BP EXPLORATION

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May 1, 2000

Mr. Jeff Walker
Regional Supervisor, Field Operations
Alaska OCS Region
U.S. Department of Interior, Minerals Management Service
949 E. 36th Avenue, Room 308
Anchorage, Alaska 99508-4392

<u>Liberty Development Project (OCS-Y-1650)</u>
<u>Transmittal of Final Report: Pipeline System Alternatives –</u>
<u>Liberty Development Project Conceptual Engineering</u>

Dear Mr. Walker:

BP Exploration (Alaska) Inc. is pleased to transmit a final report "Pipeline System Alternatives — Liberty Development Project Conceptual Engineering", prepared by INTEC Engineering, Inc. This report consists of a binder containing the original draft report dated November 1, 2000 and our response to comments from third party reviewers and agencies on that draft report. For ease of reference, we have also included copies of these comment letters in the binder. We understand that MMS will provide copies of this final report to interested agencies.

Submittal of this document is the final stage of a significant effort invested in analyzing various pipeline design alternatives for the Liberty project. Due to concerns raised during the Northstar permitting process, BPXA agreed to prepare a conceptual level report investigating design alternatives for the offshore segment of the Liberty sales oil pipeline. The scope of this report was originally proposed by BPXA in April 1999. Subsequently, based on the results of facilitated interagency discussions, you provided more direction regarding an expanded report scope in a letter to us dated July 6, 1999. We also agreed it was appropriate to have the report reviewed by a third party. You retained Stress Engineering Services to conduct this review.

We submitted the draft report to you on November 1, 1999, and you received comments on the report from the U.S. Fish and Wildlife Service on December 3, 1999 and from the Corps of Engineers on December 23, 1999 and December 30,

1999. The Stress Engineering third party review was completed on March 7, 2000. On March 17, 2000 you issued a letter to us requesting response to your comments, to Stress' third party review, as well as comments from the Corps of Engineers and from the U.S. Fish and Wildlife Service.

In our response to agency and third party comments, our major goal was to provide useful information for review of alternatives. This has been a significant undertaking. We have not before participated in a project which sought to provide this level of information regarding engineering design of alternatives. We believe that, through this process, the public and the agencies have a significant information base to consider in reviewing, commenting, and making decisions about the project.

We believe this final report is responsive to agency and Stress comments. In particular, we took comments regarding possible bias very seriously, and strove to eliminate any appearance of bias in our report. In addition, we have been careful to explain how possible failure mechanisms were identified and analyzed equitably among alternatives.

One important component of our response to comments is an Addendum to the report which addresses major substantive issues. Included in the Addendum are additional analyses of alternatives assuming a constant burial depth and assuming all alternatives are constructed in a single season. In addition, the Addendum provides an expanded discussion of secondary containment provided by pipe-in-pipe designs.

At the conclusion of this process, it is apparent that selection of the best pipeline design alternative must be based on a balancing of multiple factors. This report shows that any of these alternatives can be successfully designed. All of the alternatives show extremely small probabilities of a release of oil to the environment. The secondary containment provided by pipe-in-pipe designs provides a slight reduction in this already very small level of risk under certain circumstances. However, these pipe-in-pipe designs are also more complex to install, inspect, and repair, and cost more.

Based on a comparison of relative risk for each alternative, costs, and on our experience with the practicalities of constructing, operating, and maintaining facilities in the Arctic, we have decided not to alter our Development and Production Plan to chose a different pipeline design, and remain confident in our selection of a heavy single walled pipeline.

If you have any questions or need additional information, please call Karen Wuestenfeld at 564-5490.

Sincerely,

Peter T. Hanley, Manager Permitting
HSE-Alaska

Attachment

RESPONSE TO MMS, AGENCY, AND STRESS ENGINEERING COMMENTS

LIBERTY PIPELINE SYSTEM ALTERNATIVES

LIBERTY DEVELOPMENT PROJECT

CONCEPTUAL ENGINEERING

PREPARED FOR

BP EXPLORATION (ALASKA), INC.

ANCHORAGE, ALASKA

INTEC PROJECT NO. H-0851.02

PROJECT STUDY PS19

APRIL 2000

MMS Letter of March 17th, 2000

Request #1: We request BPXA provide a thorough explanation as to why different depths of cover were selected for the various pipeline systems.

Response #1: All pipeline systems have been conceptually evaluated against the most pressing environmental loadings (ice gouging and upheaval buckling), with the 7-foot of depth of cover as a basis. Based on this evaluation, it appeared some of the pipeline systems could safely have the depth of cover reduced and still satisfy upheaval buckling and other loading requirements. The report philosophy was to treat each alternative design as a potential actual project that might be built. Reducing cover reduces construction time, reduces construction risk, reduces cost, makes repair easier if necessary, and in some cases reduces pipeline loading (e.g. in some cases of permafrost thaw settlement). In practice, a designer seeks to reduce these aspects if possible and, thus, the necessary depth of cover has been assessed for each option. If depth of cover or wall thickness, for example, are not determined based on performance requirements, there is no apparent basis for objectively defining cases for subsequent environmental risk assessment. In other words, as would be the case in actual design practice, the analysis sought to optimize design factors to arrive at an overall optimized design. This has resulted in a reduced cover depth for the other alternatives. Completion of this analysis would not preclude a subsequent decision to bury any alternative pipeline deeper.

Thus, an Addendum to the Pipeline System Alternatives report has been generated (Attachment A) which looks at a constant burial depth for all alternatives. This Addendum also addresses single season construction for the pipe-in-pipe and pipe-in-HDPE alternatives.

Request #2: We request BPXA address the apparent disregard of the benefits of the PIP and PIH to provide secondary product containment.

Response #2: The ability of the outer pipe to contain small leaks of the inner pipe has not been discounted. All four pipeline alternatives are designed, at a conceptual level, to safely transport oil from Liberty Island to shore. Two of the alternatives, pipe-in-pipe, and pipe-in-HDPE have the ability to contain leaks of the carrier (or inner) pipe in certain conditions. These conditions are such that the outer pipe remains integral while the inner pipe experiences a leak. The corresponding failure mode is then corrosion of the inner pipe. This has been accounted for, since the frequency of corrosion failure does not translate into an oil spill into the environment for the double-walled pipe alternatives. See and compare Tables 5-14 and 9-2 of the Pipeline System Alternatives report.

More specifically, Damage Category 3 in Table 5-14 has been split into 3 different types as described in the footnotes associated with that table. In summary, due to the pipe-in-pipe redundancy, the frequency of corrosion damage of the inner or outer pipe does not translate into a spill frequency. In other words, Category 3 damage frequency in Table 5-14 adds up to $3x10^{-4}$; however, in Table 9-2, the corresponding entry for the Category 3 for the pipe-in-pipe is only $1x10^{-4}$ since the consequence of corrosion damage does not imply immediate spill to the environment.

In the Addendum to the Pipeline System Alternatives report, further narrative has been added addressing the potential benefits of secondary containment using pipe-in-pipe and pipe-in-HDPE systems and Table 9-2 of the original report has been revisited.

Request #3: We request BPXA address single season construction for the PIP and PIH alternatives.

Response #3: The implications of a single season construction for the pipe-in-pipe and pipe-in-HDPE are presented in the Addendum to the Pipeline System Alternatives report. Recent North Slope construction experience with the Northstar pipelines indicates that the pipeline was completed approximately 2 weeks prior to an anticipated end of construction cut-off date for Liberty. Given the added complexity of a pipe-in-pipe or pipe-in-HDPE system, engineering judgement suggests that it would have been very difficult to complete such a system during this year's construction window. Therefore, even though the Addendum proposes a single season scenario, there is still significant risk of not completing either of these two alternative designs in a single season.

Stress Engineering Services Draft Final Report of March, 2000

The response to the comments, observations and issues presented by Stress Engineering Services are presented in Attachment B.

MMS Comments on Pipeline System Alternatives – Liberty Development Project Conceptual Engineering Report

The response to the comments made by the MMS are presented in Attachment C.

Fish and Wildlife Service Letter of December 3rd, 1999

Issue #1, Secondary Containment - See BPXA's response to Request #2 of the MMS letter of March 17th, 2000 (above). In the Addendum to the Pipeline System Alternatives report (Attachment A), further narrative has been added addressing secondary containment using pipe-in-pipe and pipe-in-HDPE systems.

Issue #2, Leak Detection - As part of the US Army Corps of Engineer stipulations for Northstar, BPXA agreed to design, construct, operate and maintain a prototype leak detection system that would be installed with the offshore pipelines. This system would have the ability to detect an oil spill beneath current threshold detection limits (from PPA and MBLPC). The system design had to be submitted and approved by the Corps prior to initiating pipeline trenching. INTEC Engineering investigated a number of supplemental leak detection strategies for Northstar and recommended the use of the LEOS system as it was considered the best available technology. This system is currently being installed with the Northstar pipelines.

It should be noted that although the LEOS system is considered the best available technology, by the time the Liberty pipeline is ready to be installed, another system may be identified that would be considered the best available technology. This could partially result from lessons to be learned from the Northstar installation and operation.

Issue #3, Pipe-in-Pipe Design - Pipeline system alternatives evaluated in the INTEC report were the result of MMS and agency input at several meetings in 1999. Based on these meetings, several pipe-in-pipe options were carried to the conceptual design selection process where the preferred alternative was then carried forward for further analysis. This was agreed to limit the number of options to be analyzed.

As pointed out in page 5-8 of the Pipeline System Alternatives report, the calculations assumed that the inner and outer pipe had the same radius of curvature. In other words, the inner and outer pipe acted as a unit with a stiffness equal to the sum of the individual pipeline's stiffness. If the inner and outer pipe wall thickness was reduced, the stiffness of each individual pipe would be reduced and, therefore, the overall system stiffness is reduced. For a given load condition, pipeline strains would increase with a decrease in stiffness.

While assuming that both pipes have the same curvature is a valid approximation of the average structural behavior under bending at the conceptual level, the loads between the outer pipe and the inner pipe would actually be transferred at discrete points along the pipeline length where the spacers are located. The localized load transfer at spacers would magnify pipe bending strain at these locations. This localized strain increase would need to be assessed in detailed design and the spacers designed accordingly.

Issue # 4, Single Season Construction - The implications of a single season construction for the pipe-in-pipe and pipe-in-HDPE are presented in the Addendum to the Pipeline System Alternatives report (Attachment A). However, even though the Addendum proposes a single season scenario, there is still a schedule risk associated with completing the construction of either of these two alternative designs in a single season. In fact, there is even a risk that a single wall steel pipeline could not be completed in a single season.

Issue #5, Conclusions - See BPXA's response to Request #2 of the MMS letter of March 17th, 2000 (above). In the Addendum to the Pipeline System Alternatives report (Attachment A), further narrative has been added addressing secondary containment using a pipe-in-pipe or pipe-in-HDPE alternative.

Department of the Army Letter of December 23rd, 1999

An Addendum to the Pipeline System Alternatives report is attached (Attachment A). This Addendum presents an analysis of a constant burial depth for all alternatives and addresses single season construction for the pipe-in-pipe and pipe-in-HDPE alternatives. Further narrative has also been added addressing secondary containment using a pipe-in-pipe or pipe-in-HDPE alternative. Specific to concerns outlined in the DOA letter:

Pipeline Performance Standards (Paragraph 1, Page 2) – The pipeline performance standards of minimizing the likelihood of oil entering the environment, and facilitating leak detection and containment are further addressed in the attached Addendum (Attachment C).

Secondary Containment (Paragraph 2, Page 2) - Please see the response to Request #2 of the MMS letter of March 17th 2000, and response to Issue # 1 of the Fish and Wildlife Service letter of Dec. 3rd 1999. Further narrative has been included in the Addendum to the original report addressing secondary containment using a pipe-in-pipe or pipe-in-HDPE alternative.

Pipe-in-Pipe Design (Paragraph 2, Page 2) - Please see the response to Issue # 3 of the Fish and Wildlife Service letter of Dec. 3rd 1999.

Leak Detection (Paragraph 2, Page 2) - Please see the response to Issue # 2 of the Fish and Wildlife Service letter of Dec. 3rd 1999. Additional narrative on leak detection in the annulus of the pipe-in-pipe and pipe-in-HDPE alternatives is provided in the secondary containment section of the attached Addendum.

Construction Season (Paragraph 2, Page 2) - Please see the Response to Request #3 of the MMS letter of March 17th 2000, and response to Issue # 4 of the Fish and Wildlife Service letter of Dec. 3rd 1999. Further information has been included in the Addendum regarding a single season construction for the pipe-in-pipe and pipe-in-HDPE alternatives.

Department of the Army Letter of December 30th, 1999

Again, the Addendum to the Pipeline System Alternatives report (Attachment A) provides further narrative addressing secondary containment using a pipe-in-pipe or pipe-in-HDPE alternative, including leak detection in the annulus. Specific to concerns outlined in the DOA letter:

Cathodic Protection (Paragraph 3, Page 1) – The use of cathodic coatings such as thermal sprayed aluminum or discrete anodes for the inner pipeline has not been investigated at this conceptual level. Stress Engineering, in their evaluation of the INTEC report, has suggested the use of such protection but points out that the cathodic protection of the inner pipe could not be monitored. As such, it could not be verified to be effective. Providing cathodic protection between closely spaced metal components or on metal shielded by plastic is generally more difficult than on the exterior of a single wall pipeline. The conceptual evaluation addressed maintaining an inert environment of dry air, nitrogen, or a vacuum in the pipe-in-pipe or pipe-in-HDPE annulus to limit the potential for corrosion.

It is pointed out in the Stress Engineering report (p. 18) that CFR 49 195.242 requires, "… a test procedure that will be used to evaluate adequacy of the CP system" and "The code requirement will not be waived and therefore it makes the design of the CP system the critical issue". Stress Engineering notes, "… the cathodic protection of the inner pipe could not be monitored".

Leak Detection in the Annulus (Paragraph 3, Page 1) – The attached Addendum to the original report further addresses leak detection in the annulus of the pipe-in-pipe and pipe-in-HDPE system alternatives.

Leak detection within a pressure-tight, continuous annulus (e.g. pipe-in-pipe without intermediate bulkheads) is in fact considered in the report as a highly reliable early warning system for leaks (e.g. page 5-32). Details on annulus pressure monitoring procedures, gas sampling, or fiber optic sensor systems would be determined during preliminary/detailed pipeline design. These systems would be expected to be significantly more reliable than ice borehole sampling and maybe slightly more sensitive or reliable than an external LEOS system.

Leak Detection Technology (Paragraph 3, Page 1) – As stated on page 3-37 of the INTEC report, a wide range of leak sensors and leak detection systems was researched (by INTEC) for the Northstar project. Details were not provided in the Liberty Pipeline System Alternatives report but are contained in the document, "Northstar Development Project, Prototype Leak Detection System, Design Interim Report" (INTEC Engineering, 1999). Over 30 sensing technologies were considered of the following generic sensor types:

- Chemical (Subsea)
- Electrical (Subsea)
- Optical Fiber
- Well Logging Technology
- Acoustic
- Electromagnetic
- Soil Resistivity / Capacitance

This study came about as the result of the US Army Corps of Engineer stipulations for Northstar. BPXA agreed to design, construct, operate and maintain a prototype leak detection system that would be installed with the offshore pipelines. This system would have the ability to detect an oil spill beneath current threshold detection limits (from PPA and MBLPC). The system design had to be submitted and approved by the Corps prior to initiating pipeline trenching. INTEC Engineering investigated a number of supplemental leak detection strategies for Northstar and recommended the use of the LEOS system as it was considered the best available technology. This system is currently being installed with the Northstar pipelines.

It should be noted that although the LEOS system is considered the best available technology, by the time the Liberty pipeline is ready to be installed, another system may be identified that would be considered the best available technology. This could partially result from lessons to be learned from the Northstar installation and operation.

Risk Assessment Accounting for Secondary Containment (Paragraph 1, Page 2) – The risk assessment did account for the benefit of secondary containment of the pipe-in-pipe system. Please refer to the response to Request #2 of the MMS letter of March 17th and the attached Addendum.

Risk Assessment Accounting for Increased Structural Integrity (Paragraph 1, Page 2) – The increased structural integrity of the pipe-in-pipe system has been accounted for in the operational failure assessment (for example, see Subsections 5.9.1.2 or 5.9.1.3. However, the increased structural integrity is coupled with the fact that the depth of cover is less than that for a single wall steel pipeline. This results from the increased bending stiffness and reduced potential for upheaval buckling of a pipe-in-pipe system. The attached Addendum addresses a constant burial depth for all alternatives.

Probability of Spill (Paragraph 1, Page 2) - The failure assessment sections of the report provide narrative on and tables indicating the number of event occurrences during the project lifetime. The probability of each category of leak is presented for the different environmental loadings, failure mechanisms, and third party activities. The sections indicate which events would not result in a spill to the environment (e.g. corrosion of the inner pipe only of a pipe-in-pipe system). See also Response #2 to the MMS letter of March 17th, 2000.

Secondary Containment (Paragraph 1, Page 2) – The Pipeline System Alternatives report has considered the effect of a pipe-in-pipe system when looking at pipeline system failure due to ice gouging. It is expected that if an ice gouge event occurred and loaded the system to such an extent that the carrier pipe failed, that event would also cause the outer pipe to fail. Secondary containment is only effective when the inner pipe fails and the outer doesn't – such as when there is corrosion of the inner pipe only.

Expected Oil Leak (Paragraph 3, Page 2) – The rationale behind a leak rate of 97.5 barrels of oil per day is presented in Subsection 3.8.4.1. The 125 barrels loss prior to detection is the result of an assumed leak detection reading every 24 hours; $97.5 + 0.4 + 27 = 124.9 \approx 125$ barrels. If the final selection of a leak detection system on a pipe-in-pipe or pipe-in-HDPE system allows a shorter leak detection reading time, then this volume may be reduced. Calculations have also been carried out in Section 3.8.4.1 to arrive at the 27 barrels due to expansion of the oil in the overland as well as the offshore segment of the pipeline.

Detection Response Time Along the Pipeline Route (Paragraph 3, Page 2) – No site-specific calculations have been conducted to determine the LEOS response time along the Liberty Pipeline route. However, LEOS is a commercially available leak detection system. It has been used onshore and for river crossings for 21 years. The manufacturer estimates that the system would be capable of detecting hydrocarbon concentrations resulting from leak rates as low as 0.3 barrels of oil per day for Northstar. The response of the system would be expected to be similar for Liberty. The manufacturer has conducted a number of documented tests in the field and the laboratory on the performance of the system in different soil conditions and water depths to 400 feet. The manufacturer has estimated that a leak occurring farthest from the sensor tube (i.e. 180° opposite on the pipe circumference) would still result in the diffusion layer contacting the sensor tube within 4 to 6 hours.

<u>125-Barrel Oil Leak Applied to Pipe-in-Pipe (Paragraph 3, Page 2)</u> – The medium leak volume of 125 barrels also applies to the pipe-in-pipe system. But, as previously noted, this volume will vary with the specific system detection time. Soil conditions around any of the pipeline alternatives will vary from alternative to alternative and will also vary along the line. The migration path of the oil outside of the pipeline system will depend on these soil conditions and will change somewhat as a result. However, as the hydrocarbon molecules diffuse through the water-soil matrix, the system response is not significantly affected by the tube position relative to the actual leak location on the pipe circumference (and therefore visible migration pattern of the oil). As part of the validation process of the LEOS system for Northstar, numerical simulations of oil migrations in submerged soils saturated with seawater were performed. ("Northstar Development Project, Prototype Leak Detection System, Design Interim Report", INTEC Engineering, Inc., July 1999). The effect of leak rate, soil type, and water depth were investigated. Results indicated the oil would migrate into the surrounding oil and encapsulate the entire pipe circumference, even when the leak in initiated at the outboard side of the pipe.

In the attached Addendum to the Pipeline System Alternatives report, further narrative has been added addressing the potential benefits of secondary containment using pipe-in-pipe and pipe-in-HDPE systems. Other factors which may be investigated in a detailed pipe-in-pipe leak assessment may be the relative time between inner/outer pipe leakage and potential oil water flow within the annulus.

<u>Early Detection (Paragraph 3, Page 2)</u> – It is correct that any alternative which could limit the quantity of release such as by early detection would have less damage. The fact that a system has an annulus, does not necessarily mean that detection of the leak will be any earlier. It does mean that some leaks could be contained and detected. In the attached Addendum to the Pipeline System Alternatives Report, further discussion is provided on secondary containment and annular leak detection.

ATTACHMENT A

PIPELINE SYSTEM ALTERNATIVES REPORT ADDENDUM

LIBERTY DEVELOPMENT PROJECT

CONCEPTUAL ENGINEERING

PREPARED FOR

BP EXPLORATION (ALASKA), INC.

ANCHORAGE, ALASKA

INTEC PROJECT NO. H-0851.02

PROJECT STUDY PS19

APRIL 2000

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A1. INTRODUCTION, SUMMARY, AND CONCLUSIONS

A1.1 Introduction and Objectives

BP Exploration (Alaska), Inc. (BPXA) submitted a Development and Exploration Plan (DPP) for its proposed Liberty Development in February 1998. As discussed in the DPP, BPXA plans to produce sales quality crude oil at Liberty Island, located in Foggy Island Bay, east of Endicott and about 1.5 miles west of the abandoned Tern Island site. Liberty Island will be an artificial gravel island in approximately 22 feet of water and will support a self-contained drilling and production facility.

According to the DDP, sales oil will be exported from Liberty Island through a 12-inch oil pipeline, approximately 6 miles in the offshore segment and 1.5 miles in the overland segment. The Liberty oil pipeline will tie into the existing Badami 12-inch oil pipeline and flow through the Liberty/Badami/Endicott/TAPS pipeline network.

In 1999, INTEC Engineering conducted a study on behalf of BPXA to provide a comparison of offshore pipeline system alternatives that could export sales quality oil from the proposed Liberty offshore development. The study report (November, 1999) presented:

- Subsea pipeline system design issues
- Design criteria
- Installation methods
- Construction costs
- Operations and maintenance issues
- System reliability
- Leak detection system
- Comparison of the alternatives

The study is intended for use by the Minerals Management Service, (MMS) the U.S. Army Corps of Engineers and other agencies participating in the Liberty Development Environmental Impact Statement.

This Addendum to that report presents additional information in response to comments made by the Mineral Management Service, the U.S. Fish and Wildlife Service, the U.S. Department of the Army, and Stress Engineering Services. Stress Engineering Services was contracted by the MMS to review the four candidate pipeline design concepts for the Liberty Development Project. This Addendum addresses the following:

- Implications of constant burial depth for all pipeline alternatives.
- Implications of single season construction of all pipeline alternatives.
- Implications for combined consistent buried depth and single season construction.
- Secondary containment using pipe-in-pipe and pipe-in HDPE systems.

A1.2 Executive Summary

Table A1-1 summarizes for all four pipeline system alternatives, the estimated costs for a consistent (7 foot) burial depth, the estimated costs for a single season construction scenario (original burial depths), and the estimated costs for a 7 foot burial depth and single season construction.

TABLE A1-1: COST COMPARISON OF PIPELINE ALTERNATIVES FOR DIFFERENT BURIAL DEPTHS AND CONSTRUCTION SEASON SCENARIOS

Description	Cost (Million $)			
	Single Pipe	Pipe-in-Pipe	Pipe-in-HDPE	Flexible Pipe
Original Report Alternatives	31	62*	50*	37
Relative Cost (%)	100	200	161	119
All Pipeline Alternatives with 7 Foot Cover Depth and Two Season Construction Where Necessary[1]	31	66	53	40
Relative Cost (%)	100	213	171	129
All Pipeline Alternatives with One Season Construction and Variable Cover Depths[1]	31	55	46	37
Relative Cost (%)	100	177	148	119
All Pipeline Alternatives with 7 Foot Cover Depth and One Season Construction[1]	31	59	47	40
Relative Cost (%)	100	190	151	129

Notes: * Indicates this value has been changed as compared to the original report.
[1] Assumes pipe-in-pipe sub-alternative A.

Table A1-2 summarizes for all four pipeline system alternatives, the estimated damage frequency and the subsequential oil spill in barrels of oil per damage category. By definition, there is no oil spilled into the environment for Category 1 and Category 2 damage. Category 3 damage (small/medium leak) results in 125 barrels of oil lost into the environment for the single wall steel pipeline and flexible pipe. The pipe-in-pipe and pipe-in-HDPE systems would release 25 and 62.5 barrels of oil respectively for Category 3 damage, thus reflecting the benefit of secondary containment. All alternatives would result in a spill of 1,567 barrels as the result of Category 4 damage.

TABLE A1-2: COMPARISON OF OPERATIONAL DAMAGES AND CONSEQUENCES OF FAILURE

Alternative	Single Pipe	Pipe-in-Pipe	Pipe-in-HDPE	Flexible Pipe
Category 1 Damage Frequency (Project Life)	3.1×10^{-2}	2.2×10^{-2}	2.2×10^{-2}	2.2×10^{-2}
Environmental Oil Spill Volume (bbls)	- 0 barrels	- 0 barrels	- 0 barrels	- 0 barrels
Category 2 Damage Frequency (Project Life)	1.2×10^{-3}	1.2×10^{-4}	2.2×10^{-3}	5.2×10^{-3}
Environmental Oil Spill Volume (bbls)	- 0 barrels	- 0 barrels	- 0 barrels	- 0 barrels
Category 3 Damage Frequency (Project Life)	1.3×10^{-5}	2.8×10^{-7} [1]	2.2×10^{-5} [1]	1.1×10^{-4} [1]
Environmental Oil Spill Volume (bbls)	- 125 barrels	- 25 barrels	- 62.5 barrels	- 125 barrels
Category 4 Damage Frequency (Project Life)	3.0×10^{-7}	2.1×10^{-7}	2.0×10^{-7}	2.1×10^{-7}
Environmental Oil Spill Volume (bbls)	- 1,567 barrels	- 1,567 barrels	- 1,567 barrels	- 1,567 barrels

Note: [1] Pipeline failure is by an event causing both inner and outer containment to fail and release oil to the environment.

Risk is the product of the frequency times the consequence of interest, in this case, oil spilled into the environment. Table A1-3 shows the risk in barrels of oil spilled into the environment and the relative risk among alternatives. As was estimated in the original report, the pipe-in-pipe system with a 7 foot depth of cover has a risk which is about 6 times less the risk of the single wall pipeline system. The pipe-in-HDPE system has a level of risk comparable to the single wall steel pipeline. The risk associated with the flexible pipe is approximately 7 times greater than the single wall pipeline. However, these values assume the integrity of the outer pipes of the pipe-in-pipe or the pipe-in-HDPE system is not lost over time (even though they cannot be inspected).

TABLE A1-3: RISK (BARRELS) OF OIL SPILLED INTO THE ENVIRONMENT FOR DIFFERENT ALTERNATIVES

Alternatives	Single Wall	Pipe-in-Pipe	Pipe-in-HDPE	Flexible Pipe
Risk (bbls)	2.1×10^{-3}	3.4×10^{-4}	1.7×10^{-3}	1.4×10^{-2}
Relative Risk	1	0.16	0.81	6.67

This Addendum also identified both benefits and drawbacks of using a pipe-in-pipe or pipe-in-HDPE system for secondary containment. These are summarized below.

<u>Benefits</u>

- The pipe-in-pipe and pipe-in-HDPE alternative could contain the oil released under certain circumstances for certain types of small to medium sized leaks (e.g., inner pipe corrosion but no outer pipe corrosion).
- For other types of small to medium sized leaks, the outer pipe may reduce the amount of oil spilled into the environment. For the pipe-in-pipe and pipe-in-HDPE this amount may be reduced to 25 and 62.5 barrels respectively for certain events (e.g., ice keel gouging).

<u>Drawbacks</u>

- The pipe-in-pipe and pipe-in-HDPE systems are designed with an overall system reliability to meet acceptable levels of risk. However, the condition of the outer pipe of the system cannot be monitored or inspected and is therefore unknown. If the integrity of any one component of that system is not known, the integrity of the system as a whole is not known.
- INTEC concurs with the suggestion by both the MMS and SES in the SES Draft Final Report (p. 18 and p. 19) that the outer casing would probably fail and that the inner pipe should be designed as if there were no outer casing.
- The cathodic protection (CP) system performance on the inner pipe of the pipe-in-pipe system cannot be monitored. CFR 49 states that “a test procedure must be developed to determine whether adequate cathodic protection has been achieved”. This test procedure would be based on design conditions rather than direct field verification.

- If there were a leak in the outer pipe, a significant amount of water could end up in the annulus. This water could potentially travel 1000's of feet in the annulus. SES, in their Draft Final Report, suggests that corrosion could begin in the annulus prior to repair and drying. Therefore, a significant part of the pipeline length could be damaged due to corrosion (1000's of feet) and the system could not be returned to full integrity without replacing that segment of pipeline.
- A repair to the pipe-in-pipe system would return the pipe to near its original integrity but not necessarily all the way to its original integrity depending on the repair method used.
- The capital cost will be greater for pipe-in-pipe and pipe-in-HDPE alternatives.
- Both the pipe-in-pipe and pipe-in-HDPE are relatively more difficult to construct than a single wall steel pipeline. During construction, there are issues such as excluding moisture from the annulus. The complexity of the system will also affect the construction schedule.
- The cost and complexity of repairs to a pipe-in-pipe or pipe-in-HDPE system would be greater than those for a single wall steel pipeline.
- If there were ever a leak of oil into the annulus, cleanup and removal of that oil would be difficult because the oil would likely have spread over a significant length of the annulus. Residual oil in the annulus may impair the leak detection system.

A1.3 Conclusions

The different configurations and construction programs investigated for the alternatives have different implications on the costs, risk assessment, and schedule. Table A1-4 presents conclusions from this Addendum. Although the pipeline depth of burial has been set equal for all the pipeline alternatives, normal design practice would seek to reduce this aspect. Reducing cover reduces construction time, reduces construction risk, reduces cost, makes repair easier if necessary, and in some cases reduces pipeline loading.

As pointed out in the original report, there are additional construction issues with a pipe-in-pipe and pipe-in-HDPE alternative such as additional welding and excluding moisture from the annulus. In this Addendum, a single season construction scenario has been assumed for these alternatives. Since the release of the original report (November 1999), the Northstar pipelines have been constructed and installed. Even through a single season construction has been presented here for these alternatives, lessons learned from the Northstar construction suggest there still would be significant risk associated with the ability to complete the construction and installation of either of these two design alternatives in a single season. Recent North Slope construction experience with the Northstar pipelines indicates that the pipelines were completed approximately 2 weeks prior to an anticipated end of construction cut-off date for the Liberty pipeline.

The pipe-in-pipe and pipe-in HDPE alternatives could contain or retard the amount of oil released to the environment under certain circumstances. However, the overall integrity of a pipe-in-pipe or pipe-in-HDPE system will not be known over the project life and it has been suggested by external reviewers that the outer steel casing of a pipe-in-pipe system will fail and that the inner pipe should be designed as if there were no outer casing. Therefore, any containment effectiveness of a pipe-in-pipe or pipe-in-HDPE system is conjecture.

TABLE A1-4: ADDENDUM CONCLUSIONS

Scenario	Comments	Preferred Alternatives
Variable Cover Depths Original Construction Scenarios (Original Report)	The single wall steel pipeline was found to have the lowest risk of damage, lowest cost, and one of the highest probabilities of being completed in a single season. It was considered to be the best alternatives for this application.	Single Wall Steel Pipeline
7 Foot Cover Depth Original Construction Scenarios	Increasing the burial depth to 7 feet for all the original system alternatives results in the single wall steel pipeline being the preferred alternative. Although there is a slightly lower risk associated with the pipe-in-pipe and pipe-in-HDPE options (Table A2-24), there are significant differences in costs. This lower risk only applies if the integrity of the outer pipe is known to be adequate. However, the integrity of the outer pipes can not be monitored.	Single Wall Steel Pipeline
Original Cover Depth Single Season Construction	Forcing all the original alternatives to a single season construction results in the single wall steel pipeline being the preferred alternative. Both costs and risks (see original report) associated with this alternative are lower.	Single Wall Steel Pipeline
7 Foot Cover Depth Single Season Construction	Increasing the burial depth to 7 feet for all the original system alternatives and forcing a single construction season results in the single wall steel pipeline being the preferred alternative. Although there is a slightly lower risk associated with the pipe-in-pipe and pipe-in-HDPE options (Table A2-24), there are significant differences in costs. This lower risk only applies if the integrity of the outer pipe is known to be adequate. However, the integrity of the outer pipes can not be monitored.	Single Wall Steel Pipeline

A2. IMPLICATIONS OF THE SAME BURIAL DEPTH FOR ALL PIPELINE ALTERNATIVES

A2.1 Introduction

This section of the Addendum is provided in response to concerns about the impacts of optimizing the burial depth for each concept in the original report. Key aspects of the original report have been revisited, keeping the depth of cover constant at 7 feet for all the concepts. This will permit a comparison of key aspects of the designs at constant cover depth.

It should be noted that by making the depth of cover for all other pipeline system alternatives the same as for the deepest case, the system designs become somewhat arbitrary. For this reason, the original report evaluated the pipeline system alternatives based on their individual design requirements

A comment has also been made by Stress Engineering (the nominated 3rd party technical reviewer) that the inner pipe of the pipe-in-pipe concept should have been the same diameter and wall thickness as the single wall steel pipeline. However, Stress Engineering acknowledges that this effect is minor in comparison to the effect of burial depth. This is addressed in Section 2.3. It is noted that pipeline system concepts were selected based on agency input.

Trenching requirements, environmental loading, construction methodology, costs, OMR (operations, maintenance, and repair), and leak detection issues have been re-evaluated. Accordingly, the different failure assessments for each alternative have been reviewed.

A2.2 Single Wall Steel Pipeline

A2.2.1 Structural Design

A2.2.1.1 Pipeline Configuration

The optimized single wall steel pipeline option described in detail in Chapter 4 of the original report had a depth of cover of 7 feet. Principal pipeline characteristics are summarized below in Table A2-1. This information is repeated here to compare with the other options.

TABLE A2-1: PIPELINE CHARACTERISTICS FOR THE SINGLE WALL STEEL PIPELINE ALTERNATIVE

Pipe OD (in)	12.75
Wall Thickness (in)	0.688
Empty Weight in Air (lb/ft)	90.18
Empty Submerged Weight (lb/ft)	32.72
Empty Pipe SG (w.r.t. Seawater)	1.57

Note: Pipeline weight includes nominal steel weight, FBE coating, and anodes.

A2.2.1.2 Ice Keel Gouging

Ice keel gouging was addressed in detail in Chapter 4 of the original report. The ice keel loading is characterized by an extreme event ice keel design depth of 3.0 feet. As indicated in the original report, the 3.0 foot deep 30 foot wide gouge is the loading event that imposes the greatest strain for a 7 foot depth of cover. The resulting soil transverse displacement at a depth of 7.5 feet (as measured from the original seabed surface to the pipe centerline) is estimated to be 2.35 feet. The corresponding pipeline strains are summarized below in Table A2-2. All imposed strains are within allowable values.

TABLE A2-2: MAXIMUM STRAINS IN SINGLE WALL STEEL PIPELINE FOR EXTREME ICE KEEL EVENTS

Ice Keel Depth (ft)	Ice Keel Width (ft)	Tensile Strain (%)	Compressive Strain (%)
3.0	30	0.29	1.08
3.0	40	0.19	0.70
3.0	50	0.19	0.69
3.0	60	0.20	0.73
Allowable Strains (%)		1.80	3.50

A2.2.1.3 Upheaval Buckling

Upheaval buckling was addressed in detail in the original report. For a “1.5 foot prop height” (describes the design pipeline variation in vertical configuration over a length of ≈ 200 feet). the native backfill thickness required to prevent upheaval buckling is about 7.5 feet. This is an excessive backfill thickness, given a depth of cover of 7 feet. By using gravel backfill with a submerged density of 60 pcf, a backfill thickness of 5.4 feet is sufficient to prevent upheaval buckling. Another acceptable option is a combination of a one foot thick layer of gravel mats and a 5-foot layer of native material completing the trench backfill.

A2.2.1.4 Thaw Settlement

Thaw settlement was addressed in Chapter 4 of the original report. The design thaw settlement for the single wall steel pipeline is one foot and since the maximum differential thaw settlement value of one foot is considerably smaller than soil displacements resulting from ice keel scour, the resulting pipeline strains are expected to be smaller. Therefore, the resulting thaw settlement induced strains are believed to remain well within allowable strain levels.

A2.2.1.5 Strudel Scour

Strudel scour was addressed in detail in the original report. For the small pipeline span expected for this load condition, the resulting pipeline stresses will be below the allowable stress level.

A2.2.2 Construction Methodology

The most suitable methodology for installing the single wall steel pipeline for the Liberty Development is a winter construction program of conventional excavation equipment and off-ice pipe installation techniques as described in Section 4.4 of the original report.

A2.2.3 Trenching and Backfilling

The minimum depth of cover for the single wall steel pipeline is 7 feet, as presented in the original report. The target trench depth is approximately 2 feet deeper than required to ensure that the minimum depth is achieved. This implies a total trench depth of 10.5 feet (to the next nearest 0.5 foot increment). The trench has a proposed bottom width of 10 feet. Estimated trenching volumes are summarized in Table A2-3.

TABLE A2-3: TRENCHING QUANTITIES

Water Depth (feet)	Trench Length (feet)	Trench Depth (feet)	Volume (yd^3)
0 - 8	14,877	10.5	179,075
8 - 18	12,473	10.5	201,416
18 - 22	4,964	10.5	80,160
		Total	**460,651**

Trench excavation will require 3 trenching spreads, each working two shifts of 11.5 hrs. The rate of progress for each spread and days to complete each area are summarized in Table A2-4.

As described in Section 4.5.2.7 of the original report, gravel bags 1 foot thick on 25% of the pipeline are estimated to be required to prevent upheaval buckling, while the remaining depth and length is backfilled with native soil.

TABLE A2-4: TRENCHING RATE OF PROGRESS

Water Depth (feet)	Trench Length (feet)	Volume (yd^3)	Productivity (%)	Rate of Progress for Each Spread (ft/hr)	Number of Spreads	Time for Activity (Days)
0 - 8	14,877	179,075	85	40	2	10
8 - 18	12,473	201,416	75	20	2	19
18 - 22	4,964	80,160	75	5	3	20
				Total		**49**

A2.2.4 Cost Estimate Summary

Components of the cost estimate for the single wall steel pipeline were presented in Section 4.5 of the original report. The different activities associated with the construction of the Liberty offshore pipeline for the single wall steel pipeline alternative are presented in Table A2-5. Activities, quantities, and progress rates are shown together with the estimated cost for this option and are unchanged with respect to those presented in Section 4.5 of the original report.

A2.2.5 Operations, Maintenance, and Repair

The operations, Maintenance, and repair procedures are as described in Section 4.6 and Section 4.7 of the original report.

A2.2.6 Leak Detection

Leak detection strategies for the single wall steel pipeline were presented in Section 4.8 of the original report.

A2.2.7 Failure Assessment

The failure analysis for the single wall steel pipeline is fully described in Section 4.9 of the original report. The principal results are summarized in Tables A2-6 and A2-7.

Estimated oil spill volumes for each damage category remains unchanged. Cleanup strategies remain the same.

TABLE A2-5: CONCEPTUAL COST ESTIMATE FOR THE SINGLE WALL STEEL PIPELINE ALTERNATIVE – 7 FOOT DEPTH OF COVER

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	1,020	3.06
Ice Thickening and Road Construction & Maintenance	2.5 inches/day	1	32,314 feet	47	84	3.95
Ice Cutting and Slotting	1,000 feet/day	3	32,314 feet	11	29	0.96
Trenching	0 - 8 feet WD 40 feet/hour/backhoe	2	179,075 cubic yards	10	60	7.08
	8 - 18 feet WD 20 feet/hour/backhoe	2	201,416 cubic yards	19		
	18 - 22 feet WD 5 feet/hour/backhoe	3	80,160 cubic yards	20		
Pipeline Make-Up Site Preparation	11,260 square yards/day	1	416,500 cubic yards	37	41	1.52
Pipe String Make-Up (Welding)	50 welds/day	1	808 welds	17	140	2.38
Pipe String Transportation	0.9 miles/day	1	11 pipeline strings	8	78	0.62
Pipe String Field Joint	50 welds/day	1	11 welds	10	31	0.31
Pipeline Installation	1,700 feet/day	1	32,314 feet	35	43	1.51
Backfilling	1,700 feet/day	1	32,314 feet	36	42	1.51
Hydrostatic Testing		1		5	84	0.42
Demobilization	Lump Sum			2	1,020	2.04
Material Cost and Transportation	Lump Sum					3.10
Contingency	10%					2.85
					Total	**31**

TABLE A2-6: INITIATING EVENTS AND RESULTING DAMAGE FREQUENCIES PER CATEGORY - SINGLE WALL STEEL PIPELINE ALTERNATIVE

Underlying Main Cause For Initiating Event	Initiating Event	Estimated Damage Frequency (Occurrences Per Project Lifetime)			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	10^{-4}	10^{-6}	10^{-7}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-4}	10^{-6}	10^{-8}
	Strudel Scour	10^{-3}	10^{-5}	10^{-7}	10^{-8}
Pipeline Failure	Upheaval Buckling	10^{-2}	10^{-3}	10^{-5}	10^{-7}
	Internal Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Internal Corrosion	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Corrosion	10^{-8}	10^{-8}	10^{-6}	10^{-8}
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		**3.1×10^{-2}**	**1.2×10^{-3}**	**1.3×10^{-5}**	**$3.0 \times 10^{-7*}$**

Note: * Indicates this value has been changed as compared to the original report.

TABLE A2-7: DAMAGE CATEGORIES, ASSOCIATED SPILL VOLUMES, AND FREQUENCY OF DAMAGE PREDICTIONS - SINGLE WALL STEEL PIPELINE ALTERNATIVE

Damage Category	Estimated Oil Spill Volume(bbls)	Estimated Damage Frequency During Project Life
1	0	3.1×10^{-2}
2	0	1.2×10^{-3}
3	125	1.3×10^{-5}
4	1,576	3.0×10^{-7}

A2.3 Pipe-in- pipe

A2.3.1 Structural Design

A2.3.1.1 Pipeline Configuration

The conceptual design selected in Chapter 5 of the original report was sub-alternative B at a 5 foot depth of cover. As mentioned in Section A2.1, Stress Engineering has commented that the inner pipe of the chosen sub-alternative is thinner than the single wall pipe. Therefore, in response, the configuration chosen for further investigation here is the other sub-alternative, sub-alternative A, with structural bulkheads at either end of the line and spacers at regular intervals along its length. Table A2-8 presents the main pipeline characteristics.

TABLE A2-8: PIPELINE CHARACTERISTICS FOR THE PIPE-IN-PIPE ALTERNATIVE

Inner Pipe O.D. (in)	12.75
Inner Pipe Wall Thickness (in)	0.688
Outer Pipe OD (in)	16.00
Outer Pipe Wall Thickness (in)	0.500
Empty Weight in Air (lb/ft)	178
Empty Submerged Weight (lb/ft)	83
Empty Pipe SG (w.r.t. Seawater)	1.87

Note: Pipeline weight includes nominal steel weight, FBE coating, and anodes.

A2.3.1.2 Ice Keel Gouging

Ice keel gouging was addressed in detail in the original report. Again, the ice keel loading is characterized by an extreme ice keel event design depth of 3 feet. As indicated in the original report, the 3.0 foot deep, 40 foot wide gouge is the loading event that imposes the greatest strain for a 7 foot depth of cover. The corresponding pipeline strains are summarized below in Table A2-9; all are within allowable values.

TABLE A2-9: MAXIMUM STRAINS IN A PIPE-IN-PIPE SYSTEM FOR EXTREME ICE KEEL EVENTS

Ice Gouge Dimensions		Outer Pipe Strains (D/t = 32)		Inner Pipe Strains (D/t = 18.5)	
Depth (ft)	Width (ft)	Max. Tensile Strain (%)	Max. Compressive Strain (%)	Max. Tensile Strain (%)	Max. Compressive Strain (%)
3.0	30	0.27	0.71	0.22	0.57
3.0	40	0.32	0.79	0.26	0.63
3.0	50	0.21	0.51	0.17	0.41
3.0	60	0.20	0.49	0.16	0.39
Allowable Strains (%)		1.80	1.70	1.80	3.50

A2.3.1.3 Upheaval Buckling

Upheaval buckling was addressed in detail in the original report. For a 1.5 foot prop height, the native backfill thickness required to prevent upheaval buckling is approximately 3.6 feet. A cover of 7 feet can resist an upheaval buckle for a prop height in excess of 2.2 feet. No gravel bags will be required and hence back filling operations will be simpler and faster.

The pipe-in-pipe is stiffer than the single wall steel pipeline. Consequently, during installation, the pipe system requires a longer length to touchdown. Therefore, the pipe-in-pipe is slightly more susceptible to trench collapse and accordingly larger vertical imperfections.

A2.3.1.4 Thaw Settlement

The thaw settlement for the pipe-in-pipe was addressed in Chapter 5 of the original report. The estimated thaw settlement due to the cooler outer jacket pipe is 0.37 feet and is considerably smaller than soil displacements resulting from ice keel gouging. Therefore, the resulting thaw settlement induced strains are believed to remain well within allowable strain levels.

A2.3.1.5 Strudel Scour

Strudel scour was addressed in detail in the original report. For the small pipeline span expected for this load condition, the resulting pipeline stresses will be below the allowable stress level.

A2.3.2 Construction Methodology

The most suitable methodology for installing the pipe-in-pipe system is by using conventional excavation equipment and off-ice pipe installation techniques as described in Section 5.4 of the original report. This construction method would not be affected by the greater burial depth.

A2.3.3 Trenching and Backfilling

The minimum depth of cover has changed from the 5 feet proposed in the original report to 7 feet. The target trench depth is 2 feet deeper than required to ensure that the minimum depth is achieved. This implies a total trench depth of 10.5 feet (to the next nearest 0.5 foot) which is the same as for the single wall steel pipeline. The trench has a proposed bottom width of 10 feet. Therefore, excavation quantities, rates and costs are the same as for the single pipe. All excavated material will be backfilled and no additional requirements such as gravel are required.

A2.3.4 Cost Estimate Summary

Components of the cost estimate for the pipe-in-pipe alternative were presented in Section 5.5 of the original report. The different activities associated with the construction of the Liberty offshore pipeline for the pipe-in-pipe alternative are presented in Table A2-10. Activities, quantities and progression rates are shown together with the estimated cost for this option. The differences compared to the original report are the increased costs for trenching and backfilling as well as the related contingencies. The trenching costs are the same as those for the single pipe, while the backfilling costs are slightly lower than those for the single wall steel pipeline since no gravel bags are required. Material and transportation costs have decreased due to the reduced weight of sub-alternative A.

A contingency has been added for a 2nd season of construction for this alternative as there is low confidence that the pipeline would be installed in a single season. Single season construction is addressed further in Chapters A3 and A4 of this Addendum. The 2nd season contingency is calculated using the following formula:

$$\text{2}^{nd}\text{ Season Contingency} = \sum \text{costs for (mobilization) + (ice thickening and road construction and maintenance) + (ice cutting and slotting) + (trenching) + (pipeline installation) + (backfilling) + (demobilization)} \times \text{Likelihood of 2}^{nd}\text{ season construction}$$

TABLE A2-10: CONCEPTUAL COST ESTIMATE FOR THE PIPE-IN-PIPE ALTERNATIVE – 7 FOOT DEPTH OF COVER

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	1240	3.72
Ice Thickening and Road Construction & Maintenance	2.5 inches/day	1	32,314 feet	56	84	4.70
Ice Cutting and Slotting	800 feet/day	3	32,314 feet	14	29	1.22
Trenching	0 - 8 feet WD 40 feet/hour/backhoe	2	179,075 cubic yards	10	60	***7.08***
	8 - 18 feet WD 20 feet/hour/backhoe	2	201,416 cubic yards	19		
	18 - 22 feet WD 5 feet/hour/backhoe	3	80,160 cubic yards	20		
Pipe-in-Pipe Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55	2.59
Pipe-in-Pipe String Make-Up (Welding)	50 welds/day for 12.75-in P/L 38 welds/day for 16-in P/L	1	1616 welds	48	240	11.52
Pipe-in-Pipe String Transportation	0.6 miles/day	1	33 pipeline strings	10	78	0.78
Pipe-in-Pipe String Field Joint	2 welds/day	1	66 welds	33	60	1.02
Pipeline Installation		1	32,314 feet	29	88	2.55
Backfilling		1	32,314 feet	33	42	***1.39***
Hydrostatic Testing		1		5	84	0.42
Demobilization	Lump Sum			2	1240*	2.48
Material Cost and Transportation	Lump Sum					***4.00***
Contingency	10%					***4.35***
	Additional cost for 2nd season					***18.5***
					Total	**66**

Notes: * Indicates this value has been changed as compared to the original report.
Bold italic numbers indicate a variation to the original costs.

which, for the pipe-in-pipe alternative, translates into a 2nd season contingency of $18.5 million for the assumed likelihood of 80%.

