Development Project Detailed Engineering	Prepared for BP Exploration (ALASKA) Inc. Intec Project No. H-0660.03, 1998	Trench depth for ice keel protection of pipeline	Pipelines		Offshore: Northstar, Alaska	AP0050	The proposed offshore pipelines for Northstar Development Project must be protected from ice keel damage. This technical note is to establish the final trench requirements for the pipeline protection. Major factors influencing the required trench depth for ice keel protection are summarized and the calculation procedures are described. The note includes the statistical calculation of maximum expected ice gouge depth, geotechnical input to ice scour-pipeline interaction, the calculation of the under-keel clearance requirements, ANASYS/PIPLIN comparison and design trench geometries. The offshore trench for the majority of its length will have a minimum depth of cover of 7 ft and a backfill thickness of 7 ft.

AP0087	Stubblefield, F.	Get Topnotch Performance from Jacketed Pipes	Chemical Engineering, Vol. 100 (6), 1993, pp. 110-114	Design & fabrication	Jacketed pipes (PISs)	Containment	Chemical industry		Jacketed pipes have been used in the chemical process industries (CPI) as simple containment systems or as basic shell-and-tube heat exchangers. This paper presents the fabrication techniques for jacketed pipes in order that the pipe systems perform their intended function over the range of operating conditions typically encountered in a process. Shop fabrication is a must when: (1) Cross contamination (commingling of the process and heating fluids) is not allowed for the projected life of the pipe system. (2) The surface finish of the core pipe must be significantly better than mill grade. (3) The jacket and process pressures exceed 300 and 1000 psi respectively. (4) Thermal gradients due to inaccurate fabrication can cause off-specification product. (5) Close tolerances and tight fits must be maintained. (6) Difficult-to-weld alloys are used. (7) The process is a toxic service that must be contained and kept at a stable temperature. (7) Batch process results in frequent thermal cycling(250oF or more). (9) T
AP0089	Burkowsky, M., Ott, H., and Schillinger, H.	Cemented Pipe-in-pipe Casing Strings Solve Field Problems	World Oil, Oct., 1981, pp. 143-147	Structural tests	PIPs		General - oil/gas pipelines		Laboratory tests were carried out to solve a severe problem of casing collapse in old producing wells in high pressure areas. Smaller casing was cemented inside the larger, deformed pipe. The collapse resistance of a pipe-in-pipe combination was at least 10 to 30% greater than API specifications. Even when the outer pipe was deformed, the resistance to collapse was more than sufficient.
AP0090	Jee, E.I.T.	The Thermal Behaviour of Flowline Bundles	Pipes & Pipelines International, Vol. 29 (2), 1994, pp. 16-17	Thermal effect on structural behavior	Bundles		General		The paper presents an analytical method for evaluating the thermal behaviour of flowline bundles, and to define it in terms of fluid temperature drops, end movements, and stresses in the flowlines and bulkheads. The interaction between flows due to heat transfer through the annular fluid, the effect of coatings on the flowlines and gel in the annulars, and the circulation of hot water from the platform to keep production hot are considered.
AP0091	Webster, G.A., Burton, S.A., and Duncan, J.C.	The Use of Elastomers for Pipeline Protection and Insulation	Insulation, Vol. 28 (3), 1986, pp. 14-18	Coating material	Coated pipes	Thermal insulation; corrosion protection	General		Elastomers provide corrosion protection, resistance to impact and abrasion, and complete sea water resistance. This paper describes the use of elastomers as coating materials for offshore pipelines protection and insulation. The formulation and compounding of elastomers, the pipeline corrosion protection, the insulated pipe coating, and the application and development of elastomers are discussed.
AP0092	Palle, S., and Ror, L.	Thermal Insulation of Flowlines with Polyurethane Foam	OCT '98-8783	Insulation material	PIPs	Thermal insulation	Offshore - General		The paper presents the use of Polyurethane Foam (PUF) and part of the insulation sandwich construction of bonded pipe-in-pipe systems for offshore development. For the bonded pipe elements, the thermal expansion of the hot inner pipe is constrained by the outer pipe. Considerations concerning the design, production and installation of pipe-in-pipe systems with PUF. The bonded pipe-in-pipe system with PUF is a cost effective way to achieve both excellent insulation and long reliable service life.

AP0093	Intec, Inc.	Double Wall Pipe Alternative Evaluation, Northstar Development Project	Intec Project No. H-0660.03	Comprehensive evaluation	PIPs, pipes	Containment, corrosion protection, structural integrity	Offshore - Northstar		This document presents an evaluation of the relative merits of a single thick walled pipe in preference to a pipe-in-pipe system for the offshore section of the Northstar project. The comparison is restricted to significant design and construction aspects, including structural design, pipe string make-up, construction and the effect on schedule and risk, quality assurance and quality control, corrosion, leak detection, operation, maintenance and repair. The major conclusion is that the single thick-walled pipe design, as proposed for the Northstar project, is a superior design to an equivalent pipe-in-pipe approach. The pipe-in-pipe does not provide superior structural integrity for product containment.
AP0095	Braden, A., Mannikian, V., Rice, D., Swank, G., Hinnah, D., Monkelien, K., and Walker, J.	First Arctic Subsea Pipelines Moving to Reality	OTC '98-8717	Pipeline design	Pipelines		Offshore - Northstar & Liberty, Alaska		Two offshore development projects involving subsea arctic pipelines, the Northstar Development Project pipeline and the Liberty Development Project pipeline in Alaska, are being proposed by BP Exploration. This paper reviews the engineering approaches for the unique arctic conditions, with emphasis on ice gouging, strudel scour and permafrost. The focus is on the regulatory aspects of the pipelines, rather than the design specifications.
AP0096	Kolts, J., Joosten, M., Salama, M., Danielson, T.J., Humble, P., Belmear, C., Clapham, J., Tan, S., and Keilty, D.	Overview of the Britania Subsea Corrosion Control Philosophy	OTC '99-11019	Overview	Pipelines	Corrosion control	Offshore: Britania, North Sea		
AP0097	Joosten, M., Kolts, J., Humble, P., Keilty, D., Blakset, T.J., and Sirnes, G.	Internal Corrosion of Subsea Production Flowlines	OTC '99-11058	Corrosion monitoring probe	Pipelines	Corrosion control	Offshore: Britania, North Sea	AP0033, AP0096	
AP0098	Nelson, D.O., Wozniak, T., and Colguhoun, R.	New Thermal Insulations for CDTM Bundles: Formed Polyurethances and Silica Sphere Slurries	OTC '93-7373	New method	Bundles, PIPs	Thermal insulation	Offshore - North Sea		A more economical method for the thermal insulation of offshore pipeline bundles and pipe-in-pipe systems was introduced into North Sea operations. A gelling but non-setting slurry of hollow, high-strength silica spheres and seawater is pumped into the main annulus of a controlled depth tow method (CDTM) bundle after the bundle had been installed on the sea floor. The research and practical application of the improved method under field conditions are described, with emphasis on silica sphere slurries and foamed polyurethanes.
AP0099	DnV	Rules for Submarine Pipeline System	Net Norske Veritas, Horik, Norway, 1981 & 1996	Comprehensive	Submarine pipelines		Offshore: General		This document presents the rules for submarine pipeline systems. It describes the rules for project data, safety philosophy and design, loads, strength and stability, linepipe, pipeline components, equipment and structural items, corrosion protection and weight coating, installation, operation and maintenance, conditions assessment/re-qualification, structural design example, mechanical testing and corrosion testing, welding, and non-destructive testing.

AP0100	Mollison, M.I.	Reel Installation of Pipe-in-pipe Insulated Pipelines	OMAE '91, Vol. V, pp. 137-144	Installation	PIPs	Thermal insulation	Offshore: Bass strait, Australia		In 1989, two pipe-in-pipe lines, which are 11.2 km and 17.4 km long respectively, were installed by reeling for the development of the Seashore and Tarwine fields in Bass Strait, Australia. The PIP system consists of an inner steel pipe coated with high density polyurethane foam (PUFI). The successful development and installation of the PIP systems demonstrated a much cheaper alternative to the expensive coating system is available and has made reeling of insulated lines much more attractive.
AP0101	Nock, M., Bomba, J., and Brown, K.R.J.	Cased Insulated Pipe Bundles	OTC '97-8542	General techniques and approaches	Bundles, PIP, bulkheads	Thermal insulation, leakage protection, casing pressurization	Offshore - deep water: general; Gulf of Mexico		Pipeline bundle installation by bottom tow are gaining acceptance in deepwater developments, where insulation is needed to prevent paraffins and hydrates. This paper presents the approaches to mitigation of the problems associated with deepwater bundles, such as potential leakage into the outer casing and the pressurization of the casing. Bulkheading and foam filling are proposed and evaluated. Bottom tow pipeline bundles are a viable approach to installing insulated and/or heated pipelines in deep water.
AP0102	Tucker, R.N., Hays, P.R., and Antani, J.K.	Insulated Flowline Technology for Deep Water	OTC '96-8247, Vol. 4, pp. 861-873	Insulation design	Bundles, PIPs	Thermal insulation	Offshore: General		Deepwater pipelines and flowlines for hydrocarbon fluids need to be properly insulated to prevent the formation of paraffin and hydrate. The DeepStar 600 Committee on Pipelines, Flowlines and Umbilicals initiated studies during 1994-1995, addressing the insulation systems of pipe-in-pipe systems, flowline bundles and non-jacketed systems. This paper presents and discusses the potentially viable systems, design techniques, emerging technologies, feasible materials, and technical limitations. The proper design of the insulation requires a balance among cost, operability and acceptable risk level.
AP0103	Hoose, J.W., and Hazlegrove, B.M.	Design of Insulated Flowlines for Mobile Bay	OTC '93-7334	Design	Bundles	Thermal insulation	Offshore: Mobile Bay		Insulated CRA (corrosion resistant alloy) pipe-in-pipe flowlines are used in Mobile Bay development. This paper described the design of the flowline insulation system. Design issues for structural integrity are presented. The flowline consists of a 4" CRA pipe in an 8" carbon steel jacket.
AP0104	Dorgant, P.L., Hansen, M.C., and Gallaher, D.M.	Conductor Supported Pulltube Bundle - an Alternative Approach to Supporting Pipelines on a Fixed Platform	OTC '98-8825	New approach for installation	Bundles, pipeline risers	Structural support system	Offshore: Enchilada platform, Gulf of Mexico	AP0052	A new approach of pipeline installation was developed to bring pipelines to the Enchilada platform in Gulf of Mexico. The platform was designed for 17 pipeline connections. The approach developed was to bring all pipelines up to the platform deck within the conductor guide framing through vertical pipeline bundles called CONSPUB's. This paper presents the design details for the Enchilada design and discusses alternative details that may also be used. The approach provides the benefits of cost savings and future pipeline flexibility.

AP0105	Dearden, R.	The development of Hydrotherm - A Pipe In Pipe Insulation	Proc. 11th BHR Group Ltd et al. Pipeline Protection Int Conf, Oct. 9-11, 1995, Florence, Italy, pp. 341-353	New insulation technique	PIPs	Thermal insulation	Offshore: General		This paper presents a new insulation method for subsea pipelines. In 1992, British Steel was offered the opportunity to develop, manufacture and market a noval means of insulating subsea pipelines, called Hydrotherm. The Hydrotherm insulation is made up of a granular insulation material, alumina silicate microsphere, enclosed around the pipeline by a second steel pipe, called the sleeve pipe. The system is described as "pipe in pipe". Hydrotherm combines durable thermal insulation with mechanical performance, and provides excellent lay capacity, impact resistance and upheaval buckling resistance. Through a concurrent approach to market, product and process development, British Steel has been able to bring to hte market an insulation systemfor deep and hot pipelines.
AP0119	Arco Alaska Inc. and Michael Baker Jr., Inc.	Alpine Development - Colville River Crossing Design Report	Arco Alaska Inc. and Michael Baker Jr., Inc., 23100-MBJ-RP-003, 1997	Design and structral analysis	Encased pipelines	Structural integrity and comtainment	Onshore: Colville River crossing		The report presents the design and structural analysis of the Alpine Development Project pipelines crossing the east Channel of the Colville River. The pipeline system includes oil pipelines, sea water pipeline, diesel pipeline, and power and communication conduits. Several components will be installed under the river using Horizontal Direction Drill (HDD). The oil and water pipelines will be installed in individual casings. The diesel and fiber optic lines will be bundles with two other conduits within a third casing. The casings provide an additional margin of safety in the event that a carrier pipe develop a leak. The report presents the site description, soil and permafrost conditions, hydrology, crossing design plan and profile, geothermal conditions, pipe stress analysis, and mechanical design.
AP0120	Arco Alaska Inc. and Michael Baker Jr., Inc.	Alpine Development - Colville River Crossing Design Report Supplementary Information	23100-MBJ-RP-0035, 1997	Design and structral analysis	Encased pipelines	Structural integrity and comtainment	Onshore: Colville River crossing		The report provides additional information to AP0119.
AP0121	Intec, Inc.	Pipeline Design Summary, BP Liberty Project Preliminary Engineering	Intec Project No. H-0851.02, Rev. 0, 1998	Design	Pipelines		Offshore: Liberty, Alaska		This document presents preliminary engineering pipeline design summary of the Liberty project in Alaska. The objective of the document is to provide information support of the applications for the right-of-way (ROW) for the Liberty Sales and Products pipelines. It includes the design aspects of environmental data, strudel scour, ice gouge, soils and survey data, applicable codes, standards and specification, allowable stresses and strains, route selection, hydraulics, pressure containment, bundle stability, thaw settlement and upheaval buckling, island approach and shore crossing, cathodic protection, valving, VSM design, leak detection, operation and monitoring, and evaluation criteria and required action.

AP0123	Intec, Inc.	Pipeline Design Basis, TN331 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN331, Rev. 1, 1998	Pipeline design	Pipelines		Offshore - Northstar, Alaska	AP0059,	This document presents the design basis of the pipelines of the Northstar project in Alaska. The purpose of this document is to present the design input for the pipeline portion of the project in the detailed engineering phase. The document includes the description the project and the Northstar unit, the physical environment, including meteorology, oceanography, offshore pipeline route soils, ice physical environment and pipeline design ice criteria. The piepline design basis includes applicable codes, standards, specifications, and system design requirements.
AP0124	Intec, Inc.	Limit Strain Criteria, TN332 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN332, Rev. 2, 1998	Pipeline limit strain criteria	Pipelines		Offshore - Northstar, Alaska		This report describes the limit strain criteria for design of the Northstar pipelines. The influence of thaw settlement and ice gouging is considered. The mechanisms and the associated limits of allowable strains have been grouped into two main categories: tensile strain limits and compressive strain limits. The potential limiting conditions are listed.
AP0125	Intec, Inc.	Pigging, Valving and Leak Detection, TN340 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN340, Rev. 3, 1998	Pipeline pigging, valving and leak detection	Pipelines		Offshore - Northstar, Alaska		The Northstar Development pipelines have been designed to avoid potential sources of pipeline leaks. The pipelines will also be equipped with corrosion protection. The project will employ systems for monitoring, maintaining and inspecting the pipelines. This report describes the overall pipeline system including the type of pigs required, a proposed pigging program, pig trap locations, valve locations, and a leak detection system.
AP0126	Intec, Inc.	Pipeline Design Summary, TN370 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN370, Rev. 2, 1998	Pipeline design	Pipelines		Offshore - Northstar, Alaska		This document presents pipeline detailed engineering design summary of the Liberty project in Alaska. It presents the design basis, the details of pipeline design, construction, operation, maintenance and repair. The pipeline design includes pipeline routes, sale oil pipeline, gas pipeline, offshore pipeline design, overland pipeline design, seal island approach, and Point Storkersen Shore approach. The overall conclusion is that the proposed pipelines connecting Seal Island to existing onshore facilities can be safely constructed and operated.
AP0127	Intec, Inc.	Strudel Scour Evaluation, TN415 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN415, Rev. 3, 1998	Pipeline strudel scour analysis	Pipelines		Offshore - Northstar, Alaska		Strudel scour is due to Coriolis effects causing a vortex or whirlpool of water current. The Northstar Development Project cannot avoid the offshore area where strudel scour is active. This report analyzes the existing strudel scour data and predicts the extreme events. The analysis is performed to evaluate the pipeline integrity, assuming a strudel scour of sufficient depth to expose the pipe and form an unsupported span. The magnitude of water current speed flowing down through a strudel hole and water column was calculated to be 5 ft/s at the pipeline bundle depth. The possibility of a strudel scour exposing the pipelines is limited.