A2.3.5 Operations, Maintenance, and Repair

The operations, maintenance, and repair were described in Section 5.6 and Section 5.7 of the original report. Given the increased burial depth of the pipe-in-pipe system, additional backfill would need to be removed for repair. The amounts for the different repair techniques would be expected to be similar to or greater than those presented for the single wall steel pipeline.

A2.3.6 Leak Detection

Leak detection strategies for the pipe-in-pipe alternative were presented in Section 5.8 of the original report. Additional discussion on annular leak detection is presented in Chapter A5 of this Addendum.

A2.3.7 Failure Assessment

The failure analysis process for the pipe-in-pipe alternative is fully described in Section 5.9 of the original report. This assessment has been reviewed due to the additional depth of cover over the pipe-in-pipe system. The likelihood of each initial event which has been reassessed is presented below. If the initiating event is not discussed, estimated frequencies for the damage categories have not changed. Initiating event categories are as per the original report. The risk results are rounded within an order of magnitude. Results are summarized in Table A2-11 and A2-12.

The estimated oil spill volume for a pipe-in-pipe system for Category 3 damage has been reduced to 25 barrels. The rationale behind this reduction is presented in Chapter A5 of this Addendum. Cleanup strategies remain unchanged. However, the deeper burial depth may result in the removal of additional contaminated soil in the event of a leak in both the inner and outer pipes.

A2.3.7.1 Seabed Ice Gouging, Initiating Event 11

Category 1 damage occurs when the pipeline is displaced. The ice keel deforms the soil which in turn displaces the pipeline. This is assumed to occur at the design gouge depth (3.0 feet).

TABLE A2-11: INITIATING EVENTS AND RESULTING DAMAGE FREQUENCIES PER CATEGORY – PIPE-IN-PIPE ALTERNATIVE

Underlying Main Cause For Initiating Event	Initiating Event	Estimated Damage Frequency (Occurrences Per Project Lifetime)			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	10^{-4}	10^{-7}	10^{-7}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-5}	10^{-7}	10^{-8}
	Strudel Scour	10^{-3}	10^{-6}	10^{-8}	10^{-8}
Pipeline Failure	Upheaval Buckling	10^{-3}	10^{-5}	10^{-8}	10^{-8}
	Internal Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Inner Pipe Corrosion	10^{-8}	10^{-8}	10^{-4}	10^{-8}
	Outer Pipe Corrosion	10^{-8}	10^{-8}	10^{-4}	10^{-8}
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		**2.2×10^{-2}**	**1.2×10^{-4}**	**2.0×10^{-4}**	**2.1×10^{-7}**

TABLE A2-12: DAMAGE CATEGORIES, ASSOCIATED SPILL VOLUMES, AND FREQUENCY OF DAMAGE PREDICTIONS - PIPE-IN-PIPE ALTERNATIVE

Damage Category	Estimated Oil Spill Volume(bbls)	Estimated Damage Frequency During Project Life
1	0	2.2×10^{-2}
2	0	1.2×10^{-4}
3[1]	125	1.0×10^{-4}
3[2]	0	1.0×10^{-4}
3[3]	25	2.8×10^{-7}
4	1,576	2.1×10^{-7}

Notes: [1] Damage caused by corrosion of inner carrier pipe. Oil is contained by the outer jacket pipe.
[2] Damage caused by corrosion of outer pipe resulting in the ingress of seawater to the annulus.
[3] Damage caused initiating events resulting in release of oil to the environment.

Category 2 damage and Category 3 damage was assumed to occur for the single wall steel pipeline at an ice keel gouge depth of 4 feet. The stiffness of the pipe-in-pipe system is approximately 2.5 times greater than the single wall steel pipe. However, the larger OD (approximately 1.25 times larger) results in more load being transferred to the pipeline system. The assumed effect is that a 4.5 foot deep gouge would be required to cause Category 2 and Category 3 damage to the pipe-in-pipe sub-alternative A.

Category 4 damage, however unlikely, would occur only if the ice keel contacts the pipeline. In this case, it is assumed that the ice keel incision depth would need to reach the pipeline centerline.

A2.3.7.2 Subsea Permafrost Thaw Subsidence, Initiating Event 12

The estimated damage frequencies for the pipe-in-pipe system (sub-alternative A) due to subsea permafrost thaw subsidence are assumed not to change from the values originally presented for sub-alternative B. For Category 2 and Category 3 damage, the estimated damage frequencies are less than those for the single wall steel pipeline. This would be anticipated given the fact that although the OD of the pipe-in-pipe would carry more load, the stiffness of the currently proposed pipe-in-pipe more than compensates for the additional load.

A2.3.7.3 Strudel Scour, Initiating Event 13

The estimated damage frequency due to strudel scour is assumed to drop an order of magnitude for the Category 2 and Category 3 damage as compared to the values originally presented for pipe-in-pipe sub-alternative B. While the stiffness of the sub-alternative system is somewhat decreased, the slightly deeper cover tends to decrease the probability of loading.

A2.3.7.4 Upheaval Buckling, Initiating Event 14

This initiating event is less likely to happen for this pipe-in-pipe system compared to the single wall steel pipeline alternative. The vertical resistance that can be generated by the larger pipe diameter moving through the backfill is larger. Also, there is a reduction in the locked-in axial compressive force and, hence, a reduction in driving force. The estimated damage frequencies for the pipe-in-pipe are assumed not to change from the values originally presented for pipe-in-pipe sub-alternative B. Although the overall stiffness of the pipe-in-pipe system has decreased somewhat, the cover depth has increased. This is due to the fact that the original backfill thickness was in excess of what is required to prevent upheaval buckling.

A2.4 Pipe-in-HDPE

A2.4.1 Structural Design

A2.4.1.1 Pipeline Configuration

The conceptual design selected in Chapter 6 was sub-alternative B at a 6 foot depth of cover. In this sub-alternative, the annulus is empty and the inner pipeline rests directly on the outer HDPE sleeve. Table A2-13 presents the main pipeline characteristics.

TABLE A2-13: PIPELINE CHARACTERISTICS FOR THE PIPE-IN-HDPE ALTERNATIVE

Inner Pipe O.D. (in)	12.75
Inner Pipe Wall Thickness (in)	0.688
Outer HDPE Pipe OD (in)	16.25
Outer Pipe Wall Thickness (in)	0.75
Empty Weight in Air (lb/ft)	103.93
Empty Submerged Weight (lb/ft)	11.75
Empty Pipe SG (w.r.t. Seawater)	1.13

Note: Pipeline weight includes nominal steel weight and outer sleeve.

A2.4.1.2 Ice Keel Gouging

Ice keel gouging was addressed in detail in the original report. Again, the ice keel loading is characterized by an extreme ice keel event design depth of 3 feet. As described in Section 6.2 of the original report, the 3 feet deep, 30 foot wide gouge is the loading event that imposes the greatest strain for a 7 foot depth of cover. The corresponding inner pipeline strains are summarized Table A2-14 all are within the allowable values.

TABLE: A2-14: MAXIMUM STRAINS IN A PIPE-IN-HDPE SYSTEM FOR EXTREME ICE KEEL EVENTS

Ice Keel Depth (ft)	Ice Keel Width (ft)	Tensile Strain (%)	Compressive Strain (%)
3.0	30	0.77	0.80
3.0	40	0.46	0.48
3.0	50	0.44	0.47
3.0	60	0.48	0.50
Allowable Strains (%)		1.80	3.50

A2.4.1.3 Upheaval Buckling

Upheaval buckling was addressed in detail in the original report. For a 1.5 foot prop height, the native backfill thickness required to prevent upheaval buckling is about 5.8 feet. Therefore, a cover of 7 feet will prevent upheaval buckling and no gravel bags will be required.

A2.4.1.4 Thaw Settlement

The thaw settlement for the pipe-in-HDPE was addressed in Chapter 6 of the original report. The estimated thaw settlement is 0.43 feet and is considerably smaller than soil displacements resulting from ice keel gouging. Therefore, the resulting thaw settlement induced strains are believed to remain well within allowable strain levels.

A2.4.1.5 Strudel Scour

Strudel scour was addressed in detail in the original report. For the small pipeline span expected for this load condition, the resulting pipeline stresses will be below the allowable stress level.

A2.4.2 Construction Methodology

The methodology for installing the pipe-in-HDPE system is by using conventional excavation equipment and off-ice pipe installation techniques as described in

Section 6.4 of the original report. The method would not be affected by the slightly greater burial depth.

A2.4.3 Trenching and Backfilling

The minimum depth of cover has changed from the 6 feet proposed in the original report to 7 feet. The target trench depth is 2 feet deeper than required to ensure that the minimum depth is achieved. This implies a total trench depth of 10.5 feet (to the next nearest 0.5 foot increment) which is the same as for the single wall steel pipeline. The trench has a proposed bottom width of 10 feet. Therefore, excavation quantities, rates, and costs are the same as for the wall single pipeline. During backfilling gravel mounds every 100 feet are required for stability, and these require careful placement with backhoes. The remaining trench is backfilled with native soil.

A2.4.4 Cost Estimate Summary

Components of the cost estimate for the pipe-in-HDPE alternative were presented in Section 6.5 of the original report. The different activities associated with the construction of the Liberty offshore pipeline for the pipe-in-HDPE option are presented in Table A2-15. Activities, quantities, and progression rates are shown together with the estimated cost for this option. The differences compared to the original report are the increased costs for trenching and backfilling as well as the related contingencies. Backfilling costs are slightly higher due to gravel dumping required for the stability of the line during installation.

The contingency added for a 2nd season of construction for this alternative was calculated in the same manner as for the pipe-in-pipe in Section A2.3.5. This works out to $12.6 million for the assumed likelihood of 60%. The trenching costs are the same as those for the single pipe.

A2.4.5 Operations, Maintenance, and Repair

The operations, maintenance, and repair procedures were described in Sections 6.6 and 6.7 of the original report. Given the increased burial depth of the pipe-in-HDPE system, additional backfill would need to be removed for repair. The amounts for the different repair techniques would be expected to be similar to those presented for the single wall steel pipeline.

TABLE A2-15: CONCEPTUAL COST ESTIMATE FOR THE PIPE-IN-HDPE ALTERNATIVE - 7 FOOT DEPTH OF COVER

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization		Lump Sum		3	1144	3.43
Ice Thickening and Road Construction & Maintenance	2.5 inches /day	1	32,314 feet	47	84	3.95
Ice Cutting and Slotting	1,000 feet/day	3	32,314 feet	11	29	0.96
Trenching	0 - 8 ft WD 40 feet/hour/backhoe	2	179,075 cubic yards	10	60	***7.08***
	8 - 18 feet WD 20 feet/hour/backhoe	2	201,416 cubic yards	19		
	18 - 22 feet WD 5 feet/hour/backhoe	3	80,160 cubic yards	20		
Pipe Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55	2.59
Pipe-String Make-Up (Welding)	1) 50 welds/day for 12.75-in P/L 2) HDPE pipe 50 butts/day	1	1) 808 welds 2) 808 connect	34	220	7.48
Pipe String Transportation	0.8 miles/day	1	33 pipeline strings	10	78	0.78
Pipe String Field Joint	1.5 complete tie-in/day	1	66 welds	22	31	0.68
Pipeline Installation		1	32,314 feet	37	43	1.59
Backfilling		1	32,314 feet	46	42	***1.93***
Hydrostatic Testing		1		5	84	0.42
Demobilization		Lump Sum		2	1144	2.29
Material Cost and Transportation						3.33
Contingency	10%					***3.65***
	Additional cost for 2nd season					***12.74****
					Total	**53**

Notes: * Indicates this value has been changed as compared to original report.
Bold italic numbers indicate a variation to the original costs.

A2.4.6 Leak Detection

Leak detection strategies for the pipe-in-HDPE alternative were presented in Section 6.8 of the original report. Additional discussion on annular leak detection is presented in Chapter A5 of this Addendum.

A2.4.7 Failure Assessment

The failure analysis process for the pipe-in-HDPE alternative is fully described in Section 6.9 of the original report. This assessment has been reviewed due to the additional depth of cover over the pipe-in-HDPE system. The likelihood of each initiating event which has been reassessed, is presented below. If the initiating event is not discussed, estimated frequencies for the damage categories have not changed. Results are summarized in Tables A2-16 and A2-17.

The estimated oil spill volume for a pipe-in-HDPE system for Category 3 damage has been reduced to 62.5 barrels. The rationale behind this reduction is presented in Chapter A5 of this Addendum. Cleanup strategies remain unchanged. However, the deeper burial depth may result in the removal of additional contaminated soil in the event of a leak in both the inner and outer pipes.

A2.4.7.1 Seabed Ice Gouging, Initiating Event I1

The estimated damage frequencies due to ice gouging are assumed to be an order of magnitude larger for the Category 2 and Category 3 damage as compared to the single wall steel pipeline. This is due to the fact that the larger OD of the HDPE sleeve will result in more load being transferred to the pipeline system but the sleeve is not assumed to contribute to the strength of the system.

A2.4.7.2 Subsea Permafrost Thaw Subsidence, Initiating Event I2

The estimated damage frequencies due to subsea permafrost thaw subsidence are assumed to be an order of magnitude larger for the Category 2 and Category 3 damage as compared to the single wall steel pipeline. This is due to the fact that the larger OD of the HDPE sleeve will result in more load being transferred to the pipeline system as the soil thaws and settles but the sleeve is not assumed to contribute to the strength of the system.

TABLE A2-16: INITIATING EVENTS AND RESULTING DAMAGE FREQUENCIES PER CATEGORY – PIPE-IN-HDPE ALTERNATIVE

Underlying Main Cause For Initiating Event	Initiating Event	Estimated Damage Frequency			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	10^{-3}	10^{-5}	10^{-7}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-3}	10^{-5}	10^{-8}
	Strudel Scour	10^{-3}	10^{-4}	10^{-6}	10^{-8}
Pipeline Failure	Upheaval Buckling	10^{-3}	10^{-4}	10^{-6}	10^{-8}
	Internal Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Inner Pipe Corrosion	10^{-8}	10^{-8}	10^{-3}	10^{-8}
	Outer Pipe Corrosion	-	-	-	-
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		**2.2×10^{-2}**	**2.2×10^{-3}**	**1.0×10^{-3}**	**2.0×10^{-7}**

TABLE A2-17: DAMAGE CATEGORIES, ASSOCIATED SPILL VOLUMES, AND FREQUENCY OF DAMAGE PREDICTIONS – PIPE-IN-HDPE ALTERNATIVE

Damage Category	Estimated Oil Spill Volume (bbls)	Estimated Damage Frequency During Project Life
1	0	2.2×10^{-2}
2	0	2.2×10^{-3}
3[1]	125	1×10^{-3}
3[2]	62.5	2.2×10^{-5}
4	1,576	2.0×10^{-7}

Notes: [1] Damage caused by internal corrosion of inner carrier pipe. Oil is contained by the outer HDPE pipe.
[2] Damage by initiating events resulting in release of oil to the environment.

A2.4.7.3 Strudel Scour, Initiating Event I3

The estimated damage frequencies due to strudel scour is assumed to increase an order of magnitude for the Category 2 and Category 3 damage as compared to the single wall steel pipeline. This is due to the fact that the larger OD of the HDPE sleeve will result in more hydrodynamic load being transferred to the pipeline system but the sleeve is not assumed to contribute to the overall strength of the system.

A2.4.7.4 Upheaval Buckling, Initiating Event I4

This initiating event is less likely to happen for this pipe system compared to the single wall steel pipeline alternative. The vertical resistance that can be generated by the larger pipe diameter moving through the backfill is greater. Also, there is a reduction in the axial compressive force and, hence, a reduction in driving force. The estimated damage frequency due to upheaval buckling is assumed to decrease an order of magnitude for all categories of damage as compared to the single wall steel pipeline.

A2.5 Flexible Pipe

A2.5.1 Structural Design

A2.5.1.1 Pipeline Configuration

The flexible pipe alternative was described in Section 7.1 and Section 7.2 of the original report where it was originally optimized to a 5 foot depth of cover. Table A2-18 presents the original pipeline characteristics.

TABLE A2-18: PIPELINE CHARACTERISTICS FOR THE FLEXIBLE PIPE ALTERNATIVE

Pipe OD (in)	14.923
Wall Thickness (in)	2.933
Empty Weight in Air (lb/ft)	84.4
Empty Submerged Weight (lb/ft)	6.6
Empty Pipe SG (w.r.t. Seawater)	1.1

A2.5.1.2 Ice Keel Gouging

Ice keel gouging was addressed in Section 7.2 of the original report. The effects of soil displacements due to ice keel gouging would need to be verified for the end fittings; the flexible pipe itself should be able to accommodate the soil displacements.

A2.5.1.3 Upheaval Buckling

Upheaval buckling of the flexible pipe was addressed in Section 7.2 of the original report. Due to the flexible nature of the pipe, only 4 feet of native backfill is estimated to be required to resist upheaval buckling.

A2.5.1.4 Thaw Settlement

Thaw settlement effects on the flexible pipe were discussed in Section 7.2 of the original report. Thaw settlement effects would need to be verified during detailed design if a flexible pipe option was chosen.

A2.5.1.5 Strudel Scour

Strudel scour was addressed in detail in the original report. For the small pipeline span expected for this load condition, the resulting pipeline bending radius is expected to remain within the allowable level.

A2.5.2 Construction Methodology

The most suitable methodology for installing the flexible pipe system is by using conventional excavation equipment and off-ice pipe installation techniques as described in Section 7.4 of the original report. This method would not be affected by the slightly greater burial depth.

A2.5.3 Trenching and Backfilling

The minimum depth of cover has changed from the 5 feet proposed in the original report to 7 feet. The target trench depth is 2 feet deeper than required to ensure that the minimum depth is achieved. This implies a total trench depth of 10.5 feet (to the next nearest 0.5 foot increment) which is the same as for the single wall steel pipeline. The trench has a proposed bottom width of 10 feet. Therefore, excavation quantities, rates, and costs are the same as for the single wall steel pipeline. During backfilling, gravel mounds every 100 feet are required for stability and these must be carefully placed with backhoes. The remaining trench is backfilled with native soil.

A2.5.4 Cost Estimate Summary

Components of the cost estimate for the flexible pipe alternative were presented in Section 7.5 of the original report. The different activities associated with the construction of the Liberty offshore pipeline for the flexible pipe option are presented in Table A2-19. Activities, quantities, and progression rates are shown together with the estimated cost for this option. The differences compared to the original report are the increased costs for trenching and backfilling as well as the related contingencies. The trenching costs are the same as those for the single pipe. Backfilling costs are slightly higher due to gravel dumping required for the stability of the line during the installation.

A2.5.5 Operations, Maintenance, and Repair

The operations, maintenance, and repair procedures were described in Section 6.6 and Section 6.7 of the original report. Given the increased burial depth of the flexible pipe system, additional backfill would need to be removed for repair. The amounts for the different repair techniques would be expected to be similar to those presented for the single wall steel pipeline.

A2.5.6 Leak Detection

Leak detection strategies for the flexible pipe alternative were presented in Section 7.8 of the original report.

A2.5.7 Failure Assessment

The failure analysis process for the flexible pipe alternative is fully described in Section 7.9 of the original report. This assessment has been reviewed due to the additional depth of cover of the flexible pipe system. The likelihood of each initiating event which has been reassessed is presented below. If the initiating event is not discussed, estimated frequencies for the damage categories have not changed. Results are presented in Tables A2-20 and 2-21.

TABLE A2-19: CONCEPTUAL COST ESTIMATE FOR THE FLEXIBLE PIPE ALTERNATIVE – 7 FOOT DEPTH OF COVER

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	910.0	2.73
Ice Thickening and Road Construction & Maintenance	2.5 inches /day	1	32,314 ft	47	84.0	3.95
Ice Cutting and Slotting	1,000 feet/day	3	32,314 ft	11	29.0	0.96
Trenching	0 - 8 ft WD 40 feet/hour/backhoe	2	179,075 cubic yards	10	60.0	***7.08***
	8 - 18 ft WD 20 feet/hour/backhoe	2	201,416 cubic yards	19		
	18 - 22 feet WD 5 feet/hour/backhoe	3	80,160 cubic yards	20		
Spool Site Preparation	11,260 square yards/day	1	416,500 square yards	37	41.0	1.52
Unspool, Flexible Pipe String Transportation	0.9 miles/day	1	6.12 of flexible pipeline	8	78.0	0.62
Flexible Pipe Field Connection	4 welds/day	1	11 welds	9	31.0	0.28
Pipeline Installation(Lowering)		1	32,314 feet	30	43.0	1.12
Backfilling		1	32,314 feet	46	42.0	***1.93***
Hydrostatic Testing		1		5	84.0	0.42
Demobilization	Lump Sum			2	910.0	1.82
Material Cost and Transportation	Lump Sum					13.70
Contingency	10%					***3.61***
					Total	**40**

Note: Bold italic numbers indicate a variation to original cost estimate.

TABLE A2-20: INITIATING EVENTS AND RESULTING DAMAGE FREQUENCIES PER CATEGORY – FLEXIBLE PIPE ALTERNATIVE

Underlying Main Cause For Initiating Event	Initiating Event	Estimated Damage Frequency			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	5×10^{-3}	10^{-4}	10^{-7}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-4}	10^{-6}	10^{-8}
	Strudel Scour	10^{-3}	10^{-5}	10^{-7}	10^{-8}
Pipeline Failure	Upheaval Buckling	10^{-3}	10^{-4}	10^{-6}	10^{-8}
	Internal Pressure	10^{-8}	10^{-8}	10^{-5}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Internal Corrosion	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Corrosion	10^{-8}	10^{-8}	10^{-6}	10^{-8}
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		$\mathbf{2.2 \times 10^{-2}}$	$\mathbf{5.2 \times 10^{-3}}$	$\mathbf{1.1 \times 10^{-4}}$	$\mathbf{2.1 \times 10^{-7}}$

TABLE A2-21: DAMAGE CATEGORIES, ASSOCIATED SPILL VOLUMES, AND FREQUENCY OF DAMAGE PREDICTIONS – FLEXIBLE PIPE ALTERNATIVE

Damage Category	Estimated Oil Spill Volume (bbls)	Estimated Damage Frequency During Project Life
1	0	2.2×10^{-2}
2	0	5.2×10^{-3}
3	125	1.1×10^{-5}
4	1,576	2.1×10^{-7}

Cleanup strategies for the flexible pipe option remain unchanged. However, the deeper burial depth may result in the removal of additional contaminated soil in the event of a leak.

A2.5.7.1 Seabed Ice Gouging, Initiating Event I1

The estimated damage frequencies due to ice gouging for Category 1 and Category 4 damage is assumed to be the same as for the single wall steel pipeline. Following the methodology presented for the flexible pipeline failure assessment in the original report, a 5 foot deep ice gouge over the pipe or a 4 foot deep ice gouge over an end fitting connection is assumed to cause Category 3 damage. The estimated damage frequency for Category 2 damage is assumed to be midway between Category 1 and Category 3 frequencies.

A2.5.7.2 Subsea permafrost Thaw Subsidence, Initiating Event I2

The estimated damage frequencies due to subsea permafrost thaw subsidence are assumed to be the same as presented for the single wall steel pipeline. Although the larger OD of the flexible pipe will result in more load being transferred to the pipeline system as the soil thaws and settles, the flexibility in the pipe can accommodate differential settlement. The two effects are considered to offset each other.

A2.5.7.3 Strudel Scour, Initiating Event I3

The estimated damage frequencies due to strudel scour are assumed to be the same as presented for the single wall steel pipeline. Although the larger OD of the flexible pipe system will result in more hydrodynamic load being transferred to the pipeline system, the flexibility in the pipe accommodates deformation. The two effects are considered to offset each other.

A2.5.7.4 Upheaval Buckling, Initiating Event I4

This initiating event is less likely to happen for this pipe system compared to the single wall steel pipeline alternative due to the nature of the pipe composition. Also, the vertical resistance that can be generated by the larger pipe diameter moving through the backfill is larger. The estimated damage frequency due to upheaval buckling is assumed to decrease an order of magnitude for all categories of damage as compared to the single wall steel pipeline.

A2.6 Summary

A2.6.1 Comparison of Alternatives

Table A2-22 summarizes the main aspects of the pipeline system alternatives based on equal depth of cover and carrier pipe wall thickness (except for the flexible pipe). The systems are compared as per the construction schedules presented in the original report with the pipe-in-pipe and pipe-in HDPE alternatives most likely requiring an additional construction season to complete these more complex construction programs.

A2.6.2 Comparison of Risks and Failure Consequences

Table A2-23 presents, for all four pipeline system alternatives, the estimated damage frequency and the subsequent environmental oil spill in barrels of oil per damage category. As discussed in Chapter A5, the estimated oil spill volumes for Category 3 damage of a pipe-in-pipe and pipe-in HDPE system have been reduced to 25 and 62.5 barrels respectively.

Risk is the product of the damage frequency times the consequence of interest. In this case, oil spilled into the environment. Table A2-24 shows the risk in barrels of oil spilled into the environment for all alternatives and the relative risk between alternatives.

TABLE A2-22: COMPARISON OF PIPELINE ALTERNATIVES FOR A 7 FOOT DEPTH OF COVER

Description	Pipeline Alternative			
	Single Pipe	Pipe-in-Pipe	Pipe-in-HDPE	Flexible Pipe
Configuration				
Inner Carrier Pipe OD x WT (in)	12.75 x 0.688	12.75 x 0.688	12.75 x 0.688	14.92 x 2.93
Outside Pipe OD x WT (in)	-	16 x 0.5	16.25 x 0.75	-
Pipe Specific Gravity	1.6	1.87	1.2	1.1
Depth of Cover (ft)	7	7	7	7
Excavation Volume (1,000 cubic yards)	461	461	461	461
Trenching Duration (days) [1]	33	33	33	33
Gravel Backfill (1,000 cubic yards)	9 (in gravel bags/mats)	0	10 (30 yd^3 every 100 feet)	10 (30 yd^3 every 100 feet)
Number of Welds/Connections	808 welds 11 of the welds are tie-in welds	1616 welds 66 welds are tie-in welds	808 welds 808 fusion 66 connections are tie-ins connections	13 connections 11 of the connections are tie-in connections
Costs				
Budgetary Cost (Million $)	31	66	53	40
Relative Cost (%)	100	213	171	129
Schedule				
Estimated Schedule Basis	Single Winter Season	Single Winter Season	Single Winter Season	Single Winter Season
Likelihood of Requiring an Additional Season (%)	10	80	60	10
Installation				
Ice Thickness (feet)	8.5	10.5	8.5	8.5
Relative Quantity of Construction Equipment per Season (%)	100	120	110*	90

Note: [1] The trenching duration assumes the first section in the shallow water is completed followed by the simultaneous trenching of the other two sections.

* Indicates this value has been changed as compared to original report.

TABLE A2-23: LINE COMPARISON OF OPERATIONAL DAMAGES AND CONSEQUENCES OF FAILURE FOR 7 FOOT DEPTH OF COVER

Alternative	Single Pipe	Pipe-in-Pipe	Pipe-in-HDPE	Flexible Pipe
Category 1 Damage Frequency (Project Life) Environmental Oil Spill Volume (bbls)	3.1×10^{-2} - 0 barrels	2.2×10^{-2} - 0 barrels	2.2×10^{-2} - 0 barrels	2.2×10^{-2} - 0 barrels
Category 2 Damage Frequency (Project Life) Environmental Oil Spill Volume (bbls)	1.2×10^{-3} - 0 barrels	1.2×10^{-4} - 0 barrels	2.2×10^{-3} - 0 barrels	5.2×10^{-3} - 0 barrels
Category 3 Damage Frequency (Project Life) Environmental Oil Spill Volume (bbls)	1.3×10^{-5} - 125 barrels	2.8×10^{-7} [1] - 25 barrels	2.2×10^{-5} [1] - 62.5 barrels	1.1×10^{-4} [1] - 125 barrels
Category 4 Damage Frequency (Project Life) Environmental Oil Spill Volume (bbls)	3.0×10^{-7} - 1,567 barrels	2.1×10^{-7} - 1,567 barrels	2.0×10^{-7} - 1,567 barrels	2.1×10^{-7} - 1,567 barrels

Note: [1] Pipeline failure is by an event causing both inner and outer containment to fail and release oil to the environment.

TABLE A2-24: RISK (BARRELS) OF OIL SPILLED INTO THE ENVIRONMENT FOR DIFFERENT ALTERNATIVES

Alternatives	Single Wall	Pipe-in-Pipe	Pipe-in HDPE	Flexible Pipe
Risk (bbls) [1]	2.1×10^{-3}	3.4×10^{-4}	1.7×10^{-3}	1.4×10^{-2}
Relative Risk [2]	1	0.16	0.81	6.67

Notes: [1] Risk = frequency x consequences, in units of the consequence.
Example: Single wall risk = (1.3×10^{-5}) x 125 bbls + (3×10^{-7}) x 1,567 bbls = 2.1×10^{3} bbls.
[2] Relative risk = system risk divided by single wall pipeline system risk.

A3. IMPLICATIONS OF SINGLE SEASON CONSTRUCTION FOR ALL PIPELINE ALTERNATIVES

A3.1 Introduction

This section compares the alternatives for the case when the construction and installation is completed in one season, while maintaining the pipeline characteristics and variable burial depths as per the original study. New costs are derived for all the alternatives so that a comparison can be made of the effects of forcing a single season construction.

A3.2 Single Wall Steel Pipeline

All parameters are maintained as in the original report (7 foot pipeline cover depth). The confidence level of completing the installation of the pipeline in a single season is high (see Section 4.5.3 in original report and Section A 2.2 of this Addendum). Thus, there is no change in the estimated cost for the single wall steel pipeline at $31 million.

A3.3 Pipe-in-Pipe

A3.3.1 General

The pipeline configuration and construction methods are maintained as described in the original report (5 foot pipeline cover depth). However, the construction schedules and necessary equipment have been revisited to achieve a similar confidence as the single wall steel pipeline that the construction is completed in one season.

A3.3.2 Construction Costs

The critical activities have been reviewed and additional equipment and manning has been allocated to reduce the risk and increase the confidence level in achieving a one-season construction schedule.

A3.3.2.1 Ice Road and Platform Construction

Additional equipment has been allocated to ice thickening, road construction, and maintenance to increase the probability that the ice roads are completed on time (although the schedule could still be affected by weather).

A3.3.2.2 Trenching

The excavation quantities and rates are as presented in Section 5.5.2.4 of the original report. Two additional spreads have been included for the operations in the shallower sections of the pipeline route to avoid unforeseen events that could take place (e.g. repeated slumping of trench) and subsequently delay progress.

A3.3.2.3 Pipe-in-Pipe String Make-up

An additional welding crew has been added to speed up the construction of the pipe strings. At present, it is assumed that one crew will construct the 12 inch inner pipe, while a second crew will assemble the 16 inch outer pipe. The additional crew of qualified welders with relevant equipment would augment the present crews as required, thus speeding up overall production. In the cost summary table (Table A3-1), the increased cost has been incorporated by increasing the number of spreads (and hence activity unit rate) by an estimated 30 to 50% to reflect the increased size of the crew.

A3.3.2.4 Pipe-in-Pipe String Field Joint Operations

As above, additional manning and equipment has been added for this operation.

A3.3.2.5 Backfilling

Additional equipment has been included to enlarge the size of the spread. There would be more backhoes and transport trucks to ensure increased productivity.

A3.3.3 Cost Summary

The cost summary, Table A3-1 below, indicates the changes with respect to the original report. The additional equipment and personnel have been accounted for by increasing the number of spreads (and hence activity unit rate) but maintaining the same duration to carry out the activity.

A3.4 Pipe-in-HDPE

A3.4.1 General

The pipeline configuration and construction methods are maintained as described in the original report (6 foot pipeline cover depth). However, the construction schedules and necessary equipment have been revisited to ensure the construction is completed in one season.

A3.4.2 Construction Costs

The critical activities have been reviewed and additional equipment and manning has been allocated to reduce the risk and increase the confidence level in achieving a one season construction schedule.

TABLE A3-1: CONCEPTUAL COST ESTIMATE
PIPE-IN-PIPE ALTERNATIVE – 5 FOOT COVER DEPTH - SINGLE SEASON INSTALLATION

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	1240	3.72
Ice Thickening and Road Construction + Maintenance	2.5 -inches /day	***1.25***	32,314 feet	56	84	*5.90*
Ice Cutting and Slotting	800 feet/day	3	32,314 feet	14	29	1.22
Trenching	0 - 8 feet WD 40 feet/hour/backhoe	***3***	179,075 cubic yards	8	60	***6.84***
	8 - 18 feet WD 20 feet/hour/backhoe	***3***	201,416 cubic yards	15		
	18 - 22 feet WD 5 feet/hour/backhoe	3	80,160 cubic yards	15		
Pipe-in-Pipe Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55	2.59
Pipe-in-Pipe String Make-Up (Welding)	50 welds/day for 12.75-in P/L 26* welds/day for 16-in P/L	***1.3***	1616 welds	48	240	***14.98***
Pipe-in-Pipe String Transportation	0.6 miles/day	1	33 pipeline strings	10	78	0.78
Pipe-in-Pipe String Field Joint	2 welds/day	***1.5***	66 welds	33	60	*2.97*
Pipeline Installation		1	32,314 feet	29	88	2.55
Backfilling		***1.5***	32,314 feet	30	42	***1.89***
Hydrostatic Testing		1		5	84	0.42
Demobilization	Lump Sum			2	1240*	2.48
Material Cost and Transportation						***4.00***
Contingency	10%					***5.03***
	Additional cost for 2nd season					***0***
					Total	**55**

Notes: * Indicates this value has been changed compared to the original report.
Bold italic numbers indicate a variation to the original costs.

A3.4.2.1 Trenching

The excavation quantities and rates are as presented in Section 6.5.2.4 of the original report. Two additional spreads have been included for the operations in the shallower sections of the pipeline route to avoid unforeseen events that could take place (e.g. repeated slumping of trench) and subsequently delay progress.

A3.4.2.2 Pipe-in-HDPE String Make-up

An additional crew for the assembly of the HDPE pipe has been added to speed up the construction of the pipe strings. The additional crew with relevant equipment would augment the present crew, as required, to avert any complications with the pipe-in-HDPE assembly. In the cost summary table below, the increase cost has been incorporated by increasing the number spreads (and hence activity unit rate) by an estimated 30% to reflect the increased size of the crew.

A3.4.2.3 Backfilling

Additional equipment has been included to enlarge the size of the spread. There would be more backhoes and transport trucks to ensure increased productivity. Some of this equipment would be used to place gravel for pipeline stability during installation and backfill.

A3.4.3 Cost Summary

The cost summary, Table A3-2, indicates the changes with respect to the original report. The additional equipment and personnel have been accounted for by increasing the number of spreads (and hence activity rate) but maintaining the same duration to carry out the activity.

A3.5 Flexible Pipe

All parameters are maintained as in for the original report (5 foot pipeline cover depth). The confidence level of completing the installation of the pipeline in a single season is high (see Section 7.5.3 in original report and Section A2.5 of this Addendum). Thus, there is no change in the estimated cost for the flexible pipe at $37 million.

TABLE A3-2: CONCEPTUAL COST ESTIMATE
PIPE-IN-HDPE ALTERNATIVE - SINGLE SEASON INSTALLATION

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	910.0	2.73
Ice Thickening and Road Construction & Maintenance	2.5 inches/day	1	32314 feet	47	84	3.95
Ice Cutting and Slotting	1000 feet/day	3	32314 feet	11	29	0.96
Trenching	0 - 8 feet WD 40 feet/hour/backhoe	***3***	179,075 cubic yards	9	60	***8.10***
	8 - 18 ft WD 20 feet/hour/backhoe	***3***	201,416 cubic yards	18		
	18 - 22 ft WD 5 feet/hour/backhoe	3	80,160 cubic yards	18		
Pipe Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55	2.59
Pipe-String Make-Up (Welding)	1)50 welds/day for 12.75-in P/L 2) HDPE pipe 50 butts/day	***1.3***	1)808 welds 2)808 connect	34	220	***9.72***
Pipe String Transportation	0.8 miles/day	1	33 pipeline strings	10	78	0.78
Pipe String Field Joint	1.5 complete tie-in/day	1	66 welds	22	31	0.68
Pipeline Installation		1	32,314 feet	37	43	1.59
Backfilling		***2***	32,314 feet	40	42	***3.70***
Hydrostatic Testing		1		5	84	0.42
Demobilization	Lump Sum			2	1144	2.29
Material Cost and Transportation						3.33
Contingency	10%					***4.15***
	Additional cost for 2nd season					***0***
					Total	**46**

Note: Bold italic numbers indicate variation from original cost estimates.

A3.6 Summary

Table A3-3 lists the original aspects of the pipeline alternatives based on a single-season construction with the pipeline alternative characteristics as presented in the original report.

TABLE A3-3: COMPARISON OF PIPELINE ALTERNATIVES FOR SINGLE SEASON CONSTRUCTION AND VARIABLE COVER DEPTHS

Description	Pipeline Alternative			
	Single Pipe	**Pipe-in-Pipe**	**Pipe-in-HDPE**	**Flexible Pipe**
Configuration				
Carrier Pipe OD x WT (in)	12.75 x 0.688	12.75 x 0.688	12.75 x 0.688	14.92 x 2.93
Outside Pipe OD x WT (in)	-	16 x 0.5	16.25 x 0.75	-
Pipe Specific Gravity	1.6	1.87	1.2	1.1
Depth of Cover (ft)	7	5	6	5
Excavation Volume (1,000 cubic yards)	461	354	424	322
Trenching Duration (days) [1]	33	26	30	24
Gravel Backfill (1,000 cubic yards)	9 (in gravel bags/mats	0	10 (30 yd^3 every 100 feet)	10 (30 yd^3 every 100 feet)
Number of Welds/ Connections	808 welds 11 of which are tie-ins	1616 welds 66 of which are tie-ins	808 welds 66 of which are tie-ins	13 Connections 11 of which are tie-ins
Costs				
Budgetary costs (Million $)	31	55	46	37
Relative Cost (%)	100	177	148	119
Schedule				
Estimated Schedule Basis	Single winter season	Single winter season	Single winter season	Single winter season
Installation				
Ice Thickness (feet)	8.5	10.5	8.5	8.5
Relative Quantity of Construction Equipment per Season (%)	100	135	130	90

Note: [1] The trenching duration assumes the first section in the shallow water is completed, followed by the simultaneous trenching of the other two sections.

A4. IMPLICATIONS OF COMBINED SAME BURIAL DEPTH AND SINGLE SEASON CONSTRUCTION.

A4.1 Introduction

This section compares the pipeline alternatives for the case when the construction is completed in one season and all the pipeline alternatives are trenched with a 7 foot depth of cover. This requires combining the costs derived for the two options described in Section A2 and Section A3.

A4.2 Single wall Steel Pipeline

The costs for this alternative do not change compared to those provided in Section A2. That option is for a 7 foot burial depth and a one season construction scenario. Details on costs are presented in Table A2-5 with a total cost of $31 million.

A4.3 Pipe-in-Pipe

The pipe-in-pipe alternative costs are affected both by increasing the burial depth to 7 feet and forcing a single season construction scenario. The cost variation for this scenario include increase cost for trenching, backfilling and welding. Trenching and backfilling costs are those for a 7 foot cover depth but increased for one-season construction by increasing the number of spreads. The pipe stringing and field joint welding costs have been increased by the addition of spreads as shown in Table A3-1. The costs for this option are presented in Table A4-1.

A4.4 Pipe-in-HDPE

As for the pipe-in-pipe case, both the forced single season construction schedule and the 7 foot depth of cover affect this alternative. Table A4-2 below presents the revised costs.

A4.5 Flexible Pipe

A single season construction scenario was planned for the flexible pipe alternative in the original report. However, additional costs must be incorporated for increasing the depth of cover to 7 feet. Details on costs for this scenario are the same as those presented in Table A2-19 with a total cost of $40 million.

TABLE A4-1: CONCEPTUAL COST ESTIMATE - PIPE-IN-PIPE OPTION - 7 FOOT BURIAL DEPTH AND ONE SEASON CONSTRUCTION

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	1240	3.72
Ice Thickening and Road Construction & Maintenance	2.5 inches/day	***1.25***	32,314 feet	56	84	***5.90***
Ice Cutting and Slotting	800 feet/day	3	32,314 feet	14	29	1.22
Trenching	0 - 8 feet WD 40 feet/hour/backhoe	***3***	179,075 cubic yards	10	60	***8.82***
	8 - 18 feet WD 20 feet/hour/backhoe	***3***	201,416 cubic yards	19		
	18 - 22 feet WD 5 feet/hour/backhoe	3	80,160 cubic yards	20		
Pipe-in-Pipe Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55	2.59
Pipe-in-Pipe String Make-Up (Welding)	50 welds/day for 12.75-in P/L 26* welds/day for 16-in P/L	***1.3***	1616 welds	48	240	***14.98***
Pipe-in-Pipe String Transportation	0.6 miles/day	1	33 pipeline strings	10	78	0.78
Pipe-in-Pipe String Field Joint	2 welds/day	***1.5***	66 welds	33	60	***2.97***
Pipeline Installation		1	32,314 feet	29	88	2.55
Backfilling		1	32,314 feet	33	42	***1.39***
Hydrostatic Testing		***1.5***		5	84	***1.89***
Demobilization	Lump Sum			2	1240*	2.48
Material Cost and Transportation						***4.00***
Contingency	10%					***5.33***
	Additional cost for 2nd season					***0***
					Total	**59**

Notes: * Indicates this value has been changed compared to the original report.
Bold italic numbers indicate a variation to the original costs.

TABLE A4-2: CONCEPTUAL COST ESTIMATE
PIPE-IN-HDPE OPTION - 7 FOOT BURIAL DEPTH AND ONE SEASON CONSTRUCTION

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	1144	3.43
Ice Thickening and Road Construction + Maintenance	2.5-inches/day	1	32,314 feet	47	84	3.95
Ice Cutting and Slotting	1000 feet/day	3	32,314 feet	11	29	0.96
Trenching	0 - 8 feet WD --- >40 feet/hour/backhoe	***3***	179,075 cubic yards	10	60	***8.82***
	8 - 18 feet WD --- >20 feet/hour/backhoe	***3***	201,416 cubic yards	19		
	18 - 22 feet WD --- >5 feet/hr/backhoe	3	80,160 cubic yards	20		
Pipe Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55	2.59
Pipe-String Make-Up (Welding)	1)50 welds/day for 12.75-in P/L 2) HDPE pipe 50 butts/day	***1.3***	1)808 welds 2)808 connect	34	220	***9.72***
Pipe String Transportation	0.8 miles/day	1	33 pipeline strings	10	78	0.78
Pipe String Field Joint	1.5 complete tie-in/day	1	66 welds	22	31	0.68
Pipeline Installation		1	32,314 feet	37	43	1.59
Backfilling		***2***	32,314 feet	40	42	***3.7***
Hydrostatic Testing		1		5	84	0.42
Demobilization	Lump Sum			2	1144	2.29
Material Cost and Transportation						3.33
Contingency	10%					***4.20***
	Additional cost for 2nd season					***0***
					Total	**47**

Note: Bold italic numbers indicate a variation to the original costs.

A4.6 Summary

Table A4-3 below lists the original features and costs of the alternatives.

TABLE A4-3: COMPARISON OF PIPELINE ALTERNATIVES FOR A 7 FOOT BURIAL DEPTH AND ONE SEASON CONSTRUCTION

Description	Pipeline Alternative			
	Single Pipe	**Pipe-in-Pipe**	**Pipe-in-HDPE**	**Flexible Pipe**
Configuration				
Carrier Pipe OD x WT (in)	12.75 x 0.688	12.75 x 0.688	12.75 x 0.688	14.92 x 2.93
Outside Pipe OD x WT (in)	-	16 x 0.5	16.25 x 0.75	-
Pipe Specific Gravity	1.6	1.87	1.2	1.1
Depth of Cover (ft)	7	7	7	7
Excavation Volume (1,000 cubic yards)	461	461	461	461
Trenching Duration (days)[1]	33	33	33	33
Gravel Backfill (1,000 cubic yards)	9 (in gravel bags/mats)	0	10 (30 yd^3 every 100 feet)	10 (30 yd^3 every 100 feet)
Number of Welds/ Connections	808 welds 11 of which are tie-ins	1616 welds 66 of which are tie-ins	808 welds 66 of which are tie-ins	13 connections 11 of which are tie-ins
Cost				
Budgetary Cost (Million $)	31	59	47	40
Relative Cost (%)	100	190	151	129
Schedule				
Estimated Schedule Basis	Single winter season	Single winter season	Single winter season	Single winter season
Installation				
Ice Thickness (feet)	8.5	10.5	8.5	8.5
Relative Quantity of Construction Equipment per Season (%)	100	145	130	90

Note: [1] The trenching duration assumes the first section in the shallow water is completed followed by the simultaneous trenching of the other two sections.

A5. SECONDARY CONTAINMENT USING PIPE-IN-PIPE AND PIPE-IN-HDPE SYSTEMS

A5.1 Introduction

This section is provided in response to comments on the pipe-in-pipe and pipe-in-HDPE alternatives proposed by INTEC Engineering. Further narrative is provided on secondary containment and annular leak detection.

A5.2 Pipe-in-Pipe

Review comments suggest that there was an apparent disregard of the pipe-in pipe system's ability to provide secondary containment in the event of a leak. The ability of the outer pipe of the pipe-in-pipe system to contain small leaks of the inner pipe has been incorporated into the pipeline system alternatives evaluation.

Based on existing subsea arctic pipeline design experience, it is INTEC's engineering opinion that large external forces (such as loading from soil deformation due to ice keel gouging) that would damage the inner pipe of the pipe-in-pipe system would also likely damage the outer pipe at the same time. That is, if an event causes the pipeline to bend to the extent that the inner pipe is damaged, the outer pipe will also have had to bend the same amount, most likely damaging the outer pipe. The most likely initiating event for this to happen through inspection of Table A2-11 is ice gouging or permafrost thaw subsidence

There would be some benefit of the pipe-in-pipe alternative as it has the ability to contain a leak of the carrier (or inner) pipe in certain conditions. These conditions are such that the outer pipe remains integral while the inner pipe experiences a leak. For example, if there is corrosion of the inner pipe and not the outer pipe. However, given the non-corrosive is nature of the Liberty crude, pipeline failure by internal corrosion is considered extremely unlikely. Another scenario would be material imperfection or welding flaws of the inner pipe but not the outer pipe. The material and welding will be thoroughly inspected and, thus, this type of failure is also considered extremely unlikely.

Failure of the outer pipe first will result in the loss of potential secondary containment of any subsequent leaks. The annulus fills with water and becomes ineffective. For example, the Erskine Pipeline (pipe-in-pipe system) is believed to have recently failed at five (5) locations of the outer pipe and could not contain the leak from the subsequent inner pipe failure. A simultaneous failure of both outer and inner pipes is very unlikely unless due to a large rupture which would be detectable by the PPA and MBLC leak detection systems.

As pointed out by SES in their final report, the outer pipe of the steel pipe-in-pipe could be designed to contain a leak and withstand the full operating pressure of the pipeline. INTEC also agrees that if the leak was substantial and oil reached one of the ends of the pipeline, it could be removed or diverted before entering the environment. SES also rightly points out that any oil in the annulus following a such a leak might be partially pumped from the annulus prior to making repairs. INTEC contends that removal of oil from the annulus would be very difficult and probably incomplete. This might also cause issues regarding pipeline abandonment. The use of a detergent to clean the annulus may have environmental and logistical implications. The pipe-in-pipe alternative might also allow some flexibility as to when a repair might be carried out if the outer pipe was intact. Prudent operating procedures, however, would require shut-in of the pipeline system to investigate the cause of the inner pipe failure.

This secondary containment performance had been accounted for in INTEC's original analysis, since the frequency of corrosion failure does not translate into an oil spill into the environment for the double-walled pipe alternative. Table 5-14 shows the 3 main initiating events for Damage Category 3. As indicated by the footnotes of that table, only one of these three events results in oil being released into the environment (ice gouging) due to the pipe-in-pipe redundancy. In other words, Category 3 damage frequency in Table 5-14 adds up to 3×10^{-4}; however, in Table 9-2, the corresponding entry for the Category 3 for the pipe-in-pipe is only $1x10^{-4}$ since the consequence of corrosion damage does not imply immediate spill to the environment.

INTEC acknowledges there may be circumstances where the inner and outer pipes are damaged (ruptured), but not at the same location. This would have the effect of making the oil travel through the annulus to reach the rupture in the outer pipe. Depending on how far apart the damage in either pipe is, this could have the effect of delaying the exit of oil from the pipeline system. A more reasonable assumption is that the outer pipe has a larger rupture than the inner, since it would be subject to greater strain due to any displacement affecting both pipes. Therefore, the degree of leak retardation is conjecture (since the damages are most likely to be coincident) and it would be misleading to suggest a quantifiable benefit (volume reduction) from this scenario. Nevertheless, INTEC has attributed a 80% leak reduction for a small to medium leak to reflect this possibility.