AP0128	Intec, Inc.	Cathodic Protection, Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, Calcaulation No. 440, Rev. 3, 1998	Pipeline cathodic protection	Pipelines		Offshore - Northstar, Alaska		This report describes the cathodic protection of Northstar Development Project pipelines. The objective is to evaluate passive sacrificial anodes and remote anode impressed current systems for the cathodic protection, and to determine material requirement for the preferred system. A passive sacrificial anode system is the preferred CP system for the Northstar pipelines. It provides reliable cathodic protection with essentially no maintenance requirements.
AP0129	Intec, Inc.	Lagoon Permafrost, TN450 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN450, Rev. 3, 1998	Ice-bonded permafrost analysis	Pipelines		Offshore - Northstar, Alaska		The offshore Northstar pipelines will be installed in a trench, which is then backfilled. During operation, the temperature of the pipelines gradually increases the temperature of the surrounding soil. When thaw settlement occurs, the pipelines deflect into the void created by the settlement and thus induce strain in the pipe wall. This document presents the thaw settlement analysis of the pipelines. It includes designing in ice-bonded permafrost, design data, thaw bulb and settlement in ice-bonded permafrost, settlement model, settlement load cases, allowable strains, and maximum strains. The maximum thaw induced settlement is about 2 ft close to shore and the average settlement along the section of the route is about 0.64 ft. The allowable operational strain for thaw settlement is 1.2%. The maximum total strain of the pipelines due to thaw settlement and installation is about 1.1%.
AP0130	Intec, Inc.	Trench and Pipe Stability, TN470 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN470, Rev. 1, 1998	Trench and pipe stability analysis	Pipelines		Offshore - Northstar, Alaska		The relatively deep trench requirements (cover depth of 7 ft for offshore area) and the proposed winter construction methods for the Northstar pipelines make a stable pipe design and trench configuration important. This report is to define pipeline and trench stability characteristics. Stable trench side slopes are estimated based on the results from the winter test trench program and theoretical calculations of slope stability, ranging from 15 to 90 degrees depending soil properties. The pipelines are estimated to require a specific gravity of 1.6 in order to remain stable in potentially fluidized backfill soils. The twin 10" pipelines will be installed as an open bundle using spacer blocks and bundling straps.
AP0131	Intec, Inc.	Winter Test Trench Summary, TN660 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN660, Rev. 2, 1998	Field test of the trenching method for pipeline installation	Pipelines		Offshore - Northstar, Alaska		The proposed method for installing the Northstar subsea pipelines is based on winter construction from the floating ice sheet. BPXA conducted a field test of the trenching methods in March of 1996 for the verification of ice thickening, evaluation of trench side slope stability and others. The winter test trench program included ice-based excavations at three locations. Each provided information on the Northstar pipeline trenching procedures, is summarized in this report.

AP0132	Intec, Inc.	Operation, Maintenance and Repair, TN720 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN720, Rev. 3, 1998	Pipeline operation, maintenance and repair	Pipelines		Offshore - Northstar, Alaska		This report summarizes an operational, maintenance, and repair philosophy for the offshore section of the Northstar pipelines and clarifies the existing operational and maintenance philosophy for the onshore sections. In addition to routine meter, pump, and compressor station operation, the pipeline operating procedure is to monitor the pipeline integrity. The monitoring of the pipelines involves a continual review of oil flow for leak detection, pressure based monitoring of the gas pipelines and various pipeline inspections. Maintenance will be performed on a planned non-emergency basis. Repair techniques are also presented in the report.
AP0133	Intec, Inc.	Pipeline Construction Plan, TN740 Northstar Development Project Detailed Engineering	Intec Project No. H-0660.03, TN740, Rev. 3, 1998	Pipeline construction	Pipelines		Offshore - Northstar, Alaska		This report presents the winter construction procedures for the Northstar pipelines and provides the schedules defining the basic sequence of operations, overall construction schedule and key construction dates. Consideration is also given to contingencies such as ice movement and major equipment breakdown.
AP0141	Baron, J.J., Lawrence, J.E., and King, G.G.	Design and Construction of the World's Longest Liquid Sulphur Pipeline	Proc. the International Pipeline Conference, Vol. 2, 1996, pp. 785-792	Design and construction	PIP	Thermal insulation	Onshore: Alberta		In 1986 Shell Canada discovered a large reservoir of sour gas in the Rocky maintains area near Caroline, Alberta. A buried pipeline was chosen to carry 5,100 tonnes of liquid sulphur extracted from the sour gas per day from the Caroline Field to railhead 41 km away. Sulphur is difficult to handle by pipeline as it remains solid at temperature up to 118.9^{o}C. The pipeline is built from two coaxial pipes. The inner pipe with a diameter of 219.m mm carries liquid sulphur while the annular space carries circulating hot water under pressure. The outer pipe with a diameter of 323.9 mm has 80 mm of high density urethane foam insulation. The paper described the design and construction of pipeline.
AP0143	Couch, R.O.	Why and When to Use Multiple Pipe Containment	Polution Engineering, Vol. 22, No. 8, pp. 82-87	Design consideration	Bundles	Chemical containment	Onshore: general		US Environmental Protection Agency (EPA) regulations require secondary containment for piping and storing hazardous fluids. A common solution is to use double walled pipe, a pipe within a containment casing equipped with leak detection. When several pipes have the same routing and require secondary containment, such as in transmitting chemicals, combining several carrier pipes into a single containment casing offers economic advantages. This paper describes the advantages and design considerations of multiple pipe containment bundles.
AP0162	Richard, C.G.	Chemical and Refinery Piping Systems	Chapter C7, Piping Handbook, 6th Edition, edited by M.L. Nayyar, McGraw-	design consideration	Jacketed pipes	Containment & thermal insulation	Onshore: Chemical Process & oil refinery		Jacketed pipelines are commonly used to carry certain fluids in process facilities. Process fluids that require temperature control (i.e., molten sulfur) are good candidates for the applications of jacketed pipes. For molten materials (i.e., polymers) where high temperature is required, jacketed pipelines can also be used. This publication listed the advantages of jacketed pipelines as follows: (1) uniformity of heat input around circumference of process pipe; (2) tighter temperature control over entire pipeline length; and (3) elimination of cold spots that may cause degradation or localized freezing of process fluids. In jacketed pipe systems, various heating media (liquid phase and vapor

			Hill, 1992						phase fluids) can be used for temperature control of process fluids. Vacuum jacketed piping system are often used to convey cryogenic temperature process fluids. The vacuum is for minimizing heat gain from the atmosphere to the cryogenic fluids.
AP0163	Waldo, J.	Thermal Insulation of Piping	Chapter B7, Piping Handbook, 6th Edition, edited by M.L. Nayyar, McGraw-Hill, 1992.	design consideration	Pipes and PIPs	Theral insulation - general	General		This publication provides an introduction and general knowledge of the thermal insulation of pipelines and pipe-in-pipe systems. It describes the fundamentals of heat transfer, insulation design parameters, design considerations, service considerations and insulation materials.

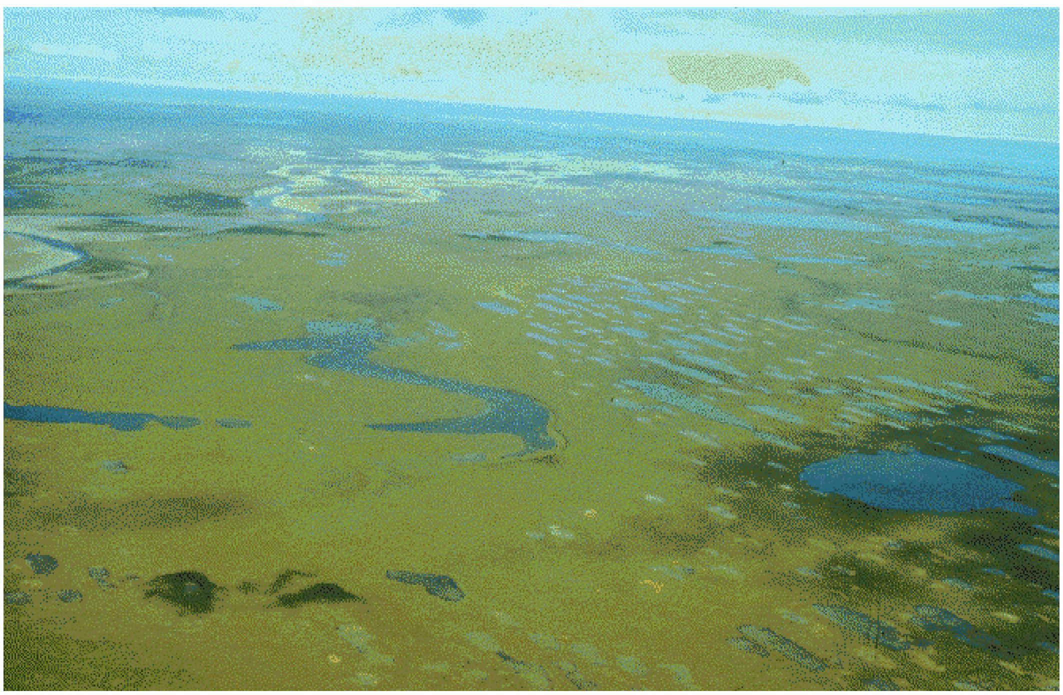
7.1 APPENDIX 7.1 : Physical Environment and Environmental Loads

7.1.1 Physical Environment

The onshore area adjacent to the study area is within the arctic coastal plain eco-region that can be characterized by flat to rolling terrain, inundated by shallow water features and permafrost (USGS, 1999). The region covers an area of approximately 50,000km^2 (20,000mi^2) with 20 to 50 percent areal coverage by surface ponds and lakes (Figure 7.1-3). The Arctic Ocean to the north and west demarcates the seaward boundaries, while approaches to the US-Canada border to the east and foothills to the south define the terrestrial extent. The treeless coastal plain rises very gradually, with slope gradients less than 1°, from sea level to the adjacent foothills at the elevation of the Brooks Mountain Range. The region is typified by low temperatures, persistent wind and low precipitation levels (COE, 1999). The National Weather Service, Alaska Region Headquarters defines the season on a climatic basis as:

Season	Months
Winter	December, January and February
Spring	March, April and May
Summer	June, July and August
Fall	September, October and November

(a)



(b)

Figure 7.1-3. (a) Alaskan Coastal Plain Region and North Slope, (b) Typical Landform of the Arctic Coastal Plain East of the Kuparak River (USGS, 1999)

The summer season has continuous daylight and the winter season has approximately 60 days of near continuous darkness. On average, the ground has a snow cover for approximately 8 months of the year.

7.1.1.1 Meteorology

Compiled statistics of meteorological data measured at various weather stations in Alaska are available through the National Weather Service, Alaska Region Headquarters (NWS, 1999). For the geographical region bounded by the proposed study area, the weather station Prudhoe Bay is most representative. The stations Barrow WSO Airport located approximately 200 miles west, and Barter Island WSO Airport, situated approximately 120 miles east, can be used to augment the data set. Information summarizing the location, operational dates and available online records for the three weather stations is presented in Table 7.1-2.

7.1.1.1.1 Temperature

The bulk of heat energy for the arctic environment is generated during the short summer season. Daily and seasonal air temperatures are moderated by maritime effects (open water and ice cover) of the Arctic Ocean and Beaufort Sea. For a given year, temperatures in the Nuiqsut-Prudhoe Bay area can range from -49°C (-56°F) to 26°C (78°F) (DNR, 1998). Equivalent windchill temperatures of -73°C (-100°F) have been recorded (COE, 1999). INTEC (1998a) considered a design temperature range of -46°C to –3.9°C (-50°F to 25°F). INTEC (1998b) assessed the temperature ranges from the same three weather stations listed in Table 7.1-2. Air temperature data records for the weather stations Prudhoe Bay and Barter Island WSO Airport are illustrated in Figure 7.1-4 and Figure 7.1-5, respectively. Although the records for the Prudhoe Bay station are only for 12 years, in comparison to 40 years for Barter Island, the data does not exhibit significant differences.

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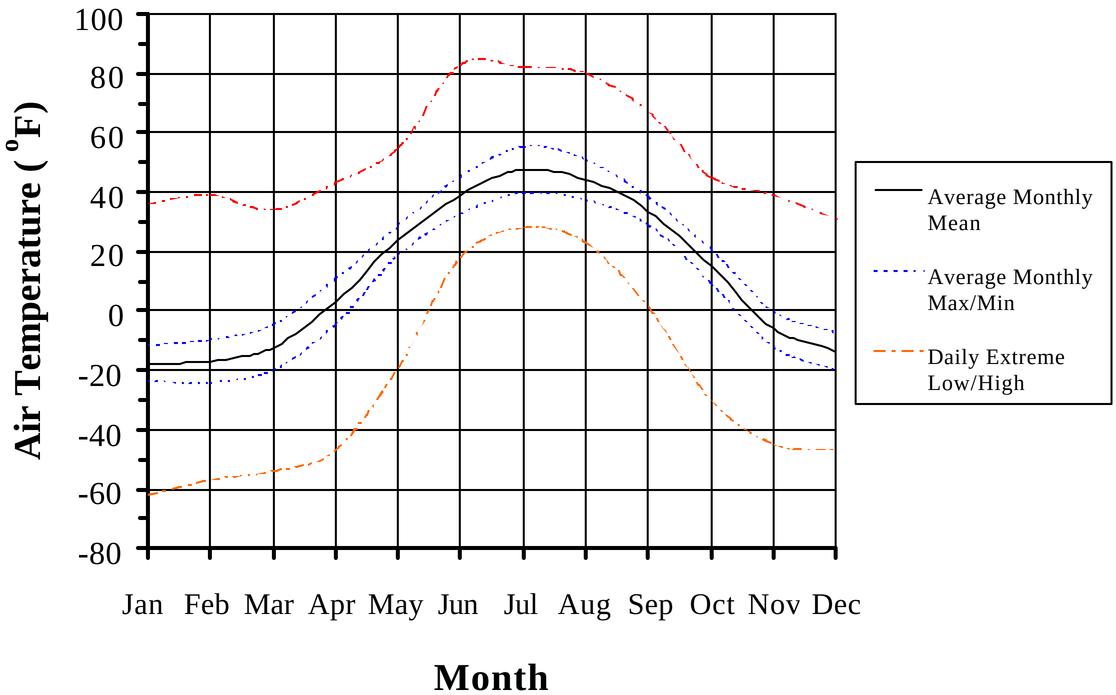


Figure 7.1-4. Monthly Average and Daily Extreme Air Temperature Statistics (1986-1998) for Station Prudhoe Bay (NWS, 1999).

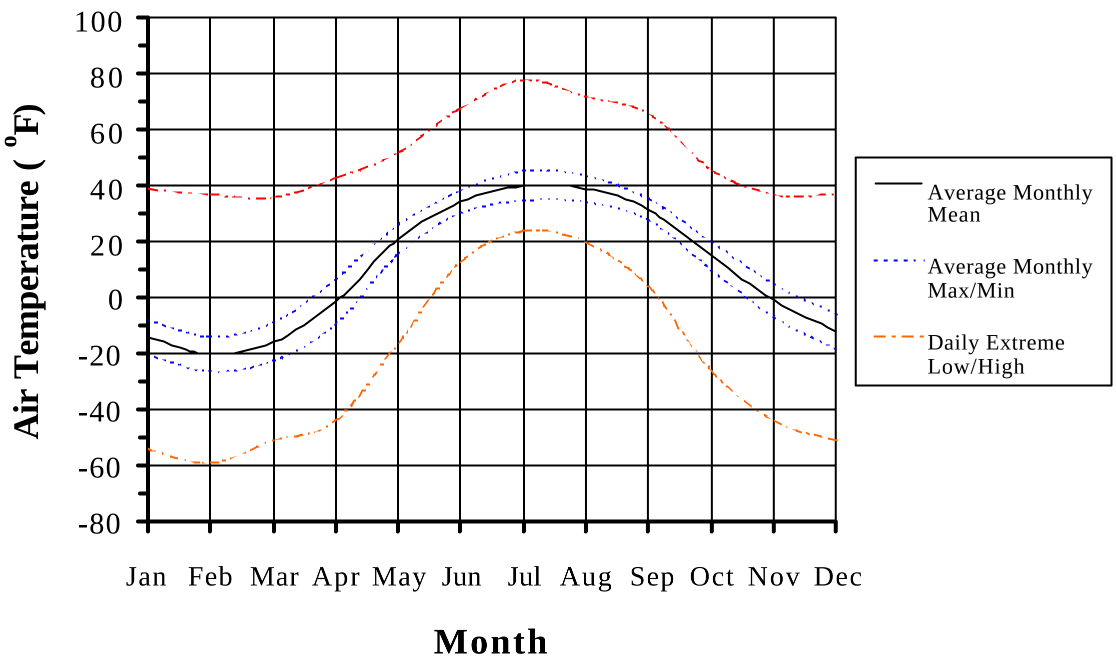


Figure 7.1-5. Monthly Average and Daily Extreme Air Temperature Statistics (1949-1988) for Station Barter Island WSO Airport (NWS, 1999).

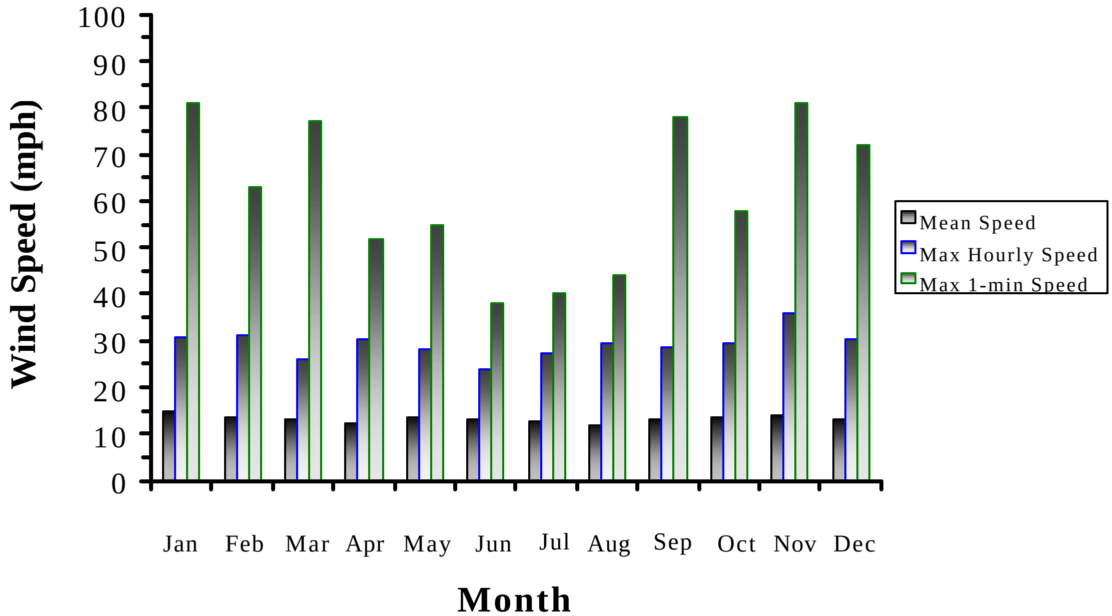


Figure 7.1-6. Mean, Average Maximum Hourly and Maximum 1-Minute Wind Speed Data (INTEC, 1998b; NWS, 1999).

Table 7.1-2.
Historical Summary of Weather Station Characteristics for the Study Area Available from NWS (1999).

Station Name	Latitude	Longitude	Elevation	Operational Date				Online Records
				Start		End		
	(deg min)	(deg min)	(ft)	Year	Month	Year	Month	(years)
Prudhoe Bay	70° 15″N	148° 20″W	50	1984	07	1985	03	1986-98
	70° 15″N	148° 20″W	80	1985	03	-	-	
Barrow WSO Airport	71° 18″N	156° 47″W	30	1946	09	1966	12	1949-98
	71° 18″N	156° 47″W	40	1967	01	1982	01	
	71° 18″N	156° 47″W	30	1982	01	-	-	
Barter Island WSO Airport	70° 08″N	143° 36″W	40	1949	09	1953	12	1949-88
	70° 08″N	143° 36″W	20	1954	01	1956	12	
	70° 08″N	143° 38″W	50	1956	12	1982	01	
	70° 08″N	143° 38″W	40	1982	01	1989	01	

7.1.1.1.2 Wind

The lack of natural protective barriers in the Arctic coastal zone and the ocean expanse (open water, ice cover) results in an average wind speed of 13.3 miles per hour (mph) or 21km per hour (km/h) (COE, 1999). INTEC (1998a) considered a 100-year return period at 177km/h (110mph). COE (1999) tabulated mean wind speeds and directions for the Barrow and Barter Island weather stations and Deadhorse Airport, which is located inland from Prudhoe Bay. INTEC (1998b) tabulated monthly mean speed and direction, maximum hourly average speed, as well as maximum one-minute speed and direction. Table 7.1-3 summarizes the information and the data are illustrated in Figure 7.1-6.

Table 7.1-3.
Summary of Mean, Average Maximum Hourly and Maximum 1-Minute Wind Speed Data (COE, 1999; INTEC, 1998b).

Month	Wind Data Station				
	Deadhorse Airport (1969-1988)		Prudhoe Bay Well Pad-A	Barter Island WSO Station	
	Mean Wind Speed (mph)	Compass Direction	Maximum Hourly Wind Speed (mph)	Maximum 1-min Wind Speed (mph)	Compass Direction
January	14.7	ENE	30.8	81	W
February	13.7	WSW	31.2	63	W
March	13.3	WSW	25.9	77	WNW
April	12.4	ENE	30.4	52	W
May	13.7	ENE	28.2	55	WSW
June	13.3	ENE	23.7	38	W
July	12.9	ENE	27.3	40	SW
August	11.9	ENE	29.5	44	W
September	13.1	ENE	28.8	78	W
October	13.6	ENE	29.3	58	W
November	13.8	ENE	35.7	81	WSW
December	13.2	WSW	30.4	72	W

7.1.1.1.3 Precipitation

Precipitation levels along the Beafort Sea coastline are low due to the cold air temperatures. The region can be classified as a desert. The relative humidity varies from 80%-95% during the summer months and drops to approximately 60% during the winter. Oliktok Point, at the western edge of the study boundary along the arctic coast receives an average annual rainfall of 137mm (5.39in) and 478mm (18.8in) of snowfall each year (DNR, 1998). The Nuiqsut-Prudhoe Bay area experience average annual rainfall levels of 127mm (5in) and snowfall accumulation of 508mm (20in). The light, granular snow and persistent wind may create inaccuracies in the snowfall measurement statistics (COE, 1999). Monthly average precipitation statistics for several geographical locations are listed in Table 7.1-4. The peak average monthly rainfall occurs during August (29mm; 1.14in) and the maximum average monthly snowfall occurs in October (237mm; 9.35in).

Table 7.1-4.
Summary of Precipitation and Snowfall Levels for Several Geographical Locations within the Study Area.

Geographic Location	Record Dates	Mean Annual		24-hour Maximum Event		Source
		Rainfall (in)	Snowfall (in)	Rainfall (in)	Snowfall (in)	
Barrow WSO Airport	1951-1980	4.75	-	1.3	-	COE (1999)
Barrow WSO Airport	1949-1998	4.55	29.0	-	7	NWS (1999)
Barter Island WSO Airport	1951-1980	6.49	-	2.3	-	COE (1999)
Barter Island WSO Airport	1949-1988	6.19	41.8	2.3	16	NWS (1999)
Oliktok Point	-	5.39	18.8	3.0	-	DNR (1998) COE (1999)
Prudhoe Bay	1986-1999	4.37	34.4	1.0	11	NWS (1999)

7.1.1.2 Oceanography

Variations in the oceanographic characteristics of the Alaskan Beaufort are primarily a function of the season and associated ice regime. The summer months generate peak distributions of wave height and current speed due to the open water conditions. During spring and fall, ice features tend to dampen surface wave generation and propagation. Wave effects are insignificant during the winter months due to the surrounding ice field and currents are minimal and respond to tidal fluctuations.

7.1.1.2.1 Bathymetry

Seabed slopes throughout the Beaufort Sea are gradual and the edge of the continental shelf is approximately 80km (50mi) offshore with a water depth on the order of 200m (660ft). Beyond 81km (50mi) the water depths significantly increase onto the Canada Abyssal Plain. Nearshore the water depths are on the order of 12m (40ft) at 10km (6mi) offshore. For example, this is the distance from the shore to Seal Island.

7.1.1.2.2 Ocean Waves

According to INTEC (1998b), ocean waves were measured only during the period August to November 1985 at the Northstar Exploration Island. During a westerly storm the maximum wave height was 2.3m (7.4ft). Consequently, wave hindcast models are developed to predict wave height and frequency characteristics based on historical data including wind velocity, duration, fetch length and water depth. The fetch length is a characteristic distance over which the wind field can travel uninterrupted to build up the surface wave height. The model is dependent on the fully developed sea state, which can be defined as a steady state process that is a function of the fetch and duration. The wave height is also limited by the seafloor topography. INTEC (1998a, 1998b) and COE (1999) provide data for several locations in the study area. The information is summarized in Table 7.1-5 for westerly and easterly storm directions for the annual recurrence and 100-year return period.

Table 7.1-5.
Predicted Wave Significant Heights (H_s) and Peak Period (T_p).

Westerly Storm Direction							
Location	Annual			100-Year Event			Source
	H_s (ft)	H_s (m)	T_p (s)	H_s (ft)	H_s (m)	T_p (s)	
Point Storkersen (Nearshore)	1.0	0.3	2.0	4.4	1.3	4.8	COE (1999) INTEC (1998b)
Liberty Shore Crossing	1.7	0.5	7.5	2.9	0.9	11.3	INTEC (1998a)
Seal Island (Offshore)	7.1	2.2	6.8	19.9	6.1	10.9	COE (1999) INTEC (1998b)

Easterly Storm Direction							
Location	Annual			100-Year Event			Source
	H_s (ft)	H_s (m)	T_p (s)	H_s (ft)	H_s (m)	T_p (s)	
Point Storkersen (Nearshore)	1.0	0.3	2.0	2.8	0.9	3.0	COE (1999) INTEC (1998b)
Liberty Shore Crossing	1.5	0.5	6.9	1.7	0.5	9.9	INTEC (1998a)
Seal Island (Offshore)	7.6	2.3	7.1	12.8	3.9	12.3	COE (1999) INTEC (1998b)

7.1.1.2.3 Water Level Fluctuations

In addition to surface waves, variation from the mean sea level (MSL) can be caused by storm surge and to a lesser extent astronomical tide. Peak levels generally occur during the open water season, which is approximately August through October. Storm surge levels are dependent on a number of factors including atmospheric pressure, wind speed, direction and duration, Coriolis effect, rainfall, fetch length, as well as the direction and speed of the storm front. The shallow seabed slope enhances the storm surge magnitude (COE, 1999).

The tidal range of the study area is of the order of +/-0.3m (+/-1ft), with COE (1999) specifying a peak range 160mm (6.3in) and INTEC (1998a, 1998b) considering a design tidal range of 213mm (8.4in). Positive storm surges are typically 0.9m (3ft) with peak magnitudes ranging from 1.0m (3.3ft) to 2.0m (6.5ft) (COE, 1999). A summary of storm surge data is presented in Table 7.1-6.

Table 7.1-6.
Peak Storm Surge Estimates.

Westerly Storm Direction					
Location	Annual		100-Year Event		Source
	Surge (ft)	Surge (m)	Surge (ft)	Surge (m)	
Point Storkersen (Nearshore)	+2.1	+0.6	+6.8	+2.1	INTEC (1998b)
Liberty Shore Crossing	+2.3	+0.7	+6.7	+2.0	INTEC (1998a)
Seal Island (Offshore)	+1.1	+0.3	+4.1	+1.2	COE (1999) INTEC (1998b)

Easterly Storm Direction					
Location	Annual		100-Year Event		Source
	Surge (ft)	Surge (m)	Surge (ft)	Surge (m)	
Liberty Shore Crossing	+2.3	+0.7	+6.7	+2.0	INTEC (1998a)
Seal Island (Offshore)	1.0	0.3	2.0	0.6	INTEC (1998b)

7.1.1.2.4 Current Speeds

Complete annual records of surface and near surface water currents are not available due to the destructive forces of the ice regime during the spring breakup and freeze-up. In general, data collection efforts have been limited to the time frame between late July and mid-September. Consequently, storm induced currents, which typically occur during October storms, are not directly measured (INTEC, 1998b). Investigations on indirect current velocity estimates were conducted between September and October of 1984. An empirical relationship was developed, relating ice floe drift velocity and wind speed, where the surface current speed was approximately five percent of the wind speed (INTEC, 1998b).

During the open water summer months, the nearshore coastal currents are primarily wind driven with a few hours lag time required for build-up. The current field is generally oriented in the direction of the bathymetric contours that parallel the coastline (COE, 1999). Oscillatory tidal currents, of lesser magnitude, are superimposed on the more dominant wind driven current. Repetitive mapping surveys conducted by INTEC (1998b) have shown that seabed scour by offshore currents in the vicinity of the Northstar project area are not significant. Open water current speed estimates are presented in Table 7.1-7.

Table 7.1-7.
Measured and Estimated Current Speeds.

Open Water Season – Summer (June – August)					
Location	Annual		100-Year Event		Source
	Surge (ft)	Surge (m)	Surge (ft)	Surge (m)	
Point Storkersen (Nearshore)	+2.1	+0.6	+6.8	+2.1	INTEC (1998b)
Liberty Shore Crossing	+2.3	+0.7	+6.7	+2.0	INTEC (1998a)
Seal Island (Offshore)	+1.1	+0.3	+4.1	+1.2	COE (1999) INTEC (1998b)

The winter ice cover has a significant moderating effect on the subsurface currents. INTEC (1998a, 1999b) consider these effects to be insignificant and fluctuations are primarily due to tidal oscillations. COE (1999) state that storm surge and regional circulation patterns can also account for the under ice, winter currents that do not exceed 0.09m/s (0.3ft/s) and are typically of the order of 0.06m/s (0.2ft/s).

7.1.1.3 Geotechnical conditions

7.1.1.3.1 General Environment

Organic surface material (peat) is distributed throughout the onshore area, which provides the bedding to support the overlying tundra mat. The coastal plain is mantled with Quaternary deposits of alluvial, glacial, and aeolian origin. Siltstone and sandstone lie beneath the unconsolidated material at depths ranging from a few meters to tens of meters. The principal soils of the Arctic Coastal Plain are Histic Pergelic Cryaquepts and Pergelic Cryaquepts (USGS, 1999). Unconsolidated alluvial deposits underlie the corridors of the Colville, Kuparuk, Sagavanirktok, Shaviovik and Canning River systems. The material is coarse grained, not susceptible to frost and generally well drained. Coastal plain deposits are typically poorly drained, high in ice content, difficult to excavate, and frost-susceptible (DNR, 1998). The majority of smaller streams dry up or freeze during the winter and have clean sand or gravel beds. Tertiary age bedrock is exposed in the White Hills, Franklin Bluffs, and rolling hills to the west of the Canning River.

7.1.1.3.2 Offshore Soil Characteristics

The seafloor deposits generally consist of clayey sand to sandy clay with minor amounts of gravel. The nearshore soil includes very stiff, silty clay, while the offshore zone comprises stiff silt with scattered gravels and cobbles. The silt is typically highly over-consolidated due to freeze-thaw cycles (COE, 1999).