In the original report, a Category 3 damage (small or medium leak) scenario for the pipe-in-pipe system resulted in a loss of an estimated 125 barrels of oil (at a reduced frequency as noted above). If credit is given for pipe-in-pipe's potential oil migration paths and possible failure of the outer pipe, the consequences of Category 3 damage leak could be reduced to say 20% of what was initially estimated; 25 barrels. This accounts for the potential ability of the pipe-in-pipe system to contain small to medium leaks.

A5.3 Pipe-in-HDPE

The ability of the outer pipe of the pipe-in-pipe system to contain small leaks of the inner pipe has not been discounted. Most of the comments made above for the pipe-in-pipe would also apply to the pipe-in HDPE. However, there is a greater likelihood of damage to the outer pipe during construction and operation of the pipeline system.

Again, it is INTEC's opinion that large external forces (such as loading from soil deformation due to ice keel gouging) that would deform the inner pipe would likely damage the outer HDPE pipe at the same time. That is, if an event causes the pipeline to bend to the extent that the inner pipe is damaged, the outer pipe will also have had to bend the same amount, most likely damaging the outer pipe. The most likely initiating events for this to happen through inspection of Table A2-16 are ice gouging or permafrost thaw subsidence.

INTEC agrees that there would be some benefit of the pipe-in-HDPE alternative as it has the ability to contain leaks of the carrier (or inner) pipe in certain conditions, such as corrosion of the inner pipe. As pointed out by SES in their final report, the outer sleeve of the steel pipe-in-HDPE could be designed to contain a small leak but could not withstand the full operating pressure of the pipeline. Most of the oil in the annulus would need to be removed prior to making repairs. Again, INTEC contends that removal of oil from the annulus would be very difficult and probably incomplete. This might also cause issues regarding pipeline abandonment. The use of a detergent to clean the annulus may have environmental and logistical implications.

This had been accounted for in INTEC's original analysis, since the frequency of corrosion failure for steel pipe does not translate into an oil spill into the environment for the pipe-in-HDPE alternative. Table 6-13 shows the 2 main initiating events for Damage Category 3. As indicated by the footnotes of that table, only one of these 2 events results in oil being released into the environment (ice gouging) due to the pipe-in-HDPE redundancy. In other words, Category 3 damage frequency in

Table 6-11 adds up to $1.1x10^{-3}$; however, in Table 9-2, the corresponding entry for the Category 3 for the pipe-in-HDPE is only $1x10^{-4}$ since the consequence of corrosion damage does not imply immediate spill of oil into the environment.

In the original report, a Category 3 damage (small or medium leak) scenario for the pipe-in-HDPE system resulted in a loss of an estimated 125 barrels of oil (at a reduced frequency as noted above). If credit is given for pipe in HDPE's potential oil migration paths and possible failure of the HDPE sleeve, the consequences of Category 3 could be reduced to say 50% of what was initially estimated; 62.5 barrels. This accounts for the potential ability of the pipe-in-HDPE system to contain small to medium leaks.

A5.4 Leak Detection in the Annulus

A wide range of leak sensors and leak detection systems was researched (by INTEC) for the Northstar project. Details were not provided in the Liberty Pipeline System Alternatives report but are contained in the document, "Northstar Development Project, Prototype Leak Detection System, Design Interim Report" (INTEC Engineering, 1999). Over 30 sensing technologies were considered of the following generic sensor types:

- Chemical (Subsea)
- Electrical (Subsea)
- Optical Fiber
- Well Logging Technology
- Acoustic
- Electromagnetic
- Soil Resistivity / Capacitance

This study came about as the result of the US Army Corps of Engineer stipulations for Northstar. BPXA agreed to design, construct, operate and maintain a prototype leak detection system that would be installed with the offshore pipelines. This system would have the ability to detect an oil spill beneath current threshold detection limits (from PPA and MBLPC). The system design had to be submitted and approved by the Corps prior to initiating pipeline trenching. INTEC Engineering investigated a number of supplemental leak detection strategies for Northstar and recommended the use of the LEOS system as it was considered the best available technology. This system is currently being installed with the Northstar pipelines. Although the LEOS system is considered the best available technology, by the time the Liberty pipeline is ready to be installed, another system may be identified that would be considered the best available technology. This could partially result from lessons to be learned form the Northstar installation and operation.

LEOS can detect the presence of very small amounts of organic hydrocarbons either through direct contact with the sensory tube as a gas, liquid, or as hydrocarbon dissolved in the water. The presence of hydrocarbon molecules in the vicinity of the sampling tube results in diffusion of the hydrocarbon through the wall of the tube.

Therefore, such a system could be used in the annulus of a pipe-in-pipe or pipe-in-HDPE system. In the event of a leak, the sensory tube may not come in direct contact with the hydrocarbon liquid. However, gas molecules from the hydrocarbon vapor would diffuse through the sensor tube indicating a leak. The location of the sensor tube relative to the leak would not be an issue given the relatively small migration path for hydrocarbon molecules to reach the LEOS tube. Seimens, the manufacturer of the LEOS system, has published detectable concentrations in air and water for crude oil; < 10 µl/l and 10 µl/l for air and water respectively based on full-scale test results and operating experience.

There are risks associated with the installation and operation of a sensor tube in the annulus. The pipe-in-pipe system would have spacers or centralizers placed at intervals along the system length. If the sensor tube was not installed properly, or if the pipeline installation was not exactly as planned, the tube could become jammed or pinched between the inner wall of the outer pipe and the outer wall of the inner pipe. There are no centralizers planned for the proposed pipe-in-HDPE system. This increases the risk of pinching or jamming the system during installation. However, this would be detected before operation started. During operation, a significant event could occur (e.g. ice keel gouge) that would not damage the integrity of the pipeline systems but yet might pinch and damage the sensor tube. If the sensor tube (which has an OD of approximately 0.6 inches for the Northstar design) required a protective conduit, the annulus size, and thus OD of outer pipe, would need to be made considerably larger. This is not to say that the installation and operation of a LEOS system with a single wall steel pipeline are without risks, but these risks might be more manageable.

The makeup of the evaluated pipe-in-pipe and pipe-in-HDPE systems without bulkheads is conducive to annulus monitoring as indicated in the Liberty Pipeline

System Alternatives report. The composition of the air in the annulus could be periodically monitored for hydrocarbons. The principle behind the operation of the LEOS system recommended for the single wall steel pipeline can be applied to the annulus of the pipe-in-pipe or pipe-in-HDPE systems. The required flow rate and effect of centralizers would need to be confirmed in the detailed design stage to ensure that there is not excessive turbulence in the annulus causing the slug of vapor from the leaked oil to mix and disperse to the point where it could not be detected or located.

One drawback of an annular leak detection system (tube or no tube) would be the fact that if there was ever a leak, residual oil may remain in the annulus. If not thoroughly cleaned, background hydrocarbon levels from the residue, could trigger the alarm system. This may impair the sensitivity of this type of leak detection system after pipeline repair.

INTEC also noted that annulus pressure could be monitored for the pipe-in-pipe and pipe-in-HDPE concepts. Different approaches to monitoring leaks in the pipe-in-pipe and pipe-in-HDPE concepts could be to monitor pressure in the annulus, to pressurize and monitor pressure, or hold a vacuum on the annulus and monitor for change. The limitation with this approach is it that it would not be possible to locate the leak and that it would not be possible to directly determine if the inner, outer, or both pipes had lost their integrity. The annulus gas could be sampled from the ends, however, to identify excess water or hydrocarbon vapors.

The DOA correctly point out in their letter of December 30th 1999, that any leak detection alternative, which can provide early detection, would reduce the potential amount of oil released. The fact that a pipe-in-pipe or pipe-in-HDPE pipeline system could have a LEOS tube in the annulus does not necessarily mean that sensitivity would be increased or the detection would be any sooner. During the proposed normal operation of the LEOS system external to the pipe for Northstar, an 18-hour hold time would be followed by 6 hours of sensor tube evacuation and analysis. Regardless as to whether or not the tube is in direct contact with oil, or in contact with dissolved hydrocarbons or hydrocarbon vapor, the 18-hour hold time will still apply. The same conditions could occur in an annulus: direct contact with hydrocarbons, dissolved hydrocarbons, or hydrocarbon vapors. Given the detection thresholds presented above, direct contact or contact through diffusion would result in a system alarm.

The Liberty pipeline system will use the “best available” leak detection technology. If annular leak detection were used, it would be as good as the LEOS system proposed as an "external-to-pipe" system which so far has been considered as the "best available technology" for a supplemental system. It should be noted that by the time the Liberty pipeline is ready to be installed, another system might be considered the best available technology. This could partially result from lessons to be learned from the Northstar installation and operation.

A5.5 Summary

There are both benefits and drawbacks of using a pipe-in-pipe or pipe-in-HDPE system for secondary containment.

<u>Benefits</u>

- The pipe-in-pipe and pipe-in-HDPE alternative could contain the oil released under certain circumstances for certain types of small to medium sized leaks (e.g., inner pipe corrosion) but no outer pipe corrosion.
- For other types of small to medium sized leaks, the outer pipe may reduce the amount of oil spilled into the environment. For the pipe-in-pipe and pipe-in-HDPE this amount may be reduced to 25 and 62.5 barrels respectively for certain events (e.g., ice keel gouging).

<u>Drawbacks</u>

- The pipe-in-pipe and pipe-in-HDPE systems are designed with an overall system reliability to meet acceptable levels of risk. However, the condition of the outer pipe of the system cannot be monitored or inspected and is therefore unknown. If the integrity of any one component of that system is not known, the integrity of the system as a whole is not known.
- INTEC concurs with the suggestion by both the MMS and SES in the SES Draft Final Report (p. 18 and p. 19) that the outer casing would probably fail and that the inner pipe should be designed as if there were no outer casing.
- The cathodic protection system performance on the inner pipe of the pipe-in-pipe system cannot be monitored. CFR 49 states that "a test procedure must be developed to determine whether adequate cathodic protection has been achieved". This test procedure would be based on design conditions rather than direct field verification.
- If there were a leak in the outer pipe, a significant mount of water could end up in the annulus. This water could potentially travel 1000's of feet in the annulus. SES, in their Draft Final Report, suggests that corrosion could begin in the annulus prior to repair and drying. Therefore, a significant part of the pipeline length could be damaged due to corrosion (1000's of feet) and the system could not be returned to full integrity without replacing that segment of pipeline.

- A repair to the pipe-in-pipe system would return the pipe to near its original integrity but not necessarily all the way to its original integrity depending on the repair method used.
- The capital cost will be greater for pipe-in-pipe and pipe-in-HDPE alternatives.
- Both the pipe-in-pipe and pipe-in-HDPE are relatively more difficult to construct than a single wall steel pipeline. During construction, there are issues such as excluding moisture from the annulus. The complexity of the system may also affect the construction schedule.
- The cost and complexity of repairs to a pipe-in-pipe or pipe-in-HDPE system would be greater than those for a single wall steel pipeline.
- If there were ever a leak of oil into the annulus, cleanup and removal of that oil would be difficult because the oil would likely have spread over a significant length of the annulus. Residual oil in the annulus may impair the leak detection system.

A6. ERRATA FROM LIBERTY PIPELINE SYSTEM ALTERNATIVES REPORT

Page 1-5, Table 1-3	2nd season contingency for the pipe-in-HDPE should read 11.0 instead of 5.0.
Page 1-5, Section 1.3.3	90% of the estimated second season cost should read 80%.
Page 1-8, Table 1-7, Row 2, Column 6	"2×10^{-7}" should read "3×10^{-7}".
Page 2-6, Section 2.3.2	The correct name of this subsections is “Wind and Ambient Temperature Data and Values”.
Page 2-6, Section 2.3.2	The offshore pipeline installation temperature for a wet trench should read 25°F.
Page 3-2, Section 3.2.1	The installation temperature on Page 3-2 should read 25°F. The maximum allowable operating temperature should read 150°F. The differential temperature used for design is 125°F.
Page 3-6, Section 3.2.6	The installation temperature should read 25°F. The differential temperature should read 125°F.
Page 4-15, Table A-7, Last Column	Delete “3 Spreads” in heading.
Page 4-18, Table 4-8, Row 11, Column 2	Delete “50 welds/day”.
Page 4-28, Section 4.9.1.2, 5th Paragraph	“Aspect ratio of I5” should read “aspect ratio of 15”.
Page 4-34, Table 4-11	Total of Category 4 column should read “3×10^{-7}”
Page 4-35, Table 4-13	Estimated damage frequency during project life for Category 4 damage should read “3×10^{-7}”.
Page 5-20, Table 5-8, Last Column	Delete “3 Spreads” in heading.
Page 5-25, Table 5-9,	
Row 9, Column 2	Change 38 to 26 welds.
Row 11 , Last Column	Change 1.02 to 1.98.
Row 15, 6th Column	Change 920 to 1,240.
Row 15, Last Column	Change 1.80 to 2.48.
Last Row	Change total from 61 to 62.
Page 5-34, Section 5.9.1.3	The first sentence should refer to strudel scour not ice scour.
Page 6-14, 9th Bullet	Fusion joining is the correct method for joining HDPE pipe, not induction-heating.
Page 6-19, Table 6-7, Last Column	Delete “3 Spreads” in heading.
Page 6-22, Table 6-8, 2nd Last Row, Last Column	Change 5 to 11.
Page 6-22, Table 6-8, Last Row	Change total from 44 to 50.
Page 7-14, Section 7.5.2.4	The second line should be changed from 354,000 to 322,000.
Page 7-16, Section 7.5.2.9	The last line should read 34 days.

Page 7-18, Table 7-4, Row 12, 5th Column	Change 38 to 34.
Page 9-4, Table 9-1	"Budgetary Cost" line should read 31, 62, 50, and 37.
Page 9-4, Table 9-1	"Relative Cost" line should read 100, 200, 161, and 119.
Page 9-6, Table 9-2, Row 5, Column 2	"2×10^{-7}" should read "3×10^{-7}"
Page 9-9, Table 9-3, Row 1	"1.6×10^{-3}" should read "1.7×10^{-3}".
Page 9-9, Table 9-3, Row 2	This row should read 1, 16, 8, and 82.
Page 9-9, Table 9-3, Note [1]	"2×10^{-7}" should read "3×10^{-7}" and "1.6×10^{-3}" should read "1.7×10^{-3}".
Page C-2, 2nd Paragraph	The sentence in that paragraph should read a minimum gouge depth of 0.3 feet and a maximum of 0.6 feet.
Figure 6.6	OD of outer HDPE pipe should read 16.25"

ATTACHMENT B

RESPONSE TO STRESS ENGINEERING SERVICES DRAFT FINAL REPORT

"INDEPENDENT EVALUATION OF LIBERTY PIPELINE SYSTEM DESIGN ALTERNATIVES"

LIBERTY DEVELOPMENT PROJECT

CONCEPTUAL ENGINEERING

PREPARED FOR

BP EXPLORATION (ALASKA), INC.

ANCHORAGE, ALASKA

INTEC PROJECT NO. H-0851.02

PROJECT STUDY PS19

APRIL 2000

The following are INTEC Engineering's responses to the “Draft Final Report: Independent Evaluation of Liberty Pipeline System Design Alternatives”, dated March 2000. This document was prepared for the Minerals Management Service by Stress Engineering Service (SES), Inc., Houston, Texas (PN 1996535GRR). These comments are intended to address SES’s comments, observations, and questions raised during their review of INTEC Engineering’s November 1999 report, "Liberty Pipeline System Alternatives". INTEC's response is limited to those issues presented in the SES report summary (p. iii - p. xvii).

Design Issues

1. The ability of the outer pipe to contain small leaks of the inner pipe has not been discounted. All four pipeline alternatives are designed, at a conceptual level, to safely transport oil from Liberty Island to shore. Two of the alternatives, pipe-in-pipe, and pipe-in-HDPE have the ability to contain leaks of the carrier (or inner) pipe in certain conditions. These conditions are such that the outer pipe remains integral while the inner pipe experiences a leak. The corresponding failure mode is then corrosion of the inner pipe. This has been accounted for, since the frequency of corrosion failure does not translate into an oil spill into the environment for the double-walled pipe alternatives. See and compare Tables 5-14 and 9-2.

   More specifically, Damage Category 3 in Table 5-14 has been split into 3 different types as described in the footnotes associated with that table. In summary, due to the pipe-in-pipe redundancy, the frequency of corrosion damage of the inner or outer pipe does not translate into a spill frequency. In other words, Category 3 damage frequency in Table 5-14 adds up to $3x10^{-4}$; however, in Table 9-2, the corresponding entry for the Category 3 for the pipe-in-pipe is only $1x10^{-4}$ since the consequence of corrosion damage does not imply immediate spill to the environment. The relative advantage of this secondary containment is limited by the low frequency of this type of damage.

   In the Addendum to the Pipeline System Alternatives report (Attachment A), the issue of leak containment using pipe-in-pipe or pipe-in-HDPE is further addressed.

2. Agree that a HDPE pipe sleeve may be able to temporarily contain a small oil leak. Please see Attachment A, "Addendum to Liberty Pipeline System Alternatives Report".

3. Agree that if the outer pipe of a pipe-in-pipe configuration is not damaged, it could be designed to contain an oil leak. Please see Attachment A, "Addendum to Liberty Pipeline System Alternatives Report".

4. All pipeline system alternatives have been conceptually evaluated against the most pressing environmental loadings (ice gouging and upheaval buckling) with the 7-foot depth of cover as a basis. Some of the pipeline systems can safely have the depth of cover reduced and satisfy upheaval buckling and other loading requirements. INTEC's philosophy was to treat each alternative design as a potential actual project that eventually might be built. Thus the required depth of cover has been assessed for each option.

   However, an Addendum to the Pipeline System Alternatives report has been generated (Attachment A) which looks at a constant buried depth for all alternatives.

   Stress Engineering suggests the flowline wall thickness might have been kept the same as the single wall pipeline. This would have resulted in selection of pipe-in-pipe sub-alternative A. The stiffness of this pipe-in-pipe system would have been approximately 20% less than sub-alternative B. The strains in the pipeline due to the design ice keel scour (Table 5-2) would then be for the most part slightly higher then these presented for sub-alternative B in Table 5-3. However, these strains are still well below allowable. This would have still resulted in a qualitative assessment at the conceptual level to reduce the depth of cover to 5 feet for the pipe-in-pipe option.

5. The driving force behind defining the different alternatives presented in the report was agency input. We cannot speak for the reasons why the agencies put these specific alternatives forward but we assume it was the result of a perceived reduction in risk when compared to a single wall steel pipeline.

Technical Merits

1. INTEC agrees that non-linear geometry effects should be included at a preliminary engineering level. However, at a conceptual level and based on experience with non-linear geometry analyses for another subsea Arctic pipeline project, the ANSYS analyses are considered sufficiently accurate. INTEC concurs that it might be prudent to narrow the candidates and conduct a check of the finite element analysis including nonlinear geometric affects.

2. A leak rate of 1 barrel per day for a small chronic leak was an assumption. We wanted to assume a value that was considerably smaller then the threshold of the mass balance and pressure point leak detection technologies but would still result in a significant quantity of oil being released if left undetected. We could have alternatively chosen 5, 10, or 29 barrels per day for a small or chronic leak.

Inspection Issues

1. The design emphasis is placed on safely avoiding an upheaval buckling event and, in the case of ice gouging, to set a depth of cover such that any pipe bending which results from sub-gouge deformations will not buckle the pipe. Pipe ovalization for pig passage was found not to control the design.

2. There is the possibility that fairly low leak rates in the annulus of the pipe-in-pipe and pipe-in-HDPE systems could be detected by directly sampling the air in the annulus given the direct exposure of the sampled air to the hydrocarbon. Based on discussions with Siemens, a gas detector unit, similar to that connected to the LEOS system, might be able to practically handle a volumetric flow of 2500 liters per hour. Therefore, if the entire volume of air in the annulus was to be sampled, approximately 6 days would be required. However, the air extracted from the annulus could be split so that only a fraction is sent to the gas detector unit. The required flow rate and effect of centralizers would need to be confirmed in detailed design to ensure that there is not excessive turbulence in the annulus causing the slug of vapor from the leaked oil to mix and disperse to the point where it could not be detected or located.

   The INTEC report assumes that the performance of this system would be as good as the LEOS system proposed for the single wall steel pipeline. If it were not, a LEOS tube could potentially be incorporated into the annulus of the pipe-in-pipe and pipe-in-HDPE systems. An alternative approach is to hold a vacuum on the annulus and monitor for a pressure increase, which may indicate a leak in either the inner or outer pipe.

   With regard to locating a leak into the annulus, this is considered secondary to identifying that a leak has occurred. Oil (or water) would spread along the annular space and make precise location for repair difficult. If an annular space is contaminated with oil, a significant portion of the line may have to be removed and replaced to avoid eventual discharge into the environment.

3. INTEC concurs that the combined MBLPC and PPA leak detection systems have the capability to allow the operator to accurately determine the difference between an actual leak and a false alarm and obtain self-diagnostics to minimize false alarms. To address this, the Liberty pipeline system will use "best available technology" for leak detection. As indicated in the INTEC report, if during an alarm, the reason for the alarm can not be determined and verified as a false alarm, the system will automatically shut-in the pipeline.

4. INTEC agrees that a flexible pipeline would be expected to expand under pressure. However, this expansion would only be expected during startup and would be constant under steady-state conditions. The effect of pressure fluctuations during operation on the reliability of the system would need to be investigated.

5. LEOS can detect the presence of very small amounts of organic hydrocarbons either through direct contact with the sensory tube as a gas or liquid, or if the gas or liquid hydrocarbon is dissolved in water. The presence of hydrocarbon molecules in the vicinity of the sampling tube results in diffusion of the hydrocarbon molecules through the water-soil matrix and the wall of the tube. Siemens has demonstrated in field and laboratory tests that the system response is not significantly affected by the tube position relative to the actual leak location on the pipe circumference.

   A leak occurring farthest from the sensor tube (i.e., 180 degrees opposite on the pipe circumference) would still result in the diffusion layer contacting the sensor tune within 4 - 6 hours. The closer the tube is to a leak, the sooner the molecular diffusion will start through the wall of the sampling tube. This will be of no practical consequence to the Northstar or Liberty pipe due to the relatively small pipe diameter. Siemens estimates (based on its experience) that the LEOS system should be capable of detecting hydrocarbon concentrations resulting from a leak rate as low 50 liters (0.3 bbl) of oil per day (for the Northstar system). They have published detectable concentrations of crude oil in air and water; < 10 μl/l and 10 μl/l for air and water respectively.

   If the tube were placed in the annulus of a pipe-in-pipe or pipe-in-HDPE system, the tube may not come in direct contact with the hydrocarbon liquid. However, gas molecules from the hydrocarbon vapor would diffuse through the sensor tube indicating a leak.

6. Based on discussions with flexible pipe suppliers, hydrocarbon gasses naturally permeate though the inner liner of flexible pipe. In order to prevent pressure build up in the annulus, each end fitting on the flexible line has vent valves. As presented in Section 7.8.1 of the INTEC report, commercial systems are available (Corrocean) that can measure the volume and flow rate of the vented gas from the annulus of the flexible pipe. In our case, we would have to interconnect the vent valves so that we have continuous flow through the annulus; Corrocean has estimated that there is 10% free volume in the armor layer permitting this flow. In our report we have assumed that the performance of this system would be as good as the LEOS system proposed for the single wall steel pipeline. If it were not, a LEOS tube could be incorporated into design of the flexible pipe bundle. Basically, at this conceptual level INTEC has accepted that annulus

monitoring is feasible but agree that there may be serious reliability issues to be addressed during preliminary/detailed design.

7. The reviewers are correct that in order to have a continuous pathway for the leak detection system to sample air in the annulus, jumpers across the end connections would be required. The simple sketch attached showing a flexible pipe jumper was provided by one of the suppliers of flexible pipe. INTEC acknowledges that such a design would probably not be rigorous enough to withstand installation, backfilling, and operation. Alternatives to this design (including adequate protection) would be investigated in the detailed design phase.

Operations Issues

1. The pour point temperature for the sales crude oil exported from Liberty will be 25°F. The minimum oil temperature should be maintained above this temperature to ensure that the pipeline remains unobstructed by a gelled oil slug. The year-round offshore ambient soil temperature along the Liberty offshore pipeline route will range from +25°F to +29°F which are both equal to or greater than the oil point temperature of +25°F. The primary concern is cooling of the insulated overland pipeline segment where the design ambient air temperature will be as low as -50 °F. In the even of a shut-in of the offshore pipeline, preliminary operational plans call for the oil to be displaced from the onshore oil pipeline using natural gas.

2. INTEC concurs. An alternative approach to monitoring leaks in the pipe-in-pipe and pipe-in-HDPE concepts would be to monitor the pressure in the annulus, to pressurize and monitor pressure, or to hold a vacuum on the annulus and monitor for a pressure increase. Any of these may indicate a leak in either the inner or outer pipe. The annular vacuum option would also improve the thermal insulation performance of the pipeline.

Repair Issues

1. The reviewers are correct that if there were a leak in the offshore pipeline, some oil would remain in the pipeline. As described in Subsection 3.8.4 of the INTEC report, the probable release volume from a hypothetical pipeline failure has four components. One of these is the oil released as the result of drainage from the leaking segment. In the case of a guillotine break, this is estimated as a maximum of 1,130 barrels based on the seabed profile from the proposed pipeline route and the resulting anticipated pipeline profile. This has been accounted for in the oil spillage calculations. As suggested in Subsections 4.9.3, 5.9.3, 6.9.3, and 7.9.3, if there is the potential for loss of remaining oil during the

repair, the line might be purged (with a vacuum from each end) or the damaged ends plugged. In the case of a small or medium leak, the oil line would be purged and no significant further leakage would occur during repair. The oil volume leaking from the line between the time when the line is shut-in and purged has been assumed to be small compared to the total spill volume for those cases.

2. INTEC agrees with the reviewers in that the removal of all moisture from the annulus after a repair would be difficult. At the conceptual level of this report, the time required for drying the annulus or to displace seawater in the annulus with a corrosion inhibited fluid has not been estimated. INTEC concurs that given the potential for a delay in repairs due to the time of year and the time required for drying of the annulus, corrosion could be initiated.

   The use of cathodic coatings such as thermal sprayed aluminum for the inner pipeline has not been investigated at this level but could be during later design stages. The use of discrete anodes on the interior pipe could be further investigated during later design stages but may provide ineffective in the limited annulus space. It is pointed out in the Stress Engineering report (p. 18) that CFR 49 195.242 requires "…a test procedure that will be used to evaluate adequacy of the CP system" and "The code requirement will not be waived and therefore it makes the design and review of the CP system the critical issue". Stress Engineering notes,"…. the cathodic protection of the inner pipe could not be monitored".

3. Mechanical repairs are not considered appropriate for Arctic offshore pipelines mainly because of potentially high bending strains that could be imposed in the pipe as a result of ice gouge or permafrost thaw subsidence, and a conservative design philosophy which seeks to exclude all flanges, valves, and fittings from the subsea pipeline. INTEC concurs that this is an overly conservative design philosophy based on industry experience but believes this is in line with many of the very conservative design assumptions applied to address perceived pipeline issues.

4. Subsection 3.6.2 directs the reader to Appendix E, where there is a more detailed description of the split sleeve referenced in the report.

5. INTEC concurs with the comment on difficulty of pipe-in-pipe repair. The type of repair proposed by Stress Engineering may repair the pipe <u>close</u> to its original integrity.

   INTEC does not agree with the statement that when designing a pipeline, the design allowables should be based on the repaired pipe strength. Normal practice is to design the pipeline not considering if there might be a repair sometime in the future. Repairs made to pipelines are assessed on a case to case basis and any reduction in operating capabilities would be based on this assessment. This repair assessment should also consider the probability of extreme event loading occurring at the specific point along the pipeline where the repair is made.

6. A flanged connection is considered temporary for the reasons stated in answer 3, Repair Issues. If the flexible pipe were to be repaired, an entire section of pipe between end connections would likely need to be replaced. However, the ability to repair a shorter section of pipe by reterminating away from the damaged pipe section would be further investigated in preliminary and detailed engineering, if flexible pipe were to be used in the Arctic offshore. The decision to stock replacement sections, if flexible pipe were used in the Arctic offshore, would be made by BPXA.

7. The decision to stock potential repair tools suitable for Arctic use has yet to be made by BPXA.

Construction Issues

1. Abandonment and recovery procedures have not been detailed in the report but this has been considered. As suggested in the report, it is possible that weather or ice conditions dictate a temporary or seasonal abandonment of the pipeline before construction is completed. Therefore, there will be a detailed abandonment and recovery plan in place for the Liberty offshore pipeline bundle prior to construction. The general procedure is outlined below.

   The offshore pipeline will be installed into the excavated trench using sidebooms equipped with roller cradles. In the case the pipeline must be abandoned, an abandonment head will be welded to the pipe and a cable will be attached to the head. This cable will then be maintained at a predetermined tension and the sidebooms advanced in the same manner as for regular pipeline installation until the end of the pipeline bundle approaches the first sideboom. The sidebooms will then proceed to lower the roller cradles to predetermined abandonment elevations. At this point, the sidebooms resume moving along the trench in the pipelay direction, the pipeline bundle end will pass the rollers, and the abandonment cable (tensioned) will ensure a controlled laydown of the pipeline bundle. The cable remains attached to the pipe end and the recovery of the pipeline bundle would be performed in the reverse sequence as the abandonment. The cable would then be slackened and lowered into the trench in the case of a seasonal abandonment.

Recovery from a seasonal abandonment may require divers to recover the cable and excavate any soil deposited over the pipeline using hand-jetting equipment.

2. The use of cathodic coatings such as thermal sprayed aluminum or clamp anodes for the inner pipeline has not been investigated at this conceptual level but could be during later design stages.

3. Yes, INTEC intended that this be the method for pipe-in-pipe assembly in order to minimize outer pipe welding requirements.

4. A fusion joining machine is the correct method for joining HDPE pipe.

5. INTEC concurs. An extensive qualification program is probably required if flexible pipe is to be used in the Arctic offshore.

6. INTEC concurs on HDPE fusion weld procedure qualification.

7. An addendum to the Pipeline System Alternatives report has been generated (Attachment A). This supplement to the original report addresses single season construction scenarios. Additional manpower has been allocated to select activities to force a single season of construction. However, INTEC maintains there would still be a greater risk of completing a pipe-in-pipe or pipe-in-HDPE system in a single season as compared to the single wall steel pipeline.

8. Scheduling would not permit waiting to backfill until after the hydrotest is complete. Stored trench excavation spoils will also freeze during winter construction. Maintaining pressure in the line during pipe lay-in and backfilling could be considered.

9. INTEC concurs. As stated on page 5-17 of the pipeline system alternatives report, an inert-gas pressure test of the annulus may be feasible to ensure the integrity of the outer sleeve of the pipe-in-pipe or pipe-in-HDPE options. Diver operations at the Liberty prospect site are often limited by winter sea ice conditions and poor summer underwater visibility.

10. INTEC agrees with the statements regarding jetting. The use of cutter suction equipment will depend on the ability to obtain regulatory permits. These and other construction procedures may be considered during detailed construction planning.

Costs

1. The costs included for a second season contingency construction are based on the estimated cost of a second season times a probability of incurring that cost. Therefore, the tabulated costs could be less than the actual estimated costs to do a full two-season construction. As pointed out in Subsection 6.5.4, "Only part of the additional cost of a two-season construction plan is included as contingency. This is to highlight the relative levels of confidence between completing the pipe-in-HDPE system and the pipe-in-pipe system…". Contingency costs for the pipe-in-HDPE system in the main report were low and have been revised in the attached Addendum.

   The rationale behind the contingency costs for the pipe-in-pipe and pipe-in-HDPE alternatives is explained further in the attached Addendum.

2. Implications of single season construction scenarios on costs are presented in the attached Addendum to the original report.

Alternative Design Concepts

1. The four different pipeline system alternatives were put forth by INTEC were the result of MMS and agency input at several meetings that took place in Mid-1999. INTEC scope of work was to analyze these four alternatives only. The Liberty crude oil is non-corrosive and the pipeline is required to be inspection piggable. Therefore, all alternatives providing secondary containment would preferably have the inner pipe of multi-layer design concepts suitable for stand-alone operation. This may limit application of some inner pipe concepts mentioned.

2. See comment above regarding the four system alternatives evaluated.

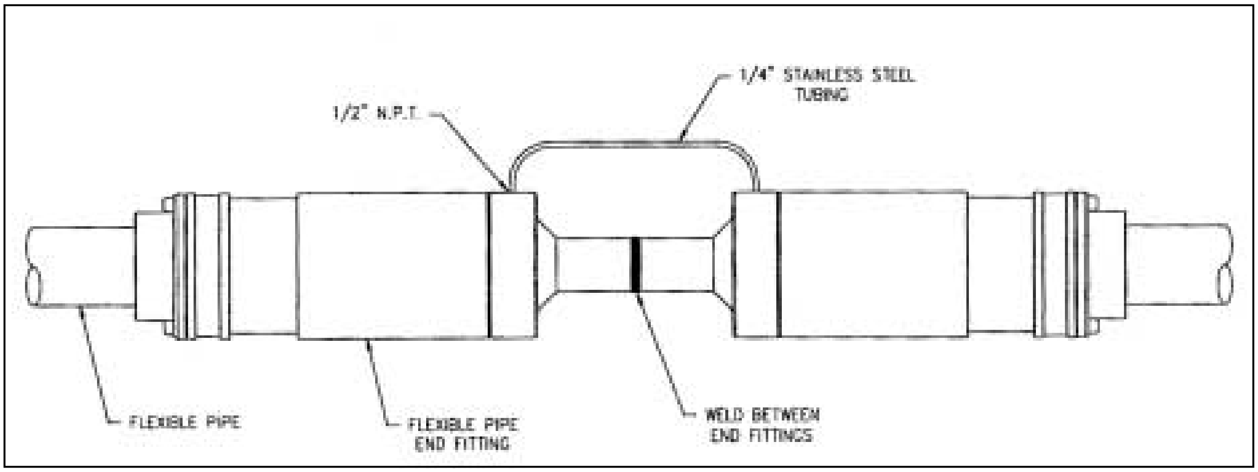
3. See comment above regarding the four system alternatives evaluated.

Items to be Considered in Preliminary Design

1. INTEC concurs regarding inner pipe buckling for pipe-in-pipe designs.

2. INTEC concurs. The external pressure collapse should be checked during preliminary design but the low D/t pipe cross sections considered are not expected to be problematic. If a hydrotest was conducted, drying of the annulus would be required. An inert-gas pressure test of the annulus may be more appropriate.

3. The lower stiffness of the outer HDPE pipe compared to the inner steel pipe was addressed at this conceptual level design by omitting annular spacers from this design alternative. Therefore, the weight of the steel pipe is distributed over the length of the HDPE pipe through direct bearing. INTEC agrees that if a thicker-walled sleeve was used, the weight of the inner pipe would be distributed over a larger area. The low stiffness of the HDPE pipe will also ensure the inner pipe deflects based on the surrounding soil conditions instead of the response of the outer pipe and spacers. Impact loads during construction / transport would be considered during detailed design.


1/4" STAINLESS STEEL
TUBING
1/2" N.P.T.
FLEXIBLE PIPE
FLEXIBLE PIPE
END FITTING
WELD BETWEEN
END FITTINGS

ATTACHMENT C

RESPONSE TO MMS COMMENTS ON PIPELINE SYSTEM ALTERNATIVES

(ATTACHED TO MMS LETTER OF MARCH 17TH 2000)

LIBERTY DEVELOPMENT PROJECT

CONCEPTUAL ENGINEERING

PREPARED FOR

BP EXPLORATION (ALASKA), INC.

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Page 1-5, Section 1.3.3 – INTEC concurs. If an 80% likelihood of a second season prediction is required, then 80% of the estimated second season costs should have been applied.

Page 2-3, Section 2.1.3 – INTEC agrees it is desirable to monitor pipeline system components where possible. The offshore pipeline system will be a continuous, welded pipeline with no valves or flanges. Therefore, the major component to be monitored is the pipeline itself. The pipe materials will be inspected and welds will be qualified prior to construction. Welding, trenching, installation, and pressure containment will be monitored/checked during construction. The pipeline system will be monitored during operation for flow, leaks, cathodic protection, corrosion, ovalization, bending, expansion, soil cover, and shoreline erosion.

Page 2-6, Section 2.3.2 – The correct name of this subsection is "Wind and Ambient Temperature Data and Values" and contains wind and temperature data. The offshore pipeline installation temperature for a wet trench should read 25°F. If the trench was dry for pipeline placement, but was backfilled with recently excavated material, the tie-in temperature would be taken as 25°F (as the backfill is not frozen). The lowest design ambient air temperature is taken as -50°F and is more relevant to the tie-in temperature for the overland pipeline.

Page 2-7, Section 2.3.3.2 - A study specific to the Liberty Project was performed that included both an analysis of historical aerial photographs of bluff position at potential shore crossing sites for the period 1949-1995, and on-site coastal observations and surveying conducted during August 1997 (Coastal Frontiers Corporation, 1997). This survey quantified blufftop elevations, beach widths, bluff composition, and nearshore bathymetry at the sites.

At the shore crossing site, bluff erosion rates were determined to average 2.0 ft/year during the 1949-1995 photo comparison period. Arctic bluff erosion rates vary in response to long periods of quiescence interspersed with episodic storm events. This leads to short-term retreat rates which can be substantially greater than long term rates. The long-term average bluff erosion rate of 2.0 ft/year at the pipeline shore crossing implicitly includes the episodic erosion events contained within the 1949-1995 time period.

Although no site-specific short-term bluff erosion data exit for the Liberty shore crossing, it is assumed that the short-term rate can exceed the long-term rate by a factor of approximately four. This assumption is predicated on the experience acquired at Heald Point, on the east side of Prudhoe Bay, along with the following two observations: (1) the bluff at the Liberty site does not contain an actively melting ice lens, and (2) the bluff face at the Liberty site is protected by slumping tundra (as opposed to the unvegetated bluff face at Heald Point).

In summary, for the 1949-1995 period, an average long-term bluff erosion rate of 2-ft/yr and a typical short-term erosion rate of 2 - 3.5-ft/yr were determined for the proposed shore crossing location. For design purposes, shoreline erosion rate values of 3-ft/year (long-term average) and 12-ft/year (short-term maximum) have been considered appropriate. The total erosion over the pipelines' design life is estimated based on 20 years at the average erosion rate and 5 years at the maximum erosion rate. This results in a design erosion distance of 120 feet over the life of the project. The proposed setback is 155 feet to account for any ice ride-up in conjunction with the preducted coastal erosion.

<u>Page 2-22, Section 2.8</u> – The occurrence of strudel scouring is limited to the region bounded on its landward side by the seaward limit of the bottomfast ice (6 foot water depth), and on its seaward side by the seaward limit of river overflood.

Overflood maps have also been analyzed for the eleven years for which data are available. The extreme seaward limit of these historical overflood boundaries was found to intersect the pipeline route at approximately one-half the distance from the shore crossing to the island site.

The ice along the pipeline route will be thickened to approximately 8 feet prior to construction, which suggests the ice will be bottomfast for approximately 50% of the pipeline route. While this construction pad could change the pattern of strudel scours along the pipeline route, it is expected that this bottom fast ice over the pipeline route would also afford some protection to the line from strudel scour.

<u>Page 2-29, Section 2.12.1</u> – As stated in Section 2.6.1, the maximum gouge depth can be calculated based on the methodology described by Weeks et al. (1983) and Lanan et al. (1986). Since the methodology is general and can be applied to any site, API RP 2N (1995) recommends it as applicable to any structure that is linear in shape. Using this methodology, the maximum expected ice keel incision depth is a function of pipeline length.

<u>Page 2-31, Section 2.12.1, Reserves and Project Value</u> – The Liberty facilities capacity is 65MBOPD (annual average), associated with this oil rate are specific produced gas, produced water and injection water rates. When production starts, the plant processes at its oil capacity (oil plateau) with produced gas and produced water rates below the facility capacity. The typical production field of this size remains on plateau three years prior to production decline. As the field matures, the gas and produced water rate increase. When the gas and water rates exceed the facility capacity, the oil rate must be reduced until the associated gas and produced water rates are within the facility capacity. The field is then on “oil production decline”. Decline continues as the field matures and as the gas and produced water rates continue to increase until the field

economic life is reached. The actual selection of the capacities for the associated gas and produced water systems is determined by reservoir modeling and economics.

If the Liberty facility oil production capacity was reduced to 23MBOPD, the capacities of the produced gas, produced water and water injection systems would also be reduced accordingly. At startup, production would initially be at 23MBOPD and the gas and water rated would be below system capacity. Again as the field matures the gas and water rates increase until the system capacities are reached. As the gas and produced water system exceed capacity the oil rate must be reduced and the field begins decline to the economic life. The Liberty facility will not be able to maintain the oil production at the plateau rate of 23MBPD for nineteen years life. At most the field may be able to maintain the 23MBOPD rate for three to four years prior to the start of a rapid production decline.

There is a substantial amount of indirect costs to develop Liberty or any other offshore arctic development due to remote location of the field and the costs of logistic support for construction and operations. Therefore the total costs of a field development is not a direct proportion of the production rate of the facilities. A production of merely 23MBOPD for a remote offshore field would not be considered as a viable development.

Page 2-32, Section 2.12.2 – The potential displacement of the pipeline due to thaw settlement is dependent upon thaw bulb dimensions and the thickness of frozen permafrost which might be thawed beneath the pipe. If the pipe is buried deeper, the distance from the pipeline to thaw stable material is reduced. A smaller layer of permafrost results in less thaw settlement.

Page 2-33, Section 2.12.2, Gravel Mats – There is currently a proposed self-limitation of mounding the backfill over the pipeline to 1 or 2 feet over the original seabed elevation. Therefore, the amount of soil which can be placed over a pipeline of a given depth is limited. If backfill soil is mounded above the seabed, it may also be eroded and not provide uplift resistance during pipeline operation.

A deeper trench could affect the ability to make the trench bottom smooth. A deeper trench will result in more exposed trench sidewall area. The more sidewall area exposed, the greater the potential for sidewall slumping. This would result in an increase in trench roughness which could affect the pipe's profile once laid in the trench. Any extreme variations in the pipelines profile would need to be corrected or the need for additional or different backfill over the pipe assessed.

Page 2-33, Section 2.12.2, Stress-Based Design Bullets - There are two components to the pipeline loading during permafrost thaw-settlement. The first is the amount of thaw-settlement beneath the pipe resulting in potential differential settlement. The second is the amount of backfill over the pipe which acts as a dead load on the pipe. The combination of this dead load with the potential differential settlement directly dictates the pipeline stress and strain.

Pages 3-2 and 3-6, Section 3.2.1 and 3.2.6 – The installation temperature on Page 3-2 should read 25°F. The maximum allowable operating temperature should read 150°F. The differential temperature used for design is 125°F. These corrected numbers were already used in the upheaval buckling analysis described in Section 3.2.6 of the report.

Page 3-4, Section 3.2.4 – The transverse soil displacement for each of the pipeline alternatives for a 3-foot ice gouging event would be as follows:

Pipeline Alternative	Proposed Depth of Cover (ft)	OD (ft)	Depth to Centerline (ft)	Transverse Soil Displacement (ft)
Single Wall	7	1.0625	7.53	2.35
Pipe-in-Pipe	5	1.3333	5.67	3.52
Pipe-in-HDPE	6	1.3542	6.68	2.81
Flexible	5	1.3333	5.67	3.52

Page 3-7, Section 3.3.2 – INTEC concurs with this clarification.

Page 3-10, Section 3.3.5.3 – In order to use a plow in the winter, the pipe would first be laid on the seabed. This would likely be achieved by cutting and removing ice, after which the pipeline would be installed through the slot in the ice. The plow would then be pulled along the pipe using the pipe as a guide. The force necessary to pull the plow would be generated using a winch on the ice, at the island, or at the shore crossing. The effectiveness of using a plow in winter would also be limited by the amount of frozen soil at the seabed. The Panarctic Drake field flowline was trenched using a plow deployed through the ice during winter.

Page 3-11, Section 3.3.5.4 – The material excavated to achieve the required depth of cover must be replaced as backfill over the pipeline. Jetting might be used to achieve the depth of cover but affords no means to ensure the required amount of backfill ends up over the pipe. During winter, a significant portion of the pipeline trench could be “dry” or in bottom fast ice, not containing sufficient water to effectively jet. Turbidity would be an issue and might be controlled through silt curtains. However, the practicality of effectively installing, removing, and repositioning silt curtains under arctic conditions would be questioned. Finally, the effectiveness of using a jetting sled in winter would be limited by the amount of frozen soil at the shore crossing.

Page 3-21, Section 3.3.11 – The advantage of HDD is that there is no excavation and backfill phases of construction. This minimizes disruption of the shoreline bluff and allows deep burial of the pipeline. Environmental loadings due to ice gouging and strudel scour can be avoided for pipeline sections installed by HDD and the potential for upheaval buckling is eliminated. Permafrost thaw settlement loads must be considered for HDD and there is an increased difficulty of drilling in arctic conditions and permafrost soils as compared to more conventional locations. HDD is not practical for a single length installation of the Liberty pipeline and thus conventional trenching and subsea tie-ins would be required at midpoints between drilled sections.

Page 3-26, Section 3.5.3 – Concur. Where applicable, the pipeline monitoring program, evaluations, and proposed remedial actions would be reviewed by the appropriate Federal and/or State regulators.

Page 3-27, Table 3-1 – A pipeline geometry pig run will be performed after construction and before freeze-up. This means that a pig run will be performed as soon as practical after construction is complete but before freeze up in the fall of that year. The plan would be to do the pig run as soon as possible so that if any remedial actions were required, construction equipment would still be available.

Page 3-28, Section 3.5.3.6 – Another way to phrase this might be: “Axial friction from the backfilled soil around the pipeline limits the thermal expansion of the pipeline and prevents axial motion away from the pipeline ends."

Page 3-29, Section 3.6 - Concur. Where applicable, pipeline repair plans would be reviewed by the appropriate Federal and/or State regulators.

Page 3-30, Section 3.6.1.1 – The division between the two zones is approximately the 6 foot isobath. In Zone I, the construction takes place from bottomfast ice where in Zone II, the construction takes place from floating ice. Bottomfast ice does not guarantee a dry trench at pipeline depth.

Page 3-34, Section 3.6.2.2 – Concur that getting the design right to begin with can avoid problems over the pipeline life. However, in the unlikely event of a leak, a repair may be necessary. Depending on the damage and time of year, a permanent or temporary repair may be made. If there is not time available during a summer or winter construction season to make a welded repair, then mechanical sleeves will be used to make temporary repairs in order to avoid long shutdown periods between the end and beginning of a repair season. Production may be restricted during periods of temporary repair. While mechanical repair tools are standard for long-term subsea pipeline repair, it has been conservatively assumed that a welded repair would be applied for Liberty.

Page 3-34, Section 3.6.4 – In the event of a leak, the pipeline would be shut in. The next step would be to determine to what extent the pipeline is losing product to the environment. The goal at that point would be to minimize the amount of oil which could be lost to the environment.

Ideally, all oil would be displaced from the pipeline prior to initiating any repairs. However, if it is not possible to displace the oil without significant loss of oil to the environment, a temporary pipeline repair using a split sleeve mechanical connection may be attempted with oil still in the pipeline. This would prevent further loss of product to the environment until the time the line could be purged for permanent repair. Alternatively, piggable plugs may be placed in the line during the repair procedure.

Page 3-38, Section 3.7.3 – A leak detection threshold of 0.15% of flow has been experienced in BPXA North Slope pipelines under steady flow conditions. Alyeska utilizes both mass balance and deviation leak detection systems on the 48-inch TAPS pipeline. Their leak detection threshold is reported between 0.12% and 0.21% depending on the flow conditions and detection time interval. The Liberty pipeline will use a well-established state-of-the-art mass balance and pressure point technologies as part of its leak detection strategy. The percentage operational time availability of these systems has not been estimated.

LEOS is a commercially available leak detection system. It has been used onshore and for river crossings for 21 years. The manufacturer estimates that the system would be capable of detecting hydrocarbon concentrations resulting from leak rates as low as 0.3 barrels of oil per day for Northstar. The accuracy of the location of the leak is 0.5% of the total length of the system; within approximately +/- 160 feet for the Liberty offshore section. The manufacturer has a number of documented tests on the performance of the system. Because of the difficult installation, operational, and repair conditions for the subsea arctic application, the LEOS system reliability has not been estimated.

Page 3-41, Section 3.7.4.4 – A periodic pipeline leak test as applied by EPA technologies analyses a 5 minute pressure hold time increment, specifically to avoid longer term thermal effects. Longer hold times have been found to not significantly improve detection accuracy. Potential valve seat leaks may be addressed through periodic valve sealing tests and/or a double block valve configuration.

Page 3-43, Section 3.8.1 – There are no assumptions required to support this statement. To most effectively minimize risk, your resources are better spent if you mitigate your highest hazard first. Please refer to Kaplan (1991).