For the Northstar project area, COE (1999) summarized sediment characteristics determined from offshore borehole investigations. The compiled data was collected from a number of sources, for a variety of locations over a number of years (1970-1996) and the data are presented in Table 7.1-8. In general, a layer of sand and silt, with a thickness ranging from 1.5m to 7.6m (5ft to 25ft) overlaid the coarser sediment primarily composed of sand and gravel. Offshore sediments were characterized by a layer of fine-grained sand and silt over a thick sequence of sands and gravels at a depth from 3m to 10.7m (10ft to 35ft) beneath the seafloor (COE, 1999). The sand/silt layer depth generally increases from nearshore to offshore and from west to east.

Table 7.1-8. Summary of Soil Characteristics from Offshore Borehole Locations in the Northstar Project Area. (COE, 1999).

Age	No.	Unit Thickness (ft)	Grain Size	Ice Bonded	% Fines Passing #200	Data Source
Inshore of Barrier Islands						
Holocene	12	13.5–27.5	SM/ML	Mixed	4.3–88.5	Miller (1996)
	2	5–13	SP/SM	Mixed	-	McClelland (1985)
	1	6.6–25.6	-	-	-	Benton (1970)
Pleistocene	5	34+	GP/SP-SM	Mixed	4–6.7	Miller (1996)
	2	31.5+	SP	Mixed	-	McClelland (1985)
	1	33.4+	-	-	-	Benton (1970)
Barrier Islands						
Holocene	7	24–42.5	SM/SP/ML	Yes	4.8–84.6	Miller (1996)
	11	11–34	SP-SM/ML	Mixed	-	McClelland (1985)
	1	30	-	-	-	Benton (1970)
Pleistocene	2	31+	GP/SP	Mixed	0.8	Miller (1996)
	11	24+	GP/SP	Mixed	-	McClelland (1985)
Offshore of Barrier Islands						
Holocene	10	15–30.5	SP/SM/ML	No	1.4–8.7	Miller (1996)
	3	8.5–17	-	No	-	McClelland (1985)
	9	3.5–23	SM/SP	No	-	Woodward-Clyde (1981)
	2	6.6–9.2	-	-	-	Benton (1970)
Pleistocene	4	72+	GP	No	0.1–7.6	Miller (1996)
	3	26.5+	-	No	-	McClelland (1985)
	8	59+	GP	No	-	Woodward-Clyde (1981)

Notes:
Holocene - < 11,000 years ago
Pleistocene - > 11,000 years ago
SM - Silty sand
ML - Silt
GP - Poorly graded gravel
SP - Poorly graded sand

Geotechnical analyses determined that the ice-bonded soil could sustain high loads, whereas the unbonded sediments and silts were susceptible to settlement. In water depths of approximately 5m (16ft), vertical test trench walls, composed of a 1.5m (5ft) thick layer of unfrozen silt overlying sand were maintained until the underlying sand compromised the stability through slumping (COE, 1999).

INTEC (1998b) characterize the Northstar project area as five typical soil conditions: shoal sand, silt, silty sand, fine sand and sandy gravel. The soil characteristics can be summarized as

Soil Type	Location	Characteristics
Shoal sand	Seabed	Mixed with fine gravel and thin layers of sand are believed to be relic shoal deposits.
Silt, Silty sand	4.5m – 7.6m (15ft – 25ft)	Underlie the shoal deposit and generally stiff to medium stiff with pockets of organic material.
Sandy gravel	18.3m – 85.3m (60ft – 280ft)	Relatively well graded mixture with sizes up to 75mm (3) and occasional cobbles.

7.1.1.3.3 Permafrost

Permafrost underlies much of the Beaufort Sea area. The origin of this subsea permafrost dates back to 25,000 years before present, when sea water levels were considerably lower, perhaps as much as 85m (280ft) lower than today (Hopkins, 1973). As sea levels rose since the last glaciation, the more extreme surface temperatures have been replaced by more moderate, yet still sub-freezing seabed temperatures of –1.7°C to –1.1°C (29°F to 30°F) (Osterkamp and Harrison, 1982). The mean ground temperature of the 'relict' permafrost was generally several degrees cooler than this new surface temperature. Warming of the subsea permafrost has resulted and salt from the seawater has diffused into the pores of the seabed sediments. Salt concentrations have resulted in freezing point depressions of as much as 1.7°C to 2.2°C (3°F to 4°F). Hence, the upper subsea profile has experienced a phase change and the ice-bonding or ice lenses most common in saturated permafrost does not exist today.

Based on investigations in the Kuparuk–Prudhoe Bay offshore region, the upper subsea sediments contain sufficient salt water in the pores, that these sediments exist with no ice bonding or ice inclusions at temperatures ranging from 0°C to –3.3°C (32°F to 26°F) (Osterkamp and Harrison, 1982). These upper sediments therefore behave as unfrozen soils. Underlying these deposits there are reports of ice-bonded sediments starting at depths as much as 31m to 70m (100ft to 230ft) and as far offshore as 16km (10mi) (Chamberlain et al., 1978; Osterkamp and Harrison, 1982). Shallower depths to ice-bonded permafrost exist within the first mile from today's shoreline (Osterkamp and Harrison, 1982).

The geotechnical data for the offshore pipeline alignments for the Northstar and Liberty projects includes subsea temperatures colder than –1.1°C (30°F) beneath water depths as much as 6m (20ft) and as much as 9km (5.7mi) from the shoreline. The geotechnical data indicate that the surface of the ice-bonded permafrost does not exist, within the depths explored, along the offshore pipeline alignments (APO107 and APO109). Some isolated, 1.2m (4ft) thick ice poor bonded permafrost was encountered beneath the proposed Liberty Island (APO109).

There is a relatively abrupt transition from the offshore unbonded permafrost sediments to the start of the shoreline ice-bonded permafrost. The transition roughly coincides with the line of seasonal bottom-fast ice. There is no visible excess ice in most of the Liberty shore approach material (APO107).

The thaw strain values for the majority of the Northstar shore approach bonded permafrost are less than 5%, however, some values between 5% and 10% were obtained (APO107). Extreme isolated thaw strains of 18% and 22% are also reported. For other shore approach ice-bonded sediments there is reported to be little, if any, thaw strain potential (APO109).

The onshore permafrost generally contains relatively high ice contents in an organic tundra veneer and the underlying silts and sands and silty sands. This ice consists of thick layers greater than 0.3m (1ft) and polygonal wedge ice (APO109). The design basis is to minimise the impact of this ice rich permafrost on the pipeline by a transition to above grade mode as close to the shoreline as feasible.

7.1.1.4 Ice Regime

The ice regime is a dominant environmental factor to consider for offshore marine pipelines, which impacts pipeline design as well as constraints on construction, operation and maintenance.

7.1.1.4.1 Ice Seasons

The ice regime life cycle for the nearshore Alaskan Beaufort Sea can be defined by four overlapping phases that roughly parallel the seasons from fall to summer:

- Freeze-up
- Ice cover or Mid-Winter
- Break-up
- Open Water

A summary of the ice conditions and seasonal variations, related to annual fluctuations in meteorological conditions, for the Alaskan Beaufort Sea are presented in Table 7.1-9.

Table 7.1-9. Summary of Seasonal Ice Conditions for the Alaskan Beaufort Sea.

	Mean Parameter	Parameter Range	Source
Freeze-up	October 4 ±9days	3rd week September 4th week October	INTEC (1998a)
	October 6	-	INTEC (1998b)
	mid-October	mid-September	COE (1999)
Ice Season Duration	288 ±10days	-	INTEC (1998a)
	292 ±8days	-	INTEC (1998b)
Break-up	July 4	2nd week July	INTEC (1998a)
	July 4	-	INTEC (1998b)
	early July	mid-June	COE (1999)
First Open Water	July 19	-	INTEC (1998a)
	July 26	-	INTEC (1998b)
Open Water	77 ±13days	-	INTEC (1998a)
	73 ±10days	-	INTEC (1998b)
	73 ±13days	-	COE (1999)
Summer Ice Invasion	3 of every 4 summers	2 times during early summer	INTEC (1998a)
	2 of every 3 summers	2 to 3 times during summer	INTEC (1998b)

The general freeze-up process is initiated in shallow waters of protected areas (e.g. lagoons, bays, leeward side of islands). Continued growth develops through increasing ice cover thickness and relatively rapid, seaward expansion. October storms can move and deform the ice field and stability of the level ice cover is usually developed by December. In addition, depending on the topography, bathymetry and prevailing winds, offshore multi-year ice features can invade the shallow waters remaining trapped until break-up.

The ice cover season extends at least from January to mid-May. The mean ice growth rate is 0.3m per month (1ft per month) with a peak level ice thickness ranging between 1.4m-2.3m (4.5ft-7.5ft) achieved by May. Nearshore and protected areas of the ice field are effectively static with total movements on the order of 1.0m-1.5m (3ft-5ft) (INTEC, 1998b). The average ice season length, between freeze-up to break-up, is approximately 9.5 months with the brief open water season occasionally interrupted by incursions of offshore ice features (e.g. icebergs, multiyear ice floes) due to onshore winds (COE, 1999).

In late May, the overflowing of the landfast, level ice, in river delta regions, by meltwater originating from the southern foothills and mountains precedes break-up of the ice cover in early July. The floodwaters stretch out to approximately the 10m (30ft) water depth contour, which is on the order of 20km-30km (12mi-19mi) offshore.

The open water season starts around mid to late July and lasts for approximately 75 days. Depending on seasonal climate and prevailing winds, ice intrusion occurs almost annually with one-tenth (1/10th) concentration, which comprise roughly two-thirds multi-year ice features. Larger ice concentrations occur once every four to five years for the Northstar project area (COE, 1999).

7.1.1.4.2 Ice Zones

The Alaskan Beaufort Sea can be generally subdivided into three zones: Landfast Ice, Seasonal Ice and Permanent Polar Pack. The average minimum extent of the polar pack and major drift pattern for the Beaufort Sea gyre is shown in Figure 7.1-7. A typical profile of the ice conditions in the southern Alaskan Beaufort Sea is illustrated in Figure 7.1-8.The landfast zone directly connects with the coastline, follows the topography and grows seaward with time from the start of freeze-up. In the Beaufort Sea, the landfast ice is stabilized by the presence of small islands and grounded pressure ridges (Cammaert and Muggeridge, 1988). The outer seaward extent of the landfast zone advances to approximately the 25m contour with variations influenced by coastline topography, water depth and degree of interaction with the seasonal and polar pack ice within the shear zone (COE, 1999). The average extent is on the order of 40km (25mi) with a maximum of approximately 75km (45mi) from the coastline. The landfast ice zones evolves to a predominantly “static” condition between December and March, with the maximum level ice thickness reaching 2m (6ft) by May. The ice can be grounded or frozen to the seabed, in shallow areas up to the 2m (6.6ft) contour, which is separated from the floating but fixed in place level ice, for deeper waters up to the 15m (50ft) contour, due to tidal fluctuations and storm surge.

The development of pressure ridges occurs between 20 to 80 kilometres from the coast and increases in frequency (3km-7km) from east to west (Cammaert and Muggeridge, 1988). Mean ridge sail heights were measured to range from 1.2m (3.9ft) in December to 1.7m (5.6ft) between February and April (Tucker et al., 1979). Due to prevailing winds and motion of the offshore polar pack, multi-year ice features (floes, icebergs) may intrude the landfast ice zone. Annual concentrations of multi-year sea ice are approximately 3/10th, between Point Barrow and Harrison Bay, located west of the study area (Dome et al., 1982). The incursions would tend to decrease for a project region where the polar pack is located further offshore (Figure 7.1-7). For example, further east in the Canadian Beaufort multi-year ice features are expected to occur once every 5 years (Cammaert and Muggeridge, 1988).

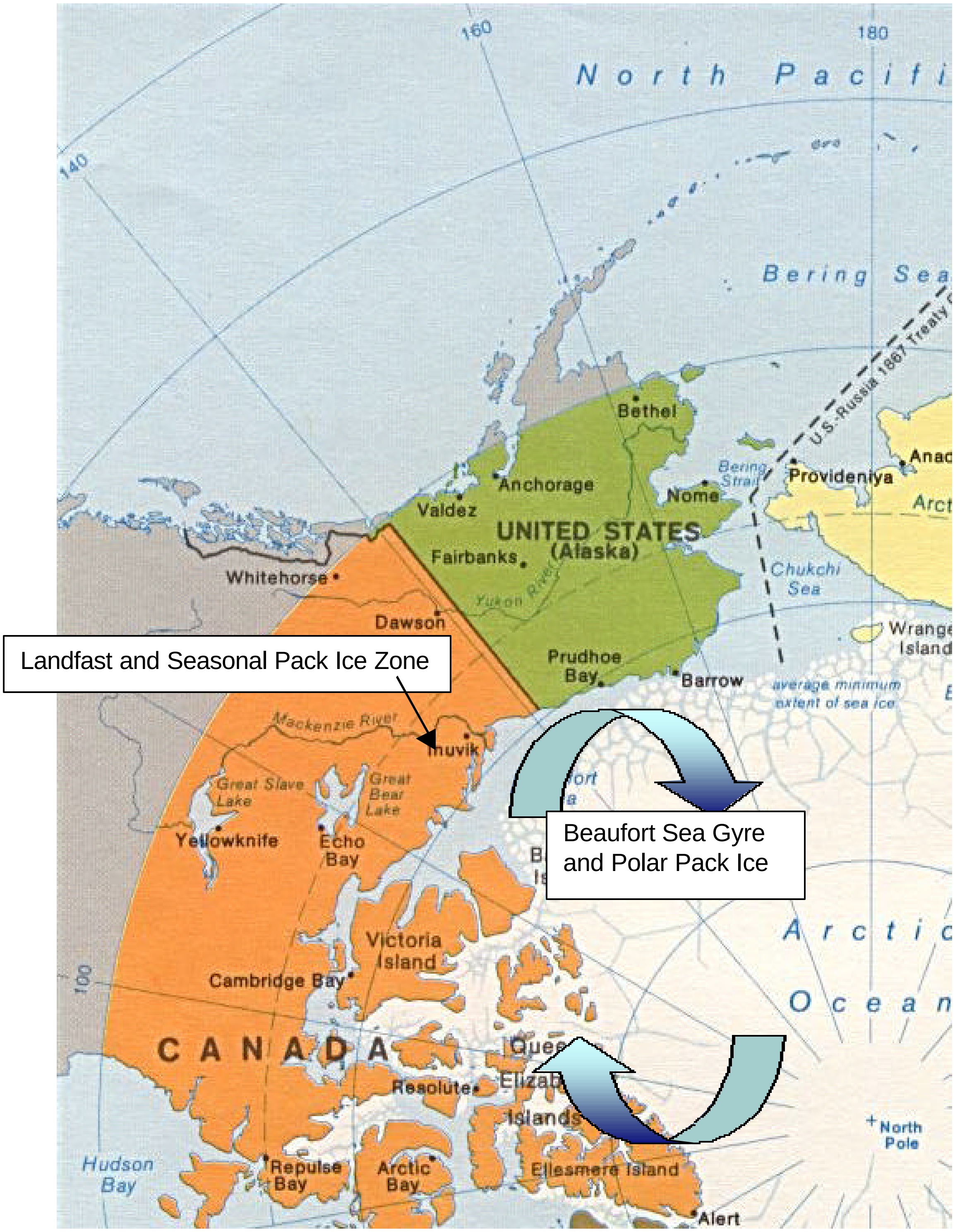


Figure 7.1-7. Average Minimum Extent of the Polar Pack and Major Drift Pattern for the Beaufort Sea Gyre.