Page 3-44, Section 3.8.2 – Fi is better characterized as occurrences per project lifetime. It is dependent on annual frequency by the equation:

$Fi = 1 – (1-Fia)^N$ [occurrences per project lifetime]

where Fia = annual frequency (occurrences per year)

N = project lifetime (years)

Page 3-46, Section 3.8.4.1 – Detailed operating procedures for the leak detection system are beyond the scope of the conceptual design presented in the report. However, during operation, leak detection system parameters will be compared to predetermined alarm set points and calculated values. Any discrepancies (i.e. variance in system parameters outside of the valid set point range) will show up immediately. Values outside of the valid set point range will cause an alarm, forcing an operator to acknowledge the change in status and investigate the cause. If the reason for the alarm cannot be determined and verified as a false alarm, the system will automatically shut-in the pipeline. The valves will be remotely controlled and mechanically operated.

If one of the valves along the pipeline were suddenly closed, a surge in pressure would occur. This would result in a “oil hammer” effect (water hammer effect caused by the oil). Because of a code allowable surge pressure of 1.1 x MAOP, the rate of valve closure must be controlled. Analysis indicates that valve closure times should be set at approximately 8.5 minutes to remain within code allowables.

Page 4-1, Section 4.1.1 – There will be residual plastic strains at each bend. However, these will not affect the pipeline performance because:

- the welds (where the fracture limit state is applicable) are away from the bends
- the residual strains are the result of controlled bending around a mandrel which does not ovalize the pipe. Therefore, the compressive strain limit (local buckling Limit State) is almost the same as in a straight, unbent pipe.

Page 4-2, Section 4.1.2.2 – Section 4.1.2 is a summary section. The actual selection of sub-alternative A occurs in section 4.3.3. The sentence is meant to convey that sections beyond the selection of the sub-alternative only apply to sub-alternative A.

Page 4-23, Section 4.8.1 – As part of the US Army Corps of Engineer stipulations, BPXA agreed to design, construct, operate and maintain a prototype leak detection system that would be installed with the Northstar pipelines. This system would have the ability to detect an oil spill beneath current threshold detection limits (from PPA and MBLPC). The system design had to be submitted and approved by the Corps prior to initiating pipeline trenching. INTEC Engineering investigated a number of supplemental leak detection strategies for Northstar and recommended the use of the LEOS system as it was considered the best available technology. This system is currently being installed with the Northstar pipelines. Although the LEOS system is considered the best available technology, by the time the Liberty pipeline is ready to be installed, another system may be identified that would be considered the best available technology. This could partially result from lessons to be learned from the Northstar installation and operation.

Page 4-27, Section 4.9.1.2 – Maximum ice gouge depth decreases with decreasing water depth.

Page 4-35, Table 4-12 – The ice is considered landfast which is not necessarily bottomfast. Although remote, it is conservatively assumed that there is the possibility that a vessel accident with the pipeline could occur.

Page 5-3, Section 5.1.2.3 – Section 5.1.2 is a summary section. The actual selection of sub-alternative B occurs in section 5.3.3. The sentence is meant to convey that sections beyond the selection of the sub-alternative only apply to sub-alternative B.

Page 5-12, Section 5.3.3 – Table 5-5 is only one of the selection criteria. Table 5-4 also indicates selection criteria. Taking into account overall structural response and installation/fabrication activities, sub-alternative B was selected.

Page 5-22, Section 5.5.3 – A detailed schedule risk analysis was beyond the scope of this report.

Page 5-27, Section 5.6.3.1 – The use of clamp anodes on the interior pipe could be further investigated in later design stages. Discrete anodes in the pipe-in-pipe annulus will have limited effectiveness. This is because the restricted (approximately 0.75 inch wide) annulus hinders electrical current flow through the annulus water to complete the cathodic protection circuit. A continuous cathodic coating may be more effective for this application.

Page 5-28, Section 5.6.3.6 – The seabed temperature in the vicinity of the pipe-in-pipe would be expected to be the ambient seawater temperature. The soil temperature at the outer wall of the pipe-in-pipe approaches the pipeline operating temperature.

Page 5-34, Section 5.9.1.3 – This section was intended to refer to strudel scour.

Page C-2, Appendix C – INTEC concurs. The numbers were reversed.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Alaska Outer Continental Shelf Region
949 East 36th Avenue, Suite 308
Anchorage, Alaska 99508-4363

Mr. Moon Lew
Liberty Project Manager
BP Exploration (Alaska) Inc.
Post Office Box 196612
Anchorage, AK 99519-6612

Dear Mr. Lew:

The Minerals Management Service (MMS) contracted with Stress Engineering Services, Inc. (Stress) to provide a third party peer review of the draft INTEC report, "Pipeline Systems Alternatives-Liberty Development Project Conceptual Engineering". The purpose of the contract was to ensure that the pipeline designs were reasonable and could accomplish the goals stated in the July 6, 1999, letter from this office to you. We have recently provided your office with two copies of Stress' Draft Final Report dated March 7, 2000. The findings of the Stress report will be used in our assessment of the various pipeline designs developed in the INTEC report for the Liberty EIS. We request that British Petroleum Exploration (Alaska) (BPXA) respond to the issues raised in the draft final report.

The US Fish and Wildlife Service (USFWS), the US Army Corps of Engineers (CORPS), and the MMS also reviewed the INTEC report and our comments are enclosed. We request that BPXA respond to these comments. The major concerns expressed in these comments are single season construction for each of the alternatives, the varying depth of cover for the alternatives, the leak detection threshold and reliability of the LEOS system, and secondary containment capability of the pipe-in-pipe (PIP) and pipe-in-HDPE (PIH) alternatives. These concerns were also raised in the Stress final draft report.

There are three issues that came from these reviews that are particularly important for assessment in the EIS. We request BPXA address the following; 1) provide a thorough explanation as to why different depths of cover were selected for the various pipeline systems, 2) the apparent disregard of the benefits of PIP and PIH to provide secondary product containment, and 3) single season construction for the PIP and PIH alternatives.

If you have any questions, please contact Mr. David Roby at 907-271-6557.

Sincerely,

Jeffrey Walker,
Regional Supervisor
Field Operations
MMS Alaska OCS Region

Enclosures

MMS Comments on Pipeline System Alternatives – Liberty Development Project Conceptual Engineering Report

Page	Section	Comment
1-5	1.3.3	The report mentions that "for pipe-in-pipe, 90% of the estimated second-season cost is added for contingency." Please explain why this is not 80%, which is the probability of requiring a second season of construction for the pipe-in-pipe.
2-3	2.1.3	As this pipeline is one of the first Arctic subsea pipelines, it seems prudent to build into the design an ability to do detailed monitoring of all pipeline system components throughout its life.
2-6	2.3.2 Table 2-2	Not sure why wind design is not in separate section. Temperature is a significant factor in these designs. Clarify that these temperatures are part of the environmental factors used during design. Construction and makeup ambient air temperature - 50 degrees F Installation temperature (wet trench) 30 degrees F Installation temperature (dry trench) - 50 degrees F
2-7	2.3.3.2	What is the design erosion distance over the life of the project and how was it determined?
2-22	2.8	Ice roads constructed in the vicinity of the pipeline can potentially cause a completely different strudel scour hazard than was analyzed.
2-29	2.12.1	"A change in pipeline length will result in a change in the design ice keel incision depth for the development area..." Maximum ice gouge depth for a region can't be dependent on the length of pipeline.. Pipeline length does change the probability that the event occurs over the pipeline.
2-31	Reserves and project Value	"With the economic life of Liberty held constant at 19 year, the actual reserves recovered are reduced as the pipeline size is reduced." A 6-inch pipeline carrying 23,000 bbl/day for 19 years would transport over 150 million barrels of oil. The 12-inch pipeline is completely filled to capacity for only 2-3 years and then has excess capacity. Economic factors such as rate of return on investment are significant influencing factors on pipeline size.
2-32	2.12.2	"Increasing the burial depths increases the load, but would reduce the potential displacement of the pipeline." Why would it reduce the potential displacement of the pipe?
2-33	Gravel mats	"Extending the burial depth will increase the amount of soil that can be placed over the pipe," In fact, you don't have to extend the burial depth in order to be able to place more soil over the pipe. Is more slumping expected if the trench is deeper? Does the ability to make the trench bottom smooth decrease with increased trench depth?
2-33	Stress-based Design bullets	"Any permafrost thaw settlement could result in substantial pipeline loading in areas prone to differential settlement due to the additional soil overburden." On page 2-32, section 2.12.2, last sentence it states that increased burial depth would reduce the potential displacement of the pipe. These sentences seem to be contradictory.
3-2 and 3-6	3.2.1 and 3.2.6	The operational and differential temperatures for the pipeline in these two sections differ. Please indicate which values are correct, or if they are purposely different what is the rationale for the difference?
3-4	3.2.4	The report mentions that "a depth of cover of 7.0 feet is tentatively established as a baseline." While this is true for the single wall pipeline system it is not true for any

		of the other three designs. Please show what the soil transverse displacement at the centerline of the other three pipelines would be for this 3-foot deep ice gouging event.
3-7	3.3.2	The report states "Only one pipeline has been built in an arctic offshore environment". This statement is not technically correct. The Endicott pipeline has been built in an arctic offshore environment, albeit on a causeway. It would be more accurate to state that only on subsea pipeline has been built in an arctic environment.
3-10	3.3.5.3	Not sure how a plow can be used in winter.
3-11	3.3.5.4	If you can plow in the winter, why can't you jet in the winter? Can turbidity be reduced by adding silt curtains?
3-21	3.3.11	The HDD discussion fails to recognize any environmental advantages or disadvantages or the consequences of going through permafrost.
3-26	3.5.3	The pipeline monitoring program is expected to be reviewed by appropriate Federal and State regulators. All pipeline evaluations and remedial actions are expected to be reviewed by appropriate Federal and State regulators.
3-27	Table 3-1	This table indicates that baseline pig runs would be performed after construction and before freeze-up. Does this mean that the pig runs will not be performed until the following open water season? It seems more practical to run the baseline pig immediately after construction is complete so that equipment will still be onsite if any remedial action was required.
3-28	3.5.3.6	"...the soil backfill around the pipe will act as a virtual anchor." Poor engineering terminology
3-29	3.6	Pipeline repair plans are expected to be reviewed by appropriate Federal, and State regulators.
3-30	3.6.1.1	It is unclear if the division between zone I and II has to do with ice road construction or liquid water in the trench. Having bottomfast ice doesn't guarantee a dry trench at pipeline depth.
3-34	3.6.2.2	Not sure why mechanical sleeves are being suggested as a temporary repair, which implies the pipeline would be operated until conditions become favorable to make a welded repair. A better assumption would be to assume the pipeline will not go back into operation until it is returned to it's original integrity and plan accordingly. This assumption also places the emphasis on getting the design right to begin with and avoiding any problems over the pipeline life.
3-34	3.6.4	"Before a repair is attempted, it would be necessary to displace the pipeline contents. If this is not possible, it may be necessary to prevent further product loss from the pipe by placing an external clamp around the pipe at the leak." It is unclear if a pipeline repair would be attempted with oil still in the pipeline. Further narrative could clarify the options and consequences.
3-38	3.7.3	The whole section is based upon an operating leak detection system. What about availability and reliability of the leak detection systems?
3-41	3.7.4.4	Add some discussion about the effects of temperature changes in the oil and associated contraction as it relates to a short pressure leak test. I agree that a bubble-tight seal at the block valves will be difficult to achieve. This type of short term pressure test warrants further study because if it could be done reliably with accurate results it would be a quick way to disprove false positive leaks rather than adjusting thresholds.
3-43	3.8.1	"Suppose that H_1 is small compared to H_2. In order to more effectively minimize risk, it would be wise to spend more resources on S_2 rather than on S_1." There are several assumptions that have to be made for this to be true. Please state those assumptions.
3-44	3.8.2	Is Fi really the number of times Si will occur during the project or is it the annualized frequency?
3-46	Large	Is the leak detection system going to require operator intervention or is it going to be

	Leak (guillotine Break)	automatic? If the operator is expected to confi[illegible] leak in less than five minutes, what will he be doing ? Taking [illegible] shore crossing valve to close seems like a long time.
4-1	4.1.1	"The zigzag sub-alternative allows controlled [illegible]ment due to thermal expansion, resulting in a smaller "locked-in" axial [illegible]ive force than a straight pipe" Doesn't it also start out with [illegible] the apex of each zag ?
4-2	4.1.2.2	"Therefore the remainder of this analysis add[illegible]ive A.". Don't understand this statement as sub-alternative B [illegible] later in Chapter 4.
4-23	4.8.1	The report indicates that LEOS is considered [illegible]ology (BAT). Was this BAT determination made by a regula[illegible] HPXA's opinion?
4-27	4.9.1.2	Bullet E5 states "Maximum ice gouge depth de[illegible]pth." This statement is unclear. Does it mean that [illegible] as water depth increases, or does it mean the ice gouge de[illegible]er depth decreases.
4-35	Table 4-12	This table indicates that damage caused by a vessel accident can occur anytime of the year. Is it really reasonable to assume that a vessel accident with the pipeline can occur during the winter when there is landfast ice?
5-3	5.1.2.3	"The remainder of this chapter considers only sub-alternative B." Don't understand this statement as sub-alternative A is mentioned profusely later in Chapter 5.
5-12	5.3.3	The report indicates that installation for pipe-in-pipe sub-alternative B is slightly better than for sub-alternative A. This statement is not supported by Table 5-5.
5-22	5.5.3	As two season construction is a critical factor in the cost of this alternative, it seems prudent to do a detailed schedule risk analysis.
5-27	5.6.3.1	Why not clamp anodes on the interior pipe as w[illegible]
5-28	5.6.3.6	What is the estimated seabed temperature in the immediate vicinity of the pipeline after it has been in operation for awhile?
5-34	5.9.1.3	The sentence is about ice gouge not strudel scour.
C-2	Analysis of the 1998 CFC Survey Data	This section states "The minimum ice gouge depth reported is 0.6ft, the maximum is 0.3 feet deep". These numbers seem to be reversed.

DEPARTMENT OF THE ARMY
U.S. ARMY ENGINEER DISTRICT, ALASKA
P.O. BOX 898
ANCHORAGE, ALASKA 99506-0898

REPLY TO ATTENTION OF:

DECEMBER 2 3 1999

Regulatory Branch
North Section
6-981109

Mr. Jeff Walker
Regional Supervisor
Field Operations
Minerals Management Service
Alaska OCS Region
949 E. 36th Avenue
Anchorage, Alaska 99508-4363

Dear Mr. Walker:

This is in reference to your November 18, 1999, letter requesting comments on BP Exploration (Alaska) Inc.'s draft report entitled "Pipeline Systems Alternatives - Liberty Development Project Conceptual Engineering". The following is in reply to your request to identify any major deficiencies that would prevent the third-party reviewer from completing an engineering review of the pipeline system alternatives.

The purpose of BPX's pipeline systems study was to provide a comparison of alternative pipeline configurations as hydrocarbon delivery systems for the proposed Liberty Development Project (LDP). The study was to equitably compare different pipeline systems design alternatives addressing system reliability in an arctic subsea environment, cost-benefits (life cycle) of different pipeline designs and supplemental state-of-the-art leak detection systems beyond pressure point analysis and mass balance line pack compensation.

The four pipeline systems concepts that were to be equitably compared were: single wall steel pipeline, double wall (steel) pipeline system, steel pipe inside and HDPE, or similar, sleeve, and flexible pipe (e.g. coflex). Factors for comparison were to include: structural design (in addressing environmental loads of ice keel, strudel scour, thaw settlement, upheavel buckling, etc., construction, operation and maintenance, repair, leak detection, costs, scheduling, spill volume determinations and failure probability analysis, etc).

Additional guidance and direction for BPX's pipeline systems alternatives study were developed during the June 22, 1999, facilitated multi-agency LDP meeting and the June 29, 1999, Liberty Environmental Impact Statement Team meeting. Your July 6, 1999, letter transmitted a list of issues, objectives, and design criteria that BPX was expected to address in the pipeline systems alternative report being prepared by INTEC. Included with your July 6 letter were written responses to your June 23, 1999, letter from the U.S. Fish and Wildlife Service and the U.S. Army Corps of Engineers that elaborated on the formulation of assumptions, objectives, and criteria to be used in the comparative analysis for alternative pipeline designs.

We determined that many of the issues identified from the direction and guidance provided to BPX as stated in your July 6 letter, with attachments, are not adequately addressed. For example, completion of a mutually agreeable comparative pipeline design alternative evaluation and trade-off analysis for engineering, economic and environmental feasibility. We find the report deficient in addressing the feasibility tests and trade-off analysis. The test and analysis were to focus on satisfying the performance standard (design function) of minimizing the likelihood of oil entering the environment, and should a spill occur, the feasibility of the pipeline design to facilitate detection, containment and recovery that minimizes environmental damage.

We also find the report deficient in addressing the specific issues, objectives and criteria as stated in enclosure 1 of your July 6 letter. This is especially true for the cased (pipe-in-pipe) pipeline system alternative. We concur with the U.S. Fish and Wildlife Service's comment letter to you dated December 3, 1999, on the inadequacies of the report in addressing secondary containment, pipe-in-pipe design, leak detection, and construction season. As stated by U.S. Fish and Wildlife Service December 3 letter and our meeting with MMS on February 26, 1999, secondary containment was to be a design function for the pipe-in-pipe and other pipeline system alternatives. Secondary containment of oil leaks from the carrier pipe continues to be a major issue with the Corps and resources agencies and the report contributes little to this topic as part of the equitable comparison of pipeline system alternatives. The report clearly fails to recognize any benefits of secondary containment.

In previous meetings with MMS, Corps, and BPX, it was our understanding that BPX was committed in undertaking this pipeline system alternative analysis to select the safest pipeline system in consideration of optimal life cycle costs and to document the rationale for the selection and non-selection of the alternatives. BPX even went to the point of putting their proposed single wall pipeline design on hold, to await the results of this study and a third party engineering review.

The purpose of third party review is to conduct an independent evaluation to confirm that sound engineering practices were followed in development of the conceptual designs, construction methodologies, construction and life cycle cost estimates, and repair methods for each of the pipeline systems. It was our understanding that the review of the environmental components of the pipeline systems alternative study, (e.g., trade-off analysis, environmental consequences and benefits) was to be undertaken by the resource agencies of the Liberty EIS team. As stated above, we consider that latter can not be accomplished due to the inadequacy of the report in addressing these issues. However, we do not object to continuing the 3rd party engineering review as scheduled, realizing that improvements, revisions and/or supplementation to BPX's report prepared by INTEC will need to be undertaken.

Although we concur with your November 18, 1999, transmittal letter statement that there is sufficient information to proceed with the third party engineering review, we do not concur that the INTEC report was prepared following guidance developed by the Liberty EIS team. We can not concur with your statement that the alternative assessment goes beyond your expectations for this conceptual engineering report. We find that the "Pipeline Systems Alternatives - Liberty Development Project Conceptual Engineering" report falls short of our expectation and the expectation of the resource agencies on the Liberty EIS team. Nor can we concur with your November 18, 1999, statement that "The draft report includes a risk assessment, which concludes that a single walled pipeline has the lowest risk of an oil spill from any of the four alternatives evaluated." The report, page 9-9, also states that "a pipe-in-pipe system with a seven-foot depth of cover would have a risk of 2.8×10^{-4} barrels of oil spilling into the environment, which is about 6 times less risk as the currently evaluated single wall pipeline system." We believe that the third party engineering review will validate this through the equitable test of project design.

We appreciate the opportunity to provide comments on the subject report. As a cooperating agency for the Liberty Development Project, EIS, we look forward in working with your office. Please contact me directly at 753-5554, or by mail at the letterhead address, if you have questions or desire further information concerning the above.

Sincerely,

Lloyd H. Fanter
Acting Northern Unit Coordinator

Original Sent to file fn

DEPARTMENT OF THE ARMY
U.S. ARMY ENGINEER DISTRICT, ALASKA
P.O. BOX 898
ANCHORAGE, ALASKA 99506-0898

REPLY TO
ATTENTION OF:

RECEIVED
Anchorage, Alaska

JAN 03 2000

REGIONAL SUPERVISOR
FIELD OPERATION
MINERALS MANAGEMENT SERVICE

Regulatory Branch
North Section
6-981109

DECEMBER 3 1 1999

Jeff Walker, Regional Supervisor
Field Operations
Minerals Management Service
Alaska OCS Region
949 E. 36th Avenue
Anchorage, Alaska 99508-4363

Dear Mr. Walker:

This is a follow-up to our December 23, 1999, letter responding to your request for comments on BP Exploration (Alaska) Inc.'s draft report entitled "Pipeline Systems Alternatives - Liberty Development Project Conceptual Engineering". The purpose of BPX's pipeline systems study was to provide an equitable comparison of alternatives that recognized the benefits and determents of each pipeline system configuration for the proposed Liberty Development Project (LDP). The following comments address risk assessments, operational damage frequency and consequences of failure comparison between pipeline systems.

The report provides little evidence toward resolving previous arguments between pipeline engineers and resource agencies, and even provides an appearance of favoring the old "concept of engineering design" through scenario selection and assumptions used. The apparent bias of the study continues the view "that it [the single wall pipeline system] would be designed not to leak, and thus, designing additional containment would contradict the concept of engineering design." page 8-3. Based on past pipeline performance, pipelines do leak. The resource agencies view is that supplemental leak detection systems and containment measures could minimize the consequences of an oil release from the carrier pipeline to the environment.

The report does little toward resolving or even attempting to address engineering challenges associated with pipe-in-pipe alternatives, such as cathodic protection. The report simply states that even with dual-layer fusion-bonded epoxy external coatings to the inner pipeline, the pipeline cannot be cathodically protected. No consideration is given to provide an inert environment within the annulus of the pipelines or other potential solutions. Although the report recommends leak detection within the annulus, the report fails to address the potential for increased sensitivity within the annulus in providing an early warning system. The report continues to reference a LEOS type system as a supplemental leak detection system for which there are concerns which remain to be addressed relating to its' operation in an arctic marine environment. The report, in attempting to address state-of-the-art supplemental detection systems regresses to the use of ice borehole sampling. Supplemental state-of-the-art sensor systems (such as a fiber optic sensor system within the annulus) are not adequately addressed nor is there a comparison of leak detection sensitivity in providing an early warning of an oil leak.

The scenarios and the four damage categories developed appear to favor a single wall pipeline system. An example is the calculation of an operational damage frequency risk assessment which does not take into account any advantages for a pipe-in-pipe system, such as secondary containment or the potential for increased structural integrity. The report assumes that for a category 1 or 2 event there would be no releases of oil into the environment. Yet the report does not calculate a probability for at what point nor at what type of condition could a spill occur from the carrier pipeline. For a category 3 event (small and medium leak) pipe-in-pipe alternative, the report assumes pipeline failure is by ice gouging causing both the inner and outer pipelines to fail and release oil into the environment. By failing to recognize the benefits of secondary containment, the report automatically assumes a 125-barrel oil leak into the environment, which would be detected by a supplemental leak detection system. In actuality, secondary containment would provide time to check and assess damage, plan and implement corrective action that should eliminate or significantly reduce the amount of an uncontrolled oil release into and damage to the environment.

The report recommends the inclusion of a supplemental leak detection system for all alternatives and incorporates this concept within the risk assessment calculations. We would like to point out that the applicant has not incorporated such a supplemental leak detection system within their permit application for the Liberty Development Project. As such, the leak detection threshold of 0.15% of product transport (maximum of 65,000 barrels per day) should be utilized when providing damage estimates for the single wall pipeline.

The report assumes that a medium leak (defined as 97.5 barrels per day) resulting from a small crack or pinhole in a single walled pipeline would be detected by the Siemens' LEOS system resulting in an expected loss of only 125-barrels of oil prior to detection. However, we are not aware of any numerical simulations of oil migration that would be necessary to determine this expected loss nor have considerations to soil type, water depth, etc. been delineated in determining response time along the proposed Liberty pipeline route. The report then assumes the same 125-barrel oil leak rate from the single wall pipeline for the pipe-in-pipe alternative that would not be hindered by varying soil permeability values and migration patterns. Since damage estimates would also be affected by the amount of oil released, it would seem reasonable that any alternative that could limit the quantity of release, such as by early detection would have less damage. Since risk is defined as the product of damage times uncertainty (*R=DxU*, page 3-42), alternatives which could reduce damage would have a lower risk.

In summary, although the report does provide some insight into risk identification, we remain concerned that the report favors the single wall pipeline system with supplemental leak detection by viewing engineering problems as challenges to be overcome. While, in contrast, other pipeline system alternative problems are viewed as being costly and complex and are quickly used to discount the alternative's viability without regard to benefits. The use of assumptions, development of scenarios and damage categories appears partial to the single wall pipeline system. The results of which are carried forward in the comparison of risk assessment and operational damage frequency between pipeline systems. We request that the third party reviewer provide a thorough review and analysis, and if necessary develop scenarios and damage categories which take into account potential benefits of the pipeline system alternatives, including secondary containment and early spill detection.

We appreciate the opportunity to provide comments on the subject report. As a cooperating agency for the Liberty Development Project, EIS, we look forward in working with your office to provide a quality document. Please contact me directly at (907) 753-5554, or by mail at the address above if you have questions or desire further information concerning the above.

Sincerely,

Lloyd H. Fanter

Lloyd H. Fanter
Project Manager

Enclosures

United States Department of the Interior
Fish and Wildlife Service
NORTHERN ALASKA ECOLOGICAL SERVICES
101 12th Ave., Box 19, Room 110
Fairbanks, Alaska 99701-6267
3 December 1999

Mr. Jeff Walker
Minerals Management Service
Alaska OCS Region
949 E. 36th Avenue
Anchorage, Alaska 99508-4363

Re: Draft Pipeline Alternatives Report

Dear Mr. Walker:

In response to your cover letter dated November 18, 1999, the Service has conducted a preliminary review of the draft report "Pipeline Systems Alternatives - Liberty Development Project Conceptual Engineering," prepared by INTEC for BP Exploration (Alaska) Inc. (BPXA). We did not receive the report until November 23; therefore, we have conducted only a cursory review of the report and are not yet able to provide detailed comments or an assessment of its adequacy. We cannot, at this time, endorse the report; however, due to the time required to review and revise a document of this nature, we see no reason to withhold the report from peer review by Stress Engineering, Inc., the selected third-party contractor. The Service will continue to review the document during this process.

Our preliminary review identified several concerns which we briefly outline below:

1. Secondary Containment. The July 6, 1999 letter from the Minerals Management Service to BPXA detailing objectives and issues to be addressed by the Pipeline Alternatives Report specifically requested that secondary containment be "identified as a consideration in the design philosophy" (Issue 2). In addition to several other factors, containment was to be compared in a narrative analysis and summary matrix of all alternatives (Issue 5). Clearly, secondary containment of leaks from the inner pipe, as unlikely as they may be, was and continues to be a major issue with resource agencies. Yet, the report fails to recognize any benefit of secondary containment to the extent that it is not even mentioned in the Executive Summary or discussed to any extent in Chapter 5 (Pipe-in-Pipe Design Analysis) or Chapter 9 (Comparative Analysis). Chapter 8 is a brief discussion of a few alternative approaches to secondary containment, none of which have been attempted in the arctic. The secondary containment characteristics of the pipe-in-pipe alternative are not discussed in this chapter. The lack of any discussion of the environmental benefits of pipe-in-pipe secondary containment, compared to the potential drawbacks of this design, is an apparent weakness in this analysis. The July 6, 1999 letter requested a comparative analysis of the "technical, economic, and environmental merits and limitations of the design options." The *environmental* merits and limitations (or consequences) of each design are not clearly articulated in the report, with the issue of secondary containment being one of the most obvious omissions.

2. Leak Detection. The Service is concerned about the degree to which the report relies upon the LEOS supplemental leak detection system. The report leads the reader to believe the problem of detecting low level (below current pressure and volume monitoring thresholds) leaks has been solved with the discovery of LEOS. Although the Service believes LEOS has promise, this technology remains untested in the arctic. The first actual test of this technology in arctic subsea conditions will be in association with the Northstar Project.

3. Pipe-in-Pipe Design. The report does not thoroughly answer several questions regarding the chosen design option for steel pipe-in-pipe. The relationships between wall thickness, interactions between the two pipes, and stiffness are not well described. It is not clear if the spacers mentioned would withstand the loads of ice gouging and supply structural connectivity between the two pipes. If they do, do the two pipes act together to resist bending? How would two pipelines of less thickness (e.g., approximately 0.5 inch) react together if connected by bulkheads or spacers, and then buried with 7 feet of backfill? While every possible option cannot be thoroughly assessed, options with potential should be considered using the data made available via this analysis.

4. Single Season Construction. This is clearly a major design criteria for the Liberty project, as proposed by BPXA. The report does not discuss multiple options or approaches for completing the pipe-in-pipe installation in a single winter season. It seems plausible that dual installation crews, working from both the landward and the seaward ends of the pipeline could provide greater assurance of single season construction of the pipe-in-pipe design. This would obviously be more expensive than a single-walled installation, but it could be less costly than using two construction seasons.

5. Conclusions. The statement: "[t]he conditions that might give rise to a loss of product from the inner pipe would also affect the outer pipe" appears in several locations in the report. This appears to say the inner pipe will never develop a small leak (or any leak for that matter) due to imperfect materials or construction. If this is the intent, data are needed to justify this statement. In addition, using the argument that containment is not a reasonable function of an outer casing because it has never been done before is not convincing. The Colville River crossing is an example of a casing being designed and constructed for the purpose of leak containment and redundant structural integrity (Alpine Development Project Environmental Evaluation Document, September 1997; letter from ARCO to State Pipeline Coordinator, June 2, 1997).

We appreciate the opportunity to supply input and request this letter be forwarded to Stress Engineering along with the draft report. If you have questions regarding this issue, please contact Larry Bright at 456-0324.

Sincerely,

Patrick Sousa

Patrick J. Sousa
Field Supervisor

cc. T. Lohman, NSB, Anchorage
T. Rockwell, EPA, Anchorage
J. Hanson, NMFS, Anchorage
G. Gray, SPCO, Anchorage
L. Fanter, COE, Anchorage

LIBERTY DEVELOPMENT PROJECT

EVALUATION OF PIPELINE SYSTEM ALTERNATIVES: EXECUTIVE SUMMARY

BP Exploration (Alaska), Inc. (BPXA) submitted a Development and Production Plan (DPP) for its proposed Liberty Development in February 1998. As discussed in the DPP, BPXA plans to produce sales-quality crude oil at Liberty Island, located in Foggy Island Bay approximately 6 miles offshore of Alaska's North Slope in the Beaufort Sea. Liberty will be a self-contained drilling and production facility built on a manmade 5-acre gravel island in about 22 feet of water (Figure 1). According to the DPP, the oil will be delivered from Liberty to the trans-Alaska pipeline by means of a 12-inch-diameter pipeline approximately 7.6 miles from Liberty Island to a tie-in with the existing Badami oil pipeline, which connects with the Endicott oil pipeline.

The 6.1-mile offshore segment of the Liberty oil pipeline is the most challenging aspect of the project, since the pipeline must be built in the nearshore landfast ice zone of the Beaufort Sea. BPXA retained INTEC Engineering, Inc. of Houston, Texas, to prepare a conceptual engineering report to evaluate and present the design alternatives for the pipeline. The report provides permitting and resource agencies information for evaluating alternatives in the Liberty Environmental Impact Statement. A peer review of these conceptual designs will be conducted by an independent engineering contractor selected by the agencies.

The INTEC report reviews four design alternatives, which are shown in Figure 2:

- Single wall steel pipeline
- Steel pipe-in-pipe system
- Single wall steel pipe inside HDPE (high-density polyethylene) sleeve
- Flexible pipe system

In order to fully evaluate these alternatives, the report covers:

- Project design criteria applicable to all alternatives
- Installation methods available for all alternatives
- Construction costs
- Operations and maintenance issues
- System reliability
- Leak detection systems

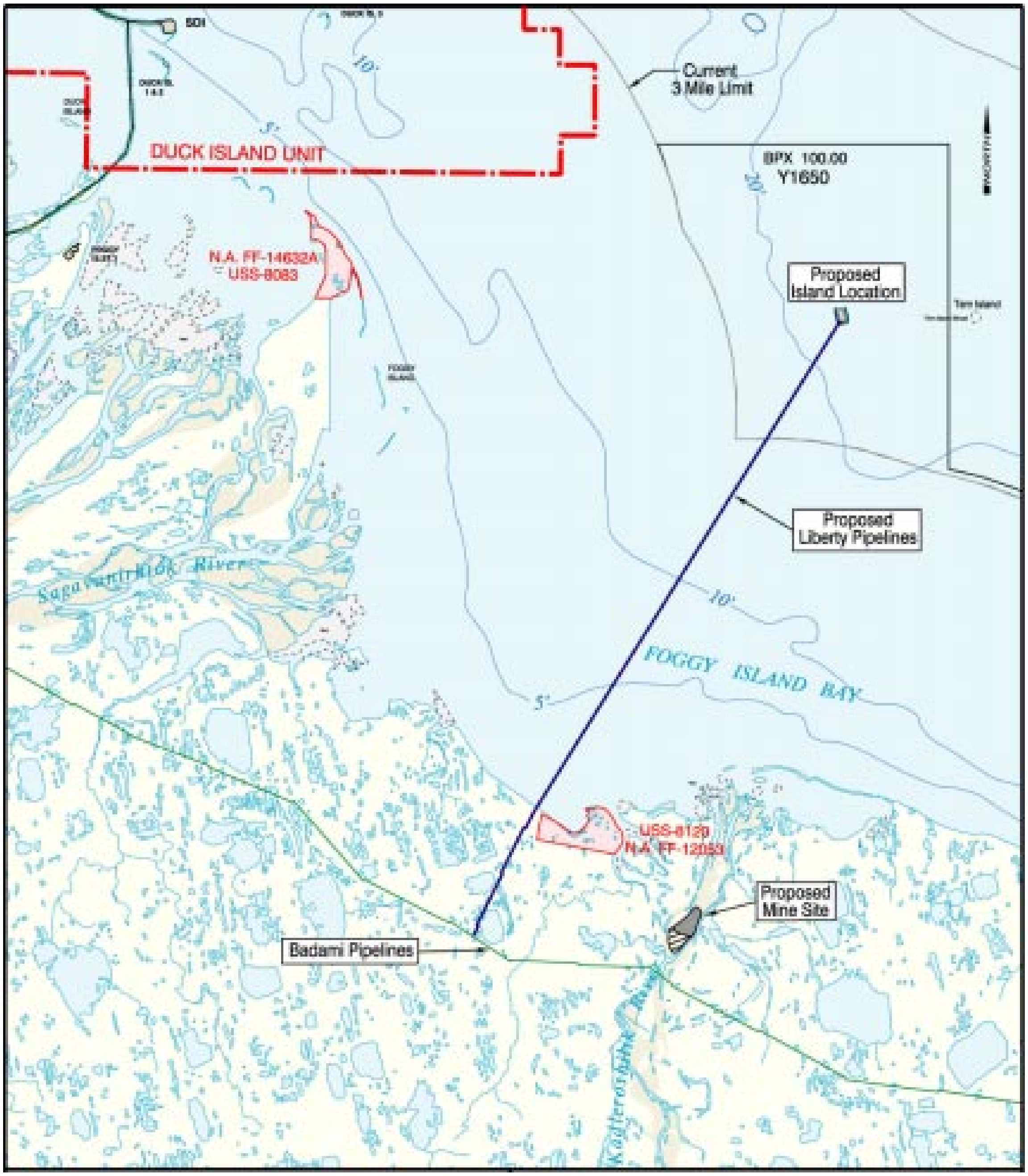


FIGURE 1
LIBERTY PROJECT LOCATION MAP

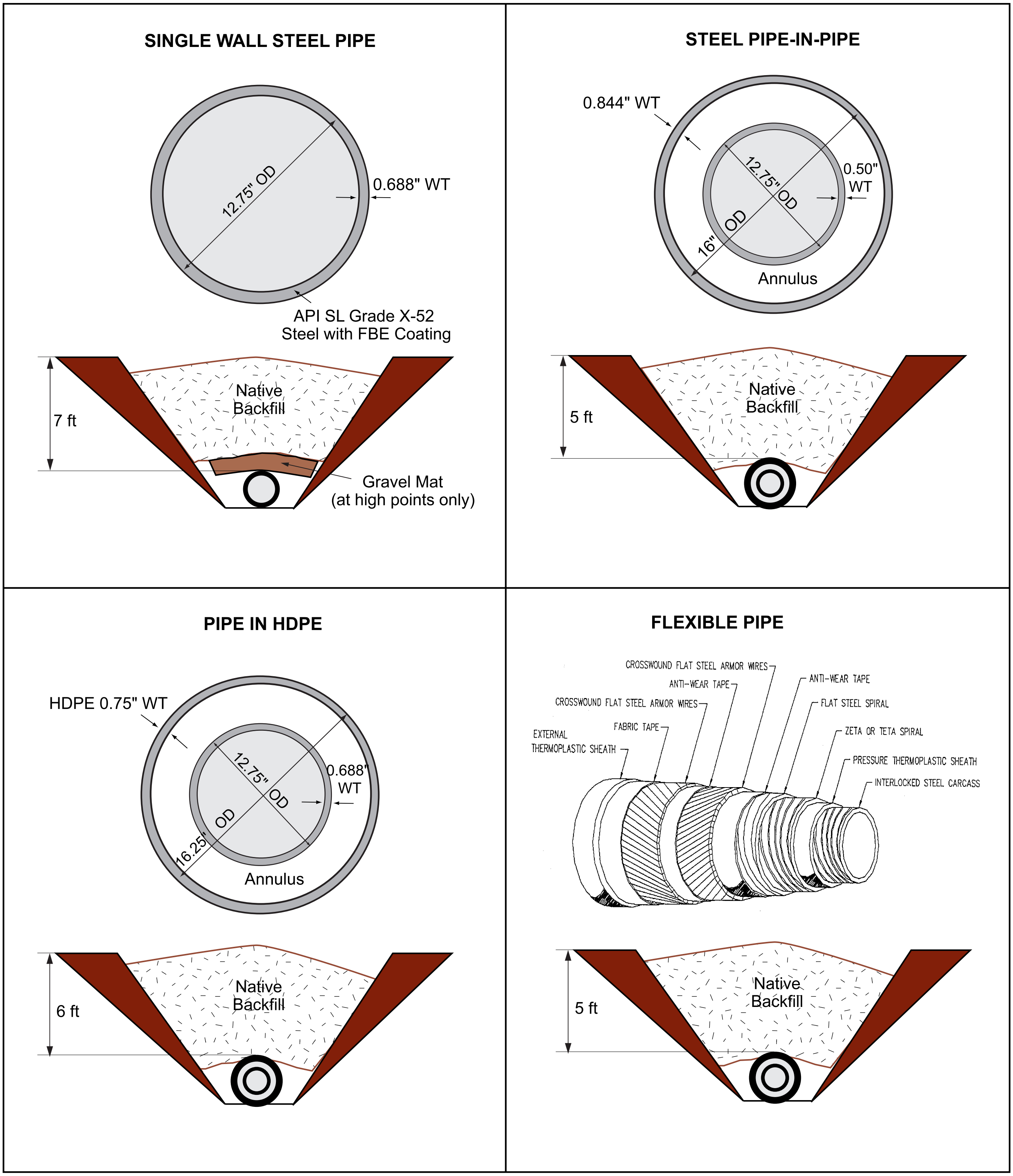


FIGURE 2
LIBERTY PIPELINE ALTERNATIVES

1. SUBSEA PIPELINE DESIGN BASIS

1.1 Safety Requirements

Any pipeline alternative must be designed for safe installation and operation. Safety requirements for a subsea arctic crude oil pipeline are based on a combination of government regulations, industry design codes, and project-specific engineering evaluations:

- U.S. Department of Transportation (DOT) Pipeline Safety Regulations, 49 CFR Part 195, Transportation of Hazardous Liquid by Pipeline.
- ASME B31.4 Code for Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.
- API RP 2N, Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions.
- Pipeline Design Technical Review – Liberty system alternatives are reviewed through the ongoing U.S. Minerals Management Service (30 CFR 250 Subpart J) and Alaska right-of-way lease procedures (A.S. 38.35), and industry peer reviews.
- State of Alaska Regulations – 18 AAC 75 includes specific design requirements for leak detection and also requires a best available technology review of certain pipeline system components (e.g., leak detection, cathodic protection, and communications systems).

1.2 Additional BP Design Objectives

In addition to regulatory and project-specific design requirements, the subsea pipeline system alternative should satisfy the following design objectives:

- Exceeding minimum Alaska State regulatory requirements for crude oil pipeline leak detection (18 AAC 75). The two state-of-the-art leak detection systems presently in use on existing North Slope pipelines and proposed for all Liberty pipeline system alternatives exceed these requirements.
- A supplemental leak detection system is desirable to detect smaller leaks before they can accumulate large volumes of spilled oil during the ice-covered season.
- Pipeline inspection pigging should monitor pipe conditions which could lead to a potential leak formation if uncorrected. This includes periodic wall thickness measurement, pipe body ovalization, and pipe geometry (bending) monitoring inspections with tools run through the pipeline.
- Pipeline construction during the winter ice-covered season is desirable for minimizing environmental impacts.
- Reasonable pipeline capital costs are required to support development economics.

1.3 Pipeline Design Criteria

A buried subsea pipeline must be designed to withstand the forces applied to it by the oil in the pipe and by any environmental events that have the potential to act on the pipeline. Table 1 summarizes these forces.

TABLE 1
DESIGN BASIS FOR LIBERTY PIPELINE ALTERNATIVES

CRITERIA	SPECIFICATION
Crude Oil API Gravity	25.4°
Crude Oil Specific Gravity	0.9 (@60°F)
Design Oil Flowrate	65,000 bbl per day
Pipeline Length (subsea section)	6.1 miles
Maximum Pressure at Badami Tie-in	1,050 psig
Maximum Allowable Operating Pressure	1,415 psig
Maximum Operating Temperature (at inlet)	150°F
Minimum Flowing Temperature: (at inlet)	120°F
Lowest Ambient Air Temperature:	-50°F
Design Ice Gouge Depth in Seafloor	3 feet
Design Strudel Scour Span	≈1 foot
Design Thaw Settlement (single wall steel)	1 foot
Design Prop Height for Upheaval Buckling	1.5 feet

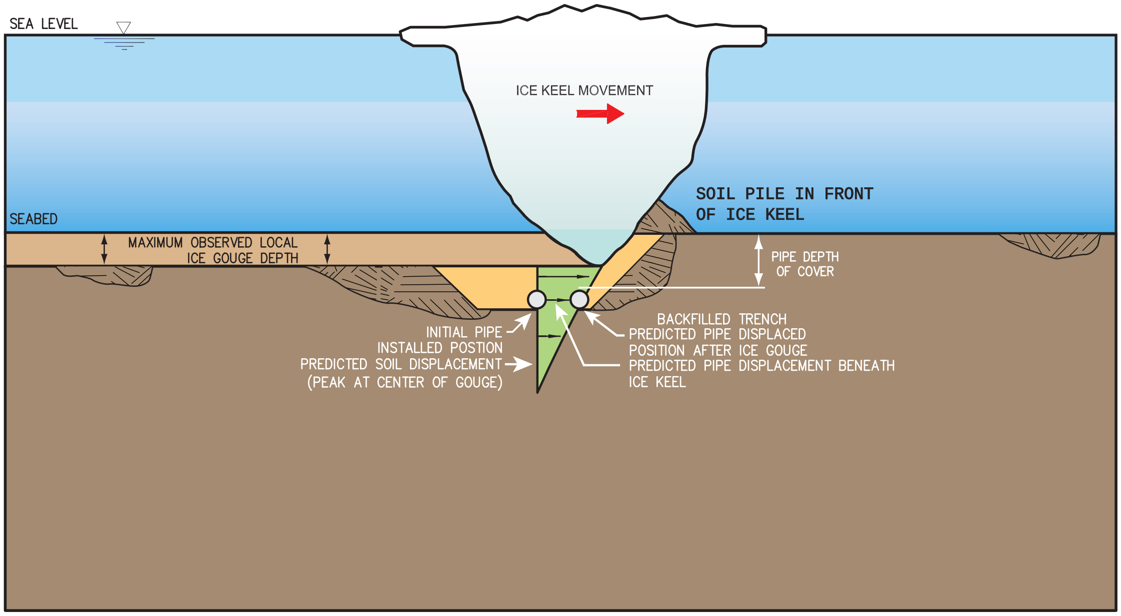
The design oil flowrate is 65,000 barrels per day based on reservoir and field production considerations. This, in turn, establishes the minimum temperature and inlet pressure at the tie-in of the Liberty pipeline with the Badami pipeline. The pipeline internal diameter is established based on **pipeline length**, **flowrate**, and **pressure**.

The **pipe submerged weight** is a key design parameter since the pipeline must be heavy enough to sink and stay in the trench during installation. When the trench is excavated and then backfilled after the pipeline is installed, a slurry of soil and sea water may form in the trench bottom. The required pipeline submerged weight to counteract the buoyancy imparted by the slurry affects the pipeline configuration and installation procedure.

Two key factors determine how deep the pipeline would be buried in the seabed. The first is the **depth of cover**, which is defined as the distance from the top of pipe to the original undisturbed seafloor. Adequate depth of cover is important for protecting the buried pipe from loads induced by "ice keel gouging" and "strudel scour."

- **Ice Keel Gouging:** During fall freeze-up and spring breakup, sea ice in the Beaufort Sea tends to pile up at some locations creating pressure ridges, some of which have keels that periodically form gouges into the seabed. Therefore, proper design requires establishing the extreme-event ice gouge depth along the pipeline route. However, in addition to being buried below the design expected ice gouge depth, the pipeline must resist strains caused by potential seabed soil movements from the gouge (Figure 3). The pipeline depth of cover (measured from the original seabed to top of pipe) performs this task. Based on an analysis of extensive data on the pipeline route, a design gouge depth of 3 feet will be used which is more than two times deeper than observed values.

ICE KEEL LOADING



STRUDEL SCOUR

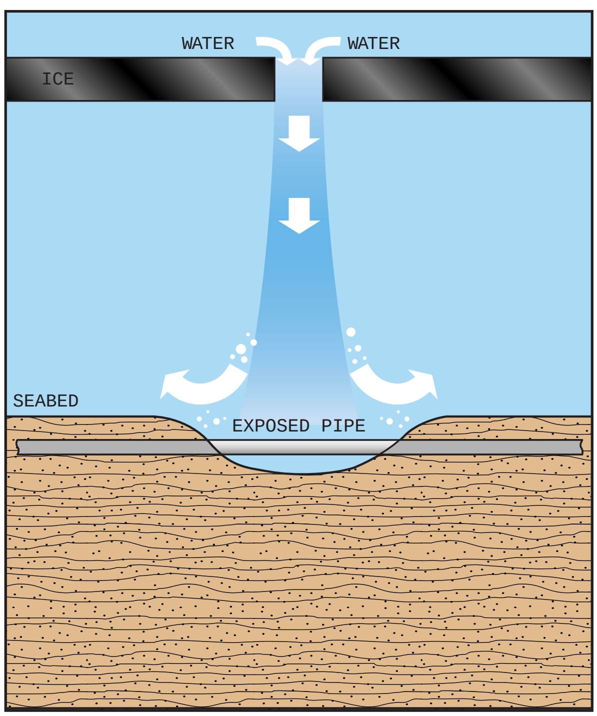


FIGURE 3
ICE KEEL LOADING AND STRUDEL SCOUR

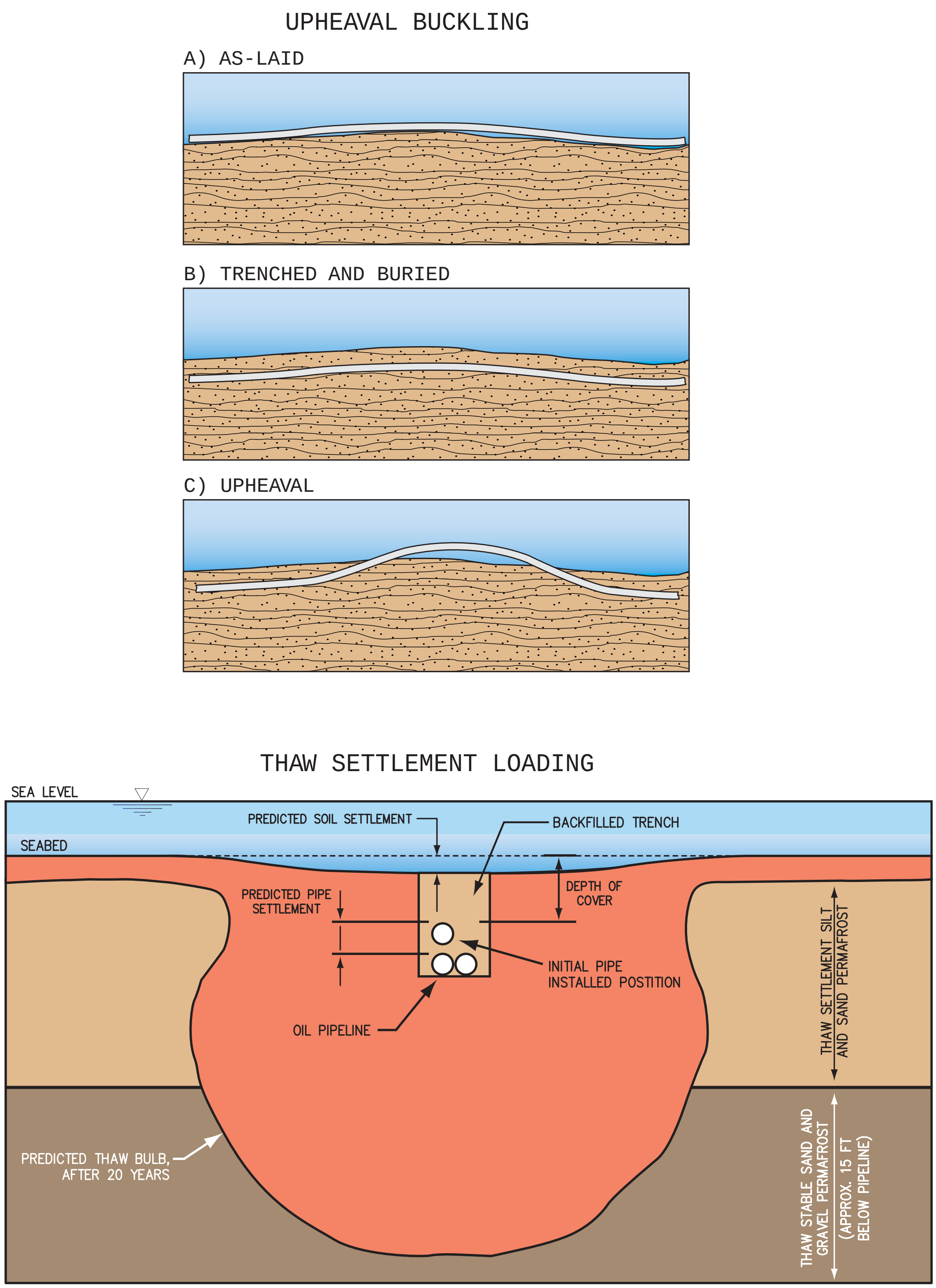


FIGURE 4
UPHEAVAL BUCKLING AND THAW SETTLEMENT

- **Strudel Sour:** Scouring of the seafloor by water draining through "strudel" holes in the ice. This occurs in spring when rivers thaw before the nearshore ice sheet, and river water flows out over the ice. Strudel scour can expose the pipeline and erode material under the pipe, causing strain on the pipeline (Figure 3).