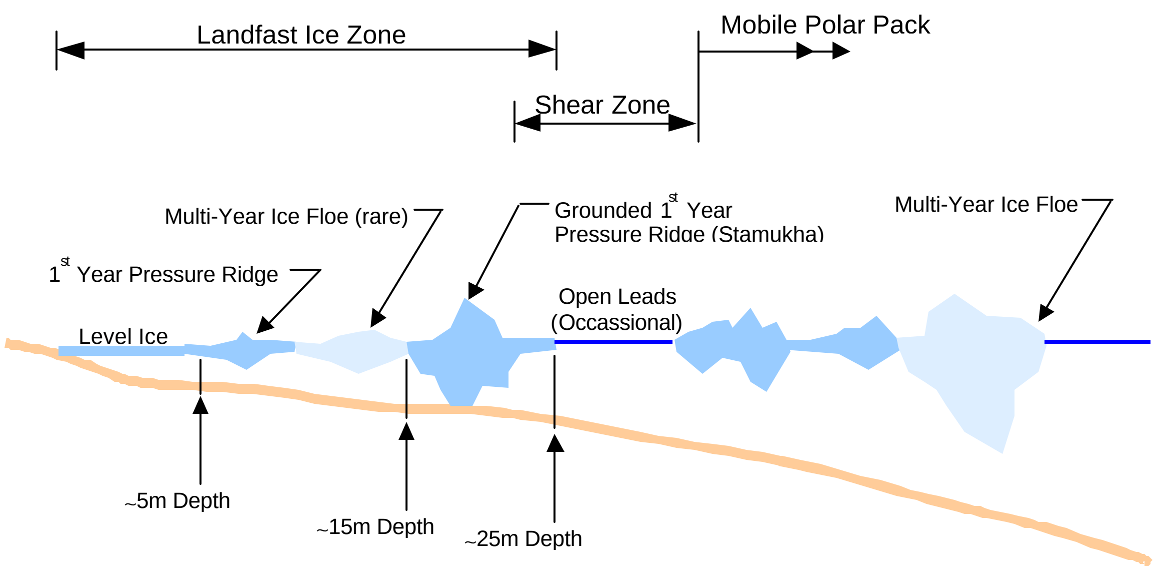


Figure 7.1-8. Typical Profile of Ice Zones and Conditions in the Alaskan Beaufort Sea.

The seasonal ice region is a dynamic transition zone, consisting of predominantly first-year ice features, bridging the landfast ice to the mobile, permanent polar pack. The width can have seasonal and annual variations between a few kilometres or up to 100 kilometres (60mi) approaching the continental shelf. The seaward extent is difficult to define due to local changes in bathymetry and seasonal changes in the offshore polar pack (COE, 1999). The dynamic ice conditions, with mean velocities on the order of 8km/day (6mi/day), continuously generate pressure ridges and shear ridges throughout the winter season (Cammaert and Muggeridge, 1988). Along the seaward edge of the landfast ice is a shear zone, characterized by a state of active flux through the interaction of first-year ice features and the polar pack with the static landfast zone. Open water leads can also develop occasionally. The pressure ridges can extend for 20km (10mi) in length with sail heights of 4m (13ft) and possibly be grounded (stamukha). Wadhams (1983) stated that average shear zone ridge keel depths were 21.2m (40ft) with a maximum draft of 28.8m (95ft) with spacing on the order of 4km (2.5mi).

The polar pack ice is a permanent, ice-covered region of predominantly multi-year on the outer edge of the continental shelf. The southernmost extent is generally 72°N latitude. Although local prevailing winds have an impact on the polar pack motion, the mean drift speed of ice features at the edge of the clockwise Beaufort Sea gyre (Figure 7.1-7) is approximately 2km/day (1.2mi/day). The polar pack interacts and influences movement of the seasonal pack ice and formation of the shear zone.

7.1.1.4.3 Ice Movement

Wind and ocean current are the primary environmental driving forces that determine the magnitude of ice movement. The degree of motion is also influenced by the topography (e.g. sheltered bay, barrier islands), bathymetry (e.g. shoals) and presence of grounded ice features (e.g. pressure ridges, icebergs). The development of open water leads increases the ice feature mobility.

For the Alaskan Beaufort, October through December during freeze-up is the critical time frame, when the ice cover is thin, where peak velocities upwards of 0.2m/s (0.7ft/s) can be attained (Cammaert and Muggeridge, 1988). The relatively weak cover produces small rubble fields, through ride-up or pile-up mechanisms, along the coastline and natural or artificial islands. Pressure ridges and ice floes exhibited drift velocities on the order of 7km/day (4.3mi/day) due to storm induced motions (COE, 1999).

In midwinter, ice movement of the order of 30m/hr can occur when the ice is approximately 1.7m in thickness (Cammaert and Muggeridge, 1988). This can cause significant ridging and grounded ice pileup. For example, in mid-March of 1979 a freeboard of 22m (72ft) was developed in 20m (66ft) of water (Gulf, 1980). For the Liberty project, INTEC (1998a) state the average annual winter maximum drift velocity was 1.5m/hr (4.8ft/hr) with a 100-year value of 4.6m/hr (15ft/hr). INTEC (1998b) state that the maximum ice movement, for sheltered locations within the Northstar project area, were 3.4m/hr (11.3ft/hr) and 3.8m/month (12.6ft/month) for a 100-year return period. The data indicates the stepwise and infrequent nature of ice motion, which is dependent on a number of factors including bathymetry, topography and degree of confinement.

7.1.2 Environmental loads

7.1.2.1 Ice scour

During the fall (freeze-up) or the spring (break-up) seasons, the motion of thin or fragmented ice features can encroach on shallow sloping areas (e.g. coastline and artificial islands). The horizontal motion, known as ice ride-up, has to overcome the associated frictional and plowing forces. Increasing or discontinuous slope gradients, grounded ice features or frictional limits cause the moving ice to fracture into blocks build vertical features, which is called ice pile-up. Ice pile-up events typically extend 10m (33ft) inland from the sea, whereas ice ride-up can extend 50m (165ft) inland (Cammaert and Muggeridge, 1988). Pile-up heights of 3 to 6m (9.8ft to 19.7ft) were reported for the seaward side of Seal Island and Stump Island, located within the Northstar project area (COE, 1999). INTEC (1998b) predicted an ice pile-up height of 17m (56ft) for a 100-year event at Seal Island. For regions throughout the Beaufort Sea, the mechanisms have the potential to alter shorelines and nearshore bathymetry, which in the longer term may pose a threat to nearshore facilities with increased erosion (DNR, 1998).

Ice gouges result from the interaction of a deep keeled ice feature (e.g. pressure ridges, icebergs) with the seabed under the action of wind, current, and wave loads. A schematic illustration of an ice gouge event is shown in Figure 7.1-9. The dominant features include a linear track depression or furrow with a gouge depth (d) and gouge width (w) referenced to the initial seabed datum. For steady-state gouge processes, a dynamic equilibrium is developed where the “plowed” soil is balanced with the creation of a frontal mound and side berms (lateral embankment, h), which are associated with clearing mechanisms.

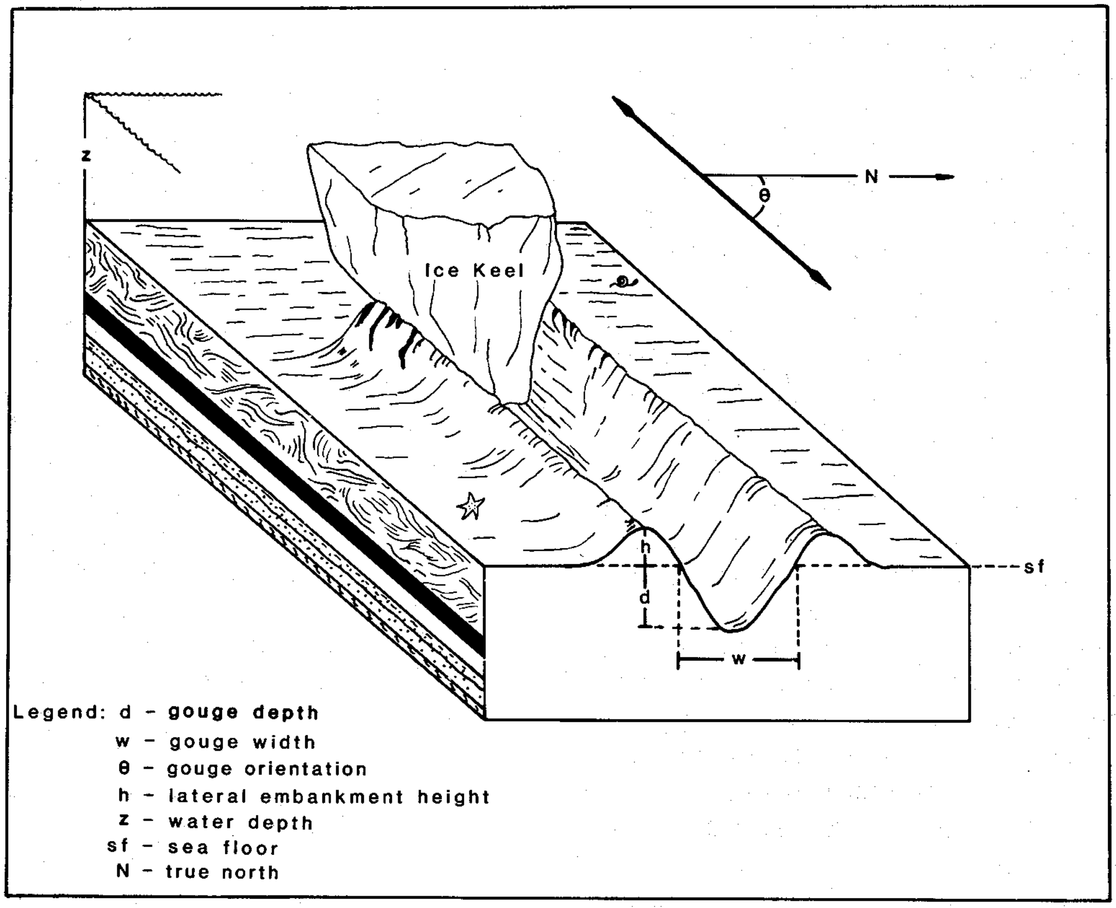


Figure 7.1-9. Schematic Illustration of an Ice Gouge Event (Weeks et al., 1983).

Typically, engineering design parameters for ice gouge events are determined through statistical analysis of an ice gouge database. The information is compiled from site or route specific investigation employing echo sounder, side scan sonar or sub-bottom profiler surveys. A typical dataset, defining the gouge depth as a function of water depth, for the Alaskan Beaufort Sea and the Northstar project area is illustrated in Figure 7.1-10. Extensive statistical analysis conducted by INTEC (1998b), consider the 100-year ice gouge event for the Northstar project area to be on the order of 1.1m (3.5ft).

One measure to address the significance and potential for ice gouging is through gouge intensity. The parameter defines the number of ice gouge events per unit area multiplied by the maximum gouge width and depth (COE, 1999). The frequency (i.e. number of gouge events) and severity (i.e. gouge depth, width magnitude) of an ice gouge event are dependent on a number of factors including topography, climate, environmental driving forces, bathymetry, soil characteristics as well as ice regime, conditions and strength. For example, in sheltered areas of the landfast ice zone, ice gouging predominantly occurs during the transition break-up period when ice features are mobile. In the seasonal zone, first-year and multi-year pressure ridges as well as significant ice features such as icebergs and ice islands can gouge the seabed at any time during the year. These characteristics are illustrated in a gouge intensity map for the Northstar project area (Figure 7.1-11).

Assessment and interpretation of the ice gouge dataset requires sound engineering judgement and experience. A number of factors must be considered in order to filter out spurious records, to account for seabed erosion and infilling rates with time, to separate relict from recent events and to determine recurrence rates (i.e. number of times per year the gouge event will occur in a particular region).

7.1.2.2 Strudel scour

Prior to the break-up season of the landfast ice zone, meltwater and spring runoff, originating in the foothills of the Brooks Mountain Range (Figure 7.1-3) to the south of the study area, flows seaward via stream and river systems (Figure 7.1-11) through the delta regions (Rawlinson, 1993). In general, the water systems west of the Colville River tend to be sluggish and meandering and those east are more braided and distributary (e.g. Sagavanirktok River) building deltas on approach to the Arctic Ocean. The nearshore, landfast ice zone acts as a catch basin for the flood waters with depths on the order of 0.6m – 1.5m (2ft – 5ft) above mean sea level as far as 30km (18miles) from shore (DNR, 1998). Tidal and thermal stress cause cracks or openings to develop in the level ice cover. Floodwaters breach the opening and vortex drainage occurs with enough force to scour (i.e. create depressions) the seabed (Reimnitz et al., 1974).

Strudel scours typically occur within 16km (10mi) of the river mouths in 1.8m – 9.1m (6ft – 30ft) water depths (COE, 1999; INTEC, 1998b). The scour geometry can be characterized as a parabaloid with horizontal dimensions on the order of 20m (66ft) and depths of 1m (3ft). Statistics on strudel scour data from a number of sources are presented in Figure 7.1-12. For the Northstar project area, the regional distribution of strudel scour density is illustrated in Figure 7.1-13.

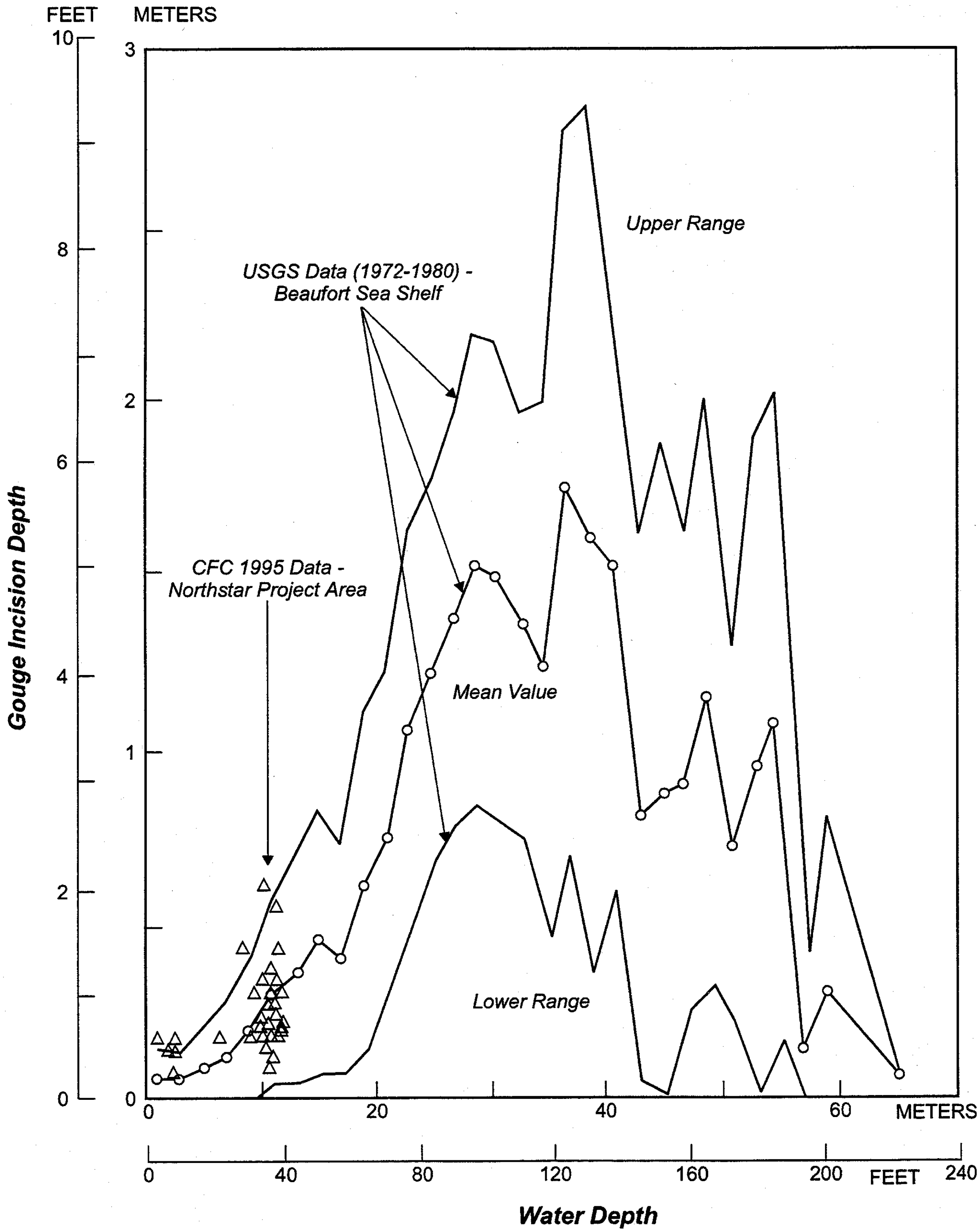


Figure 7.1-10. Gouge Depth Survey Measurements as a Function of Water Depth (COE, 1999).

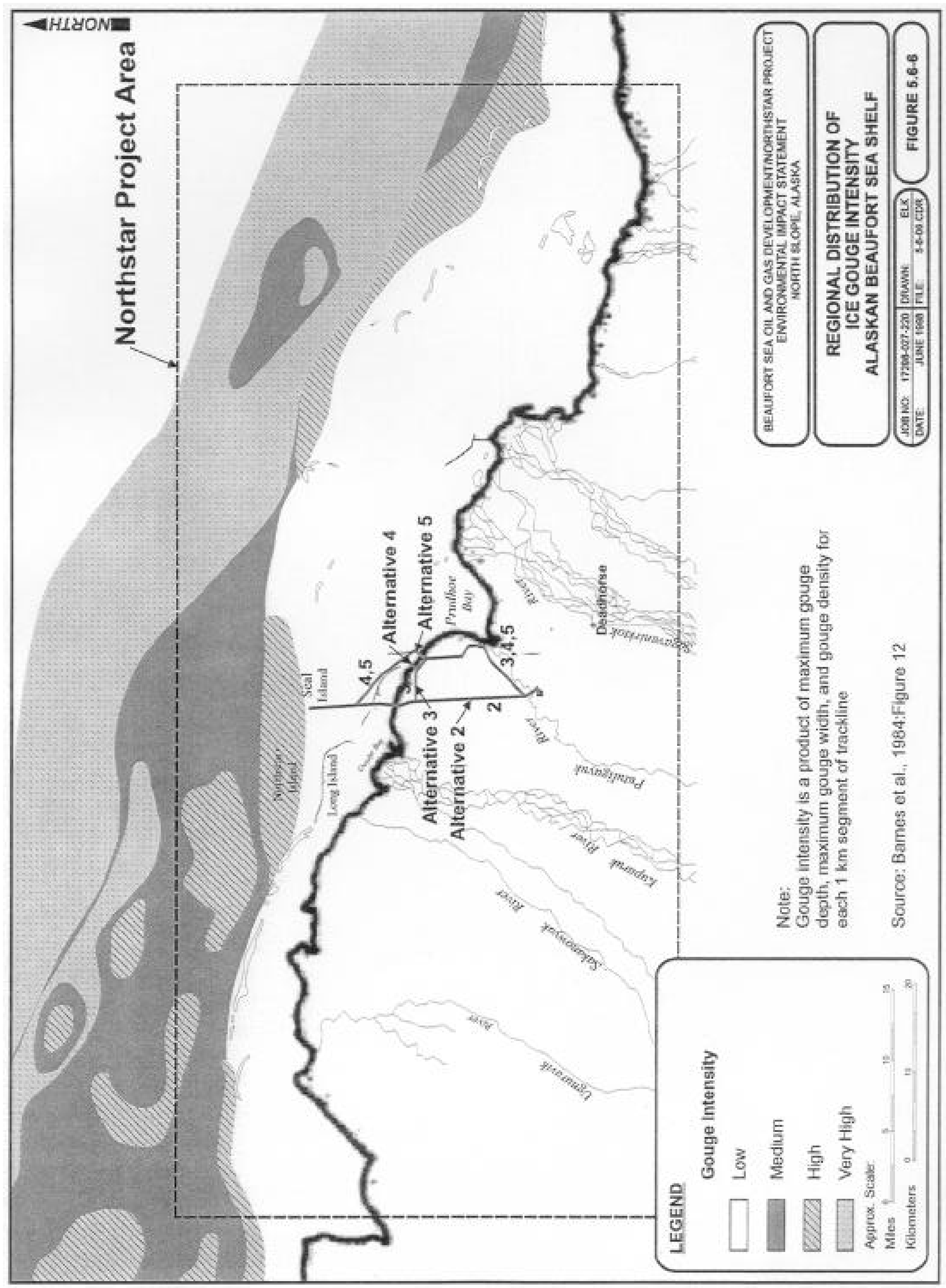


Figure 7.1-11. Regional Distribution of Ice Gouge Intensity for the Alaskan Beaufort Sea within the Northstar Study Area (COE, 1999).

7.1.2.3 Thaw settlement

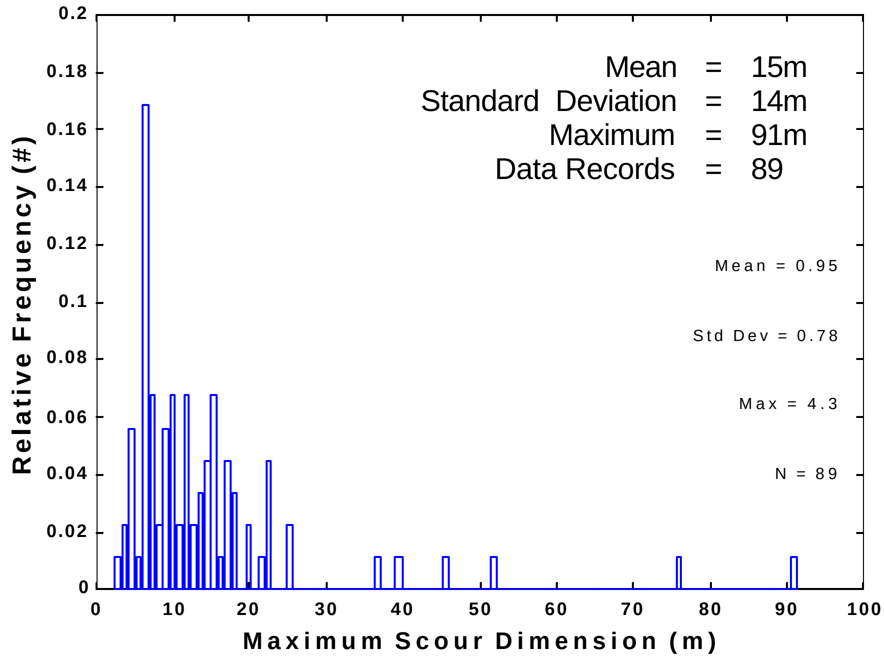
Thaw settlement will occur beneath the pipe in the shore approach section of the pipeline route. The shore approach permafrost is generally relatively ice-poor. Based on the specific design parameters for each of the Northstar and Liberty projects, the reported predictions of the long term thaw bulb and resulting thaw settlements are summarised in Table 7.1-10.

Also shown in the table are estimates of the range of thaw depths and thaw settlement values that might result from a pipe-in-pipe configuration, as defined previously. These estimates are based solely on the range of data and site conditions presented for the Northstar and Liberty projects. For the base case pipe-in-pipe scenario, it is considered that the maximum amount of thaw could be in the range of 4.6m to 15m (15ft to 50 ft), below the pipe, depending on the depth of water and the ice contents. It is considered that the base case pipe-in-pipe scenario could experience as little as about 0.2m (0.5ft) maximum thaw settlement for the Liberty conditions, to as much as 0.9m (3ft) of maximum thaw settlement for the Northstar conditions. In each case, these are the expected maximum thaw settlement values. The average thaw settlements would be approximately half of these values.

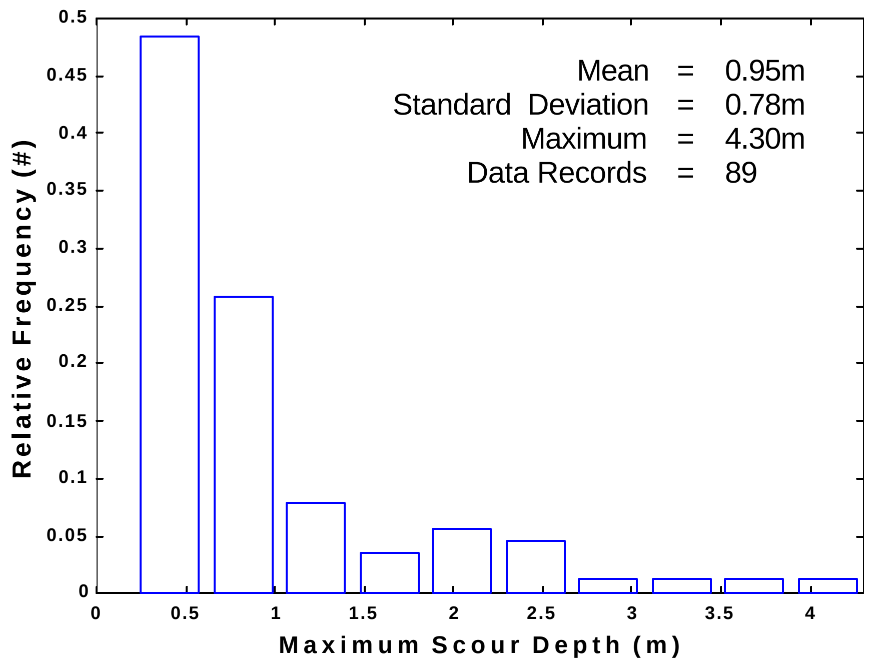
The pipe-in-pipe configuration, section 7.1.3, with the annulus filled with inert gas will create a reduced thaw bulb compared to an equivalent 12 inch, single wall pipe. However, unless the annulus were filled with a foamed insulation, it is unlikely that a major reduction in thaw depth would be realised. The merits of different thicknesses of annulus and various infill gases or insulation alternatives can only be established by site-specific geothermal modeling, which is beyond the scope of this study.

If the pipe temperatures were warmer that the 110 °F considered for the comparative assessment, the resulting thaw depths and thaw settlement could be considerably greater. Insulation in the annulus would be able to reduce these values, however, there may be a requirement for special design consideration in terms of the potential differential pipe bending.

Based on the information in the table, there is a significant difference between the Northstar and Liberty sites. At Northstar, the pipe size and temperature are less than at Liberty, and the ice contents are generally higher. The Northstar thaw depths are therefore relatively low. However, the higher ice contents result in fairly significant predicted thaw settlement values. At Liberty, the predicted thaw depths are considerably greater than Northstar.



(a)



(b)

Figure 7.1-12. Histograms of Strudel Scour Characteristics (a) Maximum Scour Dimension, (b) Maximum Scour Depth.

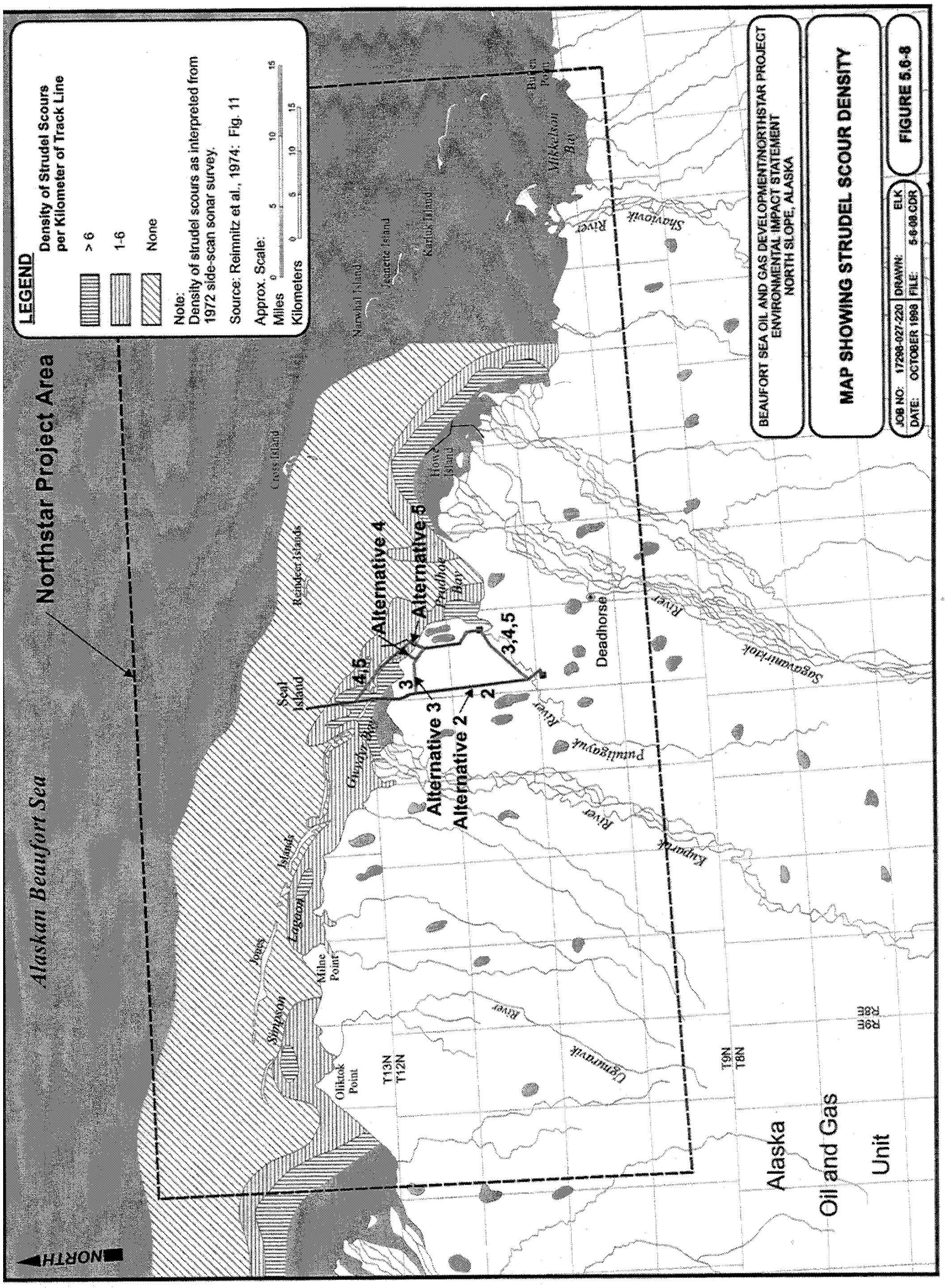


Figure 7.1-13. Regional Distribution of Strudel Scour Density for the Alaskan Beaufort Sea within the Northstar Study Area (COE, 1999).

primarily due to the much hotter pipe temperature, however, to some extent this is also due to the lower ice contents in the sediments. If the ice contents were much higher, the thaw depths would be considerably reduced. In spite of the considerable predicted thaw depth, the predicted thaw settlement values are still relatively low.

Table 7.1-10.
Summary of Thaw Depth and Thaw Settlement Predictions.

Parameter	Northstar Project (APO129)	Liberty Project (APO121)	Pipe in Pipe
Pipe diameter	10" Oil, 10 " Gas	12" Oil, 6" Prod.	12" in 14"
Pipe Temperature, °F	70	150	110
Insulation	None offshore	None offshore	Inert gas
Depth of cover, ft.	7 to 11	7	
Thaw below pipe, ft. 0 - 1 ft. water 4 ft. water	 8 28	 37 67	 15 to 25 35 to 50
Max. thaw settlement, ft.	2.0	1.0	0.5 to 3
Avg./Range thaw settlement, ft.	0.64	0.1 to 0.9	-

7.1.2.4 Rare Environmental Events

7.1.2.4.1 Earthquake Hazards

Although significant seismic activity has been recorded for the southern regions of Alaska, primarily associated with relative tectonic plate motions at the Aleutian trench, the North Slope area is relatively inactive and stable. Gravity faults, related to large rotational slump blocks, have been observed on the outer Beaufort (Grantz and Dinter, 1980). South of these slumps, which bound the seaward edge of the Beaufort Ramp, the faults have surface offsets ranging from 15m to 70m (49ft to 230ft) and are considered active in recent geologic time (Grantz et al., 1982). Consequently, the faults pose a hazard to bottom-founded structures in this area where large-scale gravity slumping of the blocks here could be triggered by shallow-focus earthquakes centered in Camden Bay or in the Brooks Range (DNR, 1998).