Another design consideration is the **backfill thickness**. This is important where the difference between the ambient temperature and pressure during the installation and pipeline operation is great. This pipe expansion due to temperature differences — in combination with the pipe wall thickness, backfill soil properties, and the levelness of the trench — affects the pipe vertical stability due to **upheaval buckling** (Figure 3). When a buried steel pipeline operates at a temperature and pressure higher than at installation, it will try to expand lengthwise, and at individual high points along the pipe, the pipe exerts an upward force into the soil cover. If the upward force exceeds the resistance of the soil cover, the pipeline stiffness, and the pipeline weight, the pipeline will move up and may be become exposed on the seafloor. This phenomenon is known as upheaval buckling.

Another external pipe load directly caused by backfill thickness is the result of **thaw settlement** (Figure 4). In nearshore shallow waters of Foggy Island Bay, the soil under the pipeline could contain permafrost. Because the pipeline will be warm, a "thaw bulb" will develop around the pipe. If the frozen soil has a high ice content, this thawing can cause the soil to settle, and the soil cover on the pipeline loads it, placing strain on the pipeline. Deeper pipeline trenching can increase the backfill thickness and thus leads to an increased overburden load during thaw settlement, but it also can reduce the amount of settlement. However, deeper pipeline trenching protects the pipeline from strudel scour and ice gouging.

Finally, the pipeline must avoid excessive internal and external corrosion over the project life, and external corrosion control is required for each pipeline alternatives.

2. INSTALLATION METHODS

Possible methods for excavating the trench and installing the pipeline were reviewed. Trenching methods include conventional excavation with dredging, plowing, jetting, and mechanical trenching. Installation methods include use of lay vessels, reel vessels, tow or pull methods, and installation in winter through an ice slot. The possibility of using directional drilling from shore was also examined, but too many technical difficulties were identified. Completing one hole and installing a pipeline by directional drilling is a relatively complex undertaking, but is nevertheless technically feasible. However, a series of directional drilling operations would magnify the complexity of the installation, would likely require two construction seasons, and would also require the design of protection of the seabed connections between drilled sections.

Only one hydrocarbon pipeline has been built in an arctic offshore environment, and it was installed using a bottom-pull method for the bundle installation and a plow for trenching. The project was installed off Melville Island in the Canadian High Arctic between 1976 and 1979. The Drake Field experience shows that a high level of quality assurance was needed during construction. However, it is important that the pipeline was only 4,000 feet long (12% of the proposed pipeline length), but the make-up of the pipe bundle lasted 4.5 months, not including pipeline installation. Thus, considerably more time was needed than for a more conventional pipeline configuration.

The different configurations of the alternatives have different implications on the construction and installation program. For example, the single wall pipeline would be buried in a deeper trench, whereas the pipe-in-pipe alternative requires extensive make-up assembly and more equipment. On balance, the pipe-in-pipe and pipe-in-HDPE alternatives are much more difficult to construct than the single wall or flexible pipe alternatives. Therefore, the risk will be much higher that the construction work will not be completed in a single season.

The preferred construction method is from an ice platform in winter using conventional excavation equipment and off-ice installation techniques. Reasons include the following:

- This method uses conventional, proven equipment available locally.
- Ice-strengthening and ice-cutting techniques are well understood.
- A through-ice test trenching program has been carried out on the North Slope to prove the feasibility.
- Other construction methods would require that significant equipment be mobilized to the North Slope, which may require the equipment to over-winter (i.e., barges).
- Open-water construction equipment is not designed for these shallow water depths.
- A skilled labor force is available.
- Alaskan content in the project is maximized.

3. COST AND SCHEDULE

Cost estimates range from $31 million for the single-wall steel pipe to $61 million for the steel pipe-in-pipe, including the base case cost plus a contingency value. The contingency value is estimated based on the confidence associated with meeting the proposed schedule. For the pipe-in-pipe and the pipe-in-HDPE alternatives, there is a high likelihood that an additional construction season will be required to complete these more complex construction programs. Therefore, the contingency includes a portion of the additional season construction costs.

4. OPERATIONS AND MAINTENANCE CONCERNS

The main difference in maintenance of the pipeline systems is that monitoring cannot be accomplished in all structural components of some alternatives. It is not presently feasible to monitor the integrity of the outer jacket pipe of the pipe-in-pipe, pipe-in-HDPE, and flexible pipe alternatives. Post-failure monitoring could be achieved for these two systems using the annular leak detection system to detect the presence of water and oil. However, no preventive monitoring of the outer jacket pipe can be performed for these systems.

TABLE 2
SUMMARY COMPARISON OF ALTERNATIVES

Description	Pipeline Alternative			
	Single Wall	**Pipe-in-Pipe**	**Pipe-in-HDPE**	**Flexible Pipe**
Configuration				
Depth of Cover (feet)	7	5	6	5
Duration of Trenching (days)	33	26	30	24
Gravel Backfill (yds^3) [Does not include 50% contingency]	9,000 (in gravel mats)	0	10,000 (30 yds^3 every 100 feet)	10,000 (30 yds^3 every 100 feet)
Pipe Specific Gravity	1.6	2.2	1.2	1.1
Number of Welds/ Connections	808 welds; 11 are tie-ins	1616 welds; 66 are tie-ins	808 welds, 808 fusions; 66 connections are tie-ins	13 connections; 11 tie-ins
Cost				
Budgetary Cost ($ millions)	31	61	44	37
Relative Cost (%)	100	195	140	120
Schedule				
Estimated Schedule Basis	Single winter season	Single winter season	Single winter season	Single winter season
Likelihood of Additional Season for Construction (%)	10	80	60	10
Installation				
Ice Thickness (feet)	8.5	10.5	8.5	8.5
Relative Quantity of Construction Equipment per Season (%)	100	120	115	90
Considerations	Identification of vertical pipeline profiles that do not meet the design criteria	• Pipe-in-pipe assembly logistics • Assurance of dryness of 12-in. pipe prior to pipe-in-pipe assembly • Achieving pull-in of 12-in. to outer jacket • Handling pipe-in-pipe system (210 lb/ft) and large stiffness • Thicker ice platform needed	• Assurance of dryness of 12-in. pipe prior to pipe-in-HDPE assembly • Executing pipe-in-HDPE assembly • Maintaining pipeline stability in trench • First application of the HDPE of this type	• Logistics for transporting and handling heavy reels • Maintaining pipeline stability in trench
Operation & Maintenance Concerns	Conventional operations	Monitoring of outer pipe integrity	Monitoring of outer pipe integrity	Monitoring of flexible cross-section
Leak Detection				
Standard Mass Balance and Pressure Point Analysis	Yes	Yes	Yes	Yes
Supplemental System	LEOS	Annulus monitoring	Annulus monitoring	Annulus monitoring

Cleanup strategies for a potential spill would be similar for any of the pipeline alternatives. The manpower and capabilities would be in place to successfully monitor, control, and clean up any spill at any time of the year, however remote the possibility. There is a risk of a secondary spill volume during repair of alternatives with an annulus; this risk must be considered during the development of detailed repair procedures.

- For all pipeline alternatives, there are periods (breakup and freeze-up) when a repair could not be carried out.
- For alternatives with an annulus, all moisture and oil would need to be removed from the annulus during repair. Any moisture that remains in the annulus could potentially cause corrosion of the inner or outer pipe. Any oil that remained in the annulus could potentially leak out at a later time if the integrity of outer pipe, jacket, or sheath was compromised.
- Not all repairs are able to return some pipeline systems to the same integrity level as originally constructed.

For all alternatives except the single wall pipe, repair is difficult, if not prohibitive. The issues include pipe retrieval, repair splicing and annulus purging (for pipe-in-pipe and pipe-in-HDPE), and long-term pipe integrity.

5. LEAK DETECTION SYSTEMS

Conventional state-of-the-art leak detection for any of the pipeline alternatives can be achieved using two independent systems. Mass balance line pack compensation (MBLPC) and pressure point analysis (PPA) can be applied to any of the alternatives and combined have an expected threshold of 0.15% of the volumetric flow. Leaks beneath this threshold would be detected using a supplemental system such as LEOS, which is a commercially available system installed alongside the pipe in the trench. LEOS is able to detect leaks smaller than the 0.15% threshold and is currently considered the best available technology. Annulus monitoring has been recommended as a supplemental leak detection system for those configurations with an annulus and would be expected to provide a threshold of detection as good as LEOS. However, if desired, LEOS could be applied to any of the pipeline alternative systems.

The offshore oil pipeline would be continuously monitored, and all system parameters would be relayed back as electronic signals to a standalone computer. The system parameters would be compared to predetermined alarm set-points and calculated values.

6. RISK ASSESSMENT

In order to determine the probability of the pipeline being damaged from external forces, a risk assessment was performed which evaluated the likelihood of four categories of damage to each alternative:

1. Displaced pipeline with no leak
2. Cross-section buckle in the pipe with no leak

3. Small or medium leak (125 bbl to environment)
4. Large leak or rupture (1,567 bbl to environment)

Figure 5 identifies the initiating events and causes of a failure.

The main conclusion of the risk analysis is that the risk, expressed in barrels of oil spilled into the environment, is negligible for all alternatives. The safeguards in the single wall pipeline alternative (i.e., depth of cover; trench backfill material and procedures; pipe wall thickness; cathodic protection system, anodes and coating; routine geometry pig inspections; and leak detection systems) provide a total system reliability that minimizes the risk of environmental oil spills. The single wall pipeline system is also relatively easier to repair.

The double wall systems are the second best. Their risk of oil spills is more than an order of magnitude greater than the single wall pipe, but the risk is still very small and acceptable and can be further reduced with the increased cost of greater depth of cover. Given the higher risk, cost, and the difficulty of repair, these systems are less suitable than the single wall system. The flexible pipe system has a risk of oil spill nearly 100 times greater than the single wall pipeline. This risk is still relatively low and can be decreased by increasing its burial depth. However, even if the depth of cover is increased, this alternative is unattractive because of the extra difficulties for installation with heavy reels and the possible repair of 2,800-foot segments. This system is not recommended for this application.

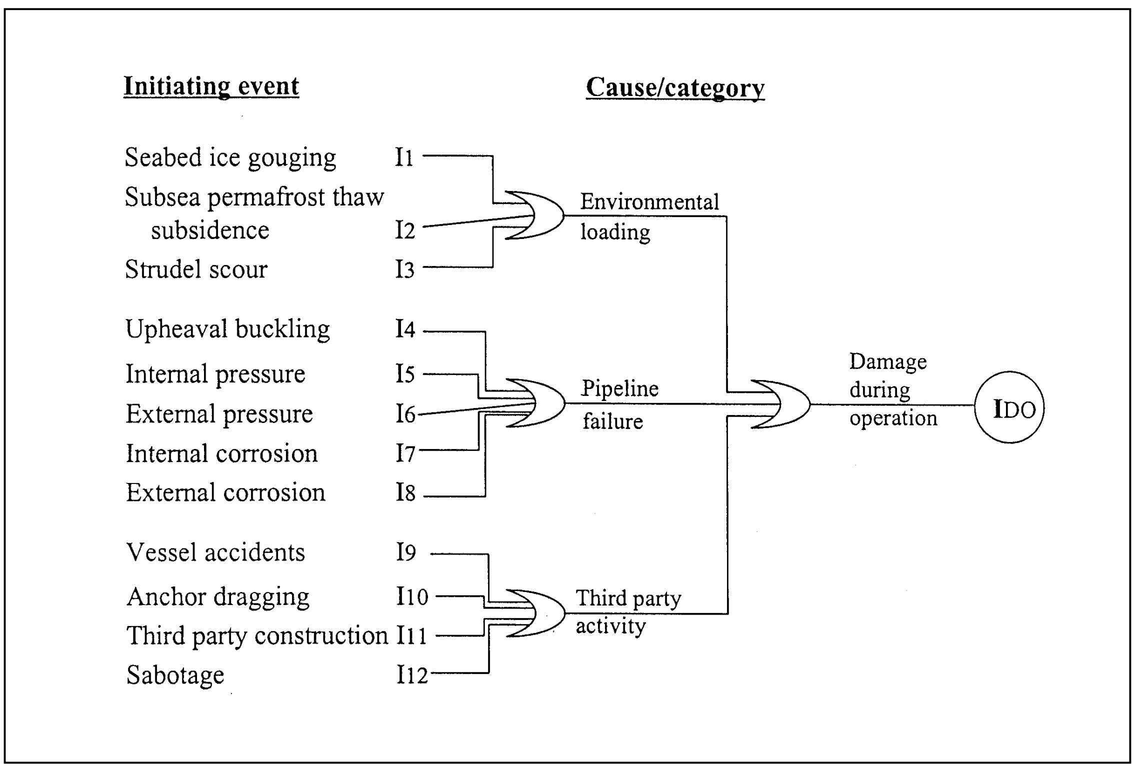


FIGURE 5
POTENTIAL DAMAGE-CAUSING EVENTS EVALUATED IN RISK ASSESSMENT

The shallower depth of cover for the pipe-in-pipe system is the main factor increasing the risk of oil spilled into the environment. To make this risk similar to that of the single wall pipe, the depth of cover needs to be increased to 7 feet — at an increased cost of about $10 million.

TABLE 3
RISK OF OIL SPILLED INTO ENVIRONMENT FOR DIFFERENT ALTERNATIVES

Alternative	Single Wall	Pipe-In-Pipe	Pipe-In-HDPE	Flexible Pipe
Risk (bbls)	0.0016	0.028	0.014	0.14
Relative risk	1	18	9	88

"Risk" = frequency x consequences, in units of the consequence
Example: Single wall risk = (1×10^{-5}) x 125 bbls + (2×10^{-7}) x 1,567 = 1.6×10^{-3} bbls
"Relative risk" = system risk divide single wall pipe system risk

7. CONCLUSIONS AND OBSERVATIONS

The evaluation of pipeline alternatives for BP Exploration's Liberty Development concluded that any of the alternatives can be designed structurally to meet the functional requirement of transporting oil and resisting forces imposed by environmental factors. However, the single wall steel pipeline offers the most advantages over the other alternatives by providing the lowest risk of a spill to the environment.

The primary aim of pipeline design is to engineer a pipe or conduit that will transport a product from one location to another without failing from internal or external forces. A significant part of the design effort is to economically optimize the pipe diameter, wall thickness, and material strength, while still safely achieving the design throughput. In the case of steel pipe materials, close attention is paid to protecting the pipe from corrosion. Internal corrosion may be due to the product transported in the line or the unintentional introduction of a corrosive substance at some point during pipeline operation. External corrosion may be due to the surrounding soil or water if the line is buried or installed under water. Generally, steps are always taken to limit corrosion by application of an external corrosion coating, installation of cathodic protection, and if required, the injection of corrosion inhibitors into the product stream during pumping or compression.

Pipeline design codes and standards do not suggest a requirement to provide an outside pipe jacket whose sole purpose is to contain any loss of contents of the pipeline it surrounds. The conditions that might give rise to a loss of product from the inner pipe would also affect the outer pipe. Specific conditions such as the corrosiveness of the transported product are always considered in the design. Pipe-in-pipe systems are used in some cases, but the outer pipe does not serve as a back-up in the event that something has been omitted in the original design effort. Their prime function is to satisfy installation economics or another design condition, such as to thermally insulate or facilitate field installation.

The pipe-in-pipe and pipe-in-HDPE alternatives are more expensive and would most likely require an additional construction season compared to the single wall and flexible alternatives. Monitoring of the pipeline's integrity during operation is required to allow for preventive maintenance. The single wall pipe alternative is the only solution that allows all the design aspects to be monitored during operation — a very important consideration for a buried subsea pipeline.

PIPELINE SYSTEM ALTERNATIVES

LIBERTY DEVELOPMENT PROJECT
CONCEPTUAL ENGINEERING

PREPARED FOR

BP EXPLORATION (ALASKA) INC.
ANCHORAGE, ALASKA

DRAFT

INTEC PROJECT NO. H-0851.02
PROJECT STUDY PS 19

NOVEMBER 1, 1999

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APPENDIX A: DRAWINGS

Note: Drawings are referenced in report by numerical extensions only (i.e. 0002)

APPENDIX B: FIGURES

1. INTRODUCTION, REPORT STRUCTURE, AND CONCLUSIONS

1.1 Introduction and Objectives

BP Exploration (Alaska), Inc. (BPXA) submitted a Development and Exploration Plan (DPP) for its proposed Liberty Development in February 1998. As discussed in the DPP, BPXA plans to produce sales quality crude oil at Liberty Island, located in Foggy Island Bay, east of Endicott and about 1.5 miles west of the abandoned Tern Island site, as shown in Drawing 0002 (INTEC Engineering, Inc. 1998). Liberty Island will be an artificial gravel island in approximately 22 feet of water and will support a self-contained drilling and production facility.

According to the DPP, sales oil will be exported from Liberty Island through a 12-inch oil pipeline, approximately 6 miles in the offshore segment and 1.5 miles in the overland segment. The Liberty oil pipeline will tie into the existing Badami 12-inch oil pipeline and flow through the Liberty/Badami/Endicott/TAPS pipeline network.

The purpose of this study is to provide a comparison of offshore pipeline system alternatives that can export sales quality oil from the proposed Liberty offshore development. The study presents:

- Subsea pipeline system design issues
- Design criteria
- Installation methods
- Construction costs
- Operations and maintenance issues
- System reliability
- Leak detection systems
- Comparison of the alternatives

The study is intended for use by the Minerals Management Service, the U.S. Army Corps of Engineers and other agencies participating in the Liberty Development Environmental Impact Statement.

1.2 Report Structure and Organization

This report presents the conceptual design of four pipeline system alternatives that may be considered for the Liberty Development based on pipeline performance objectives and the physical environment of the development area. The alternatives include:

- Single wall steel pipeline
- Double wall pipeline system (pipe-in-pipe)
- Steel pipe inside an HDPE sleeve (pipe-in-HDPE)
- Flexible pipe

Evaluation of each alternative considers the topics outlined in Section 1.1. Conclusions are presented below in Section 1.3. A flowchart summarizing the report structure and organization is presented as Figure 1-1.

Chapter 2 presents quantitative data on the environment, which together with the flow requirements define the loads on the pipeline. Pipeline systems design objectives are presented, and allowable stresses and strains are defined. The physical data and operational requirements are Liberty-specific, as are the findings of this work; a different design data set could change the overall findings.

Chapter 3 provides general information that could be associated with each of the alternatives. This information is then taken into consideration in each design alternative chapter and the appropriateness of its application assessed.

Chapters 4 through 7 present the design alternatives. Each chapter presents the conceptual level design for the alternative. Referring to Figure 1-1, each chapter consists of nine sections; the "*" on the figure refers to each respective alternative chapter (4, 5, 6 or 7). The sections within these chapters include:

- Section 1 contains an introduction, summary, and conclusions.

- Section 2 presents the structural design of the pipeline alternative and includes flow analysis, installation stability evaluation, design for environmental loading, and corrosion protection.

- Section 3 presents the conceptual design selection of one of the sub-alternatives to be the configuration of the alternative to be considered further in the study. This selection is based on structural behavior and perceived fabrication and installation considerations. In this section, the configuration of this alternative to be considered further is presented.

- Section 4 reviews the construction methods that could be used and describes the most suitable method for installation. The installation sequence is presented and specific construction considerations for the design alternative noted.

- Section 5 summarizes the basis for the order of magnitude costs required to install each alternative. The construction sequence is outlined, along with quantities and rates of progress. A schedule and cost estimate are presented.

- Section 6 presents operations and maintenance considerations including operations monitoring, pipeline inspection, maintenance activities, and evaluation criteria.

- Section 7 identifies repair methods that could be used for each alternative and identifies repair scenarios in the form of damage categories. Repair methods are recommended dependent on the damage category and time of year.

- Section 8 reviews leak detection methods that could be used with each of the pipeline alternatives. The most suitable leak detection technologies are selected, and factors that would influence leak detection performance are identified.

- Section 9 addresses failure by considering causes (e.g., environmental loadings), mechanisms of failure, and likelihood of occurrence. This is then combined with leak detection performance to identify what failure scenarios can occur for each pipeline alternative. The failure scenarios identify the likely time of year, the potential oil loss, the likelihood of occurrence, the volume of oil spilled, cleanup, and repair.

Chapter 8 addresses alternative containment concepts. This chapter is included to address questions which have been raised during the course of this study regarding the feasibility of coatings, wraps, or oil sorbent materials as containment strategies.

Chapter 9 provides a comparison of the pipeline system alternatives. The objective of this section is not to summarize the findings from the review of each alternative but to identify the key differences among the alternatives.

1.3 Conclusions

1.3.1 Structural Design

The structural design evaluation of the pipeline alternatives indicates that any of the alternatives can be designed structurally to meet the functional requirement of transporting oil and resisting environmental loads. The configuration of each alternative is summarized in Table 1-1. An outer steel pipeline for the pipe-in-pipe alternative would likely be manufactured by the UOE process and would thus contain a longitudinal seam weld, the implications of which would need to be further assessed in detailed design.

TABLE 1-1: PIPELINE SYSTEM ALTERNATIVE CONFIGURATIONS

Pipeline System Alternative	Target Trench Depth (ft)	Backfill Requirements	Weight in Air (lbs/ft)	Specific Gravity	Cathodic Protection of Oil-Carrying Pipe
Single Wall Pipeline	10.5	1-foot gravel mat + 5 feet of native for 25% of the line. 5 feet of native backfill for 75% of the line.	90	1.6	yes
Pipe-in-Pipe	9	4 feet of native backfill	210	2.2	no
Pipe-in-HDPE	10	gravel mounds at 100-foot spacings + 0 to 5 feet of native backfill	104	1.1	no
Flexible Pipe	8.5	gravel mounds only at connections + 4 feet of native backfill	85	1.2	no

1.3.2 Constructability

Conclusions regarding constructability are presented below and in Table 1-2. The preferred method of construction for all alternatives is using an ice platform from which conventional excavation equipment and off-ice installation techniques are used.

- Possible pipe flotation refers to the potential for any pipeline alternative with a specific gravity of 1.0-1.2 to float in the sand/slurry mixture that may be generated during trenching and backfilling.
- Some pipeline system alternatives can likely be constructed in one season, while others would likely carry over into a second season.
- Tie-in welds for an outer steel pipe could not be subjected to the same level of inspection as an inner steel pipe.
- Fusion welding of an HDPE outer pipe could only be visually inspected after the weld was completed.
- The pipe-in-pipe and pipe-in-HDPE alternatives require additional care during construction to ensure that the annuli remained dry.

TABLE 1-2: CONSTRUCTION ASPECTS

Pipeline System Alternative	Recommended Construction Method	Possible Pipe Flotation	Likelihood of Requiring an Additional Season to Complete Construction (%)	Required Excavation Volume (yd^3)	Make-Up Site Area (yd^3)
Single Wall Pipeline	Conventional excavation equipment and off-ice techniques	no	10	461,000	417,000
Pipe-in-Pipe	"	no	80	354,000	533,000
Pipe-in-HDPE	"	yes	60	424,000	533,000
Flexible Pipe	"	yes	10	322,000	417,000

1.3.3 Costs

Construction costs for each alternative are presented in Table 1-3. Costs have been broken down into installation and material cost; 10% of these costs has been included as contingency. If the probability of completing the construction in a single season is small, a contingency has been included that apportions part of a second-season construction cost based on the perceived likelihood of requiring a second season. For example, for pipe-in-pipe, 90% of the estimated second-season cost is added for contingency.

TABLE 1-3: ALTERNATIVE COSTS ($ MILLION)

Pipeline System Alternative	Installation Costs	Material Costs	10% Contingency	2^{nd} Season Contingency	Total (to nearest $ million)
Single Wall Pipeline	25.4	3.1	2.85	0.0	31
Pipe-in-Pipe	37.0	4.5	4.15	15.0	61
Pipe-in-HDPE	32.5	3.3	3.6	5.0	44
Flexible Pipe	19.8	13.7	3.35	0.0	37

1.3.4 Operations and Maintenance

The main conclusions regarding operations and maintenance are presented below and in Table 1-4.

- The integrity of the oil-carrier pipe of any of the alternatives can be monitored for integrity.
- The pipeline three-dimensional configuration can only be measured in the oil carrier pipe.
- The "ability to monitor outer pipe" in Table 1-4 refers to the ability to monitor the configuration and integrity of the outer pipe by detecting dents, buckles or the loss of wall thickness.
- It is assumed that a failure of the outer jacket that resulted in water in the annulus would be detected by the supplemental leak detection system.

TABLE 1-4: OPERATIONS AND MAINTENANCE CONCLUSIONS

Pipeline System Alternative	Ability to Monitor Oil-Carrying Pipe Integrity	Ability to Monitor Geometry Changes in Oil-Carrying Pipe	Ability to Monitor Outer Pipe
Single Wall Pipeline	yes	yes	n/a
Pipe-in-Pipe	yes	yes	no
Pipe-in-HDPE	yes	yes	no
Flexible Pipe	yes	yes	no

1.3.5 Cleanup and Repair

Cleanup strategies would be similar for any of the pipeline alternatives. In accordance with the approved spill contingency plan. the manpower and capabilities would be in place to monitor, control, and clean up any spill anytime of the year, however remote the possibility. There is a risk of a secondary spill volume during repair of alternatives with an annulus; this risk must be considered during the development of detailed repair procedures. Conclusions regarding repair are presented below and in Table 1-5.

- For all pipeline alternatives, there are periods (breakup and freeze-up) when a repair could not be carried out.
- For alternatives with an annulus, all moisture and oil would need to be removed from the annulus during repair. Any moisture that remains in the annulus could potentially cause corrosion of the inner or outer pipe. Any oil that remained in the annulus could potentially leak out at a later time if the integrity of outer pipe, jacket, or sheath was compromised.
- Not all repairs are able to return the pipeline to the same integrity level as originally constructed.

TABLE 1-5: REPAIR CONCLUSIONS

Pipeline System Alternative	Winter Repair	Summer Repair	Inner Pipe Integrity Re-established	Outer Pipe Integrity Re-established
Single Wall Pipeline	yes	yes	yes	n/a
Pipe-in-Pipe	yes	yes	yes	no
Pipe-in-HDPE	yes	yes	yes	yes
Flexible Pipe	yes	yes	yes	yes

1.3.6 Leak Detection

Leak detection strategies for the alternatives are presented in Table 1-6. Mass balance line pack compensation (MBLPC) and pressure point analysis (PPA) can be applied to any of the alternatives and combined have an expected threshold of 0.15% of the volumetric flow. Leaks beneath this threshold would be detected using a supplemental system. LEOS is a commercially available system which is installed external to the pipe. Annulus monitoring has been recommended as a supplemental leak detection system for those configurations with an annulus. However, if desired, LEOS could be applied to any of the pipeline alternative systems.

TABLE 1-6: LEAK DETECTION

Pipeline System Alternative	MBLPC and PPA	Supplemental System	Loss of Oil from Carrier [1] (bbls)	Time to Detection (hrs)
Single Wall Pipeline	yes	LEOS	125	24
Pipe-in-Pipe	yes	annulus monitoring	125	24
Pipe-in-HDPE	yes	annulus monitoring	125	24
Flexible Pipe	yes	annulus monitoring	125	24

Note: [1] For a 0.15% leak detected by the supplemental system.

1.3.7 Failure Assessment

Table 1-7 presents estimated damage frequencies for each of the pipeline alternatives according to damage category.

- These are total frequencies based on occurrences per project lifetime, which has been taken as 20 years.

- A small or medium leak could happen any time of the year.
- A pipeline rupture or large leak might be expected only in the fall of the year.
- The above conclusion does not address the possibility that a combined less-severe series of events might result in a large leak or rupture during other times of year; this is beyond the scope of this study (it is assumed that the combined less-severe events for the same damage category have a lower damage frequency than those reported in Table 1-7).
- The manpower and capabilities would be in place to successfully monitor, control, and cleanup any spill at anytime of the year.

TABLE 1-7: ESTIMATED DAMAGE FREQUENCIES

Pipeline System Alternative	Category 1 Pipeline Displaced	Category 2 Buckle/ No Leak	Category 3 (Inner Pipe) Small/ Medium Leak	Category 3 (System) Small/ Medium Leak	Category 4 Large Leak/ Rupture
Single Wall Pipeline	3×10^{-2}	1×10^{-3}	n/a	1×10^{-5}	2×10^{-7}
Pipe-in-Pipe	2×10^{-2}	1×10^{-3}	1×10^{-4}	3×10^{-4}	1×10^{-5}
Pipe-in-HDPE	3×10^{-2}	2×10^{-3}	1×10^{-3}	1.1×10^{-3}	1×10^{-6}
Flexible Pipe	4×10^{-2}	6×10^{-3}	1×10^{-8}	1×10^{-3}	1×10^{-5}

2. DESIGN BASIS

The offshore physical environment of the Beaufort Sea is a key determining factor in Liberty Project engineering. Regarding construction seasons, offshore winter construction on top of artificially thickened ice typically can begin in late January and last until early May. Summer open water construction typically can take place from late July to late September.

Regarding pipeline operation, several environmental phenomena are unique to arctic nearshore conditions. The major environmental loads applicable to the Liberty pipeline are those caused by

- Ice keel,
- Permafrost thaw settlement, and
- Strudel scour.

This chapter also presents quantitative data on the environment, which together with the flow requirements define the loads on the pipeline. Such definitions are required in order to apply the loadings equally to all pipeline alternatives.

2.1 Pipeline System Design Objectives

An equitable evaluation of pipeline system alternatives for the Liberty subsea pipeline requires a clear definition of the design objectives, which all pipeline systems must meet. The objectives are described below under the general headings of functional, safety, and additional project requirements.

2.1.1 Functional Requirements

The following functional requirements are common to all pipeline system alternatives based on meeting the Liberty crude oil transportation objectives:

- Pipeline subsea length is approximately 6 miles based on the proposed Liberty Island and Badami tie-in locations.
- Pipeline inside diameter is approximately 12 inches based on hydraulic flow requirements.
- Pipeline maximum allowable operating pressure (MAOP) is 1,415 psig based on hydraulic flow requirements.
- Minimal pipeline operating and maintenance requirements based on project economics and environmental considerations.

2.1.2 Safety Requirements

Safety requirements for a subsea arctic crude oil pipeline are based on a combination of government regulations, industry design codes and project-specific engineering evaluations. The following paragraphs outline and give a basis for the major safety requirements considered with the Liberty pipeline.

- U.S. Department of Transportation (DOT) Pipeline Safety Regulations, 49 CFR Part 195, Transportation of Hazardous Liquid by Pipeline – This federal regulation lists minimum safety requirements including design temperature, internal design pressure, external pressure, external loads, inspection pig passage, construction, pressure testing, operation, maintenance, cathodic protection, and internal corrosion control. This regulation has contributed to the excellent safety record for U.S. pipeline systems.
- ASME B31.4 Code for Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids – The primary purpose of this industry code is to establish requirements for safe design, construction, inspection, testing, operation, and maintenance of liquid pipeline systems for protection of the general public, operating personnel and the environment [400 (c)]. This code is referenced in the DOT regulations for safe pipeline design requirements [49 CFR Part 195.110 (a)], but it is not an all-inclusive design handbook and cites the need for "competent engineering judgement."
- API RP 2N, Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions – This is a compendium of the latest state-of-the-art techniques for planning, designing, constructing and operating a safe offshore pipeline. In this context, a safe pipeline (outside the limits of all facilities, valve stations, etc.) must not leak and should remain serviceable throughout its design life. Codes and project-specific safety requirements are based on offshore pipeline industry experience supplemented with knowledge of relevant offshore arctic conditions such as ice gouging, strudel scour and permafrost thaw settlement. Examples of this information include relevant industry design data and standards, site-specific field surveys, and pipeline design calculations.
- Pipeline Design Technical Review – The Liberty system alternatives are reviewed through the ongoing Minerals Management Service (30 CFR 250 Subpart J) and Alaska right-of-way lease procedures (A.S. 38.35), and industry peer reviews initiated by the Liberty Project.
- State of Alaska Regulations –18 AAC 75 includes specific design requirements for leak detection and also require a best available technology review of certain

pipeline system components (e.g., leak detection, cathodic protection, and communications systems.

2.1.3 Additional Project Requirements

The Liberty crude oil sales pipeline must comply with multiple state, local, BPXA, and project-specific design requirements. In addition, the overall preferred subsea pipeline system alternative should satisfy the following design objectives. Avoiding pipeline leak formation and a potential oil spill is addressed above in the safety design objectives but may potentially be influenced by one or more of the following design objectives:

- Exceeding minimum Alaska State regulatory requirements for crude oil pipeline leak detection (18 AAC 75). The two state-of-the-art leak detection systems presently in use on existing North Slope pipelines and proposed for all Liberty pipeline system alternatives exceed these requirements.
- A supplemental leak detection system is desirable to detect potential below-minimum-threshold pipeline leaks before they can accumulate large volumes of spilled oil during the winter ice-covered season.
- Pipeline inspection pigging should monitor pipe conditions which could lead to a potential leak formation if uncorrected. This includes periodic wall thickness measurement, pipe body ovalization, and pipe geometry (bending) monitoring inspections with tools run through the pipeline.
- Pipeline construction during the winter ice-covered season is desirable for minimizing environmental impacts.
- Reasonable pipeline capital costs are required to support Liberty field development economics.

2.2 Conceptual Engineering Design Level Definition

The pipeline system alternatives presented in this report are developed to a conceptual engineering design level. This section defines design level in the context of this study.

The typical phases for executing large engineering projects are:

- Feasibility study,
- Conceptual engineering design,
- Preliminary engineering, and
- Detailed engineering.

These phases are explained in Table 2-1, where the values shown in the column entitled “resources” are approximate percentages of the total project design cost required to achieve the stated objectives. Typically, the design of a project costs 2% to 10% of the total constructed project. Routine projects are at the lower range of engineering cost, and unique projects, such as the Liberty subsea pipeline, tend toward the higher range.

TABLE 2-1: PHASES OF ENGINEERING PROJECTS

Phase of Project	Resources	Objectives
Feasibility Study	5%	Feasibility Studies evaluate the practicality and cost of engineering developments in remote areas or using new technology. The farther the requirements are from proven technologies, the broader the range of considerations needs to be. Conversely, this phase may be omitted if similar engineering projects have been done several times before.
Conceptual Engineering Design	10%	Conceptual Engineering Design studies are more specific than feasibility studies and usually focus less on global issues. The objectives are: • To define the basic engineering system parameters to safely meet the project objectives and, • To obtain a cost estimate within 40% to 50%.
Preliminary Engineering Design	30%	At this phase, there is enough confidence that the project can be safely constructed and cost-effective. The objectives of this phase are: • To confirm that the engineering system defined by the conceptual design phase meets the project objectives. • Perform calculations to define various system components. • Do the basic drawings and plan the full set of drawings. • Develop specifications. • Developed a construction plan. • Obtain a cost estimate within 30% to 40%.
Detailed Engineering Design	55%	At the end of this phase, the project must be complete and ready for procurement and construction. The objectives are: • Complete all calculations. • Define all components of the engineering systems and their connections. • Conclude all specifications. • Complete all drawings and details, so that a bill of materials can be readily done. • Finish the construction plan. • Solicit bids for construction with bid packages.

2.2.1 Conceptual Design for Offshore Arctic Pipelines

This section lists the engineering aspects which are covered at a conceptual engineering design level for an offshore arctic pipeline system, such as the Liberty offshore pipeline. Five major engineering aspects are identified, and specific engineering parameters are listed for each, as follows:

- Environmental Loading
  - Environmental conditions summary
  - Review or definition of major environmental loads
  - Pipeline structural response to environmental loads
  - Establishing a preliminary trenching depth of cover
- Flow Assurance
  - Pipeline internal diameter
  - Pressure, thermal regime, and flow
- Corrosion Design
  - Cathodic protection system
- Installation Issues
  - Submerged weight and pipeline wall thickness
  - Winter vs. summer construction
  - Welding processes
  - Preliminary construction plan
- Operations, Maintenance and Repair
  - Operation monitoring
  - Leak detection
  - Pipeline inspection
  - Maintenance
  - Repair

2.3 Route Definition and Environmental Characteristics Related to Offshore Design

The site of the proposed Liberty Island is within Foggy Island Bay. Since only the proposed offshore pipeline alignment is considered for this study, the different pipeline systems can be compared within the constraint of a given route and the associated environmental characteristics.

2.3.1 Route Alignment

The Liberty offshore pipeline alignment is a straight line approximately 6.1 miles long connecting Liberty Island (see point A in Drawing 0010) to the shore crossing (see point B in Drawing 0010). The overall pipeline length is approximately 7.6 miles and ties in to the existing Badami pipeline just east of the Sagavanirktok River. The sea floor (mudline) profile along the proposed offshore pipeline alignment can be seen in the Offshore Alignment Plan and Profile, Drawings 0021 to 0023. At the Liberty Island, the water depth is 22 feet below MLLW (see Drawing 0021) and it gradually becomes shallower closer to shore (see Drawings 0022 and 0023). Drawing 0021 refers to an additional 6-inch-diameter products pipeline bundled with the 12-inch sales oil pipeline. For the purpose of this study, the 6-inch pipeline has been disregarded.

The bathymetry shown in Drawings 0021 to 0023 was acquired by Coastal Frontiers Corporation in the summer of 1997, as reported in the Liberty Development 1997 Pipeline Route Survey (Coastal Frontiers Corporation 1998). The soil characteristics shown in Drawing 0021 (see also the soil boring locations in Drawing 0010) were acquired by Duane Miller & Associates in the spring of 1997 (Duane Miller & Associates 1997).

2.3.2 Ambient Temperature and Values

Meteorological factors affect both the overland and offshore pipeline designs during construction and operation. The wind design value which will be used will be a 100-year return period (unilateral direction) with a 110 mph wind speed as defined in ASCE 7-95. Table 2-2 identifies the temperatures to be used in the pipeline design.

TABLE 2-2: DESIGN TEMPERATURES

Offshore Pipeline Installation Temperature	30°
Lowest Design Ambient Air Temperature (During Operation)	-50°F

These values are based on field measurements (Duane Miller & Associates 1997, 1998; Montgomery Watson 1997).

2.3.3 Oceanography

Beaufort Sea ice conditions include:

- Open water summertime ocean conditions during which waves and currents achieve their maximum values.

- Partial ice cover during which wave generation and propagation are dampened by the surrounding sea ice.
- Wintertime conditions when large expanses of open water generally do not exist, thereby precluding wave generation.
- Variation of the seasonal extent of ice-free water from year to year. Freeze-up at offshore sites in this region generally occurs by mid-October, see Table 2-5.

2.3.3.1 Ocean Current Data

Wintertime current velocities beneath the ice are near zero. Current data collected in March 1996 indicated virtually no ocean currents beneath the ice over a period of five days (Montgomery Watson 1996). This is also supported by other Montgomery Watson work in 1997, where the peak velocity measured was 2 cm/s. However, the tidal fluctuations that do occur in winter indicate that a low-velocity current does exist.

2.3.3.2 Shoreline Erosion Values

For the 1948 to 1995 period, an average long-term bluff erosion rate of 2 feet/year at the shore crossing is assumed. Maximum short-term (i.e., annual) erosion rates would be approximately four times this value. The design shoreline erosion rate values are assumed to be 3 feet/year (long-term) and 12 feet/year (maximum annual). These values are conservative for the immediate area of the pipeline shore crossing. These erosion rates are based on a review of historical aerial photographs (1949 to 1995) at the shore crossing location (Coastal Frontiers Corporation 1997).

2.3.3.3 Storm Surge

A combination of astronomical tide and factors dictated by atmospheric phenomena (wind, atmospheric pressure, related wave action) causes the fluctuation of ocean water level in the Alaskan Beaufort Sea. While the astronomical tide range is slight (about 0.7 feet), the range of sea level rise and fall due to major storms (storm surge) can be as much as 8 feet at the shore. The exaggerated effect of the Coriolis force at high latitudes causes the moving ocean water mass to be deflected to the right in the Northern Hemisphere. Westerly winds tend to force water onto the shore, thereby causing an increase in sea level, or “set up”. Conversely, easterly winds tend to force water away from the coast, resulting in a lower water level, or “set down”. Water level decreases caused by easterly storms tend to be less than water level increases caused by westerly storms, with water level reductions varying from one to two feet during severe easterly storms.

The 100-year design condition at the shore is predicted to be +6.7 feet MSL (Offshore and Coastal Technologies Inc. 1997). Table 2-3 presents storm surge values (annual and "design" conditions) and tidal variance for the Liberty Development area.

TABLE 2-3: STORM SURGE, CURRENT AND WAVE HEIGHT VALUES

Parameter		1-Year Return Period	100-Year Return Period ("Design" Condition)
Surface Currents Under Ice		Negligible	Negligible
Tidal Variation		0.7 feet	—
Storm Surge		+2.3 feet MSL (nearshore)	+6.7 feet MSL (nearshore)
Nearshore Waves	Westerly Storm	HS = 1.7 feet T_{peak} = 7.5 seconds	HS = 2.9 feet T_{peak} = 11.3 seconds
	Easterly Storm	HS = 1.5 feet T_{peak} = 6.9 seconds	HS = 1.7 feet T_{peak} = 9.9 seconds

2.3.3.4 *Ocean Waves Data*

Shallow water locations in the Liberty area have less severe design wave conditions because nearshore waves are limited by water depth. As waves move landward into shallower water, wave breaking will dissipate the energy. Wave data has been generated using a hindcast model (Oceanweather, Inc. 1982) and made site specific (Offshore and Coastal Technologies, Inc. 1997). This model was used to determine wave conditions at the shore-crossing site. The results of the hindcast study of these shallow water sites are shown in Table 2-4.

The Beaufort Sea hindcast study (Oceanweather, Inc. 1982) also considered storm duration during the open-water season, when wave development could occur. Based on 30 years of National Weather Service weather records to 1979, the longest storm duration (wind speed exceeding 30 knots) was 42 hours for a westerly storm (September, 1954) and 66 hours for an easterly storm (September, 1979). As a result, the 100-year storm duration for the Liberty project area is conservatively estimated to be 80 hours.

TABLE 2-4: WAVE CONDITION, LIBERTY SHORE CROSSING SITES BASED ON BEAUFORT SEA HINDCAST STUDY

West Site Return Event (yrs)	Westerly Storm		Easterly Storm	
	H_S (Feet)	T_{PEAK} (Seconds)	H_S (Feet)	T_{PEAK} (Seconds)
1	1.7	7.5	1.5	6.9
10	2.1	8.0	1.7	7.3
50	2.4	10.3	1.7	9.3
100	2.9	11.3	1.7	9.9

2.3.4 Ice Physical Environment and Conditions Affecting the Liberty Development

This section describes the general ice conditions and the ice environment in the vicinity of the Liberty Development. Included are:

- Freeze-up, breakup, and first open-water dates;
- First-year ice growth; and
- Ice movement as a function of water depth and time of year.

A summary of the average (typical) and design (extreme) ice parameters is presented in Table 2-5 (Vaudrey 1997). These predicted values would assist in the safe construction/installation sequencing of the pipeline system.

2.3.5 Strudel Holes and Strudel Scour Data

Strudel scours are formed during the spring river breakup, when overflood waters (due to warming of the snow pack) flow on top of the nearshore ice sheet. If the water head is sufficiently high and there is a pathway through the ice sheet, a downward water jet has the potential to scour the seafloor. Thus, the phenomenon is named “strudel scour”.

Four strudel scour data sets have been collected during the past 17 years near the Sagavanirktok, Colville, and Kuparuk River deltas. These have been reviewed and their relevance assessed in determining a Liberty design strudel scour dimension. The four years of survey data are from: 1981 survey by Harding Lawson Associates, 1982 survey by McClelland Engineers (both located in the Duck Island/Sag Delta area), and 1997 and 1998 surveys by Coastal Frontiers in the Liberty Project region. These studies are reviewed in detail in Section 2.8 of this report.

Strudel scour data from the 1997 offshore pipeline survey are summarized in Figures 2-1 and 2-2, and their location plotted in the General Arrangement Drawing 0002.

TABLE 2-5: DESIGN BASIS ICE CRITERIA FOR THE LIBERTY DEVELOPMENT

Ice Condition or Parameter	Average or Typical Values	Design or Extreme Values
Ice Type:	First-Year Ice	Thick First-Year Ice Consolidated Rubble
Ice Zone:	Landfast Ice	Landfast Ice
Ice Season: Freeze-up River Overflood Break-up First Open Water Ice Season Duration Gross Open-Water Season Duration Summer Ice Invasion	 October 4 ± 9 days May 27 ± 6 days July 4 July 19 288 ± 10 days 77 ± 13 days 3 out of every 4 summers	 3rd week in September to the 4th week in October 4th week in June to the 2nd week in July 2 times during early summer
Max. Sheet Ice Thickness:	6 feet	7.5 feet
Ice Speed (10-20 feet of water): Summer Freeze-up Winter (annual maximum)	 0.15 to 0.25 knots 0.15 to 0.25 knots 0.5 to 0.8 feet per 10 minutes	 2.5 to 3 knots 2.5 to 3 knots 1.7 to 2.5 feet per 10 minutes

2.3.6 Ice Gouge Data

Quantitative and qualitative ice gouge depth data for the proposed pipeline route is available from several sources. This ice gouge data within Foggy Island Bay is less extensive, however, than at other more exposed sites in the Beaufort Sea. The reduced amount of quantitative ice gouge data can be attributed to both fewer site-specific surveys and a reduced gouge formation rate in the shallow water depths along the Liberty pipeline route.

The 1997 summer Liberty pipeline route survey was in part planned to compensate for limited gouge depth data. Rather than just survey the two alternative 6-mile pipeline route options within Foggy Island Bay, Coastal Frontiers ran approximately 175 miles of survey line throughout the eastern end of Stefansson Sound (up to 8 miles north, 4 miles east, and 5 miles west of the project location, see Figure 2-3). This expanded survey identified 17 gouges with depths greater than the vertical resolution of the sonar system, which had a measurement threshold of approximately 3 inches. These were only a small fraction of the total number of gouges detected on the side-scan survey, but most were too shallow to measure. The data from the Coastal Frontiers 1997 summer survey are summarized in Figure 2-4, and Section 2.6 of this report reviews in detail the 1998 summer survey data (Coastal Frontiers Co. 1998, 1999).

2.3.7 Offshore Pipeline Route Soils

Two geotechnical field programs were performed specifically for the Liberty Development. The first, initiated by BPXA in March of 1997, assessed the soil conditions at the originally proposed island site and along the original pipeline route alternatives. However, the boring locations were based on a previous island position and do not directly overlay the entire pipeline route. The second field program, which was performed in March 1998, consisted of 27 additional boreholes, 17 of which were drilled along the pipeline route (Duane Miller & Associates 1998). A summary of the program is presented as part of Section 2.5.

2.4 Flow, Pressure, and Temperature Requirements

All pipelines and components will be designed for a 20-year design life. However, the operational life of the pipeline may be extended beyond this design life by demonstration of its integrity.

2.4.1 Transported Fluids

A summary of the properties of the sales oil to be transported in the pipeline is provided in Table 2-6.

TABLE 2-6: SALES OIL DATA

Property	Value
Nominal API Gravity	25.4°
Specific Gravity	0.9 (@ 60°F)
Liberty Design Flowrate	65,000 bbl/day

2.4.2 Operating Pressure

The design maximum allowable operating pressure (MAOP) for the pipeline is 1415 psig.

2.4.3 Operating Temperature

The design operating temperatures for the pipelines are shown below.

- Maximum operating temperature (inlet): 150°F
- Average operating temperature (inlet): 135°F

2.4.4 Test Pressure

The pipelines will be tested at a minimum pressure of 1.25 x MAOP for a minimum of 8 hours.

The island approach riser sections of the offshore products pipeline will be tested at a minimum pressure of 1.50 x MAOP for a minimum of 8 hours.

2.5 Geotechnical Conditions and Pipeline/Soil Interaction

Soil characteristics and behavior are of primary importance for buried offshore pipelines. For example, (a) the pipeline segment near the shore crossing is likely to induce soil settlement by thawing the permafrost strata, (b) the remolded soil characteristics are a major factor in how much resistance the native backfilled material provides against upheaval buckling, and (c) the stiffness and strength of the soil helps determine how much the pipeline is likely to be displaced due to passage of an ice keel above it.

This section summarizes the site-specific data gathered for the Liberty alignment. The interpretation of the data as it relates to soil-pipe interaction is also discussed.

2.5.1 Introduction

In 1997, Duane Miller & Associates (1997) drilled and sampled 30 geotechnical borings in Foggy Island Bay for the Liberty Development project. They reported that the soils are generally fine-grained in the top 10 feet and are commonly medium stiff except for occasional pockets of soft material where Holocene soils are present. Four boreholes were placed in the vicinity of the proposed production island, and nine holes were placed along the offshore portion of the current pipeline route that extends approximately 6 miles SSW from Liberty Island to shore.

In 1998, Duane Miller & Associates (1998) completed 27 geotechnical borings for the Liberty Development. Five of these borings were conducted at the island site and 17 along the offshore pipeline route. Duane Miller & Associates generally divide the soils at the island into three primary layers: (1) an upper layer of 5 to 6 feet of soft, compressible, Holocene, non-plastic silt; (2) an intermediate layer of Pleistocene stiff, over-consolidated clayey silt that extends to depths of 18 to 22 feet; and (3) underlying granular sand and gravel that extend to the depths explored.

2.5.2 Analysis of Field Data

Data provided by Duane Miller & Associates (1998) from tests conducted on composite samples of material from the top 10 feet of the trench section indicated backfill submerged unit weights ranging from 34 to 53 pounds per cubic foot, with an average of 43 pounds per cubic foot. This is the backfill unit weight which will be used in the majority of analyses, since it is considered representative of expected backfill conditions. The only exception to the use of this value will be in any upheaval buckling analysis, where a more conservative lower-bound backfill submerged unit weight value of 37 pounds per cubic foot will be used. This value is based on tests on remolded soils in the top 10 feet of soil in the vicinity of the pipeline (Duane Miller & Associates 1998). Those tests indicated buoyant unit weights ranging from 25 to 45 pounds per cubic foot, with an average of approximately 38 pounds per cubic foot (at a consolidation pressure of 170 pounds per square foot). The low value presented among the data (25 pounds per cubic foot) appears to be an extreme condition and not one that would occur throughout the thickness of the trench backfill soil at any given location. The reason for using different backfill unit weights for different loading conditions is that values chosen for each analysis should impose the more stringent loading conditions on the pipe.

A submerged unit weight value of 60 pounds per cubic foot will be used in analyses requiring in-situ soil density. This is considered to be an approximate upper bound to typical in-situ soil unit weights which might be found along the pipeline route based on the 1997 and 1998 geotechnical exploration reports (Duane Miller & Associates 1997, 1998) and would provide a more conservative result from pipe loading conditions by in-situ soils.

Triaxial tests have been carried out on “undisturbed” soil samples taken from the island site and proposed pipeline route (Duane Miller & Associates 1997, 1998). The average in-situ undrained shear strength obtained from the inorganic silts along the pipeline alignment in the 0 to 12 foot soil depth range was approximately 1,150 pounds per square foot. The soils at these depths are quite sensitive to disturbance, and the likely remolded strength of the trench backfill at this depth would be lower than this (Nixon Geotech Ltd. 1997a). Values for remolded undrained shear strength can be estimated to be less than one-half of the undisturbed values of undrained shear strength. Therefore, a value of 500 pounds per square foot will be used in analysis requiring the undrained shear strength of a cohesive material. The lowest undrained shear strength value from the pipeline route recorded in the 1998 geotechnical investigation report (360 pounds per square foot) will be used in trench excavation calculations to estimate soil excavation volumes.

Consolidated, drained tests conducted on samples from the vicinity of Liberty Island from the 1997 and 1998 geotechnical surveys suggest an angle of internal friction of 30° and a cohesive intercept of approximately 400 pounds per square foot. More conservative soil friction angle values, such as 25° for sandy soils and 15° for silty soils, will be used in trench stability analyses to estimate soil excavation volumes.

The pipeline/soil interface friction angle (δ) to be used in analyses will be 18°. In the literature, values of δ ranging from 0.5ϕ to 1.0ϕ have been reported (ASCE 1984). ASCE (1984) suggests values of 0.5ϕ to 0.7ϕ are applicable for the soil/pipe friction angle used on pipes with smooth, hard, water-resistant coatings. The ASCE guideline also reports the interface friction angle between sand and smooth steel varies from 0.5ϕ to 0.7ϕ and suggests a value of 0.6ϕ for the interface between sand and plastic pipelines. Here a value of 0.6ϕ will be used.

The coefficient of lateral earth pressure to be used in analyses will range from 0.5 to 0.7. The 0.5 is obtained from the general formula, $1\text{-}\sin\phi$, and is an appropriate static value where the pipeline and the soil interact vertically. In cases where the pipe and the soil interact horizontally, such as during ice gouging, there is the potential for earth pressure on the pipe to increase. As the effect of this occurrence is indeterminate, the analysis should be carried out for a lateral earth pressure coefficient of 0.6. This value is on the lower end of the range expected and will permit maximum axial expansion of the pipe resulting in maximum pipeline flexure at the edges of the gouges.

In the case of upheaval buckling, the native soil will be assumed to be a very loose non-cohesive material with the lowest uplift resistance coefficient within the range for cohesive soils. The lower bound value of 0.15, as recommended by Schaminee et al. (1990) based on their full-scale test results, will be used in calculating soil resistance to upheaval buckling. In any analyses with gravel as a backfill, the buoyant unit weight of the gravel will be taken to be 60 pounds per cubic foot.

2.5.3 Derivation of Pipeline/Soil Interaction Curves

The state of the art for buried pipeline design in areas where the soil may move relative to the pipeline (such as beneath ice gouges or in thaw settlement locations) involves performing finite element analysis. The industry standard for pipeline/soil interaction is to model the soil as a series of individual springs/sliders which represent the elastic-plastic behavior of the soil. Parameters describing the interaction curves or soil springs (known as P-Y curves) are input to the computer-based programs. Pipeline response to soil movements can be determined from such analysis and provides a basis for design.

In these models, the total interaction between the pipe and soil is represented as three distinct interactions: axial, transverse horizontal, and transverse vertical (upwards and downwards) as shown in the schematic of Figure 2-5. Generally, there is considered to be a maximum force per unit length that can be transmitted to the pipe by the soil, P_{ult}. These maximum forces occur at a characteristic displacement designated as Y_U in the upward direction, Y_A in the axial, Y_L in the lateral direction, and Y_D in the downward direction. The actual response between a pipeline and the soil is nonlinear (normally approximately hyperbolic) but is often simplified by means of a bilinear relationship.

The load-displacement relationship parameters (ultimate load and distance to ultimate load) to be used in the analysis of ice keel/seabed/pipeline interaction are summarized below in Table 2-7. The formulations for the P-Y curves used to analyze the effects of ice keel scour were provided by Nixon Geotech Ltd. (Nixon Geotech Ltd. 1997b) and are similar to those recommended by ASCE (1984). In this case, the pipe is buried with a depth of cover of 7.0 feet from seabed to the top of pipe, and the soil properties are presented above.

TABLE 2-7: ULTIMATE LOADS AND YIELD DISPLACEMENTS FOR ICE KEEL/SOIL/PIPELINE INTERACTION ANALYSES

Pipe Size OD	Direction of Pipe Motion	Ultimate Soil Resistance, P_{ult}	Characteristic Displacement to Ultimate Resistance
12.75-inch (Single Wall)	Lateral Axial	3,816 lb/ft 281 lb/ft	Y_L = 2.71 inch Y_A = 0.18 inch
14.94-inch (Flexible)	Lateral Axial	4,374 lb/ft 333 lb/ft	Y_L = 2.74 inch Y_A = 0.21 inch
15.25-inch (HDPE Sleeve)	Lateral Axial	4,453 lb/ft 275 lb/ft	Y_L = 2.75 inch Y_A = 0.20 inch
16-inch (Pipe-in-Pipe)	Lateral Axial	4,640 lb/ft 359 lb/ft	Y_L = 2.76 inch Y_A = 0.23 inch

The lateral P-Y curve was calculated in accordance with ASCE guidelines (ASCE 1984) for cohesive soil. This formulation was used rather than that for a frictional soil because it results in a larger ultimate lateral soil resistance. The P-Y curve is considered to be hyperbolic in form, and the P and Y values are calculated as outlined in Section 5.1.2 of ASCE. The P_{ult} and Y_L values have been calculated as shown in Table 2-7.

The axial P-Y curve was calculated in accordance with ASCE guidelines (ASCE 1984). The P-Y curve is considered to be bilinear in form. The ultimate P value has been calculated as summarized in Section 5.1.1 of the ASCE guidelines. The characteristic Y value is calculated using elastic soil parameters and results in a value in the range suggested by ASCE.

2.6 Ice Keel Loading

During spring breakup, sea ice in the Beaufort Sea tends to pile up at some locations creating pressure ridges. Such pressure ridges have keels extending below the water surface, and are driven primarily by ocean currents and secondarily by wind, wind-generated currents, and loading from other ice. These sea ice keels are known to periodically contact and form gouges into the seabed in the offshore arctic environment. Therefore, avoiding ice keel contact and potential pipeline damage is a design criterion for the offshore buried lines. Proper design requires establishing the maximum design ice gouge depth along the proposed pipeline route. However, in addition to being buried below the maximum expected ice gouge depth, the pipeline must also be analyzed for bending strains caused by potential seabed soil movements beneath the keel of the intersecting ice gouge. The required pipeline depth of cover (measured from the original seabed to top of pipe) is established to limit bending strains to acceptable levels.

The negative exponential function has been found to give a good fit to observed seabed gouge depth data and forms the basis for the Liberty pipeline extreme gouge depth predictions (Weeks et al. 1983; Lanan et al. 1986). It has been shown to represent gouge data over the full range of available gouge statistics and has also been shown to characterize the depth distribution for ice keels as recorded by upward looking sonar on submarines (Weeks et al. 1983). Wheeler and Wang (1985) compared various theoretical distributions to ice gouge survey data and found that the exponential distribution was more conservative than either Gamma, Weibull, or Gumbel extreme value distributions, and also tends to overpredict the number of deep gouges compared to survey data. Therefore, an exponential gouge depth distribution is considered to be both applicable and conservative for this project.

2.6.1 Model Summary

The maximum gouge depth can be calculated based on the methodology described by Weeks et al. (1983) and Lanan et al. (1986). Since the methodology is general and can be applied to any site, API RP 2N (1995) recommends it as applicable to any structure that is linear in shape. The maximum expected ice keel incision depth, d, can be calculated for different values of return periods using the following formula:

$$d = c + \frac{1}{\lambda} \cdot \ln(g \cdot T \cdot L \cdot \sin\theta) \qquad (2\text{-}1)$$

where: c = the cutoff incision depth below which gouges become too small to identify and count (and ice gouge incision depth which all of the observed gouges exceed) (feet); g = the annual ice gouge recurrence rate (new gouges/mile/year); T = extreme gouge average return period (years); L = pipeline length (miles); θ = the angle between the pipeline route and the trend of the ice gouges (degrees); and λ is a constant specifying the slope of the negative exponential gouge depth distribution curve (1/feet).

Two approaches, graphical and analytical, can be taken to solve for the two parameters λ and c. The graphical approach is where λ and c can be found from the exponential best-fit function for the points in a graph of "Exceedence of Gouge Depth vs. Incision Depth" where the exponential probability density function (PDF) is of the form:

$$PDF(x > c) = \lambda e^{-\lambda(x-c))} \qquad (2\text{-}2)$$

which has the following characteristics:

$$\lambda = 1/\left(\overline{X} - c\right) \qquad (2\text{-}3)$$

and

$$EP(x > D) = e^{-\lambda(D-c)} \qquad (2\text{-}4)$$

where: $\overline{X}$ is the mean; *c* is a cutoff point, which means all observations, *x*, are greater than *c*; and $EP(x > D)$ is the probability that *x* exceeds a certain value *D*. It should be noted that the cutoff incision depth cannot be negative and if so would be taken as zero.

In the analytical approach, c is taken as the lower bound of the class depth interval below which no gouges were observed (100% exceedence). Then λ is calculated as

$$\lambda = \frac{1}{d_{bar} - c} \qquad (2\text{-}5)$$

as suggested by Lanan et al. (1986) and Weeks et al. (1983), where d_{bar} = the mean gouge depth.

Engineering design codes such as API RP 2N (1995) and DNV (1996) recommend that 100-year average return periods be used for extreme environmental loading events. The above procedures have been followed for the 1997 and 1998 pipeline route survey data sets to determine the maximum expected ice keel depth for a return period of 100 years.

2.6.2 Design Ice Gouge Depth

Standard analysis techniques have been used (Appendix C) to analyze two years of data specific to the Liberty pipeline route (see Figure 2-3). The negative exponential function has been found to give a good fit to observed seabed gouge depth data and forms the basis for the Liberty pipeline extreme gouge depth predictions. The maximum gouge depth is calculated using a general methodology recommended by API RP 2N and application of Equation 2-1 results in the following relation from analysis of available 1997 ice gouge data:

$$d = 0.00 + \frac{1}{2.5629} \cdot \ln(0.097 \cdot 100 \cdot 6.12 \cdot \sin 90°) \quad [\text{ft}] \qquad (2\text{-}6)$$

Analysis of the 1997 ice gouge data presented in Appendix C suggests that the design ice gouge (100-year ARP) be 1.59 feet. The 1998 survey data indicated a maximum gouge incision depth of 1.13 feet. Combined, the data sets suggest a design depth of 1.36 feet.

An ice gouge depth of 3.0 feet has been conservatively assumed in pipeline design for the analysis of pipeline bending strains due to ice keel gouging. During the Northstar design (INTEC Engineering 1997), analysis of ice gouge data suggests a 100-year ARP maximum gouge depth of approximately 3.3 feet. The Liberty Island site will be subjected to smaller ice features than Northstar due to the comparatively large amount of land and shoal area shielding. Other ice gouge observations (Harding Lawson Associates 1982; McLelland Engineers 1982; Weeks et al. 1983; Reimnitz and Ross 1979; Watson Company 1998a, 1998b) suggest a maximum gouge depth of 2.3 feet or less.

The design scour depth of 3.0 feet is 2.21 times deeper (221%) than the combined data set value of 1.36 feet. The average return period for a 3.0-foot-deep design ice gouge is estimated to be greater than 3,600 years based on Equation 2-6 above.

2.6.3 Subgouge Deformation of the Seabed

As an ice keel passes over any point in the seabed, vertical and tangential stresses are applied to the soil at the keel base, resulting in some distribution of vertical and lateral soil displacements with depth beneath the ice keel depth. The soil deformation at the pipeline depth is a function of ice gouge depth and width and is calculated from soil displacement functions derived from ice gouge physical modeling (Woodworth-Lynas et al. 1996; Nixon et al. 1996). The equations that define the soil displacement for clays and sands are in Appendix C. Figure 2-6 presents resultant transverse soil displacement as a function of depth below the undisturbed seabed for a 30-foot-wide ice keel with a 3-foot gouge depth. As the backfill around the pipeline will be silty sand, the average of the clay and sand relationships was used to calculate the vertical and horizontal soil movements. As expected, the subgouge deformations decrease rapidly with depth below the ice keel. The magnitude of subgouge deformation beneath a gouging ice keel also varies along the pipeline length as indicated by Figure 2-7.

2.7 Permafrost Thaw Settlement Potential

2.7.1 Introduction

The offshore section of the BPXA Liberty pipeline for the proposed route would be installed in a trench, which would then be backfilled. In shallow water, the soil underlying the trench could contain ice-bonded permafrost. When the pipeline becomes operational, the temperature of the pipelines will gradually increase the temperature of the surrounding soil. The volume of soil that is affected by the pipeline's temperature will increase over the operational life of the pipeline. This increase in temperature will change the load carrying properties of the ice-bonded permafrost.

Initially, the loads in the soil are carried by a combination of the soil skeleton material strength and frozen water in the soil pores. As the temperature of the soil increases, the ice in the soil pores melts, and so the majority of the load that was previously shared by the two components now must be carried by the soil material. This can result in settlement of the soil. When thaw settlement occurs, the pipes are no longer supported vertically and are now supporting the soil cover above. The pipelines therefore deflect into the void created by the settlement, and strain is thus induced in the pipe wall.

The geotechnical analysis associated with the thaw settlement design for the original Liberty concept was performed by Nixon Geotech Ltd. (1997a). A summary of this analysis is presented below, since it forms the basis for the current evaluation of alternative concepts.

2.7.2 Analysis of Field Data

Soil investigations along potential pipeline routes during the 1997 survey (Duane Miller & Associates 1997) indicated that the soils are generally fine-grained sandy silt or silt deposits overlying denser gravel and sandy gravel deposits at depth. The thickness of the surficial finer deposits varies from 8 to 15 feet in shallower water. Water contents in the surface layers vary between 10% and 35%, with significant variations where organic or icy layers are present. In the depth range from 0 to 17.5 feet, typical water content for frozen samples is assumed to be 20% for geothermal analysis purposes (Nixon Geotech Ltd. 1997a). Water contents in the underlying granular material have a typical value of 10%. Frozen boring data from the 1998 survey (Duane Miller & Associates 1998) are in agreement with the geothermal analysis assumptions used in the Nixon Geotech (1997a) analysis.

The salinity profiles from the 1997 and 1998 Liberty soil borings in the areas with frozen nearshore soils do not follow any discernable trends. The average salinity from the 1997 and 1998 data combined is 24.7 parts per thousand. The areas of unfrozen or non-ice-bonded soils are saline, with salinities equal to or somewhat greater than seawater. An average salinity of 30 parts per thousand (roughly equal to seawater) has been assumed for the geothermal thaw bulb analysis.

Water depth variation was also accounted for in the analyses. Increased water depth results in warmer initial ground temperatures, which in turn reduces the amount of ice initially in the soil and also influences the ultimate size of the thaw bulb. Based on experience from other investigations in the area, permafrost or ice-bonded soil is present close to the seabed generally where the water depth is less than 5.5 feet (Nixon Geotech Ltd. 1997a). The depth to the top of the ice-bonded permafrost then drops away quite quickly as the water depth increases. This is borne out by the boreholes drilled at Liberty. In the nearshore areas where the ice is landfast, heat is removed from the seabottom during the winter months, maintaining the permafrost. In areas where there is no landfast ice, the seawater is above freezing, resulting in a year-round average temperature above the melting temperature of the saline subsoils.

2.7.3 Geothermal Simulations

The geothermal analysis was conducted by Nixon Geotech Ltd. (1997a). Two-dimensional geothermal analyses were carried out using the Nixon Geotech Ltd. THERM2 simulator for the single wall steel pipeline system with 12.75-inch OD and 0.688-inch WT.

Two cases were analyzed during thermal simulations. The first case involved a pipeline in onshore or very shallow water conditions (a foot or less of water where cold permafrost is present). The second case is located in the transition area (4-foot water depth) where the top of the ice-bonded permafrost drops away quite quickly as the water depth increases. Initial soil temperatures were 20°F for the shallow water condition and 25.7°F for the deeper (4-foot) water depth. Thermal properties are based on standard published correlations (Nixon Gertech Ltd. 1997a) with water content, density and soil type. The latent heat is temperature dependent and is calculated by the program based on the liquid water content of the soil and as described in the documentation on the THERM2 geothermal program. The unfrozen water content is a power law function with negative temperature which accurately models the phase composition in saline soils.

All thaw bulb growth simulations assumed an annual average temperature of the pipeline to be 137°F. As previously stated, initial soil temperature inputs varied from 20°F for the 1-foot water depth area to 25.7°F for the 4-foot water depth. These temperatures were based on the borehole data presented in the Duane Miller & Associates (1997) geotechnical report. The borehole temperature data from Duane Miller & Associates (1998) geotechnical report follows the same trends as Duane Miller & Associates (1997) data. This indicates that the soil temperature input data originally assumed for the 1997 analyses were appropriate.

Nixon Geotech Ltd. (1997a) used published values for soil thermal conductivity and heat capacity for the different soil and backfill layers of the region. For analysis purposes, in shallow water, it is estimated that the trench can be excavated with vertical side slopes to a depth of 8 feet and backfilled with local silt and sandy silt. Of particular importance in the analysis was the estimation of the unfrozen water content function for the saline soils around the pipe. These were calculated based on the methods of Patterson and Smith (1983) for saline, fine-grained soils. As stated above, all the soils in the analysis were assumed to have an average salinity of 30 parts per thousand. The upper (above 17.5-foot depth) silt layers are assumed to have a 20% moisture content, and the lower (below 17.5-foot depth) sand/gravel subsoil layers are assumed to have a 10% moisture content.

The analysis predicted thaw depths of 36 to 67 feet below the pipe base after 20 years of operation. The 36-foot thaw bulb depth represents the 1-foot (very shallow) water depth case, and the 67-foot thaw bulb depth represents the 4-foot (transition area) water depth case. As no soils with excess ice are anticipated at these depths, small changes in predicted thaw depth will not result in any changes to predicted thaw settlement.

2.7.4 Thaw Settlement

Settlement of the permafrost soils beneath the pipe results from thawing and drainage of excess meltwater from the soil. In soils such as silts present at the site, drainage should proceed concurrently with the thaw, and therefore settlement can be estimated from the product of the increased thaw depth and the thaw strain of the soil layer in question.

Thaw settlement analysis details are provided in the Nixon Geotech Ltd. (1997a) report for the original Liberty pipeline design. The thaw settlement was calculated for each of the five frozen 1997 borehole locations (Duane Miller & Associates 1997) by estimating the thaw strain for each soil layer where a soil water content was available, multiplying the thaw strain by the appropriate depth increment, and integrating the thaw settlement increments with depth. Only the depth interval from the pipe base to the maximum thaw depth has been included in this calculation. Based on the analysis, pipe settlements of 0.1 to 0.9 feet could be anticipated for that particular pipeline configuration in water depths ranging from 0 to 4 feet. In greater water depths, the saline soils are extremely warm and close to their melting point, and predicted thaw depths would be even greater. However, it is unlikely that significant ice contents could be maintained in such warm saline soils close to their melting point. For the thaw settlement design, a loadcase with a settlement of 1.0 feet is used.

The thaw settlement pipeline strain analysis must assume the worst case condition for settlement of the pipeline due to the thawing of the supporting soil. When thaw settlement occurs, the pipe is no longer supported vertically and is now supporting the soil cover above. The worst case condition is analyzed for the critical settlement length – namely the length over which the differential settlement occurs that will induce the highest strains in the pipeline. This analysis also assumes that the maximum predicted settlement is a differential settlement in that one section of the soil settles by the maximum amount while an adjacent section of soil does not settle (see Figure 2-8). Thaw settlement should be combined with the residual installation strains to provide the maximum combined strains even though it is very unlikely that the maximum residual installation strain will occur at the same point as the maximum thaw settlement and be the same sign.

2.8 Design Strudel Scour Dimensions

Strudel scour depressions in the sea floor are formed during river breakup in the spring, when the river water overfloods the bottomfast sea ice in the nearshore coastal zone (Coastal Frontiers Corporation 1998). The overflood water spreads offshore and drains through discontinuities in the ice sheet, which typically consist of tidal cracks, thermal cracks, and seal breathing holes. In those instances where the drainage rate is high and the water depth relatively shallow, scouring of the sea floor can occur from the water action on the seabed. The majority of strudel scours are circular in plan form, but linear scours can be created by drainage through elongated cracks.

The rivers that feed into Foggy Island Bay, where the Liberty Development is located, are the Sagavanirktok (Sag), the Kadleroshilik (Kad), and the Shaviovik (Shav) rivers. In the shallow water (typically less than 6 feet deep) offshore of these rivers, the sea ice sheet freezes to the seafloor during the winter, forming the so-called bottomfast ice sheet. Strudel scours are more often found beyond the bottomfast ice boundary up to about the 15-foot isobath.

Potential strudel scour loading of a pipeline is shown on Figure 2-9. Strudel scours are a hazard only if certain conditions occur. In order for the pipeline to experience a loading event equaling or exceeding the design strudel scour span length, the strudel scour must:

- Be located on top of the pipeline alignment,
- Exceed the distance to the bottom of the pipe (otherwise the pipe remains supported by the soil), and
- Have a horizontal dimension at the pipeline depth equal to or exceeding the design span length.

Each of these conditions has been addressed separately using available strudel scour survey data. The design strudel scour dimension is then defined based on combining these necessary conditions.

Statistical analysis of four strudel scour data sets is presented in Appendix D. The first two data sets were obtained by site-specific surveys during the summers of 1997 and 1998, and are specific to the Liberty project (Coastal Frontiers Corporation 1998, 1999). These surveys were conceived and executed to examine the proposed pipeline alignment and surrounding area. The other data sets used in this analysis were obtained from surveys performed in 1981 and 1982 (Harding Lawson Associates 1982; McClelland Engineers 1982). Since these surveys were performed at the mouth of the Sag River in support of the Endicott project, the data has been assessed qualitatively as well as quantitatively, as described below.

2.8.1 Model Summary

In engineering applications, the most important parameter is the risk, which is assessed by the exceedence probability function. Therefore, the preferred methodology based on engineering judgement is the best fit of the exceedence probability. Wheeler and Wang (1985) have applied various probability density functions (PDFs) to predict extreme event occurrences. Specifically, Wheeler and Wang (1985) compared the exponential, gamma, Weibull, and Gumbel PDFs in relation to ice gouge sample data. The exponential distribution is the one that conservatively predicts large estimates of the risk.

Based on this assessment, the exponential PDF is chosen to also model diameter and depth for extreme strudel scour events.

The exponential PDF is of the form:

$$PDF(x > c) = \lambda e^{-\lambda(x-c))} \tag{2-7}$$

which has the following characteristics:

$$\lambda = 1/\left(\overline{X} - c\right) \tag{2-8}$$

$$EP(x > D) = e^{-\lambda(D-c)} \tag{2-9}$$

where: $\overline{X}$ is the mean; c is a cutoff point, which means all observations, x, are greater than c; and $EP(x > D)$ is the probability that x exceeds a certain value D.

2.8.2 Design Strudel Scour

Based on analysis of the data from the 1981, 1982, 1997, and 1998 surveys presented in Appendix D, it is concluded that the average value of 17.4 strudel scours per mile of shoreline per year determined from the 1997 data is reasonable. The 1997 survey (Coastal Frontiers Corporation 1998) has 251 observations, which produces a robust and conservative prediction of risk:

$$EP_{T\&D\&H} = 0.085 \times e^{-0.4148(D-0.307)} \times e^{-0.0456(H-3.66)} \tag{2-10}$$

The subscript on the left side of the above equation is meant to convey a strudel scour on **T**op of the pipeline, with a certain **D**epth, and a certain **H**orizontal diameter. The above equation quantifies the risk that a strudel scour event: 1) forms right on top of the pipeline, 2) has a depth greater than a given depth D, and 3) has a horizontal diameter (at seafloor level) greater than H. For example, the likelihood of a strudel scour having a diameter (at the seabed) greater than 15 feet and being deeper than 8 feet is,

$$EP_{T\&D\&H} = 0.085 \times e^{-0.4148(8-0.307)} \times e^{-0.0456(15-3.66)} = 0.21\%$$

Note that such an event has a return period of T = 1/0.21% $\cong$ 480 years.

2.9 Upheaval Buckling

When a buried steel pipeline is operated at a temperature higher than the installation temperature, it will try to expand longitudinally. Since a long buried pipeline is not free to expand due to the restraint provided by the surrounding soil, it will develop an axial compressive force. If the buried pipeline has some residual vertical curvature, possibly due to trench bottom irregularities during installation (Figure 2-10, a and b), the axial force near the localized high points of the pipeline will attempt to move the pipe upward at these locations (Figure 2-10c). Thus, an upward force from the pipe into the soil cover results. If upward force exceeds the downward force due to the combination of the resistance of the soil cover, the pipeline stiffness, and the pipeline self-weight, then the pipeline will move upward and may be exposed out of the trench (Figure 2-10d). This phenomenon is known as upheaval buckling.

If upheaval buckling takes place, the pipeline may become exposed at the mudline level if the pipeline moves enough. Although significant plastic deformation occurs, unstable fracture is not expected to take place due to the high deformation capability of steel pipe. This has been documented in a previous occurrence of the phenomenon (see, for example, Craig et al. 1990). Still, upheaval buckling is a limit state, that is, an undesired condition, or state, which must be designed against.

Upheaval buckling has been the subject of much research over the last two decades. Rich and Alleyne (1998) presented a system design evaluation for a buried high-temperature pipeline considering the issues of expansion and upheaval buckling. Lanan and Barry (1992) mitigated the potential for upheaval buckling in the Fairway Field (offshore Mobile Bay, Alabama) by adopting a horizontal zigzag pipeline configuration in combination with adequate burial depth. Palmer et al. (1990) described the upheaval buckling phenomenon in detail and proposed a simplified analytical model to quantify the problem. The model proposed by Palmer et al. (1990) has been checked against a full-scale laboratory test (Schaminee et al. 1990), as well as more sophisticated computational tools (Klever et al 1990), and found to yield good results. Therefore, the model proposed by Palmer et al. (1990) is used herein in order to evaluate upheaval buckling potential.

2.9.1 Model Summary

The model presented by Palmer et al. (1990) can be summarized as follows. For a pipeline operating with a certain locked-in compressive force, P, and with a trench bottom roughness resulting in an imperfection height, δ, the required download for stability is:

$$W = P\left(\frac{\delta w_o}{EI}\right)^{\frac{1}{2}}\left[1.16 - \frac{4.76}{P}\left(\frac{EIw_o}{\delta}\right)^{\frac{1}{2}}\right] \qquad (2\text{-}11)$$

where: w_o = the installation submerged weight; EI = the flexural rigidity; P = effective axial force in operation; and δ = maximum imperfection height, resulting from trench bottom roughness tolerance.

Research into uplift resistance of the soil cover recommended the following equation for buried pipelines in sand and silty soils:

$$q = \gamma HD\left(1 + f\, {}^{H}\!/_{D}\right) \qquad (2\text{-}12)$$

where: q = uplift resistance per unit length of pipe; H = backfill thickness (distance from the top of pipe to the surface of backfill material directly above the pipe); D = outside diameter of the pipe; γ = submerged unit weight of the backfill material; and f = uplift coefficient equal to 0.5 for dense materials and 0.2 for loose materials.

With the pipeline data (w_o, EI, P) and the maximum imperfection height δ = 1.5 feet for the Liberty project, the required downward force to keep the pipeline in the as-laid position is calculated. By applying a factor of safety of 2, the soil uplift resistance, q, is determined as:

$$q = 2W \qquad (2\text{-}13)$$

From the above equation, the required backfill thickness, H, is established, in conjunction with the required submerged weight, γ, of the backfill material.

2.10 Leak Detection Systems

Conventional, yet state-of-the-art leak detection systems are assessed with the pipeline system alternatives. These include pressure point analysis (PPA) and mass balance line pack compensation (MBLPC).

Supplemental leak detection systems for the pipeline options have also been considered. These include:

- Leak detection sensor technology (such as LEOS)
- Through-ice borehole sampling
- Remote sensing
- Field sensing using non-intrusive techniques
- Periodic leak pressure testing

The basic design for each pipeline system alternative provides a high level of assurance of never developing an oil leak. The conventional pipeline leak detection system is then expected to identify most sizes of leaks which could potentially develop over the pipeline's operating lifetime and allow pipeline shut-in to stop oil leakage. The supplemental leak detection systems should therefore be considered as essentially a third line of defense to minimize the volume of oil spilled in the unlikely event of a below-detection-threshold pipeline leak during the winter ice-covered season. For each pipeline system alternative, appropriate leak detection methods are discussed in the corresponding sections of this report.

2.11 Pipeline Allowable Stresses and Strains

In general, pipelines are designed to stress criteria. However, for restrained (buried) offshore pipelines, a limit strain design methodology can be used. This section outlines which areas of design would apply a stress-based criterion and which areas of design would apply a limit strain design.

2.11.1 Stress Criteria Designs

The load cases that need to be analyzed for a stress design along with the allowable design factor are defined for oil lines in ASME 31.4. The load cases for each part of the pipeline design are summarized in these codes; however, these are applicable only when the pipe can move unrestrained due to the applied forces.

For buried offshore pipelines, the surrounding soil provides restraint. For arctic environmental loading conditions, the only environmental phenomenon that has the potential to apply forces in an unrestrained condition is an extreme event strudel scour, which might remove the surrounding soil and uncover the pipeline. Thus, a span might develop, and forces due to pipeline self-weight and strudel-induced currents act on the pipe. For strudel scour loading, Table 2-8 summarizes the pipeline allowable stress as a percent of SMYS.

2.11.2 Strain Criteria Designs

In situations where the pipeline may experience noncyclic displacement of its support (e.g., thaw settlement and soil deformation beneath ice gouges), strain in the pipe would be calculated to be sure the integrity of the pipeline is not threatened. Allowable strain levels are determined based on pipe dimensions and material grade and account for factors including pipe out-of-roundness and maximum pipeline butt weld defect sizes.

TABLE 2-8: CODE ALLOWABLE STRESS FOR UNRESTRAINED PIPELINE

Loadcase Reference	Applied Loads	Code Allowable Stress (% SMYS)
ASME B31.4 Sec.402.3.2(c), Sec.419.6.4(c)	Temperature Differential Only	$\sigma_L \leq 72$
ASME B31.4 Sec. 402.3.2 (d)	Pressure + Dead Load (Pipe Weight) + Sustained Load (Content)	$\sigma_L \leq 54$
ASME B31.4 Sec. 402.3.3 (a)	Pressure + Dead Load (Pipe Weight) + Sustained Load (Content) + Occasional Load (Current)	$\sigma_L \leq 80$
ASME B31.4 Sec 402.2.3(c), Sec 419.6.4 (b)	Pressure + Dead Load (Pipe Weight) + Sustained Load (Content) + Thermal Load + Occasional Load (Current)	$\sigma_L \leq 90$

This section outlines the allowable strain criteria to be used for the offshore portion of the pipeline.

The limit strain design has been reviewed for both tensile and compressive limiting strain conditions. The tensile strain limiting criteria involve the propagation of a flaw in the pipeline weld that is loaded by a tensile strain. In determining this pipeline strain limit, it was assumed that the flaw exists at the point where the maximum allowable strain exists and is orientated in the circumferential direction. The British Standard Institute document PD6493:1991 is used to establish an ultimate tensile strain of 3.6%. By applying a factor of safety of 3 for operational loading cases and 2 for extreme event loading cases, the allowable tensile strains shown in Table 2-9 are obtained.

The compressive strain limiting criteria are set primarily by buckling under bending. DNV (1996) is used to establish an ultimate compressive strain given by:

$$\varepsilon_u = (t/D - 0.01)\,\alpha_{gw} \qquad (2\text{-}14)$$

By adopting a girth weld reduction factor of $\alpha_{gw} = 0.95$, a factor of safety of 1.6 for operational loading cases, and 1.2 for extreme event loading cases, the allowable compressive strains shown in Table 2-9 are obtained.

TABLE 2-9: ALLOWABLE STRAIN LIMITS

Design Conditions	Tensile Limit Strain (%)	Compressive Limit Strain		
	All D/t	D/t=18.53	D/t=25.5	D/t=32
Thaw Settlement	1.2	2.6	1.7	1.3
Ice Keel	1.8	3.5	2.3	1.7
Island Settlement	1.2	2.6	1.7	1.3

2.12 Effect of Parametric Variation

A full parametric analysis of design conditions and pipeline parameters is beyond the scope of this study. However, this section is provided to address the expected implications of changes in pipeline geometry and burial depth to the Liberty Development.

2.12.1 Pipeline Geometry

A change in pipeline length will result in a change in the design ice keel incision depth for the development area, as this is a function of the annual ice gouge recurrence rate (new gouges/mile/year). For example, based on the 1997 Liberty ice gouge data and a pipeline length of 6.12 miles, the analysis results in a 100-year ice gouge depth of 1.59 feet (see Section 2.6). Doubling the length of the pipeline results in an increase in the 100-year gouge depth to 1.86 feet. However, the design value used for ice keel gouging is 3 feet, which is not affected by pipeline length. A change in pipeline length may also affect the pipeline diameter to achieve the same flowrate at inlet pressure.

Increasing the pipeline diameter, and thus the D/t ratio, results in a decrease in allowable strains. An increase in D would also change the pipeline response for an identical loading condition. If the loading was the result of pipeline/soil interaction, such as from an ice keel event, the pipeline loading would increase as its magnitude is directly proportional to D.

Increasing the wall thickness, which decreases the D/t ratio, results in an increase in allowable strains. Any increase in t would also change the pipeline response for an identical load condition. However, this response change would not be as significant as a diameter change. Any soil loading would remain constant, as the outer diameter of the pipe has not changed.

If the D/t ratio was maintained for pipelines with different outer diameters, the allowable strains are assumed to remain the same. An increase in diameter would result in an increase in loading due to soil movement. However, the measured strains would be different for a similar soil pressure as the pipeline stiffness is approximately proportional to wall thickness and the cube of the diameter ($\propto tD^3$).

A conceptual engineering level pipeline design typically follows the following sequence:

- An internal diameter that satisfies the flow requirement is selected,
- A wall thickness that ensures mechanical safety and constructability is estimated, and
- A steel grade compatible with the application is chosen.

Preliminary engineering level pipeline design further investigates performance requirements, loading conditions and constructability. Allowable strain levels are determined based on pipe dimensions and material grade and account for factors such as weld characteristics, pipeline ovality, misalignment, and weld defect sizes.

Reducing pipeline diameter or using a number of smaller-diameter pipelines has implications regarding flowrate, depletion schedules and reservoir economics. BP has evaluated the effect of reducing pipeline diameter on production rates, recoverable reserves, and net present value of the development (BPXA 1999).

Effect of Reducing Pipeline Diameter

The Liberty production rate has been evaluated as a function of pipeline diameter, and results are shown in Table 2-10 below (assuming normal backpressure at Pump Station #1 and Badami operation at design rate).

TABLE 2-10: PRODUCTION RATE AS A FUNCTION OF PIPE DIAMETER

Pipeline Diameter	Liberty Production Rate (1,000 bbl/day)
6 inch	23
8 inch	41
10 inch	57
12 inch	67

Reserves and Project Value

The net present value of the Liberty project is a function of the facility cost and the operating life of the facility. For this discussion, the facilities costs are assumed to be the same for all cases. The operating life of the facility is a function of the operating cost and the oil recovery rate and the value of the oil. Once the value of the oil recovered approaches the operating cost of the facility, the facility has reached its economic operating life. The economic life of Liberty is currently estimated to be approximately 17 to 19 years. With the economic life of Liberty held constant at 19 years, the actual reserves recovered are reduced as the pipeline size is reduced. The current reserves recovery for the Liberty is estimated to be 120 million barrels. The net present value of the project to BP is also significantly reduced with reduction in rate. The approximate percent reduction in the Liberty recoverable reserves and net present value of the project is shown in Table 2-11 as a function of pipeline diameter.

TABLE 2-11: EFFECT OF PIPE DIAMETER ON RECOVERABLE RESERVES AND NET PRESENT VALUE

Pipeline Diameter	% Reduction Recoverable Reserves from Liberty Design Case	% Reduction Net Present Value from Liberty Design Case
6 inch	40%	Approximately 100%
8 inch	21%	66%
10 inch	5%	33%

Mechanical Integrity

The design and specification of the pipeline will be dependent on the diameter of the pipeline. However, the overall safety of the pipeline must meet codes and standards of practice. Therefore, other design parameters such as wall thickness, steel grade, and depth of cover are adjusted to assure an adequate level of mechanical integrity.

Pipeline Leak

There are two basic types of leaks that can happen to the pipeline: (1) a small hole in the pipeline or (2) a guillotine cut. The leak volume from a hole in the pipeline is determined by the pipeline pressure and the diameter of the hole, and is not a function of pipeline diameter. With a guillotine cut, the pipeline pressure would drop, and low-pressure controls will shut down and isolate the Liberty plant in approximately 60 seconds. For the guillotine cut scenario in the subsea section of the pipeline, the actual leak volume will be approximately 35% of the pipeline volume (hydrostatic pressure on the outside of the pipe will balance pressure and trap approximately 65% of the oil in the pipeline). Table 2-12 shows the pipeline volume and the estimated leak volume for a guillotine cut in the subsea pipeline.

TABLE 2-12: EFFECT OF PIPE DIAMETER ON POTENTIAL LEAK VOLUME

Pipeline Diameter	Pipeline Volume (bbl)	Approximate Leak Volume (bbl)
6 inch	1,108	388
8 inch	1,968	689
10 inch	3,075	1,076
12 inch	4,500	1,576

Cleanup Costs

Four costs are associated with spill prevention and cleanup: (1) preparedness costs, (2) mobilization of the cleanup team, (3) actual cost for labor and materials for the clean up and (4) demobilization of the cleanup team. Preparedness costs include the cost for pre-staged material and equipment and are based on the well blowout, which exceeds predicted pipeline leaks. The mobilization and de-mobilization costs are the same regardless of the leak volume, since BPXA will mobilize all equipment and personnel regardless of the estimated leak volume. The actual time required to clean up a spill may differ by a day or two depending on the volume of the spill. The resulting daily costs will be significantly less than the mobilization/demobilization costs for the spill team.

2.12.2 Burial Depth

Increasing the burial depth affects the pipeline in the following ways:

- *Increases the depth of cover over the pipeline.* The section of pipeline close to shore that is susceptible to thaw settlement will be completely backfilled. Any differential settlement under the pipeline would result in this overburden being carried by the pipeline. Increasing the burial depths increases the load, but would reduce the potential displacement of the pipeline.

- *Decreases the potential creation of a free span due to strudel scour.* However, even at 7-foot depth of cover, the expected strudel scour span was small and could easily be accommodated by the pipeline within elastic limits.
- *Reduces the strain level in the pipeline due to subgouge deformation from ice keels.* However, as the offshore pipeline design for ice gouging is a limit state design which uses acceptable strain levels, there would be no added benefit with respect to ice keel gouging to bury the pipeline deeper.
- *Will affect the need for gravel mats in the design for upheaval buckling if additional backfill thickness was applied to the pipe.* The net benefit is not immediately apparent. Extending the burial depth will increase the amount of soil that can be placed over the pipe, but it will also increase the roughness of the excavated trench bottom due to slumping of unstable trench sides.

As discussed in Section 2.11, a limit state design methodology is used for the Liberty buried offshore pipeline. If a stress-based design were to be used in the analysis of ice gouge, the pipeline would have to be buried considerably deeper to meet design criteria. In the absence of detailed calculations, it is estimated that a pipeline would need to be buried to a depth of cover of 15 to 20 feet below the seabed to meet a stress-based criteria. This has several implications to the development:

- An excavation of 18 feet (15 feet plus overdig) may be beyond the capability of conventional excavation equipment.
- Large quantities of soil would need to be excavated, stored, and replaced to achieve this burial depth which also adds environmental impact.
- Any permafrost thaw settlement could result in substantial pipeline loading in areas prone to differential settlement due to the additional soil overburden.
- The cost to bury the pipeline to such a depth may make the project uneconomical.

3. GENERAL CONSIDERATIONS

3.1 Introduction

This section provides general information that is associated with each of the alternatives. This information is then taken into consideration in each alternative chapter and the appropriateness of its application assessed. The general information is provided in different forms depending upon the topic being discussed. The following list outlines the different forms in which the information may be presented:

- General background/considerations applicable to all design alternatives. For example, the failure assessment section summarizes the general approach to failure assessment and some of the oil spill scenarios that will be considered for each alternative.
- Summaries of the general requirements of the pipeline alternatives. For example, what design conditions each alternative must withstand or design functionality that each alternative must exhibit.
- Summaries of the various options. For example, different construction methodologies that could be considered.
- Summaries of the technologies or capabilities that can be applied to each alternative. For example, the main operations and maintenance techniques used to monitor pipelines.

This section is included to provide an understanding of the design criteria and the available technologies that have been considered for each pipeline alternative. Each alternative is then reviewed as to how it meets the criteria and what is the most appropriate technology (for example, for construction or repair). The complete review of each alternative, therefore, consists of information presented in this chapter and the associated alternative chapter; the chapters must be read together.

3.2 Design Considerations

The following is a summary of the design conditions that must be achieved and the main considerations that affect the design alternatives.

3.2.1 General

The design for each pipeline alternative must ensure safe pipeline installation and operation. The design flowrate is 65,000 barrels per day. This, in turn, establishes the operational boundary conditions, i.e., minimum temperature and inlet pressure at the Badami tie-in. The detailed flow analysis is described in Section 3.2.2, Flow Analysis.

The pipeline internal diameter is established based on pipeline length, flowrate and pressure.

The pipe submerged unit weight is a key design parameter and is based on the anticipated sea water density and possible soil/water slurry that may form in the trench bottom caused by soil/water agitation as the result of trenching and trench backfilling activities. During winter installation, the hydrodynamic current loads are small (< 0.5 knots) and do not become an overriding design consideration. Therefore, the required pipeline submerged weight is a major factor in the selection of wall thickness (Section 3.2.3).

Two key factors determine how deep the pipeline would be trenched into the seabed. The first is the so-called "depth of cover" (Figure 3-1), which is defined as the distance from the top of pipe to the original undisturbed seafloor. This is an important factor for keeping ice keel and strudel scour loads to safe limits. These aspects of the structural design are discussed in Section 3.2.4 and 3.2.8.

Another design consideration is the backfill thickness, which is important where there is a large difference between the ambient temperature during the installation and pipeline operation. The installation temperature is approximately 30°F (for winter or summer installation). The maximum allowable operating temperature is 135°F, resulting in a differential temperature of 100°F. This, in combination with the pipe wall thickness, operating pressure, backfill soil properties and trench smoothness, affects the pipe vertical stability due to upheaval buckling. Upheaval buckling is discussed in Section 3.2.6.

Another external pipe load that is directly the result of backfill thickness is caused by thaw settlement. Deeper pipeline trenching can increase the backfill thickness and thus leads to an increased overburden load during thaw settlement. This is considered in more detail in Section 3.2.7. However, deeper pipeline trenching protects the pipeline from strudel scour (Section 3.2.8).

Finally, excessive internal or external corrosion of the pipeline must be avoided over the project life. External corrosion control for each of the pipeline alternatives is discussed in the respective chapters.

3.2.2 Flow Analysis

As noted previously, the Liberty design flowrate is 65,000 barrels per day. The system flow conditions are established by considering the maximum and minimum pressures at the Badami tie-in (1440 psig and approximately 1050 psig), and the minimum flow temperature of approximately 120°F (to keep the optimum Liberty crude oil flow characteristics). Based on these parameters, as well as the thermal conductivity properties of the pipeline, hydraulic analyses were performed to determine whether the pipeline alternatives would achieve the design flowrate.

The hydraulic analyses included a range of ambient air temperatures as low as -50°F. Each pipeline alternative can achieve the target throughput of 65,000 barrels of oil per day, without exceeding the pressure rating of the Badami pipeline system (ANSI Class 600, 1,440 psig).

3.2.3 Pipeline Stability

The focus of pipeline stability is normally to resist wind and wave forces. During winter installation, the trench would be backfilled before the pipe is exposed to any significant wave or current forces. The Liberty pipeline must, however, be designed to be stable before, during and after backfilling. Vertical pipe stability during operation would be ensured by the added weight of the pipe contents and the backfill. Potential pipeline movement due to thaw settlement or upheaval buckling is addressed separately.

3.2.3.1 Pipe Weight

The pipeline must have a specific gravity greater than 1.0 to make it sink. Typically, increased pipe wall thickness is used to achieve pipe stability in small-diameter offshore pipelines.