The Camden Bay area, situated east of the project study boundary, is seismically active with the majority of events clustering along the axis of the Camden anticline. The seismicity is typically shallow, on the order of 32km (20mi) deep, which indicates near-surface faulting. Recent significant events include two magnitude 5 earthquakes in the eastern part of the sale area, one in 1993 and one in 1995. The largest earthquake recorded in the area was a magnitude 5.3 event north of Kaktovik in 1968 (DNR, 1998). Figure 7.1-14 illustrates the location of earthquake epicenters for the North Slope area. A histogram of earthquake magnitude levels for the region bounded by 160°W to 140°W longitude and 68°N to 72°N latitude with records dating from 1968 to 1995 is presented in Figure 7.1-15.

In an areawide North Slope study, for lease sale 87, Algermissen et al. (1991) estimated a 10% probability of exceeding 0.025g in the eastern zone, and 0.01g in the western regions for a 50-year period (DNR, 1998). The peak ground acceleration map for Alaska is illustrated in Figure 7.1-16.

The project study area can be characterized by a low earthquake potential. The region is bounded by the seismic zones 0 and 1 of the Uniform Building Code, where a maximum value of 4 represents the highest earthquake hazard (Combellick, 1994). The thick permafrost layer may tend to be more representative of a stiff material, thus limiting ground motion amplification, and also reduce the likelihood of soil failure mechanisms such as liquefaction.

7.1.2.4.2 Tsunami

A tsunami can be characterized by long period (i.e. wavelength) wave train of finite amplitude generated by an impulsive disturbance that displaces a significant volume of water. The term tsunami means literally “harbour wave” and is commonly incorrectly referred to as a tidal wave. Although typically associated with seismic activity, submarine landslides or volcanic activity can also initiate an event. Tsunamis generated by non-seismic mechanisms usually dissipate quickly and rarely affect coastlines far from the source area.

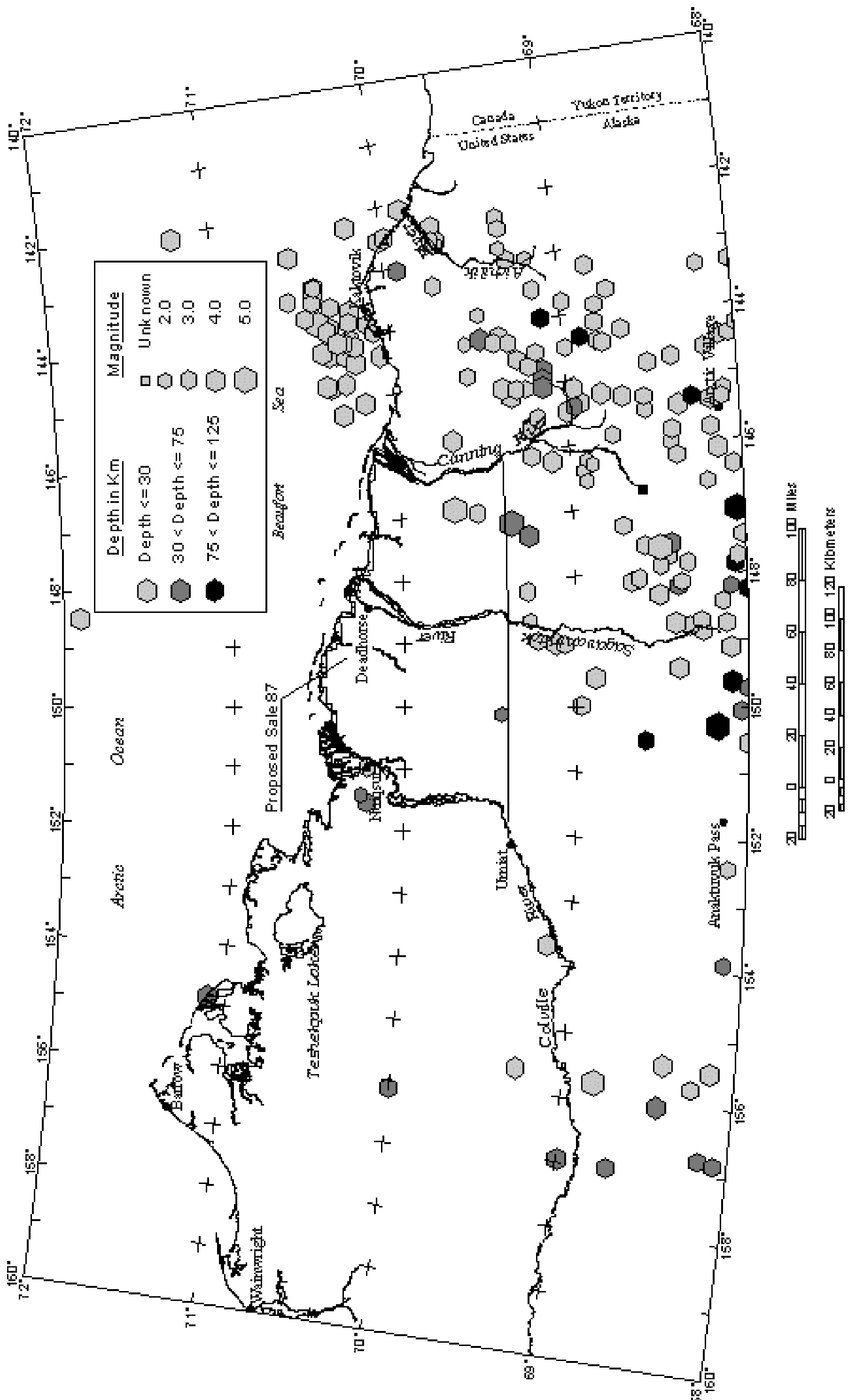


Figure 7.1-14. Epicenters for Major Earthquake Events in Northern Alaska (DNR, 1998).

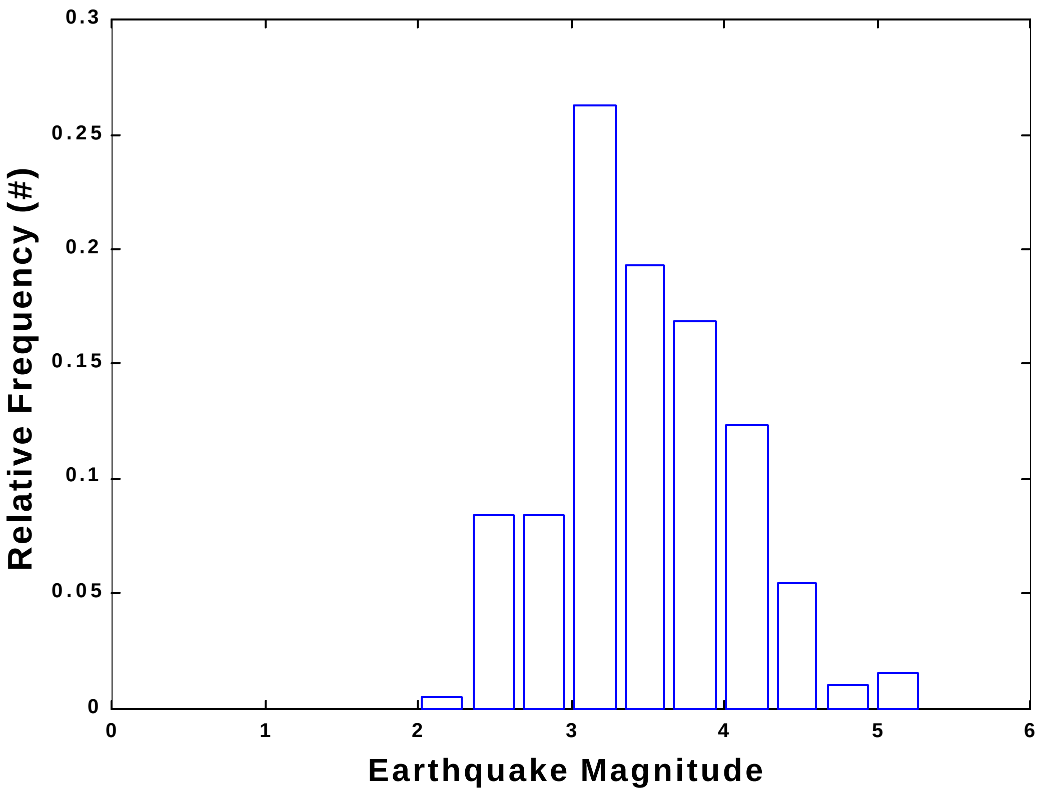
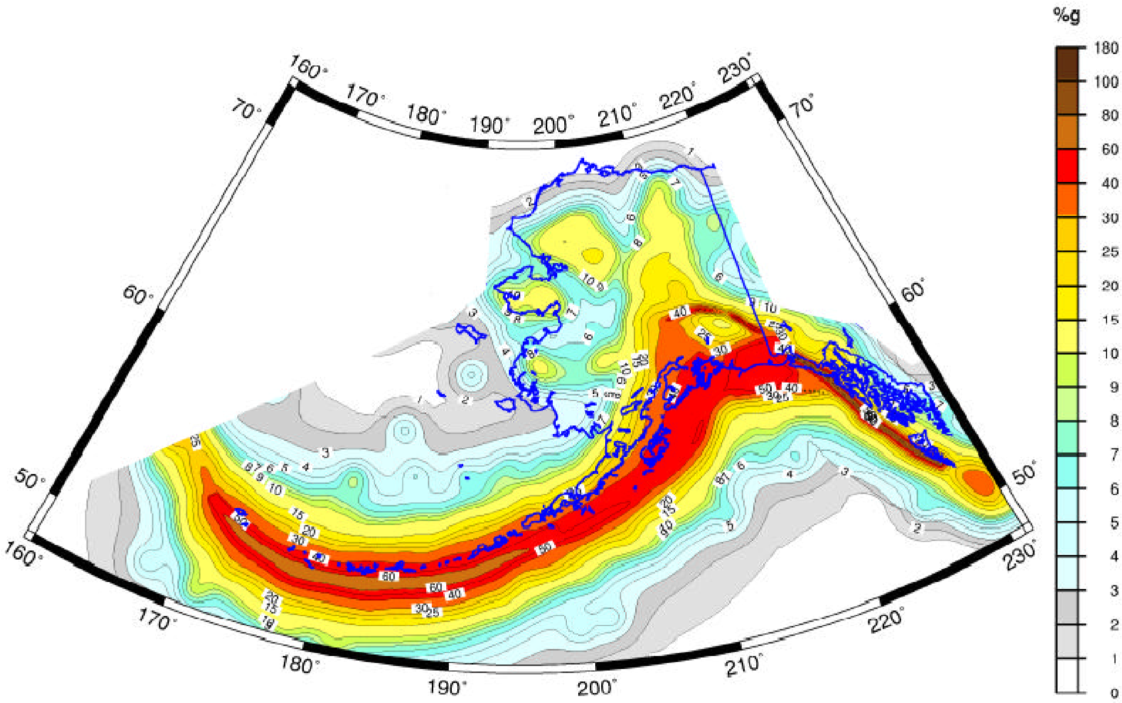


Figure 7.1-15. Histogram of Earthquake Magnitudes for North Slope Alaska (AEIC, 1999).



Peak Ground Acceleration (%g) with 10% Probability of Exceedance in 50 Years

Figure 7.1-16. Peak Ground Acceleration (%g) with a 10% Probability of Exceedance in 50 Years (USGS, 1999).

Physical characteristics of a tsunami (wave speed, period, amplitude) are primarily a function of the change in the vertical sea floor deformation, which is dependent on the earthquake magnitude, epicenter depth, fault characteristics and coincident slumping of sediments. Other factors include shoreline topography, seafloor bathymetry, seafloor deformation velocity, water depth near the earthquake source, and the efficiency with which energy is transferred from the earth's crust to the water column (Sokolowski, 1999). Wavelengths can exceed 300miles (483km) with wave crest amplitude on the order of a couple of feet, wave periods ranging from 10 minutes to a couple of hours and maximum wave speeds of 600mph (966km/h). The significant impact of a tsunami event is encountered when the wave train encroaches on the shallow coastline waters where the wave crest can build up to heights exceeding 100 feet (30m). A landslide generated tsunami that struck Lituya Bay, Alaska during 1958 produced a 1722ft (525m) wave (Sokolowski, 1999).

Appendix 7.9-1: Pipeline Integrity Monitoring Methods
Summary of Applicability vs Observed Major Defect Types and Study Case Pipeline Configurations

	Applicability[7] of Inspection Methods to Defect Types to Indicated Study Case Pipeline(s)				
Inspection Method	**corrosion**	**mechanical damage**	**girth/long seam weld defect**	**S-N (fatigue) And crack Growth**	**SCC**
1.0 Prevention/Predictive:					
1.1 scheduled/periodic methods:					
MFL/TFI pigs[1]	A inside pipe only for B,C,D	A inside pipe only for B,C,D	A inside pipe only for B,C,D	surface cracks only for A inside pipe only for B,C,D	surface cracks only for A, inside pipe only for B,C,D
UT pig[2]	A, inside pipe only for B,C,D	A, inside pipe only for B,C,D	A, inside pipe only for B,C,D	A inside pipe only for B,C,D	A inside pipe only for B,C,D
caliper pig (2D)	-	A, inside pipe only for B,C,D	-	-	-
inertial mapping pig (3D)	-	A, inside pipe only for B,C,D	-	-	-
corrosion coupons[3]	A inside pipe only for B,C,D	-	-	-	-
chemical analyses[4]	A,C,D inside pipe only for B	-	-	-	-
cut-out and inspect	A,B,C,D	A,B.C,D	A,B.C,D	A,B.C,D	A,B.C,D
acoustic emission[11]	-	plastic deformation and active crack-type defects for A,B.C,D	active crack-type defects for A,B.C,D	active crack-type defects for A,B.C,D	active crack-type defects for A,B.C,D
hydrotest[9]	A,C,D inside pipe only for B	A,C,D inside pipe only for B	A,C,D inside pipe only for B	A,C,D inside pipe only for B	A,C,D inside pipe only for B
1.2 continuous, non-intrusive[5] methods:					
thin-layer activation (TLA), fixed point	A inside pipe only for B,C,D	-	-	-	-
neutron activation (NA), fixed point	A inside pipe only for B,C,D	-	-	-	-
field signature (FS), fixed point	A,B,C,D	-	-	-	-
ultrasonic (UT), fixed point	A, outside pipe only for B,C,D	-	-	-	-
strain gauge, external[10]	-	A,B,C,D	-	-	-
1.3 continuous, intrusive[5] methods:					
electric resistance probe, fixed point	A,C,D inside pipe only for B	-	-	-	-
electrochemical probe, fixed point	A,C,D inside pipe only for B	-	-	-	-
2.0 Contingent					
2.1 scheduled/periodic methods:					
visual surveillance, various[13]	A,B,C,D only applicable upon failure	A,B,C,D only applicable upon failure	A,B,C,D only applicable upon failure	A,B,C,D only applicable upon failure	A,B,C,D only applicable upon failure
fixed point leak detection, non-RTC[8]	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure
leak detection, acoustic emission pig[14]	A, inside pipe only for B,C,D only applicable upon failure	A, inside pipe only for B,C,D only applicable upon failure	A, inside pipe only for B,C,D only applicable upon failure	A, inside pipe only for B,C,D only applicable upon failure	A, inside pipe only for B,C,D only applicable upon failure
2.2 continuous, methods:					
fixed point leak detection, RTC	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure	A,C,D inside pipe only for B only applicable upon failure
distributed[12] leak detection, RTC	A,C,D only applicable upon failure	A,C,D only applicable upon failure	A,C,D only applicable upon failure	A,C,D only applicable upon failure	A,C,D only applicable upon failure

Notes:

1. Equally applicable in "wet" or "dry" service pipelines. Magnetic Flux Leakage (MFL) and Transverse Field Inspection (TFI) pigs are both based on magnetic flux leakage technology. Available for pipe sizes 4 NPS and greater. More suitable than UT pigs for "heavy wall" and / or very long subsea pipelines. MFL accuracy is typically on the order of 10% of total metal loss, or greater. Pigs with accuracies on the order of 5% of total metal loss are available, but use of seamless pipe can reduce this accuracy due to the lower dimensional mill tolerances for this type of pipe. MFL is not typically effective for detecting SCC.

2. Applicable in relatively "clean" and "wet" service pipelines. The technology requires a liquid medium in which to function. Available for pipe sizes down to a minimum of 8 NPS. Pigs with accuracies on the order of 0.5 mm of depth and greater are available.

3. Used to measure weight loss corrosion. Use and effectiveness is limited by access to inlet, outlet, and corrosion susceptable sections of the pipeline.

4. Eg.: iron content analysis of water samples, pig trap returns, inhibitor residuals drawn from the pipeline.

5. The term "intrusive" is used in the sense that the methods intrude physically into the pipeline with consequent maintenance requirements and interference with pigging operations.

6. Applicability and effectiveness varies with corrosion mechanism. Examples include the following:
   6.1 The TLA, NA, fixed UT and FS methods are all effective in monitoring "general" corrosion
   6.2 The FS method is also effective in monitoring "pitting" corrosion

7. Though applicable, technologies vary in detection/measurement accuracy a complete comparison of which is beyond the scope of this simple table. Example resolution accuracies follow:
   7.1 The TLA and NA methods have a resolution of 1% of the activated thickness
   7.2 The fixed UT method has a resolution of 100 micrometers
   7.3 The fixed FS method has a resolution of 0.1% of the wall thickness

   Not all technologies have been adapted for, or have operational experience with, subsea pipelines.

8. Real Time Computational (RTC)

9. Hydrotesting is a non-defect specific "pass/fail" test that can not detect defects if they do not lead to leaks or ruptures during the test.

10. Depending on pipelne length fiber optic strain gauge technology will be more applicable

11. The status of this technology is experimental

12. This class of technology includes the following; sensing tape, cable and tube-based systems

13. This includes surveillance by aircraft and remotely operated vehicle (ROV)

14. Pigs with accuracies on the order of 10 litre/hr or greater are available.

Appendix 7.9-2: Subsea Pipeline Repair
Summary of Applicability of Installation and Repair Methods to Study Case Pipeline Configurations

Connection Installation Method	Connection System Applicability to Indicated Study Case Pipeline(s)			
	Sleeve [1]	**Spool** [2]	**String** [3]	**Clamp** [4]
Surface [5]	none	A,B,C,D	A,B,C,D	A, outside pipe only for B,C,D
Subsurface [6]**, dry:**				
coffer dam [7]	none	A	none	A, outside pipe only for B,C,D
hyperbaric chamber [8]	none	A	none	A, outside pipe only for B,C,D
Subsurface [6]**, wet:**				
diver assisted [9]	none	A	A	A, outside pipe only for B,C,D
diverless / ROV assisted [10]	none	A	A	A, outside pipe only for B,C,D
diverless / proprietary PRS [11]	none	none	none	A

Notes:

1. "Sleeve" refers to a material, steel or composite, that is applied to the exterior wall of a damaged section of a pipe to repair it. None of the available systems have been applied to the repair of subsea pipelines.
2. "Spool" refers to a short section of pipe used to replace a relatively short, damaged section of a pipeline.
3. "String" refers to a long, prefabricated section of pipe used to replace a relatively long, damaged section of a pipeline.
4. The term "clamp" or "split sleeve" or "connector" refers to a device that is applied externally to repair a relatively short damaged section of pipeline. Operational systems are presently available for a limited range of pipe sizes.
5. This method of installation requires that the damaged pipeline is brought to the surface for repair. This method typically requires the use of a construction barge.
6. This installation strategy repairs the damaged pipeline in place, on the sea bottom. Depending on the installation and repair methods used, and the extent of damage, this strategy may require the use of a construction barge or a smaller support vessel.
7. Used for shallow water repairs, at atmospheric conditions. Not typically used for repair of subsea pipelines.
8. Presently capable of subsurface repairs down to 400 m depths, approx. Chamber pressures increase, and potential weld quality decreases, with increasing water depth. Very complex, specialized and expensive; not well suited to shallow water repairs.
9. Typically used for subsurface repairs down to 180 m depths, approx. Depths to 360 m are possible. Not generally well suited to arctic conditions.
10. Presently capable of subsurface repairs down to 400 m (welded) 600 m depths (mechanically connected), approx. Preferred to diver assist at depths of 100 m, approx. and greater.
11. Pipeline Repair Systems (PRS) are typically capable of subsurface repairs down to 1000 m depths, approx. Some systems are capable of repairs to 3000 m, approx. Operational systems are presently limited to certain pipe sizes. PRS's, including SNAM and Framo PD, tend to be complex, specialized and expensive; not well suited to shallow water repairs.

Appendix 8.4-1

12" x 0.500 WT SINGLE WALLED PIPELINE
BASIC CONSTRUCTION COST

TASK	LABOUR	EQUIPMENT	OTHER	TOTAL
STOCKPILE PREPARATION	$ 4,778	$ 8,304	$ 23,472	$ 36,554
OFFLOAD PIPE	$ 10,944	$ 15,948	$ 2,256	$ 29,148
SKID DEPLOYMENT	$ 52,268	$ 29,328	$ 92,288	$ 173,884
PIPE HAUL & STRING	$ 126,896	$ 167,967	$ 24,871	$ 319,733
PIPE GANG 12"	$ 318,753	$ 216,161	$ 59,887	$ 594,801
	$ -	$ -	$ -	$ -
FIRING LINE 12"	$ 364,445	$ 132,208	$ 148,848	$ 645,500
	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -
CUT OUTS	$ 229,167	$ 159,083	$ 32,674	$ 420,923
ANODE	$ 109,546	$ 71,518	$ 20,549	$ 201,612
LOWER IN SHALLOW	$ 46,962	$ 58,784	$ 7,419	$ 113,165
LOWER IN DEEP	$ 441,423	$ 496,124	$ 63,420	$ 1,000,967
HYDRO-TEST 12"	$ 146,525	$ 119,094	$ 25,898	$ 291,517
	$ -	$ -	$ -	$ -
GEO-PIG SUPPORT	$ 23,123	$ 18,382	$ 5,267	$ 46,772
MOBE/DE-MOBE	$ 72,694	$ 64,534	$ 15,236	$ 152,464
YARD SUPPORT	$ 65,278	$ 122,593	$ 14,033	$ 201,903
GENERAL SERVICES	$ 265,946	$ 57,072	$ 32,016	$ 355,034
GENERAL CLEAN UP	$ 214,634	$ 25,132	$ 31,756	$ 271,522
FINAL CLEAN UP	$ 50,056	$ 9,766	$ 9,384	$ 69,206
FIELD MAINTENANCE	$ 71,627	$ 72,846	$ 9,386	$ 153,859
EQUIPMENT PREPARATION	$ 228,175	$ 115,290	$ 29,587	$ 373,052
FIELD SERVICING	$ 100,455	$ 93,436	$ 14,133	$ 208,024
EQUIPMENT SHOP	$ 364,304	$ 166,796	$ 48,658	$ 579,758
EXPEDITING	$ 90,028	$ 30,544	$ 12,015	$ 132,587
JOINT COATING	$ 156,370	$ 158,627	$ 31,314	$ 346,310
TOTAL direct construction	**$ 2,031,198**	**$ 1,651,527**	**$ 538,162**	**$ 4,220,887**
TOTAL indirect construction	**$ 758,635**	**$ 309,640**	**$ 114,439**	**$ 1,182,715**
TOTAL field maintenance	**$ 172,082**	**$ 166,282**	**$ 23,519**	**$ 361,883**
TOTAL maintenance shop	**$ 592,479**	**$ 282,086**	**$ 78,246**	**$ 952,811**
TOTAL	**$ 5,093,149**	**$ 2,653,335**	**$ 901,341**	**$ 8,647,825**

12" x 0.500 WT SINGLE WALLED PIPELINE
CONSTRUCTION AND MATERIALS COST ESTIMATE SUMMARY

TASK		TOTAL
BASIC CONSTRUCTION		
TOTAL direct construction		$ 4,220,887
TOTAL indirect construction		$ 1,182,715
TOTAL administration		$ 1,929,530
TOTAL field maintenance		$ 361,883
TOTAL maintenance shop		$ 952,811
TOTAL		**$ 8,647,825**
MISCELLANEOUS		
Support		$ 1,408,000
contractor vehicles		$ 80,800
pipeline trends		$ 3,218,000
welder test (labor & fees)		$ 36,000
Airfare		$ 254,500
drug testing		$ 38,250
refuse – nsb		$ 106,450
envire vac servicing		$ 99,750
glycol for hydrotest		$ 446,200
saftey and environmental		$ 81,650
small tools & consumables		$ 408,100
misc. consumables		$ 170,200
misc. freight		$ 65,300
saftey awards		$ 16,300
office & equipment		$ 65,300
office supplies		$ 24,500
x ray		$ 100,800
pipe, coating, FOB North Slope		$ 4,681,055
misc. valves & fittings		$ 10,500
Anodes		$ 46,000
other misc. materials		$ 293,690
TOTAL		**$ 11,651,345**
SUBTOTAL		**$ 20,299,170**
Anchorage G & A	4.50%	$ 913,463
ESTIMATE PRICE		**$ 21,212,633**
Profit	6.50%	$ 1,378,821
TOTAL ESTIMATE		**$ 22,591,454**

DOUBLE WALLED PIPELINE
12" x 0.375 WT INNER PIPE; 14" x 0.375 WT OUTER PIPE
BASIC CONSTRUCTION COST

TASK	LABOUR	EQUIPMENT	OTHER	TOTAL
STOCKPILE PREPARATION	$ 8,362	$ 14,532	$ 46,027	$ 68,921
OFFLOAD PIPE	$ 17,510	$ 25,517	$ 3,426	$ 46,453
SKID DEPLOYMENT	$ 104,536	$ 55,968	$ 184,576	$ 345,081
PIPE HAUL & STRING	$ 153,652	$ 202,547	$ 30,138	$ 386,337
PIPE GANG 12"	$ 237,212	$ 160,864	$ 45,587	$ 443,663
PIPE GANG 14"	$ 252,037	$ 170,918	$ 48,187	$ 471,142
FIRING LINE 12"	$ 183,322	$ 86,227	$ 122,912	$ 392,461
FIRING LINE 14"	$ 194,779	$ 91,616	$ 124,472	$ 410,868
INSERT AND TIE IN	$ 152,461	$ 217,226	$ 47,115	$ 416,802
CUT OUTS	$ 351,744	$ 215,807	$ 50,469	$ 618,020
ANODE	$ 94,260	$ 61,538	$ 17,819	$ 173,617
LOWER IN SHALLOW	$ 46,962	$ 58,784	$ 7,419	$ 113,165
LOWER IN DEEP	$ 441,423	$ 496,124	$ 63,420	$ 1,000,967
HYDRO-TEST 12"	$ 146,525	$ 119,094	$ 25,898	$ 291,517
PNEUMATIC TEST 14"	$ 146,525	$ 102,518	$ 24,721	$ 273,764
GEO-PIG SUPPORT	$ 23,123	$ 18,382	$ 5,267	$ 46,772
MOBE/DE-MOBE	$ 84,810	$ 75,289	$ 17,186	$ 177,285
YARD SUPPORT	$ 74,179	$ 139,310	$ 15,593	$ 229,082
GENERAL SERVICES	$ 296,216	$ 63,568	$ 35,656	$ 395,440
GENERAL CLEAN UP	$ 214,634	$ 25,132	$ 31,756	$ 271,522
FINAL CLEAN UP	$ 50,056	$ 9,766	$ 9,384	$ 69,206
FIELD MAINTENANCE	$ 80,707	$ 82,080	$ 10,556	$ 173,343
EQUIPMENT PREPARATION	$ 230,710	$ 116,571	$ 29,912	$ 377,194
FIELD SERVICING	$ 113,189	$ 105,280	$ 15,888	$ 234,357
EQUIPMENT SHOP	$ 411,822	$ 188,552	$ 54,898	$ 655,272
EXPEDITING	$ 101,770	$ 34,528	$ 13,575	$ 149,873
JOINT COATING	$ 204,897	$ 212,091	$ 42,275	$ 459,263
TOTAL direct construction	**$ 2,759,330**	**$ 2,309,754**	**$ 889,729**	**$ 5,958,813**
TOTAL indirect construction	**$ 821,665**	**$ 347,593**	**$ 123,149**	**$ 1,292,408**
TOTAL field maintenance	**$ 193,896**	**$ 187,360**	**$ 26,444**	**$ 407,700**
TOTAL maintenance shop	**$ 642,532**	**$ 305,123**	**$ 84,811**	**$ 1,032,466**
TOTAL	**$ 6,103,328**	**$ 3,425,082**	**$ 1,281,637**	**$10,810,047**

DOUBLE WALLED PIPELINE
12" x 0.375 WT INNER PIPE; 14" x 0.375 WT OUTER PIPE
CONSTRUCTION AND MATERIALS COST ESTIMATE SUMMARY

TASK		TOTAL
BASIC CONSTRUCTION		
TOTAL direct construction		$ 5,958,813
TOTAL indirect construction		$ 1,292,408
TOTAL administration		$ 2,118,662
TOTAL field maintenance		$ 407,700
TOTAL maintenance shop		$ 1,032,466
TOTAL		**$ 10,810,047**
MISCELLANEOUS		
Support		$ 1,591,000
contractor vehicles		$ 91,350
pipeline trends		$ 3,637,000
welder test (labor & fees)		$ 31,600
Airfare		$ 287,500
drug testing		$ 31,950
refuse – nsb		$ 112,800
envire vac servicing		$ 120,300
glycol for hydrotest		$ 455,700
saftey and environmental		$ 92,250
small tools & consumables		$ 461,300
misc. consumables		$ 192,400
misc. freight		$ 73,800
saftey awards		$ 18,450
office & equipment		$ 73,800
office supplies		$ 27,700
x ray		$ 100,800
pipe, coating, FOB North Slope		$ 7,174,710
misc. valves & fittings		$ 10,500
Anodes		$ 51,500
other misc. materials		$ 293,700
TOTAL		**$ 14,930,110**
SUBTOTAL		**$ 25,740,157**
Anchorage G & A	4.50%	$ 1,158,307
ESTIMATE PRICE		**$ 26,898,465**
Profit	6.50%	$ 1,748,400
TOTAL ESTIMATE		**$ 28,646,865**

Appendix 10.1 - Civil Works Cost Estimates for an Offshore Pipeline

The following is an estimate of civil works costs associated with a typical offshore pipeline installation in the winter, in the study area. It is expected that, apart from a slight increase in ice workpad width, there would be no differences in the civil works costs associated with either of the single wall or a double wall pipeline systems considered.

1) Grounded ice road/workpad
2.0 mi. length/300' (100 m) width - up to 10' depth , including shore transition/approach
25 x 24 hrs x 15 days + equipment = $0.5M

2) Floating ice road/workpad
10.0 mi. length/300' (100 m) width x 7.5' to 10' thick, including offshore facility transition
20 x 24 hrs x 40 days + equipment = $4.0M

3) Pipe make-up/fabrication of materials/maintenance pad
1000' x 1000' x 1’ average thickness
10 x 12 hrs x 15 days + equipment = $0.5M.

4) Spoil storage area for temporary material storage(ditch spoil)
3500' x 1000' x 1/2’ thick = $1.0M

5) Trench ice/remove and haul
12 x 12 hrs x 25 days + equipment = $2.5M.

6) Trench ditch bottom and preparation for pipe lay - inclusive of blasting near shore
15 x 12 hrs x 60 days + equipment and standby = $5.5 M.

7) Backfill of pipe, material haul, clean-up
10 x 12 hrs x 60 days + equipment = $3.5 M

8) Miscellaneous costs inclusive of indirect costs, admin, maintenance of road and equipment, transportation = $6.5 M

9) Gravel materials for shore access to location, select backfill, etc.
= $4.0 M

Total Civil = $28.0 M

Since these cost estimates are very similar for both the double walled and the single walled configuration, the major effect of the cost is to reduce the significance of the increase in the installation and material cost difference (about $6.4M, section 8.4.5)