3.2.3.2 Water Density in Trench

Increased seawater density may occur in the trench due to high salinity nearshore and suspended sediments or slurry formation during trench backfilling. Low-specific-gravity offshore pipelines have been observed to float in trenches filled with silty water. Where this is a concern, a minimum pipe/bundle specific gravity of approximately 1.6 is suggested to counteract this tendency.

3.2.3.3 Pipe Contents Weight

The pipe contents (oil) during operation would significantly increase its submerged weight. Under certain circumstances, the pipeline submerged weight can be increased by adding water (or water/glycol) during installation. This is not considered necessary for the steel pipelines, but may need to be considered for the flexible pipe alternative.

The construction scenario for the Liberty pipeline assumes concurrent installation and trenching. Increased pipe weight is desired primarily during trench backfilling.

3.2.3.4 Backfill Materials and Procedures

Trench backfilling returns previously excavated material to the trench and restores the original seafloor topography as closely as practical to its original elevation. Subsequent summer storms would smooth residual seafloor undulations after backfilling, particularly in shallow water. Backfilling reduces the potential for ice keel/pipe contact. The backfill also provides uplift resistance against any tendency for the pipe to move up in the trench due to upheaval buckling.

Gravel bags would be necessary in areas where the pipeline bridges over a high spot exceeding "prop height" tolerances (see Section 3.2.6 on upheaval buckling). Several bags may be added over the pipeline at the high spot depending on the overbend severity.

3.2.4 Ice Keel Gouging

The ice keel loading is characterized by an "extreme event" ice keel. The "extreme event" loading (also referred to by engineers as the "worst case" load) is an engineering term that describes the maximum load for this load condition that the pipeline would be expected to resist. It suggests the most extreme ice keel event that might be encountered in the Arctic. The expectation would be that the pipeline would remain operational after such an event, subject to confirmation by visual inspection and geometry pigging. However, it should be noted that there are regional geographic features that limit the size of ice keels in the vicinity of Liberty, and this is reflected in the selected ice keel design depth of 3.0 feet (see Section 2.6). In the ice keel soil/pipe interaction analysis, the ice keel width is varied so that multiple loading conditions are applied to the pipeline, and the worst case captured. However, a minimum aspect ratio of 10 (width to depth) is used; that is, ice keel widths are equal to or greater than 30 feet. This aspect ratio constraint is based on repetitive observation of ice keel signatures on the seafloor.

The resulting soil transverse displacement at a depth of 7.5 feet (as measured from the original seabed surface to the pipe centerline) is estimated to be 2.35 feet, based on the empirical relationships presented in Appendix C. A depth of cover of 7.0 feet is tentatively established as a baseline, which provides a clearance of 4.0 feet with respect to the "extreme event" design ice keel depth. The required trench depth to achieve a 7-foot depth of cover can be accomplished using on-ice trenching techniques. The total soil displacement for an ice keel event with a 3.0-foot incision depth and a 30-foot width was presented in Figure 2-7.

3.2.5 ANSYS Structural Analysis Summary

The ANSYS finite element package was used to analyze the ice keel soil/pipe interaction effects on selected pipeline alternatives. Approximately one mile of pipeline length was modeled for each ice-keel event. A fine mesh of 10-inch-long elements is used within the 100-foot center section of the pipeline model, where the ice keel displacements are imposed. Transversal and longitudinal soil springs are attached to the pipeline elements at every node to model the effects of soil displacement. The transverse spring nodes are fixed out-of-plane (z-axis direction) and longitudinally (x-axis direction).

The ice keel displacements are imposed by moving spring nodes along the pipe y-axis, as described by the displacement field in Section 2.6. Since the soil along the route for the most part is silty-sand, it can be approximated by average displacements for sand and clay. Thus, referring to the equations of Section 2.6 and Appendix C, for an ice keel 3.0 feet deep and 30 feet wide, at a depth of 7.5 feet (centerline of the pipeline), the soil directly below the ice keel is displaced approximately 1.17 feet vertically and 2.06 feet horizontally. The resulting displacement vector has a magnitude of 2.35 feet.

In addition to the displacement field imposed by the ice keel, pressure and temperature effects have been included in the analysis where possible to correctly model the axial stress in the pipe during operation. Results of the analysis are presented in the respective alternative sections.

3.2.5.1 Second Order Effects

The pipe strain values obtained are based on finite element analysis including material non-linearities. That is, kinematic hardening plasticity is used to capture the elasto-plastic steel behavior. Non-linear geometry effects were <u>not</u> included in the conceptual design analysis. The additional strains due to geometric nonlinearities (P-Δ effects) would require evaluation during detailed design.

3.2.6 Upheaval Buckling

Certain conditions (very high differential temperature) can cause the pipeline to move upwards from its originally installed position, forcing its way through the backfill. In severe cases, the pipe may even rise above the seafloor. This phenomenon is primarily caused by elevated pipeline operating temperature and pressure.

The severity of this condition depends on the longitudinal restraint provided by the soil resulting in “locked-in” compressive forces (the pipe can be imagined to be like a woundup spring waiting for release). If the pipe is laid relatively flat in the trench, the pipe would not be predisposed to an upheaval condition. However, if the pipe is laid over a "prop" (i.e., local high spot in the trench) and is subsequently backfilled causing a localized arch at that location, then the pipe would tend to push upwards as soon as the temperature increases in the line at operating start-up. Upheaval buckling is very sensitive to temperature, particularly above a predetermined threshold temperature. The axial forces in the pipe can be considerable.

The methodology described in Section 2.9 is used to evaluate the upheaval buckling potential for the pipeline alternatives. The basic parameters used in the calculations are:

- Installation temperature (subsea) = 30ºF
- Operational temperature = 150ºF
- Differential temperature = 120ºF
- Maximum (prop) height = 1.5 feet
- Factor of safety = 2
- Backfill thickness at prop = 6 feet

A density of 37 pounds per cubic foot was conservatively used for remolded native backfill material, and a density of 60 pounds per cubic foot was used for the gravel backfill (i.e., gravel bags).

Gravel mats or bags can be used to restrain the pipe. The pipe is prevented from moving upwards by the additional weight of the bag on the pipe and the increased uplift resistance mobilized through the bag pushing against the column of soil above it.

The design basis for the analysis conservatively assumes a maximum operational temperature of 150ºF compared to the average operating temperature of 135ºF. In addition, where gravel mats are used, the effective soil column mobilized above the pipe is assumed to be only two pipe diameters in width, whereas the gravel mat would, in fact, mobilize a wider soil column.

3.2.7 Thaw Settlement

The analysis of potential permafrost thaw settlement is described in Section 2.7. The soil/pipe interaction analysis for thaw settlement would be carried out in a similar manner to the ice keel analysis. A relatively long pipe segment is modeled as a series of elements with hyperbolic springs modeling the soil behavior. However, since the pipe displacement field occurs in the vertical plane, the soil response differs depending on the direction of pipeline/soil interaction. If the pipe tends to move downward, compressing the soil below, the soil resistance is relatively greater. If the pipe loses support (due to settlement) and supports the overlying soil or tends to move upward, the soil resistance is relatively weaker. Therefore, different soil spring properties are used, depending on the direction of the pipeline displacement relative to the surrounding soil.

3.2.8 Strudel Scour

The strudel scour design dimension is 15 feet at the seafloor, as described in Section 2.8. The loading event representing a strudel scour forming directly over the pipeline, with a horizontal dimension of 15 feet and deep enough to uncover the pipe, has a conservatively estimated return period of approximately 500 years. The resulting strudel scour geometry is a cone with a side slope of 1:2 (vertical: horizontal). If the pipeline is installed with a 7-foot depth of cover, the bottom of the strudel scour would almost coincide with the top of the pipeline. This would create a very small pipeline free span (approximately 1 to 2 feet). The resultant hydrodynamic loads would not adversely affect pipe stability.

3.3 Construction Methods

3.3.1 Objectives

In this section, construction methods for summer (open water) and winter construction are evaluated to identify the best candidate method with respect to logistics, practicality, cost and schedule.

This section discusses general factors concerning mobilization and demobilization, equipment and installation alternatives for both summer and winter construction. The equipment and logistics requirements for summer and winter construction are quite different. The advantages and disadvantages of each are discussed in the context of its appropriateness for each pipeline design alternative. The key tasks and sequence of events are discussed for the summer and winter candidate construction methods.

More information is provided for a winter construction program, as this is the recommended method for all alternatives.

3.3.2 Drake Field Experience

Only one pipeline has been built in an arctic offshore environment (Palmer et al. 1979) and it was installed using a bottom-pull method for the bundle installation and a plow for trenching. A Canadian company, Pan Arctic Oil Ltd., sponsored the Drake Field subsea completion. The project was installed off Melville Island in the Canadian High Arctic between 1976 and 1979. There are some similarities in what was achieved on this project compared to what might be required for a similar project on the North Slope. The pipeline bundle was approximately 4,000 feet long and comprised two 6-inch-diameter production lines, well head annulus monitoring tube, and control umbilical, as well as heat tracing and power cables. The bundle was successfully installed in 1978 after a three-year schedule to design, fabricate and construct.

Fabrication occurred on Melville Island during the winter of 1977-78. A “stove pipe” technique was employed for pipe string and bundle make-up under a temporary shelter. This necessitated a significant staging area for pipe handling. The outer jacket pipe was pulled over the inner bundle of pipes, tubing and power cables. An important point to note is that the pipeline was only 4,000 feet long (12% of the proposed pipeline length), but the pipe bundle make-up lasted four and a half months, not including pipeline installation.

The Drake Field experience is instructive, since it shows the effort required for bundled pipeline construction in the Arctic. The implication is that the schedule lengthens considerably over that which would be anticipated from a more conventional pipeline configuration.

3.3.3 General Pipeline Construction Activities

The are several key construction activities associated with each of the pipeline alternatives. These include:

- Mobilization and demobilization,
- Trenching,
- Pipe joining, and
- Pipeline laying.

} Pipeline installation

Weather and environmental constraints greatly influence the choice of equipment and schedule for construction. Methods are considered for summer construction, during open water, and winter, when equipment may be deployed from a thickened ice pad.

3.3.4 General Summer Construction Considerations (Open-water Season)

Construction activities and their timing during the open-water season are affected primarily by considerations for environmental protection. For instance, work is not typically planned on the tundra in the summer in order to avoid harassing migrating caribou and bird nesting and feeding areas, and also to protect the permafrost and overlying active layer of tundra from vehicular traffic. This restricts access to any shore-based staging area from the sea or air only. For similar reasons, water-borne activities may be restricted to avoid interfering with migrating whales and other marine mammals, as well as to avoid water quality changes affecting fish. Nevertheless, marine traffic is permissible if care can be taken to avoid effects on wildlife. Summer construction makes sense only if its duration is short and its effect on the environment is within acceptable biological limits. The following construction methods are reviewed in this context.

3.3.5 Trenching (Summer)

Several trenching techniques could be used during the summer. Some are applicable only to pre-trenching i.e., before the pipeline is installed, whereas others are best suited to post-pipeline installation. These methods include, but are not limited to (see Figure 3-2):

- Conventional excavation,
- Hydraulic dredging,
- Plowing,
- Jetting, and
- Mechanical trenching.

3.3.5.1 Conventional Excavation

Hydraulic backhoes, clamshell buckets or dragline could be used. In summer, the equipment would be operated from a flat-deck barge, which could maneuver by winching itself forwards and spudding-in to remain on location while digging. Intruding ice (greater than 3/10 ice cover) could affect the operations depending on the station-keeping ability of the barge (Figure 3-3). Conventional excavation is a proven, but time-consuming method, and productivity would be similar for winter or summer construction. Also, the reach of an extended or long-reach backhoe is limited (practically) to a combined water and trench depth of approximately 50 feet. Backhoe trenching could be used for any of the pipeline alternatives considered.

Regardless of the season, replacing excavated material in the trench after the pipeline is installed can create a dense liquid or slurry. This has the potential to make the pipeline temporarily buoyant, unless it is sufficiently heavy to resist the uplift forces.

3.3.5.2 Hydraulic Dredging

The most common hydraulic dredges used for the excavation of pipeline trenches are cutter-suction and trailing-suction hopper dredges. The cutter-suction dredge (Figure 3-3) excavates the trench with a rotating cutter head on the end of a ladder extended to the seabed. The cutter head breaks the soil, and pumps transport the soil/water slurry through a pipe up the ladder and through a discharge pipe. The end of the discharge pipe is typically located several hundred feet from the dredge and is moved often to prevent excessive dredged soil from accumulating in one area. Soil can also be disposed of by discharging into barges, which can then travel to a disposal area. This would have the advantage of limiting the amount of sediment in the water column. Silt curtains have been used successfully to limit sediment dispersion during soil dumping. The dredge advances by sweeping the cutter head back and forth while advancing longitudinally using spud piles. Because of the sweeping motion of the vessel, the trench tends to be wide.

Trailing-suction hopper dredges (Figure 3-4) excavate the trench by lowering a suction head to the seabed and pumping slurry into a hopper in the vessel's hull. A dredge of this type is not feasible for Liberty since it requires water depths greater than 20 feet.

3.3.5.3 Plowing

Plows can also be used to lower a pipeline into a trench. This is usually accomplished after the pipeline has been installed on the seafloor (Figure 3-4). Plows are an attractive tool, especially when the pipeline route is long. A plow could be used in either summer or winter. The primary determining factors for plow design, and ultimately its size, are the type of soil and the desired trench depth. This, in turn, affects the force required to pull the plow. The plow is advanced over the seabed by pulling with a large tug or a winch mounted on a frame traveling over the ice.

Historically, plows have achieved a depth of cover on the order of 5 feet (for a 12-inch-diameter pipe). As noted previously, a plow was fabricated and used for installation of the Drake Field bundled pipeline. Multiple-pass plows capable of excavating a trench 13 feet deep have been investigated and tested on a small scale by Sohio (Soil Machine Dynamics, Ltd.). Recently, some multiple-pass plows have been built which should have the capability of achieving a depth of cover of 7 feet if the soils are soft enough to allow plowing but strong enough to remain stable until the pipeline touches down in the bottom of the trench.

Generally, plows tend to be quite large (approximately 100 tons to 300 tons dry weight and 30 feet to 90 feet in length). Several plows have been fabricated for previous pipeline projects, and these may be available for lease or purchase for arctic projects. A plow could be used for any of the pipeline alternatives, although special design consideration would need to be given to the HDPE and flexible pipe alternatives as these designs could be more susceptible to plowing damage. The pipelines would be laid along the route and the plow would be pulled along the pipe, using the pipe as a guide. The shore and island approaches would be excavated using a backhoe or dragline.

3.3.5.4 Jetting

This method involves pulling a sled along the top of a pipeline after it has been installed (Figure 3-5). Water under high pressure is used to liquefy the soil, and air is used to lift it from under the pipeline. The pipeline lowers itself to the bottom of the trench as the jet sled advances.

To achieve a depth of cover of 7 feet in most soil conditions, the jetting sled would have to be towed over the pipeline several times, thereby increasing the risk of damage to the pipeline. Using this method as the primary excavation method would require a trench barge, anchor-handling tugs, and a survey vessel. The work can be performed only in summer, would be subject to ice activity, and causes turbidity in the water column. Due to the very large sediment load created, jetting is not a candidate trenching technique for any of the alternatives. However, localized jetting may be necessary to fluidize the trench bottom in order to lower a pipe that has become “high grounded” during installation.

3.3.5.5 Mechanical Trenching

This method is commonly used for burying cables and umbilicals, and has been used on several occasions for pipeline trenching. The trenchers typically rely on hydraulic power to propel the caterpillar tracks used for propulsion and to operate the cutting equipment. The hydraulic power requirements make these trenchers very large, often requiring large buoyancy tanks to keep the trencher from sinking into the soil and collapsing the trench, and to facilitate handling of the machine. Mechanical trenchers for pipelines are quite large pieces of equipment and require a large marine vessel from which to operate, including a large A-frame to launch and recover the mechanical trencher.

3.3.6 Trenching (Winter)

Many of the open-water trenching techniques require special marine vessels to deploy the equipment and therefore are not suitable for winter construction. However, some of the equipment can be used for off-ice construction. Conventional backhoes with extended or long-reach booms are proposed for the Northstar project and would work equally well for Liberty since the water and trench depths are comparatively shallower. Likewise, the cutter-suction dredge equipment described above could also be used for Liberty.

A plow was used on the Drake Field installation, although its design limited the trench depth to 4 to 5 feet. In this case, a 24-inch carrier pipe was used resulting in a depth of cover of only approximately 3 feet. The length of trench required for installation was only approximately 800 feet. The trench for Liberty will need to be longer and deeper to accommodate any of the alternatives. While possible, this is not considered the desired alternative.

Mechanical trenchers could also be deployed off the thickened ice pad. There are no known pieces of equipment that could be used, but heavy equipment suppliers can be innovative in such endeavors. A wheel bucket ditcher could readily be designed for arctic use, given the relatively shallow water depths considered for Liberty. The equipment weight would be a limiting factor, but the prize of increased trench rates would be worth pursuing. This would require further research.

3.3.7 Pipeline Summer Installation (Open Water)

Subsea pipelines are typically welded together and installed from lay vessels, although pipelines can also be welded into lengths on land and pulled or towed into location. The following methods may be considered for subsea construction (see Figure 3-2):

- Lay vessel,
- Reel vessel, and
- Tow or pull methods.

3.3.7.1 Lay Vessel

A lay vessel (Figure 3-6) is a specially built oceangoing vessel aboard which the pipeline is fabricated as the vessel moves along the pipeline route. Such a vessel moves either by means of an anchoring system or by its own propulsion, and can only operate in the summer. If the lay vessel moves on anchors, anchor-handling vessels are needed to help reposition the anchors so the lay vessel can advance. A moored lay vessel usually does not have propulsion and is moved from one work location to another by tug. The lay vessel can carry a limited amount of pipe on its deck, and pipe carrier vessels or barges carry additional pipe.

Pipelines in sheltered locations such as lakes are occasionally installed with a shallow-draft lay barge. This barge can be trucked to the site in modules or adapted from locally available vessels. While this would facilitate mobilization to and demobilization from the work site, these lay vessels are very sensitive to wind, waves, currents, and ice conditions.

Because of its large draft, a conventional lay vessel would not be able to operate in the water depths at Liberty. However, if flat-bottomed vessels were used as lay vessels, then a minimum operational depth of 10 to 15 feet of water could be achieved. The pipeline section from the nearest vessel location to the shore would be pulled to the shore, where facilities would be built for the pull equipment. After having completed the pull, the vessel would then lay the pipeline towards Liberty Island. At this location, the pipeline would be lowered to the seabed adjacent to the island. A tie-in would then be made to the island piping. Ice in the area would most likely affect the activities of the lay vessel.

Protection of the installed pipeline could be provided by pre- or post-trenching techniques. A pre-trenching method would most likely be required for Liberty, since the pipeline would otherwise rest on the seabed and be exposed to the action of ice moving through the area.

3.3.7.2 Reel Vessel

Essentially, two types of reel vessel are available. The first is a self-propelled, ship-shape vessel with a vertical reel. A reel ship can be used only in summer. The advantage of a reel ship is that it could lay 8 to 10 miles of 12-inch pipeline in one continuous operation. The pipeline would need to be pre-fabricated at a shore-based staging area, where it would then be reeled into the vessel. The relatively shallow water depth at Liberty for much of the route would preclude a reel ship from serious consideration.

An alternative to the reel ship is flat-decked barge with a horizontally mounted reel. These have been used extensively in the Gulf of Mexico. The pipe make-up logistics are the same as for the reel ship. The barge would need to be towed to the work site. This vessel may be dynamically positioned but usually advances by winching forward on its mooring system. A horizontal reel barge could be used to spool either steel or flexible pipe.

There are considerations which need to be taken into account with the use either of these vessels. The first has to do with the availability of such specialized equipment. The second would have to do with the time needed to mobilize the equipment for the start of construction i.e., does the vessel need to over-winter in Alaska in order to be ready for summer installation?

3.3.7.3 Tow and Pull Methods

There are a number of variations of the pipeline tow method; however, the principles for installation are basically the same in each case. In each instance it would be necessary to fabricate lengths of pipe (pipe strings) at an onshore facility. The pipe strings would be between 1,000 feet and 3,000 feet long and would be welded together to form the complete pipeline. The design of the total weight of the pipeline during the pull is such that the total force required to pull the pipeline does not exceed the capacity of the pulling equipment. The length of the pipeline for Liberty (6.12 miles) could be installed using one of these methods. The pipe specific gravity affects the submerged weight and therefore the pull force required for pull and tow methods. This in turn affects the size of winches and pull frames or, conversely, limits the length of pipe string that can be installed in a single pull. The advantage of this method is that when the pull gets under way it is a very rapid installation technique. Although it might be possible to pull the pipeline into a pre-excavated trench, the pipeline is usually post-trenched after it has been installed in this manner.

An alternative method would be to perform a surface tow and make surface tie-ins. This is feasible in relatively sheltered waters. Again, the pipe strings would be made up on land and launched into the water with flotation tanks or buoys attached. A small tie-in barge would be used to join the strings together, after which the floats would be released and the pipeline would sink to the seabed. This method is very fast and feasible in shallow water. Small tugs would be required for pipe string towing and hold-back during the mid-line tie-ins.

Bottom Tow

This is most likely a summer technique using a vessel to tow the pipeline from the onshore fabrication site to its final offshore position. Since the tow vessel can sail at a relatively high speed (2 to 4 knots), this method ensures that the pull can be accomplished in a relatively short time. Pipeline abandonment can be quickly achieved by disconnecting the pipe string from the pull cable. The pull can be resumed without major effort. The pull force for a bottom tow is typically 150 tons, which requires a fairly powerful tug of approximately 7,500 to 10,000 horsepower.

This method could be used to install any of the pipeline alternatives. The installation is limited by the maximum pull load, which depends on the pipeline length and the pull capacity of the vessel. The optimum solution is to install the pipeline in one unit. This is achieved by making up the 6.12-mile string onshore and then towing it into place. Alternatively, the pipe strings could be launched sequentially, making tie-ins at the shore crossing before pulling the next section out.

Off-Bottom Tow

The principles of this method are the same as for the bottom tow, except the pipe does not make direct contact with the seabed and the pull forces are then greatly reduced. Two vessels are used, one at either end of the pipeline to pull the string: one in front pulling and one in the rear holding tension on the string. When the pipe is on location, the floats required to keep the pipe off-bottom are released to lower the pipeline to the seabed. This method is also fast but requires diver support to release the floats.

Bottom Pull

As with the bottom and off-bottom tow methods, a shore-based staging area is required to prefabricate the pipeline strings. In this instance, however, a pull or winch barge is used to pull the pipeline along the seabed. The pull forces are significantly higher than before, and pipeline advancement is slow.

Pull or tow methods may be applicable for any of the pipeline alternatives considered. The bottom or off-bottom pull methods are also possible for winter installation by using an ice-mounted pull frame. This has been contemplated previously for arctic pipelines (Polar Gas pipeline, et al.).

3.3.8 Pipeline Summer Construction (Open Water)

All combinations of open-water trenching and pipeline installation methodologies would follow a similar installation sequence. It would be necessary to establish a shore-based gravel-pad staging area to stockpile and make up pipe strings or the entire pipeline length. The required shore-crossing site could occupy a significant area of tundra. In the case of a pull, the pipe would be launched from the temporary right-of-way towards the island. In the case of a reel installation, the pipe would be winched towards the shore crossing before laying away towards the island. Trenching would most likely follow pipe installation, although laying into a pre-excavated trench is possible but not likely desirable. The study scope does not permit further elaboration of these installation alternatives.

3.3.9 Pipeline Winter Installation (Ice Platform)

This method, known as through-ice or off-ice, requires the preparation of a work pad on the ice. The ice must be thickened so that it can bear the weight of construction equipment during the pipeline installation. A slot would be cut through the ice wide enough for equipment to dig a trench in the seabed. The pipe must be welded together into a continuous pipe string, either in sections near shore or alongside the ice slot, similar to a land-based operation. After the strings have been welded, they are towed over the ice and laid end to end alongside the ice slot. Tie-in welds join the pipeline strings together into a continuous length before it is lowered into the trench through the slot in the ice. The soil from the excavation would then be placed in the trench over the pipeline as backfill.

This offshore construction method has not yet been used, although river crossings installed on the North Slope are similar in scope. The advantage of the through-ice method is that it relies on techniques and equipment that are proven technology. Ice-strengthening and ice-cutting techniques are well understood, and as a result, there is good confidence in this approach. Backhoes are used universally for land and marine trenching within the limits of their capabilities. This technique, however, has not been used to excavate a relatively deep trench in deep water through the ice. A potential disadvantage is that floating ice has a limit to its load bearing capacity, and the combined weight of equipment and pipe must be considered before electing to use this method.

Pull or tow methods may be applicable for any of the pipeline alternatives considered. The methods are also capable of being used in winter by using an ice-mounted pull frame. This has been contemplated previously for arctic pipelines (e.g., the Polar Gas pipeline). However, the scope of this study does not permit further elaboration of these construction methods.

3.3.10 Pipeline Winter Construction (Ice Platform)

The preferred method of construction is an ice platform construction method. The reasons for using conventional excavation equipment and off-ice installation techniques are as follows:

- It uses conventional, proven equipment available locally.
- Ice-strengthening and ice-cutting techniques are well understood.
- A through-ice test trenching program has been carried out on the North Slope to prove the feasibility.
- Other construction methods would require significant equipment be mobilized to the North Slope, which may require the equipment to over-winter (i.e., barges).
- Open-water construction equipment is not designed for these shallow water depths.
- A skilled labor force is available.
- Alaskan content in the project is maximized.

The following describes general tasks to be completed for off-ice construction. Deviations from this installation sequence, production rates associated with each of these activities, and the amount of equipment required are discussed in each of the pipeline alternative chapters.

Subsea pipeline installation involves several major activities. The sequence starts by making ice roads for access and material resupply. This is followed by construction pad preparation, ice slotting, trenching, welding, pipeline lowering-in, and backfilling.

3.3.10.1 Pipeline Fabrication and Installation Activities

The following describes the activities for off-ice pipeline construction.

Mobilize Equipment, Material and Workforce

This activity includes mobilizing major equipment, e.g., sidebooms, trucks, cranes, welding rigs, power generators, lights, etc. Mobilization of the trenching spreads also occurs at this time and consists of backhoes, dumpsters, front-end loaders, etc. Personnel would travel to the North Slope at this time and receive job orientation and safety training.

Ice Road Construction and Ice Thickening

Ice roads would be the main means of access to the construction and stockpiling areas. They would need to be provided to the work areas before material is stockpiled and pipeline construction starts. Ice roads must be formed and the sea ice must be thickened along the route to provide an ice-strengthened surface for construction equipment. The ice roads and construction pad would be maintained throughout construction. Ice roads would be the main means of access to the construction area. The construction ice pad would be approximately 200 feet wide.

The ice is thickened to ensure that it is bottomfast or a minimum of 8 to 9 feet thick as soon as possible to permit safe transit of construction equipment. Seawater would be pumped to the surface of the ice until the required thickness has been achieved.

Ice-Slotting

A 10-foot-wide slot would be cut in the ice using “Ditch Witch” trenching tools. The ice would be cut into approximately 6-foot by 6-foot blocks and removed using backhoes. The blocks would be moved by front-end loaders to locations away from the work site to prevent excessive deflections of the ice in the working areas.

Trenching

The trench would be excavated using backhoes. This method of construction would permit a continuous trenching, pipe-laying and backfilling program. Excavation may start at more than one location concurrently. It is anticipated that three independent trenching spreads would be required for Liberty.

The trenching activity is characterized by water depth, as this affects backhoe efficiency. The backhoe boom length needs to be increased in deeper water which requires changing out the associated bucket size. Shorter-reach backhoes with larger buckets (4 cubic yards) are used in shallower water. In deeper water, an extended-reach boom and smaller bucket (1 cubic yard) are used.

The trench depth is checked as excavation proceeds. A suction-cutter dredge pump would be used to achieve the desired trench-bottom smoothness immediately before the pipeline is installed.

Temporary Storage Site Preparation

A temporary pipe storage area would be required to stockpile pipe and double-joint pipes. The area required would depend on the length and number of pipe strings to be prefabricated. A significantly larger area would be required for bundle (pipe-in-pipe or pipe-in-HDPE) fabrication.

Pipe String Make-up (Welding)

There are several options for pipeline welding. The pipes may be double jointed and then made up into long pipeline strings that would be towed out over the ice and laid next to the ice slot. Alternatively, the pipes could be transported individually or double-jointed and strung out alongside the ice slot to await being welded into the line. This would be similar to a land-based pipeline installation lay spread. Welds would be subject to non-destructive examination with X-ray and ultrasonic equipment.

A bundled pipe configuration would very likely be pre-assembled at the make-up site before transportation onto the ice pad.

Pipe String Transport and Tie-In Welds

The pipeline strings would be towed using tracked equipment to the side of the trench. Pipe strings would be lifted by sidebooms and maneuvered into position next to the ice slot ready for lowering-in. The two ends to be joined would be covered with a protective shelter. Lowering-in would proceed to a point where the next pipe string would be tied-in. This would be determined in the field depending on water depth and the slack needed for lowering-in. Tie-in welds would be X-rayed and ultrasonically inspected before or after the field joint coating is applied.

Any external leak detection system would be strapped to the pipeline prior to lowering-in.

Pipeline Installation

Pipeline installation would follow as soon as possible behind the trenching spread and immediately after a pass of the clean out dredge. Sidebooms would be used to lower the pipe through the ice-slot and into the trench.

Backfilling the Trench

Once the pipeline is installed in the trench, a final survey would be performed to confirm the position of the pipe in the trench. From this information, a determination can be made as to whether there are any high spots or props along the pipeline. If any locations of this nature are measured, gravel mats or bags would be placed at the “high point” to ensure that when the pipeline becomes operational, it would not move vertically.

Backhoes and front-end loaders would complete the backfilling. Gravel mats or bags would be lowered onto the pipe using slings attached to a backhoe bucket or attachment.

Hydrostatic Testing and Smart Pigging

Once the pipeline has been installed, it would be pressure-tested to satisfy applicable regulations and codes. A water/glycol mixture is typically used to prevent the hydrostatic test medium from freezing in the pipe.

Once pressure-testing is complete, the geometry and wall thickness pig run would be conducted to establish the baseline information against which subsequent runs can be compared.

Demobilize Equipment

After site cleanup, all equipment, excess materials and personnel would be demobilized. As-built documentation would be prepared and forwarded to the appropriate authorities and document control.

3.3.10.2 General Quality Assurance and Quality Control Considerations

Quality assurance and quality control documentation would ensure that the construction complies with the design. The key requisites of this program are:

- Pipe material properties based on pipe mill test results, as well as NDE results.
- Pipe corrosion coating properties and testing.
- Weld material properties and testing.
- Weld non-destructive testing procedures and qualification.
- Minimum depth of cover, pipeline survey, and backfill requirements.

3.3.10.3 General Pipe Manufacture, Welding and Assembly Considerations

The majority of offshore small-diameter pipelines use seamless pipe due to the uniformity of wall thickness and its more favorable material qualities. For larger pipe sizes and wall thickness, it may be necessary to consider alternative pipe manufacturing processes. The inclusion of a long seam weld in the pipe may affect the ability of the pipe to tolerate cyclic loading. Butt weld procedures may become more stringent and necessitate full-scale bend testing.

Welding is accomplished using a line-up clamp to align the pipe ends while the first few weld passes are made. This is important to ensure a high-quality weld. Any pipe movement during this process can be detrimental to weld quality. An internal line-up clamp is preferred since it is easier to use and therefore speeds pipe-joint alignment. However, is not always possible to use an internal line-up clamp, particularly in the case of making a tie-in weld.

For the pipe-in-pipe alternative, it would be necessary to further evaluate the effect of load transference from the outer casing pipe to the inner pipe during bending. The centralizer roller system would need to be evaluated to ensure that high stress concentrations are not induced due to bending. This could result in accelerated, localized corrosion that might not be readily detected by internal or external examination. This is not a serious consideration for a non-strain-based design.

3.3.10.4 General Temporary Storage of Excavated Material Considerations

Most of the excavated trench soil would need to be temporarily stored on the ice before backfilling. This could last between 10 to 15 days of excavation in the nearshore section (0 to 8 feet water depth). The material excavated beyond the 5-foot isobath would be stored temporarily on bottomfast ice in a designated area; otherwise it would be stockpiled alongside the ice slot. Once a section of the pipeline is installed in the trench, backfilling using recently excavated trench spoils would commence.

3.3.11 Directional Drilling – An Alternative to Trenching and Pipe Installation

Technical advances in horizontal directional drilling (HDD) in recent years qualify this technique for consideration as a construction method. HDD is commonly used for pipeline river and road crossings and some shore approaches (Figure 3-5). The method involves using a slant drilling rig to drill a pilot hole along a predetermined path. The pilot-hole drill bit is then replaced with a reamer, which enlarges the hole to allow installation of a pipeline or casing. Drilling fluids are used to remove cuttings, keep the hole open, and lubricate the pipeline during installation.

The main technical constraint involves the influence of soil conditions and the handling of the drilling fluids used. The presence of gravel or ice lenses would reduce the efficiency of the drilling operations and could result in collapse of the hole. The maximum length that can be drilled in the local soil conditions is on the order of 5,000 to 6,000 feet for a 12-inch pipeline. Typically, as the pipe diameter increases, the length or reach that can be directionally drilled decreases. The Liberty route length (6 miles) exceeds the capabilities of current technology for a single drilled crossing. However, it might be possible to drill a series of holes between small intermediate artificial islands. Tie-ins would be required at these island locations. These tie-ins could be performed above ground on the islands or within a temporary cofferdam that would be removed and backfilled after the pipe was in place.

Completing one hole and installing a pipeline by directional drilling is a relatively complex undertaking, but is nevertheless technically feasible. A series of directional drilling operations would magnify the complexity of the operation. Two directional drilling techniques are available and described below.

Pullback Technique

This technique requires attachment of the reamer at the exit point of the pilot hole. The pipeline or casing is attached behind the reamer and pulled into the hole as the hole is enlarged. This is currently the most commonly used method for pipeline installation, and lengths of approximately 5,000 feet have been achieved. This technique can be used either in winter or summer.

Forward Thrust Technique

The drill string is retracted and the reamer attached at the entry point of the pilot hole. As with the pullback technique, the pipeline is attached behind the reamer, but it is then pushed into the hole with the advancement of the reamer. This technique can also be used either in winter of summer.

The mobilization cost for a large HDD rig would be considerable. The logistics of the rig set-up and take-down would be manageable, but the supply or possible recirculation of drilling mud would be a major logistics consideration. A large staging area would be required for drill pipe and transmission pipe. This method would, however, avoid the need for trenching.

3.4 Construction Costs for a Winter Construction Program

The following section summarizes the general activities common to each alternative for an off-ice winter construction program. The summary identifies the assumed quantities, productivities and durations associated with each task.

3.4.1 Construction Sequence

A discussion of construction sequence, quantities, rate of progress, schedule and a cost estimate summary for each of the pipeline alternatives is presented in the respective chapters. In general, the following activities and sequence have been considered for construction:

- Equipment/Material Mobilization
- Ice Road Construction and Ice Thickening
- Ice Cutting and Slotting
- Trenching
- Pipeline Make-up Site Preparation
- Pipe String Make-up (Welding)
- Pipe String Transportation
- Pipe String Tie-in Welds and Bundle Make-up
- Pipeline Installation (Lowering)
- Backfilling the Trench
- Hydrostatic Test
- Demobilization

3.4.2 Quantities and Rates of Progress

General comments regarding quantities and rates for a winter installation are presented here. Only those activities common to all pipeline alternatives are presented. Specific comments regarding the design alternatives are presented in the respective chapters.

3.4.2.1 Mobilize Equipment and Material

Mobilization of land-based pipeline construction equipment and mobilization of the trenching spread from Prudhoe to the site are assumed to take 3 days for each spread.

3.4.2.2 Ice Road Construction and Ice Thickening

Ice roads would be prepared and maintained along the pipeline route and would be the main means of access to the construction area. The ice roads would be built within an approximately 200-foot-wide ice platform where pipeline construction would take place. This ice platform would extend for approximately 6.12 miles between the shore approach and Liberty Island.

A minimum ice thickness of 8.5 feet is assumed necessary to satisfy load requirements and achieve safe operations. The ice would be thickened for a width of approximately 200 feet (about 100 feet on each side of the pipeline trench) to permit the transit and operation of the construction spreads.

An effective ice buildup rate of 2.5 inches per day, based on analysis of historical ice construction data in Alaska, is used to estimate the progress of thickening the ice. Based on a minimum ice thickness of 8.5 feet and an initial ice thickness of 2.5 feet, 6 feet of thickening would be required.

Once the ice roads are complete, a smaller spread would remain operational to repair and maintain the roads as required. This spread would be mobilized for the entire winter season until the end of April. An additional cost of 15 days at the spread rate is incorporated into the cost to account for the smaller spread for maintenance over the construction period.

3.4.2.3 Ice Cutting and Slotting

The ice would be cut into 6-foot by 6-foot blocks, with a minimum thickness of 8.5 feet, and removed using backhoes. This operation would be performed over the pipeline route within the area that has been thickened.

Three spreads would be required so that one ice-cutting spread leads the way for each of the three trenching spreads. The rate of progress of the ice cutting and slotting activities is estimated to be 1,000 feet per day. Considering a total pipeline length of 32,314 feet, this activity is estimated to take 32 days.

3.5 Operations and Maintenance

The following sections summarize the tools that can be used to monitor the different aspects of the design as part of the operations and maintenance program. The summary also identifies an envisioned program for these monitoring activities. The subsequent chapters on each alternative discuss whether these tools can be used to monitor the design and how the design configuration impacts the information that can be gathered.

3.5.1 Operations

In addition to production metering and product pumping operations, the main focus of the pipeline operations would be to monitor the pipeline integrity. Such monitoring would involve continuous leak detection and various types of pipeline inspections. The following sections describe monitoring required to support the design considerations.

3.5.1.1 Metering

Oil flow would be metered through the combination of a number of systems. A lease automatic custody transfer (LACT) flow meter would be located upstream of the Liberty Island pumps, and an ultrasonic flow meter located downstream from the pumps upstream of the Liberty Island pig launcher. Another flow meter would be located downstream of the Badami tie-in pig receiver before the oil enters the Badami pipeline. All measured inlet and outlet flowrates, along with pressure and temperature measurements obtained at Liberty Island, the shore crossing, and at the Badami tie-in, would be relayed via the supervisory control and data acquisition (SCADA) system to Liberty Island. This information would be used to:

- Provide an accurate measurement of oil being exported to sale, and
- Provide an internal method of leak detection.

The SCADA system continually reviews the flow parameters and assesses whether all product input to the pipeline arrives at the outlet location.

3.5.1.2 Maximum Operating Limits

As stated in Section 2.4, the maximum allowable pipeline operating temperature would be 150°F, and the pipeline's maximum daily average temperature would be 135°F. The pipeline pressure would not exceed a maximum allowable operating pressure of 1415 psig. Pipeline shutdown would occur if the maximum allowable operating pressure or temperature was exceeded.

3.5.2 Pipeline Inspection

A pipeline inspection philosophy is vital to successful operation of the pipeline. A sound inspection plan optimizes the amount of useful information that can be gained from inspection surveys and pigging schedules, and must take into account the criticality of the various systems in the field. If test results are satisfactory, it can generally be inferred that the system is fit for service. When degradation is discovered, these areas may be designated for further evaluation or may be severe enough to warrant immediate corrective repairs.

During detailed engineering, a recommended inspection plan and schedule would be developed. The monitoring of the various components and parameters is described below. Pipeline "states" or "conditions" may be characterized as follows:

- Conditions that require no action,
- Conditions that require more rigorous monitoring schedules, and
- Conditions that require immediate intervention.

Such conditions are determined based on pigging test data and route survey data. Details on the types of inspections associated with this plan are summarized below.

3.5.2.1 External Offshore Route Survey

The integrity of the pipeline backfill (soil thickness between top of pipe and the mudline) would be monitored every 5 years. This would be carried out using typical marine survey techniques such as bathymetry or swath surveys in water depths greater than 6 feet and a single-beam fathometer in water depths less than 6 feet. This data would be collected along the route, and parameters such as depth of cover, backfill thickness and observations of gouges or scouring in the seabed would be recorded.

3.5.2.2 Shoreline Erosion Survey

Survey data would also be recorded annually to determine shoreline erosion rates from the zero water level (MLLW) to the shore valve pad. Placement of the valve pad has been set far enough back from the shoreline so that its infrastructure is not expected to be affected by erosion.

All offshore and erosion surveys would be performed during open water. Initial baseline surveys would be made soon after construction, with further surveys scheduled every five years or as required by government regulations. Any unusual shoreline erosion conditions at the shore crossing would be monitored during routine maintenance trips to the valve pad.

3.5.2.3 Pipeline Leak Detection

Pipeline leak detection is presented in each of the respective design alternative chapters.

3.5.3 Maintenance

To maintain the offshore pipeline system's integrity, the best offshore pipeline monitoring techniques would be utilized. Maintenance would be performed on the pipeline system components on a planned, non-emergency basis in accordance with U.S. Department of Transportation (DOT) codes and regulations.

3.5.3.1 Monitoring of Cathodic Protection

To ensure that the anodes are providing adequate cathodic protection to the offshore pipeline, the electrical potential of the pipeline would be measured annually at both Liberty Island and the shore crossing. If the pipeline system in the offshore section was exposed for repair or close inspection, the cathodic protection potential would be measured at the exposed location.

3.5.3.2 Monitoring of Pipe Wall Thickness (Internal Corrosion) and Internal Damage

The pipeline wall thickness would be monitored by inspection pigging, either ultrasonic or magnetic flux leakage, at the periodic intervals listed in Table 3-1. The pipeline would also be assessed for any internal denting or deformations using mechanical caliper pigs or equivalent.

3.5.3.3 Monitoring of Pipeline Configuration

The pipeline's geometry would be monitored by inspection pigging and compared to the baseline of its as-built configuration. Changes to the pipeline's offshore configuration could potentially be caused by thaw settlement, strudel scour, ice gouging or upheaval buckling. Table 3-1 summarizes a typical inspection schedule.

3.5.3.4 Monitoring of External Corrosion

External corrosion would be controlled with a dual-layer fusion-bonded epoxy pipe coating and a sacrificial anode, cathodic protection system for the offshore pipeline. External corrosion would also be assessed as part of the wall thickness pigging operation.

3.5.3.5 Pigging Schedule

A typical pigging schedule is summarized in Table 3-1. These are the most likely intervals for the pigging operations and may change based on the requirements of the pipeline operator. The schedule is based on typical pigging schedules for other pipelines and on the expected performance of the Liberty offshore pipeline.

TABLE 3-1: TYPICAL INSPECTION PIGGING SCHEDULE

Pig Inspection	Inspection Schedule
Wall Thickness Measurement - Pigs will be run in early winter so that any repairs required can be performed during the same winter season.	Start-up. Every two years thereafter.
Pipeline Geometry - The purpose of the geometry pigging is to monitor the pipeline configuration offshore.	Baseline pig runs after pipeline construction completed before freeze-up. Once every calendar year for the first five years. Duration between consecutive pig runs will not exceed 18 months during these first five years. Every subsequent two years thereafter. Additional geometry runs will be carried out if severe ice gouges or strudel scours are suspected or observed to have occurred.
Mechanical Damage - Mechanical caliper pigs will be run to assess internal deformations.	Start-up; prior to initial wall thickness or geometry pig survey. Prior to every wall thickness or geometry pig survey.

3.5.3.6 Monitoring of Pipeline Expansion

Thermal expansion would be limited because the soil backfill around the pipeline will act as a virtual anchor. However, expansion is expected to occur at the island and shore approach. Both of these locations would incorporate a thermal expansion loop designed to absorb the maximum expected thermal expansion. Expansion of the pipeline at the surfacing point on the island and in the riser casing at the shore crossing would be noted during routine checks.

3.5.3.7 Pipeline Shore Approach Geometry Survey

The shore crossing is the area along the pipeline route where thaw settlement might occur. Geometry pigging of the pipeline would indicate alignment changes in the offshore pipeline section. If changes are observed in the vicinity of the shoreline, detailed inspection of these areas would be initiated. Requirements for any corrective repairs would be assessed based on evaluation of the survey results, pigging data, and any detailed inspections. Detailed inspections would include visual monitoring of the pipeline settlement at the shore crossing. Thaw settlement would occur over a period of time, and as such, pipeline settlement at the vertical transition could be visually monitored over the lifetime of the pipeline. The following section describes evaluation criteria and required action for the pig inspections and is applicable to settlement of the vertical pipeline transition observed by visual monitoring.

3.5.4 Evaluation Criteria and Required Action

Upon completion of the various pig inspections and surveys, the data would be reviewed for any anomalies such as sections of the pipeline that have moved from their original position or where the wall thickness has reduced. These anomalies would be compared against allowable criteria for pipeline operation. Table 3-2 lists potential allowable criteria and required action.

As listed in Table 3-2, strain-based criteria would be used to assess the need for offshore pipeline re-evaluation or repair when pipeline displacements are detected. Geometry pig measurements would be converted to pipeline curvatures, which can be related to pipeline strains. These strains would then be compared to the maximum predicted and allowable pipeline strains. During the first few years, the yearly change in strain would also be determined by comparing the average strain rate from consecutive pig runs. This calculated change in strain would then be used to estimate the strain that would be obtained from the next scheduled pig run. Depending upon the average rate of strain increase, an assessment can be made as to whether the next pig run should be performed earlier than scheduled or if corrective action is required during the interim.

TABLE 3-2: PIPELINE EVALUATION AND REMEDIAL ACTION

Anomaly Type	Criteria
Wall Thickness Corrosion	Dealt with on a case-by-case basis. Wall thickness reduction will occur gradually, and changes will be easily detected during scheduled inspection pigging. The pipeline operator will determine action.
Geometry Changes and Misalignment / Displacement	Strain-based criteria are recommended for determining the need for repairs based on the results of consecutive geometry pigging. Strain values will be derived from geometry pig measurements based on curvature / strain relationships. These strains will then be used to determine the acceptability of changes to the pipeline's position, between consecutive pig inspections, based on specified strain criteria.
Backfill / Bathymetry Anomalies	Corrective action should be considered if the pipeline has been undermined to the degree that a span has developed. Such undermining may occur from strudel scour. The pipeline has been evaluated for a maximum span which will not be subject to vibration fatigue. Offshore pipe with less than the required backfill thickness (top of pipe to mudline) should be provided with additional backfill during the next available construction season and referenced for future evaluation surveys. Course of action should be coordinated with geometry pigging results.
Other Anomalies Including Shoreline Erosion	Dealt with qualitatively on a case-by-case basis in a manner that is warranted by inspection survey results. The pipeline operator will determine action in accordance with normal North Slope practice.

3.6 Repair

The objective of this section is to:

- Qualify the repair assumptions and definitions,
- Summarize the general repair techniques associated with the pipelines, and

- Identify the key aspects to consider when assessing a repair technique including water depth, season, diving requirements and excavation.

The applicability of these repair technologies to different designs is reviewed in the associated chapter for each alternative.

3.6.1 Repair Assumptions and Definitions

Before a pipeline repair is attempted, all oil would be removed from the pipeline. Repair operations would not interfere with oil cleanup operations, and the repair could result in additional product loss from the pipeline. The following assumptions are made:

1. A subsequent pipeline repair can be accomplished from either floating equipment or a stabilized (landfast) thickened ice sheet.
2. In winter, if a large volume of oil has been discharged, additional consideration shall be given to potential reduction of ice strength. For a leak less than 3,000 barrels, the strength of the ice is not affected (Dickins 1981; NORCOR 1975).
3. The logistics for pipeline repairs depend largely on the season and the sea ice conditions.

3.6.1.1 Offshore Zoning

The offshore pipeline route has been divided into two zones for logistical considerations, each with characteristic water depths and ice conditions. Zone I extends from the shore, approximately 2 miles north of the shore crossing, in water depths ranging from 0 to 6 feet. Winter ice conditions in this zone result in bottomfast ice. By December, the ice is stable. Breakup usually occurs at the end of May.

Zone II extends between approximately 2 miles north of the shore crossing to Liberty Island and has water depths ranging from 6 to 21 feet. Mid-winter ice conditions in this zone are characterized by landfast ice. An ice sheet forms by late December or early January, and the maximum ice thickness achieved is approximately 6 feet. The potential breakup period is any time after the end of June.

3.6.1.2 Types of Repair

Repair methods address major and minor pipe damage. Minor damage is assumed to affect a localized segment of pipe 40 feet or less in length. The pipe may either remain structurally sound or be damaged to the extent that a short replacement segment is necessary. A repair requiring replacement of more than 40 feet of pipe is considered major damage. A length of 40 feet has been arbitrarily selected based on a single pipe-joint length.

3.6.2 Repair Technique Review

Some repair techniques are compatible only with specific support equipment. Most of the techniques, however, can be used both from marine equipment and, with minor modifications, from a stable ice sheet of sufficient thickness.

Repair methods are described in detail in Appendix E. They may be categorized as follows:

- Welded repair with cofferdam,
- Hyperbaric weld repair,
- Surface repair,
- Tow-out of replacement string,
- Spool piece with mechanical connectors, and
- Split sleeve.

Although mechanical repair devices have been used worldwide for permanent pipeline repairs, they are not considered appropriate for an arctic offshore repair. The design and repair philosophy is to remediate pipeline damage by replacing the section of pipe and restoring the pipeline integrity to the highest degree.

Mechanical repair devices have the advantage that they are relatively easily deployed compared to a pipeline cut out and replacement. They are not applicable for a pipe-in-pipe repair where the outer pipe has been perforated, and they cannot be used to repair a flexible pipe.

Subsea repairs are difficult to accomplish under any circumstances. The degree of difficulty differs significantly for each of the pipeline alternatives. In fact, it may be necessary to replace a complete pipeline segment of flexible pipe. In addition, there is no record of repair of a pipe-in-pipe system where annulus flooding occurred.

3.6.2.1 Repair Technique Evaluation

Table 3-3 summarizes the six repair techniques. Specifics regarding each of the pipeline design alternatives are presented in each of the respective chapters.

TABLE 3-3: REPAIR TECHNIQUE EVALUATION

Repair Technique	Season	Applicable Zone	Diving Requirements	Level of Excavation	Temporary or Permanent	Comments
Welded Repair with Cofferdam	Winter	I	Not Required	Moderate	Permanent	Advantage is that repair is performed in a dry environment.
	Winter	II	Minimal	Moderate	Permanent	
	Open Water	I, II	Minimal	Moderate	Permanent	
Hyperbaric Weld Repair	Winter	II	Extensive	Moderate	Permanent	Applicable for repairs of minor damage.
	Open Water	I, II	Extensive	Moderate	Permanent	
Surface Tie-In Repair	Winter	I	Not Required	Large	Permanent	
	Winter	II	Moderate	Large	Permanent	
	Open Water	I, II	Moderate	Large	Permanent	
Tow-Out of Replacement String	Winter	I	Not Required	Large	Temporary	Permanent repair if a spool piece is welded and a temporary repair if mechanical connectors are used.
	Winter	II	Extensive	Large	Temporary	
	Open Water	I, II	Extensive	Large	Temporary	
Rigid Spool Piece with Mechanical Connectors	Winter	I	Not Required	Moderate	Temporary	Would be used only if there was not enough time to carry out a permanent repair.
	Winter	II	Extensive	Moderate	Temporary	
	Open Water	I, II	Extensive	Moderate	Temporary	
Split Sleeve Repair Method	Winter	I	Not Required	Low	Temporary	Used for stopping leaks and for lowering the potential for rupture when external dents or bulges have been detected in the pipeline.
	Winter	II	Moderate	Low	Temporary	
	Open Water	I, II	Moderate	Low	Temporary	

3.6.2.2 Repair Technique Philosophy

A welded permanent repair is the preferred method of repair for an offshore pipeline. A mechanical sleeve could be used to make a temporary repair. Any temporary mechanical device would be replaced by a welded repair when conditions became favorable to do so.

Based on the average ice conditions along the route, it is not practical to effect repairs year round. Repair is not possible during early winter when the ice is too mobile for effective station-keeping of marine equipment and not sufficiently thick to support ice-based operations. This lasts three to four months in Zones I and II: from early October to December in Zone I and early October to January in Zone II. Repair would not be attempted during breakup when the potential for river overflooding or local ice failure is high and the moving ice floes are too large for marine operations. This period extends for approximately two months between late May and July in Zone I and between June and July in Zone II.

In general, repairs could be conducted during open water from a repair barge or shallow-draft vessel, or during winter using a thickened ice pad. A diving spread would be an essential part of a repair scenario. The shallow water depth (<22 feet) would greatly facilitate diving support and speed the overall repair schedule.

3.6.3 Repair Scenarios

Repair methods for damage scenarios for each alternative are presented in the respective chapters.

3.6.4 Seasonal Repair Method Considerations

A pipeline repair would be planned and coordinated with the oil spill and emergency response plan. Field operations would be coordinated with the cleanup effort. After shutting-in the pipeline, the next step would be to determine the extent to which the pipeline is still losing product to the environment. Before a repair is attempted, it would be necessary to displace the pipeline contents.

If this procedure is not possible, it may be necessary to prevent further product loss from the pipe by placing an external clamp around the pipe at the leak. This would involve using the same or similar equipment and personnel as would be used to complete a permanent repair. If the leak occurred in winter, it would be necessary to cut an access hole through the ice. This operation would be followed by locating the leak. Dredging equipment would then be lowered (through the ice in winter) to expose the line and to permit deployment of the temporary repair clamp.

During repairs, the pipe would be raised to the surface and secured. The damaged pipe would be removed, and a spool piece would be welded into place and non-destructively tested. The repaired section would then be lowered into a pre-excavated trench and backfilled. The pipeline would be pressure-tested before restarting the line.

3.6.4.1 Open-water Repair

In both zones, a repair could be completed between late July and late October. The amount of time to complete a repair would depend on personnel being familiar with all phases of the intended repair procedure. Open-water repairs could be mobilized from a special vessel with diver capability. Specialized crews would be required for repair work. The latest start dates allow for the completion of the work plus time to demobilize all equipment.

3.6.4.2 Off-Ice Repair

Winter repair would depend on the availability of bottomfast ice as a thickened ice pad. An off-ice repair spread would be similar to an installation spread. Equipment would include backhoes, a suction dredge, sidebooms, etc. Dredging equipment would be deployed through the access hole in the ice to expose the line and allow visual examination of the damage.

The earliest winter start date refers to the survey and diving activities which can be performed as soon as the ice sheet is stable. Generally, the closer to shore the leak is, the sooner the repair can be attempted. This is due to the faster formation of a more stable ice-sheet nearer to shore. The latest completion date is the last date to begin safe demobilization prior to ice breakup.

3.7 Leak Detection

The objective of the following sections is to summarize the different approaches that could be used to monitor the pipeline for leaks. Detail is provided for internal and external systems that are considered to be proven technologies and factors that affect their performance. Alternative techniques that could be considered for monitoring are listed for information.

All transmission pipelines within the State of Alaska must subscribe to a “best available technology” (BAT) evaluation regarding leak detection. The criteria for a BAT evaluation are prescribed by the Alaska Department of Environmental Conservation and include availability (i.e., proven technology), compatibility with existing SCADA and hardware, transferability, effectiveness, etc. Pipeline integrity checking and leak detection for arctic subsea pipelines can generally be categorized as follows (with no implied order):

- Volumetric flow measurement
- Pressure monitoring
- Pressure measurement with computational analysis
- External (adjacent to pipe) oil detection
- Remote sensing (airborne or satellite)
- Geophysical sensing techniques
- Pressure or proof testing
- Pipe integrity checking (i.e., smart pigging)
- Visual inspection
- Through-ice borehole sampling

There are many variants of the above that are either experimental or are being developed. The following discusses those that are considered proven technology, but recognizes that other technologies may be under development.

3.7.1 Mass Balance Line Pack Compensation and Pressure Point Analysis

Conventional state-of-practice leak detection for any of the pipeline alternatives could be achieved using two independent systems: the mass balance line pack compensation (MBLPC) system and the pressure point analysis (PPA) system. These systems would work in parallel, providing a redundancy. The SCADA system would record all leak detection system parameters continuously. Readings would be averaged and compared periodically with historic data (usually the previous 5, 20 minutes, and 1 and 2 hours). Under optimal conditions, these systems would be capable of rapidly detecting a leak of as little as 0.15% of volumetric flowrate in the pipe. The equipment requirements are:

- Flow meters at the inlet and outlet ends of the crude oil pipeline.
- Pressure and temperature indicators and transmitters at each flow meter position to allow for flowrate correction.
- A communications link with the SCADA system that can update the complete data set every 30 seconds for MBLPC or every 0.25 seconds for PPA.

The offshore oil pipeline would be continuously monitored, and all system parameters (e.g., discharge and receipt pressures, temperatures, and flow meter readouts) would be relayed back as electronic signals to a standalone computer. The system parameters would be compared to predetermined alarm set-points and calculated values. Flowrates would be calculated based on algorithms which incorporate the system characteristics for the range of actual operating flowrate and pressure conditions.

These system parameters would be displayed on a graphics control panel and screen at the operator's station. Also, the MBLPC system results would be continuously compared with those from the PPA system. Any discrepancies (i.e., variance in system parameters outside of the valid set-point range) would show up immediately. Values outside of set-points would cause an alarm, forcing an operator to acknowledge the change in status and investigate the cause. If it is not verified that the indication is a false alarm, the system would automatically shut-in the pipeline affected. A disadvantage of these systems is that they can be prone to false alarms. Therefore, operator training is very important so that when an alarm occurs the operator will take the appropriate actions to determine whether the pipeline pressure conditions that caused the alarm can be explained. This can be caused by hydraulic "noise" in the pipeline resulting from a variety of sources such as valve closure, pumping surges, etc.

Custody transfer metering would add further capability to the leak detection system. Any cumulative loss of product in a given time period (one to two days) and exceeding a 100- to 200-barrel threshold would become obvious. Operations personnel would be required to reconcile discrepancies between dispatch and receipt flow metering. The situation would be investigated further if, after meter-proving, the flow meters are not the source of the anomalous readings.

The PPA and MBLPC leak detection methods can be used for any of the pipeline alternatives considered. The pressure and flow measurements would be similar for each alternative, as would the computational treatment of the data.

3.7.2 LEOS Leak Detection System

A wide range of leak sensors and leak detection systems was researched for the Northstar project. Each system was assessed against the performance requirements set forth for the system. The LEOS system has emerged as a contender for this particular application based on its proven performance and industry experience. The LEOS system is a leak detection system with over 21 years continuous operation and more than 20 worldwide applications. It is capable of detecting hydrocarbons on buried fuel, gas, and liquid hydrocarbon transmission systems and tank farms.

The working principle of the LEOS system is depicted in Figure 3-7. The main features of the sensor are summarized below:

- Status: commercially available product
- Type: continuous monitoring system
- Vendor: Siemens Power Generation Group (KWU), Germany
- Service history: 21 years, river crossing and other onshore buried pipelines
- Life span: one of the earliest system is 21 years old and is still in operation
- Length limitation: 15 kilometers
- Minimum bend radius: 0.6 meters (2 feet)
- Reaction time: determined by air circulation frequency, normally 12 or 24 hours
- Locating leak: approximately 0.5% of total length accuracy
- Availability: commercially available with four to six months lead time
- Main advantages: long and successful service history, availability, discerning, capable of detecting small leaks
- Main concerns: protection required, handling

Siemens estimates that the LEOS system should be capable of detecting hydrocarbon concentrations resulting from a leak rate as low as 50 liters (0.3 barrels) of oil per day for Northstar. Detection capabilities for Liberty would not be expected to be significantly different. It is also possible to determine the location of a leak using the LEOS system to within ±0.5% of the pipeline length (approximately ±160 feet for the Liberty offshore section). A conceptual drawing of the LEOS system installation for offshore use is presented as Figure 3-8.

3.7.3 Factors Affecting Leak Detection Performance

Mass balance and pressure point technologies are well-established state-of-the-art computational leak detection systems. The leak detection sensitivity can be affected by hydraulic noise arising from pumping, separation and valve closures. These operations can introduce pressure variations into the pipeline system that can be misinterpreted as signaling a leak. This affects the leak threshold set-point, which should avoid repetitive false alarms. Also, it is important to match the performance characteristics of the flow meters so that the combined meter error is not dominated by one of the meters (i.e., the least sensitive meter).

The LEOS system would be installed in a protective conduit, and functionality checks would be made during installation to ensure its integrity. If a small leak were to occur at the farthest point from the LEOS tube, it would take several hours for the oil to diffuse towards the tube. Given that it would take approximately 5 to 6 hours to pump out the sample air, sampling is planned every 24 hours, thus providing a high degree of assurance in the sample sensing results.

The MBLPC, PPA, and LEOS systems would be integrated into the pipeline's SCADA system, which would record all leak detection system parameters simultaneously. Combined, it is expected the systems would detect a large leak within 30 seconds and a small leak within 24 hours. Potential leak volumes and times to detection are discussed further in Section 3.8 and the respective pipeline design alternative chapters.

A major design consideration regarding the ultimate success of a supplementary (external to pipe) leak detection system is the ability to fabricate and install the system under arctic winter conditions. It is important that the physical properties of materials/components are able to meet the rigors of construction in the Arctic. The anticipated cold temperatures (air temperatures could be as low as -50 to -60°F) and physical air/water/ice/soil interfaces, plus poor visibility once the pipeline is placed in the trench, will add to the challenge of installing such a leak detection system.

3.7.4 Alternative Leak Detection Strategies

In addition to the principal leak detection methods cited above, there are other possible leak detection strategies that involve remote sensing techniques. These are discussed here for completeness but are not warranted in view of recent developments with the LEOS system.

3.7.4.1 Through-Ice Borehole Sampling

This method could be used to confirm the presence or absence of oil under the ice sheet or embedded in the ice sheet during winter. Oil can be detected by inspecting the coring sample for discoloration, or the water-air interface could be sampled for the presence of trace hydrocarbon vapors.

Oil from a leak would saturate the backfilled pipe trench and float upwards through the water column to become trapped under the ice sheet. Underwater currents may cause the leaking oil to drift away from directly over the pipe. However, under-ice currents are expected to be small, and oil from a significant leak would still be detected in the vicinity of the pipeline route within a few days. In the event of a prolonged leak (over a few weeks to a month), the oil would spread naturally between depressions in the ice undersurface, gradually expanding in aerial extent with the increased volume of oil.

Various researchers have estimated under-ice storage capacities resulting from large-scale under-ice roughness features correlated to surface snow patterns (e.g., Barnes et al. 1979; Kovacs 1977). These natural features can be used to guide the most effective pattern of drill holes aimed at detecting any oil present under the ice. The assumed leakage rate can be converted into an expected contaminated area over any desired period of time. The diameter associated with these areas is then used to select an appropriate spacing between sampling sites to achieve a high probability of detecting oil which may be present beneath or encapsulated within the ice.

This method is considered a last resort since it is cumbersome, requires significant equipment and personnel resources, and puts people at risk by putting them on the ice.

3.7.4.2 Remote Sensing

Satellite systems can provide data to classify terrain and map the earth's surface. Specialists in providing products and services relating to and involving radar remote sensing (airborne and satellite), image analysis, advanced signal processing applications, and synthetic aperture radar have been contacted regarding the ability to detect oil under ice. They did not believe that spaceborne or airborne radar could be used for this application as there would be insufficient penetration through the ice. In the absence of ice or in broken ice, satellite remote sensing might be potentially used to detect spills. However, data must be ordered, processed, and mapped to determine if oil has been detected. It is estimated that this process would take a month to acquire and process the data and so is not considered to provide the desired response time.

Aerial reconnaissance is a regulatory requirement. If there is oil on the water surface when the ice sheet is absent or broken, it would be visually detected during airborne reconnaissance.

3.7.4.3 Through-Ice Sensing Techniques

Ground penetrating radar (GPR) is a noninvasive, electromagnetic, geophysical technique for subsurface exploration, characterization, and monitoring. Environmental changes impact ground penetrating radar as the electrical properties of the medium being investigated change. The replacement of water by oil in the soil or water column may alter the response of the GPR, thus indicating contamination. However, GPR relies on contrast of the dielectric constant, which would be small between ice and oil. Thus, using GPR to differentiate oil from seawater would be difficult.

Several sources of information suggest that acoustic methods have potential, but due to the similarities in water and oil acoustic properties, it may be difficult to distinguish between the two liquids (e.g., Gill et al. 1979). Ultrasonic tools showed promise in freshwater ice, but there were anomalous results when applied to saline ice studies.

Studies have suggested that radar, while being able to penetrate reasonable depths in ice, is limited in resolution due to high attenuation at wavelengths that would give the desired resolution (e.g., Gill et al. 1979). Other studies have suggested that radar can theoretically detect a layer of oil if a clear ice/oil boundary is present.

Hydrocarbon vapor sniffer technology over ice has been identified in the literature as a potential technology, assuming hydrocarbons do travel through the ice cover. However, since ambient levels of hydrocarbons would exist during the search for spilled oil (helicopter or snowmobile), it is suggested that this would not be a reliable tool.

3.7.4.4 Periodic Leak Pressure-Testing

Leak pressure-testing consists of shutting in the pipeline between sectioning block valves and monitoring the pressure in the line for a relatively short period of time (compared to hydrotests that last up to 24 hours). The test time depends on how quickly a “steady state” is achieved in the line. Typically, pressure leak tests last 20 to 30 minutes, or until it has been established that there is no leak. If the line maintains pressure over that period of time, there are no leaks in the system. If there is pressure loss, the pressure decay is measured as a function of time. During the test, the produced oil is initially diverted to a surge tank or similar containment so that the production wells continue producing oil. After the static leak test, the oil is redirected through the production facility and exported.

This technique is considered cumbersome by operations personnel, and the results may lead to erroneous or ambiguous results, as it is very difficult to achieve a bubble-tight seal at a block valve, even with a block and bleed arrangement. Any interruption of production introduces with it the opportunity for operator error.

3.8 Failure Assessment Considerations

The failure analysis methodology used in this report is depicted in Figure 3-9. Each of the systems is defined in its respective chapter. In the failure analysis, cause and effect of failure are investigated and a relative likelihood associated with each scenario. Leak detection options have been reviewed in Section 3.7. Given the associated performance of the chosen leak detection option and the failure assessment for the pipeline, spill scenarios can be developed for the pipeline. The spill scenarios can then be evaluated with respect to cleanup and repair. Select information presented in this section has been extracted from the Oil Spill Response Information Document for Northstar (BPXA 1977) and the Final Environmental Impact Statement (FEIS) for Northstar (U.S. Army Corps of Engineers 1999).

In this section, the subject of failure, or more appropriately, risk of failure is introduced. For further details, the reader should refer to Kaplan (1991). In the absence of operational data to provide an historic basis for risk analysis, a different approach is necessary. The following sections present qualitative and quantitative aspects of risk of failures. Specifically, the ideas associated with risk, hazard, safeguard, failure, and uncertainty are discussed. Spill scenarios are described including potential oil loss. Cleanup, repair, and environmental impact variables are also discussed.

3.8.1 Failure Assessment: Qualitative Aspects of Risk

In order to objectively study engineering failure assessment, the subject of risk needs to be reviewed. The traditional and intuitive qualitative processes of risk assessment used in engineering have evolved into a highly structured and formalized discipline known as quantitative risk assessment (QRA) or probabilistic risk assessment (PRA). The value of such a structured approach to risk and failure analysis is that it offers the possibility of a unified approach to risk assessment of any engineering system, which leads to a common language for discussing risk of failures. By adoption of a common language, greater communication and better understanding are achieved across different disciplines.

The first step in the structured approach to risk assessment is to define risk. This section first looks at qualitative aspects of risk and then systematically quantifies risk. Specifically, the qualitative aspects of hazard, risk, safeguard, readiness level, and uncertainty are discussed.

Hazard, risk, safeguard and readiness level can be defined as follows:

- Hazard is a source of injury or failure.
- Risk is the likelihood that the injury or failure will actually be realized.
- Safeguards are means that minimize the frequency of a hazard.
- Readiness level refers to the ability to effectively deal with the consequences of a failure given that it happens.

Thus, the relationship among hazard, risk, and safeguard can be captured as:

$$\text{RISK} = \frac{\text{HAZARD}}{\text{SAFEGUARD}} \ , \quad \text{or}$$

$$R = \frac{H}{S} \ .$$

The above is a symbolic equation, not a numerical one. Nevertheless, for a given *H*, the larger the *S*, the smaller the resulting *R*. Thus, given a hazard, the risk can never be zero, but it can be made small by providing better safeguards. However, safeguards have a cost.

For example, if the Atlantic Ocean is considered a hazard, and if one tries to cross it in a rowboat, one incurs large risk. If instead, the *Queen Elizabeth* is used, the risk is small. The *Queen Elizabeth* is therefore a safeguard that converts a large hazard into a small risk.

From the above, it follows that:

$$R = R_1 + R_2 = \frac{H_1}{S_1} + \frac{H_2}{S_2} \ .$$

Suppose that H_1 is small compared to H_2. In order to more effectively minimize risk, it would be wise to spend more resources on S_2 rather than on S_1.

The idea of risk also involves both uncertainties and damage. Note that damage is defined as consequences of a failure, not the failure itself. This may also be expressed as a symbolic equation:

$$\text{RISK} = \text{DAMAGE} \times \text{UNCERTAINTY} \ , \quad \text{or}$$

$$R = D \times U \ .$$

Thus, if there is no damage, there would be no risk. Note that damage is not the failure itself; rather, damage is defined as consequences of a failure. Since different people will evaluate uncertainty and damage differently, people will perceive risk differently. This subjectivity of risk sometimes makes it difficult to achieve understanding and consensus. In order to minimize the subjectivity, real evidence must be brought into the record. If real evidence is not available, similar events must be used as evidence, carefully stating the qualifiers to such similar evidence.

3.8.2 The Quantitative Definition of Risk

To ask “What is risk?” for an engineering project is really to ask three questions:

1. What can go wrong with this project?
2. How likely is that to happen?
3. If it does happen, what are the consequences?

The answer to the first question is provided by writing down “scenarios” describing what can go wrong and how that might happen. We symbolize this with the following notation:

Si = The i-th scenario.

The likelihood of a scenario can be assessed by its frequency, in units of “occurrences per project”, with the notation:

Fi = frequency of the scenario Si.

Thus, the numerical value of Fi is the number of times Si will occur during the project.

The answer to the third question is denoted by Xi, which is the “damage vector” associated with scenario Si. Xi will have components Ci, the cost increment, and Ti, the time delay to rectify the damage caused by Si.

Thus, an answer to the three risk questions stated above is given by the triplet:

< Si, Fi, Xi >.

Using brackets to denote “set of”, and appending “c” to denote complete, one arrives at the quantitative definition of risk, R:

R = < Si, Fi, Xi >c.

Having defined the risk scenario, Si, the way the project is planned to unfold, given that nothing goes wrong, must also be defined. This is denoted:

So = The “as planned” scenario.

3.8.3 Detailing the Process

The basic strategy for identifying the scenario Si is to first become clear on what is the as-planned condition So and ask "what can go wrong here?" The answer to what can go wrong takes the form of one or more "initiating events" of main importance.

In this process, the key aspects are:

- To list all relevant/potential initiating events, and
- To estimate each frequency in a consistent manner.

When listing all relevant initiating events, a "scenario tree" emerges in which all initiating events that can potentially lead to damage are visualized and grouped. Such representation is key in organizing the risk assessment process, and helps provide the desirable common language for risk of failures.

The frequency of each initiating event might be obtained from the use of probability density functions that reflect a state of knowledge or state of confidence about the numerical value of a parameter. Such a parameter is usually defined in general terms. Different experts will have different states of knowledge about a specific parameter, which results in different values for its frequency or split fractions.

To minimize the subjectivity of this aspect of risk assessment, experts should be asked to provide first and foremost, actual evidence. In this approach, experts are not asked for their opinions, rather for their information and factual experience, i.e., their evidence. Each item of evidence related to an initiating event, or a scenario path, is recorded and given an identifier E1, E2, etc.

Thus, the goal is to produce an evidence listing for the probability curves, the scenario frequencies Fi, for the damage parameters Xi, etc. Then the entire risk assessment may be considered "evidence based", rather then a weaker "opinion based".

3.8.4 Spill Scenarios

3.8.4.1 Potential Oil Loss

In the assessment of potential oil loss, it is assumed that a PPA system is combined with an MBLPC system to provide a leak detection threshold capability of 0.15% of the flow (97.5 barrels per day). It is assumed that a supplemental leak detection system is used with each pipeline option. It is also assumed that there is a remotely controlled, mechanically operated valve installed at both ends of the offshore pipeline, which would be shutdown if a leak is detected. Oil loss through a leak in the offshore section due to water intrusion into the pipeline is limited by the undulating pipeline profile. From the seabed profile for the proposed route, the maximum length of pipeline that would lose oil by water intrusion is assumed to be approximately 9,000 feet (based on a bathymetric survey along the pipeline route).

The probable release volume from a hypothetical pipeline failure has four components:

- The volume of oil released before the leak is detected.
- The volume released during the reaction time.
- Oil released due to expansion of the fluid trapped in the leaking segment as the pressure is relieved.
- Oil released as the result of drainage under the influence of gravity from the leaking segment.

Scenarios for potential volume loss have been evaluated and are presented in the following paragraphs.

Large Leak (Guillotine Break)

The response time for the PPA and MBLPC system, given a complete rupture of the line, is assumed to be less than 30 seconds. The loss of oil during this period of time would be approximately 23 barrels. The volume of oil released during the reaction time is a function of the scanning rate of the system and whether the system is shutdown remotely or manually. Five minutes are estimated as the time required for the operator to confirm the probability of a line leak and initiate a shutdown. This timing assumes that the shutdown valves at either end of the pipeline are remotely controlled and mechanically operated. This five-minute reaction time would result in a loss of approximately 226 barrels of oil. There would also be a loss of volume due to a reduction in line pressure and an associated expansion in oil volume. This oil loss is estimated to be 27 barrels. Once a leak is detected and confirmed, the remotely controlled mechanically operated valves at the island, shore crossing, and the Badami pipeline tie-in would be closed. Closure time for the shore crossing valve is estimated to be 8.5 minutes. During this time, the overland section may drain into the offshore section. The estimated volume of oil due to drainage is 170 barrels. The maximum oil loss due to water intrusion would be the volume of oil contained in the length of the pipeline that is lower than the position of the leak. The rate at which the oil is displaced depends on the relative densities of oil and water, the inclination of the pipeline, the size of the hole, and whether or not the pipeline is buried. The maximum oil volume that would be displaced by water intrusion is estimated to be 1,130 barrels. Accounting for all losses yields a total volume loss of 1,576 barrels of oil.

Medium Leak (Small Crack or Pinhole Leak)

For a medium-size spill, it is assumed that the leak rate is below the threshold of the MBLPC and PPA systems. This 0.15% threshold would result in a leak rate of 97.5 barrels per day. The volume of oil lost during the reaction time of each of the supplemental leak detection systems is presented in each of the respective alternative chapters. The time required to confirm the possibility of a line leak and effect a shutdown (five minutes) would result in a loss of an additional 0.4 barrels of oil. If it is also assumed that there is volume lost from a reduction in pressure (and expansion of oil) after shutdown, there is potential for an additional loss of 27 barrels of oil. During the valve closure time, the potential oil loss due to drainage of the overland section of pipeline into the offshore pipeline would not exist due to the fact that pressure within the pipeline would be reduced to the point that very little oil could leak from the pipeline. Oil loss due to water intrusion is assumed to be minimal due to the nature of the leak and given that a minimal amount of oil would have continued to leak before the line is purged.

Small Leak (Chronic Leak)

A small chronic leak is considered to be 1 barrel per day. Such a leak may be the result of a weeping fracture or the loss of integrity of a flange seal. The volume of oil lost during the reaction time of each of the supplemental leak detection systems is presented in the respective design alternative chapter. Subsequent to discovery, during shutdown and purging, very little oil would be expected to continue to escape under this scenario due to the nature of the leak.

3.8.4.2 Seasonal Considerations

Open Water (Summer)

During the open-water season, the oil released from any pipeline leak would travel through the backfill and rise to the water surface through the water column. There it would be exposed to wind, wave and current action tending to transport the oil away from the location of the spill.

Solid Ice (Winter)

Oil released into the water column under a floating solid ice cover would rise and gather in pools or lenses on the underside of the ice sheet. Under-ice currents are expected to be low, and as a result, most of the oil would contact the ice undersurface in the vicinity of the pipe centerline. Two physical factors that act to naturally limit the area contaminated by oil under the ice are natural depressions related to variability in snow depth, and rapid incorporation of the oil by new ice growth around and beneath the oil layer. Ice naturally develops an undulating bottom surface in response to snow drift patterns on the surface. As the natural containment increases with ice thickness, the area needed to contain a given spill volume decreases steadily throughout the winter.

In areas where the ice eventually becomes bottom-founded, from the first establishment of stable ice in November until approximately mid-February, most of the ice in this area is free-floating, and any pipeline spill at this time would behave as discussed above. From mid-February on, the ice would become bottom-founded. If the ice rises and falls with the tides, oil would be able to spread somewhat laterally. After approximately the end of March, the ice will have reached its maximum thickness of approximately 6 feet. In waters of this depth or shallower, much of the ice would rest firmly on the bottom, with a layer of frozen sediment at the ice seabed interface. In this situation, a leak would result in a gradually expanded area of oiled sediment within the thaw zone surrounding the pipe.

If the oil beneath or trapped inside the solid ice is not removed, it would remain locked in the ice until approximately late May, at which time the process of vertical migration would begin with the gradual warming of the ice sheet. The rate of vertical migration depends on the degree of brine drainage within the ice (a function of internal temperature), oil pool thickness, and oil viscosity. Natural melt from the ice surface downward also acts to release the oil. This oil would likely be released to rise through the water column once the ice lifts off the bottom with the drainage of the river overflood waters in spring. Once the oil reaches the ice surface, it lies in melt pools or remains in patches on the melting ice surface. Any oil remaining on the ice at final breakup and disintegration of the ice cover would be released into the water.

Broken Ice (Spring or Fall)

In this case, oil would rise to the surface and collect in the openings between individual floes or be trapped underneath the floes themselves. During the primary period of broken ice in the spring, portions of the oil rising beneath the floes would naturally migrate through the rotting ice and appear on the ice surface within a matter of hours. For the case of oil trapped under newly forming pancakes or sheet ice in the fall, the likely fate would be rapid entrapment, with new ice growing beneath the oil as already discussed.

The fate of the oil trapped between floes would depend largely on the ice concentration and the time of year.

During freeze-up, the oil could be entrained in the freezing slush present on the water before the sheet ice forms. From approximately early October until mid-December, the pipeline could lie under a condition of moving ice with breaks and open patches. A large leak at this time of year could result in a pool of oil moving within the forming ice sheet. A small leak could result in a narrow ribbon of oiled ice with long dimensions corresponding to the actual drift track and ice drift rate prior to shutdown of the line or the cessation of ice movement.

At breakup, ice concentrations are highly variable from hour to hour and over short distances. In high ice concentrations (greater than 5/10 coverage), oil spreading is reduced, and the oil is partially contained by the ice. As the ice cover loosens, more oil is able to escape into larger openings as the floes move apart. Eventually, as the ice concentration decreases to less than 3/10, the oil on the water surface behaves essentially as an open-water spill, with localized oil patches being trapped by wind against individual floes. Any oil present on the surface of individual floes would move with the ice as it responds to winds and nearshore currents.

3.8.5 Cleanup, Repair, and Environmental Impact Variables

3.8.5.1 Response Time

There would be oil spill equipment and trained manpower positioned at Liberty for immediate response in accordance with the approved spill contingency plan. The second wave of response would come from the nearest operating field (Endicott) and then cascade out from there to include Alaska Clean Seas and other North Slope operators.

Response time is a function of mobilization time, travel time and deployment time. Mobilization time is the time to get a piece of equipment out of storage, prepare it for operation and make it ready to travel. Mobilization time for most North Slope equipment is one hour. Deployment time is the time to make a piece of equipment operational for its intended use at the spill site. This would vary from 0.5 to 3 hours, depending upon the specific equipment. The longer deployment times are usually associated with large vessel and/or boom deployments. Travel time is the time to transit from a base to the spill site. Response time is not as critical in a winter spill as in open water, as the ice tends to keep the oil from spreading to a large area. Transit speeds for vessels, helicopters and rolling stock are presented in Table 3-4.

TABLE 3-4: TRANSIT SPEEDS

Deployment Location	Vessel Transit Time (hrs) @ 5 knots	Helicopter Travel Time (hrs) @ 100 mph	Road Travel Speed (mph)
Badami	1.8	0.1	35
West Dock	4.5	0.2	35
East Dock	3.5	0.2	35
Endicott MPI	1.8	0.1	35
Endicott SDI	1.5	0.1	35
Northstar	4.7	0.3	35

Note: The exact distance via road to a spill would be a function of the ice road location(s) and lengths.

3.8.5.2 Cleanup Capability

There is a large inventory of response equipment on the North Slope that has been strategically positioned for response and a large labor pool that can be called upon 24 hours per day.

3.8.5.3 Cleanup

In the event of a leak, cleanup actions would start with the containment of the spilled oil followed by recovery. Booms and absorbent barriers could be used to retard further spreading of any spilled oil. For any of the scenarios, there would likely be the requirement for some manual recovery or mopping-up operation utilizing buckets, shovels, and absorbents. Methods of cleaning up spilled oil from different pipeline spill scenarios are presented below where information has been extracted from the Northstar Oil Spill Response Information Document (BPXA 1997) and the Northstar FEIS (U.S. Army Corps of Engineers 1999).

Open Water (Summer)

The priority of any oil spill contingency plan is to protect the areas used for harvesting of subsistence resources by the local residents and to protect wildlife habitat. The key focus of the marine response operation would be to prevent oil from affecting wildlife and reaching the shoreline, while trying to rapidly remove as much of the oil from the marine environment as possible. Containment of spilled material would be accomplished through the use of booms at the edge of the spilled material.

Open-water cleanup strategies would involve a combination of mechanical recovery and in-situ burning. Mechanical recovery is considered a primary means of response for both fresh crude and emulsified oil in calm to moderate seas. The ability to deploy and maintain conventional booms, skimmers, and support boats in drifting ice would be severely affected in ice concentrations greater than 3/10. As ice concentrations increase, the effectiveness of mechanical containment using boom systems decreases. Fortunately, the ice provides natural containment. In-situ burning in open water using fire-resistant booms offers the potential of achieving almost complete oil removal from the water under a range of conditions. Burning is a proven response technique that, depending on circumstances, would be used with mechanical recovery to substantially increase the oil recovery rate. In the event of a spill in open water or broken ice, oiled sediments in the vicinity of the leak would need to be removed and properly treated or disposed of.

Solid Floating Ice (Winter)

From approximately late November until late May, spill cleanup operations can use the ice cover as an operating platform for supporting equipment. In the case of a known reservoir of oil trapped within the ice sheet in mid-winter, direct pumping and ice road haul operations would result in almost complete removal of the spilled oil. Depending on the time of year, helicopters may be used to ferry ice cutters, pumps, and bladders to the site. Stable landfast ice might be accessed by Rolligons or ice roads. Burning on site could become the preferred option in winter when there may be insufficient time to transport the recovered oil or when ice road access is impossible. Oiled sediments around the leak would need be excavated and properly treated or disposed of.

Bottom-founded Ice (Winter)

Bottom-founded ice refers to the condition where a portion of the fast ice becomes thick enough to rest on the bottom in shallow water. Winds can affect water level, and a significant increase in water level could result in the ice sheet being temporarily lifted off the bottom during mid-winter. If any oil had accumulated at the ice/soil interface, it could then spread laterally and fill the natural collection pockets on the underside of the ice. After approximately March, much of the ice would rest firmly on the seabed, with an attached layer of frozen sediment at the ice/seabed interface. The oil in this case would expand laterally within the thawed soil around the pipeline. In this bottom-founded ice condition, cleanup crews would have to trench completely through the ice and recover oiled sediments lying over the pipeline. These sediments would then be properly treated or disposed of. This cleanup activity may occur in conjunction with pipeline repair.

Broken Ice (Fall)

There are limited mechanical options for recovering large volumes of oil spilled under or among new and young ice in the fall months. A rope-mop-style skimmer can be deployed by crane over the side of a response barge or vessel to recover localized oil patches trapped in water and slush between floes.

The most effective strategy during freeze-up would likely use in-situ burning, with the ice providing natural containment, rather then trying to deploy booms and barriers and trying to recover the oil mechanically.

It is envisioned that satellite tracking beacons would be deployed at the spill source to monitor the drift of any oiled ice away from the spill site. The oiled ice might move short distances before becoming landfast some distance from the original spill location. Conventional solid-ice winter response procedures could then be followed.

Weakened or Broken Ice (Spring)

The period between the first onset of surface snowmelt and final deterioration of the landfast ice provides the best opportunity for in-situ burning of oil that naturally appears on the surface or that remains on the surface following a winter cleanup operation. However, this period also marks the end of easy site access with heavy equipment. In-situ burning is an efficient and effective method of removing oil from a solid ice cover after ice roads are closed to traffic. The small amount of residue left after burning can be recovered manually with crews on the ice and transported to shore with helicopter buckets.

As the ice begins to break up, the response options would depend on the ice concentrations. There would be a period of several weeks where response operations would need to apply a mix of strategies over short periods as conditions allow: booms and skimmers operated from shallow draft barges in light to moderate ice, in-situ burning of thick oil trapped between the floes in heavier ice, and traditional open-water techniques as ice concentrations diminish to less than 3/10.

3.8.5.4 Repair

The repair options for each of the pipeline alternatives are presented in the respective chapters. The timing between pipeline repairs and oil spill cleanup would depend on the season and the location of the leak. During the summer, it is assumed that cleanup would be performed prior to or during pipeline repairs. However, as oil would spread quickly during the open-water season, priority would be given to oil spill cleanup operations.

During the ice-covered season, ice-based pipeline repairs would be scheduled before or during an oil spill cleanup, since the landfast ice would contain the oil in a small area. Repair prior to or during oil spill cleanup operations is preferred because cleanup operations would remove the ice work surface that is required to make the ice-based pipeline repairs. If a pipeline repair is postponed to the following open-water season, cleanup would occur prior to repair. Also, if it is late winter and there is not enough time to complete repairs and cleanup, then cleanup operations would take precedence.

Where possible, field repair operations would be coordinated with the cleanup effort. In the event a leak was detected, the pipeline would first be shut in. After this, the next step would be to determine the extent to which the pipeline is still losing product to the environment. If this is significant and depending on the location and the nature of the leak, the pipeline might be purged. If the spill has been caused by complete rupture of the line, no further oil would be leaking from the line. In this case, it may not be possible or desirable to purge the line, as this activity might release more oil into the environment. In the event of a small or medium leak, a minimal amount of oil would have leaked out prior to purging the line. If the attempt to displace the pipeline contents is not successful, it may be necessary to prevent further product loss from the pipe by placing an external clamp (temporary) around the pipe at the leak.

3.8.5.5 Environmental Impact Variables

Spilled oil could have an effect on the physical environment, biological communities, or human population. The response activities themselves could also have impacts (e.g., noise effects on marine mammals). A number of variables play a role in determining the environmental impact of an oil spill. These include, but are not limited to:

- Location of the spill,
- Water currents (for an open-water spill),
- Sea state,
- Ice (concentration, movement),
- Wind conditions (direction and speed),
- Time of the year (are there critical resources in the area),
- Effectiveness of the spill response,
- Persistence of the oil, and
- Receiving environment.

The environmental impact of a spill in winter is expected to be significantly less than for an open-water spill. The ice contains the oil and stops it from spreading. Oil spilled under growing ice would typically be encapsulated in the ice within 24 hours. There it would remain until spring, when the oil makes its way through brine channels that form in the ice. This oil would then show up in melt pools on the ice surface, typically in June.

3.8.5.6 Effectiveness of Cleanup and Verification of Rehabilitation

The determination as to whether or not the spill has been cleaned up adequately would be made by the Federal and State On-Scene Coordinators (FOSC and SOSC). There is a possibility that, if a spill impacts a shoreline, cleanup or rehabilitation could be conducted over several summer seasons.

3.8.5.7 Overall System Down Time

System down time would be a function of cleanup operations, repair and confirmation to regulators on the integrity of the line. In an open-water spill, the cleanup and repair operations could probably be handled concurrently. Repair time, in summer or winter, would be dependent on the availability of equipment and the familiarity of personnel with the repair procedure.

For a winter spill, oil would be trapped under the ice and also in the soils in and around the pipeline where the leak occurred. The removal of the ice cover for spill response would significantly weaken the bearing capacity of the ice. There would most likely be an ongoing cleanup during the repair operation as the ice is cut to create a slot and remove contaminated soils. Once the repair had been completed, the spill cleanup would be complete. As much oil as possible would be removed in the winter, and the remaining oil would be recovered in spring, when the unrecovered oil would come to the ice surface through brine channels and collect in melt pools.

4. SINGLE WALL STEEL PIPELINE

This section presents the conceptual level design for a single wall carbon steel pipeline system. Section 4.1 is an executive summary of this system. The subsequent sections detail the conceptual design.

4.1 Introduction, Summary and Conclusions

4.1.1 Introduction

This single wall steel pipe consists of a 12.75-inch outside diameter (OD) pipe with a 0.688-inch wall thickness (WT). The grade of steel to be used for this application is API 5L grade X-52. The size and grade are compatible with potentially high environmental and operational strains. The offshore section consists of approximately 6 miles of 40-foot pipe joints manually welded together via shielded metal arc welding (SMAW). There are no subsea valves, flanges, or fittings, which are potential sources for leaks.

To protect the pipeline from damage as well as corrosion, a dual-layer fusion-bonded epoxy (FBE) external coating 40 mils thick would be applied to the pipeline. This coating consists of an FBE corrosion coating and an FBE impact-resistant coating. Sacrificial anodes spaced at 120-foot intervals would be installed on the pipe for cathodic protection.

The pipeline system would be trenched and would require a minimum depth of cover to protect it from environmental loads such as those caused by ice gouge, strudel scour, and upheaval buckling. This pipeline system is illustrated in Figure 4-1.

The structural response of two sub-alternatives has been studied in connection with the single wall steel pipeline system; both are based on X-52 steel pipe with a 12.75-inch OD and a 0.688-inch WT:

- Sub-alternative A: straight pipe.
- Sub-alternative B: zigzag pattern.

The zigzag sub-alternative allows controlled lateral pipeline movement due to thermal expansion, resulting in a smaller “locked-in” axial compressive force than the straight pipe. Therefore, its structural response with respect to environmental loads is different from sub-alternative A.

Either alternative could be fitted with an external leak detection system.

4.1.2 Summary

This section summarizes the structural analysis, construction plan, costs, operations and maintenance, repair, leak detection and failure assessment.

4.1.2.1 Structural Design Summary

The single wall steel pipeline evaluated has a diameter-to-thickness ratio, D/t, of 18.53. This results in a specific gravity of 1.57, ensuring hydrodynamic vertical stability during and after installation (that is, the pipe would remain at the bottom of the trench). Such a low D/t ratio combined with the relatively low (X-52 yield stress) grade steel ensures good bending ductility and relatively high allowable strains for displacement controlled loading.

For sub-alternative A, the design against upheaval buckling requires a 1-foot-thick gravel mat layer to be placed on top of the pipeline at measured high curvatures. This ensures that the pipe would remain in the trench, as installed, in the presence of a 1.5-foot prop or crest. Native backfill 5 feet thick would be added on top of the gravel mats. The combination of gravel mats and native backfill needs to be installed only in the vicinity of the prop or crest. For sub-alternative B, the design against upheaval buckling requires a 4-foot native backfill thickness; no gravel mats are required.

4.1.2.2 Sub-alternative Selection

Both sub-alternatives are safe structurally and can safely resist all environmental loads such as ice gouge, thaw settlement and strudel scour. The overall structural response of sub-alternative B is slightly better than A. However, fabrication and installation are more similar to standard construction practice for A as compared to B. Therefore, the remainder of this analysis addresses only sub-alternative A.

4.1.2.3 Construction Summary

The most suitable methodology for installing a single wall pipeline from the island to shore is a winter construction program of conventional excavation equipment and off-ice pipe installation techniques.

4.1.2.4 Cost and Schedule Summary

It is estimated that the overall construction of this alternative would be performed in a single winter season between December and April. The associated estimated cost for this program is $31 million. There is a high confidence level that this program would be completed in this time frame for this cost.

4.1.2.5 Operations and Maintenance Summary

The envisioned operations and maintenance program for the single wall pipe alternative uses available technology to monitor the condition of the pipeline. This program would monitor all design aspects that are considered to be gradual processes (for example, thaw settlement) and would allow mitigating steps to be taken in a timely manner. The program would also identify all events that have occurred between inspections and that did not impact the operation of the pipeline, but may have affected the pipeline condition — for example, an ice keel passing over the pipeline route and displacing the pipeline.

4.1.2.6 Repair Summary

The single wall pipeline alternative can be repaired to its original condition or full integrity during a summer or winter season. Four permanent repair and two temporary repair options are available.

For the localized damage categories, buckle/no leak (Category 2 damage) and small/medium leak (Category 3 damage), that affects less than a 40-foot length of pipe, the recommended permanent repair methods are:

- Summer: Cofferdam or hyperbaric tie-in.
- Winter: Surface tie-in or hyperbaric tie-in.

For damage categories that affect pipeline lengths greater than 40 feet, large leak/rupture (Category 4 damage), the recommended permanent repair methods are the same for both seasons:

- Summer: Tow out replacement string with a surface tie-in or hyperbaric tie-in.
- Winter: Tow out replacement string with a surface tie-in or hyperbaric tie-in.

4.1.2.7 Leak Detection System Summary

Leak detection systems for the single wall pipeline are: a mass balance line pack compensation (MBLPC) system, a pressure point analysis (PPA) system, and a supplemental system. The first two systems would work in parallel, providing redundancy, and have an accuracy to detect leaks as small as approximately 0.15% of the volume of flow. The supplemental leak detection system, the LEOS system, is capable of detecting leaks below this threshold.

4.1.2.8 Failure Assessment Summary

Damage that does not result in loss of containment is summarized as Category 1 (large displacement) and Category 2 (cross-section buckle/without leak). Damage that does result in loss of primary containment is summarized as Category 3 (small or medium leak) and Category 4 (large leak/rupture).

It is estimated that a Category 1 incident of damage during operation (displaced pipeline) has a 3% probability of occurrence during the project lifetime. This type of damage is non-critical and time is available to check and assess the damage without shutting down the system. A planned intervention, if required, could be initiated to correct the condition. Category 2 damage (buckles without leakage) is estimated to have a 0.04% project lifetime frequency. The predicted frequencies for small, medium, or large leaks are very small.

A leak due to Category 4 damage (rupture or large leak) might be expected only during freeze-up. A Category 3 damage scenario (small or medium leak) could happen any time of the year. In any event, cleanup would be conducted.

This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less severe events; this might result in a large leak or rupture during other times of year. Such an analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear. Therefore, a response plan would need to be in place that could manage all damage in all seasons.

4.1.3 Conclusions

Two sub-alternatives, a straight single wall pipe and a zigzag option, have been evaluated. There would be some small differences in the structural response of the systems, but both would be well within design criteria. As the fabrication and installation of the straight pipe is more similar to conventional on-land installation into a trench, it is preferred over the zigzag option. Therefore, the single wall steel pipeline was carried forward for more detailed evaluation.

The single wall steel pipeline system evaluated — that is, a pipeline with a 12.75-inch OD and a 0.688-inch WT — would meet the functional requirements of flow and pressure for the Liberty Development.

A configuration with a 7-foot depth of cover consisting of native backfill and gravel mats has been judged adequate for design while optimizing such variables as constructability, operability, or reparability.

The most suitable method for installing the single wall steel pipeline option is a combination of conventional excavation equipment (backhoes with extended or long-reach booms) to excavate a trench through the ice. The pipeline string is then installed through the ice using techniques similar to overland construction.

The estimated cost for the single wall steel pipeline program is $31 million, and construction of this alternative would be performed in a single winter season. The recommended method of construction and installation is similar to what is used for a conventional on-land trenched pipeline, and contractors and personnel are therefore familiar with the scenario. This reduces potential risks associated with quality, schedule, and costs. There is a high confidence level that this pipeline could be built in this time frame for approximately this cost.

Available technology would be used to monitor the pipe as part of the operations and maintenance programs.

Leak detection for the single wall steel pipeline alternative would be achieved using three independent systems: a mass balance line pack compensation (MBLPC) system, a pressure point analysis (PPA) system, and a supplemental system. The first two systems would work in parallel, providing redundancy, and would have an accuracy to detect leaks as small as 0.15% of the volume of flow. Supplemental leak detection technology that can detect very minor leaks is proposed for use with the single wall steel pipeline. Leaks greater than 0.15% of the volumetric flowrate would be detected in minutes, while leaks less than this threshold would be identified within 24 hours.

The probability of a leak from the single wall steel pipeline is small. The single wall pipeline alternative can be repaired to full integrity during a summer or winter repair operation. Manpower and equipment would be in place to clean up any spill in the event of a leak.

4.2 Structural Design

4.2.1 Flow Analysis

General comments on flow analysis have been made in Section 3.2.2. The combination of gravel backfill as thermal insulation and a –50°F ambient air temperature results in a Liberty Island inlet pressure of 1,280 psig and inlet temperature of 135°F, with a tie-in pressure and temperature of 1,050 psig and 121°F.

4.2.2 Pipeline Installation Stability

General comments on pipeline stability are presented in Section 3.2.3. The empty pipe weights are summarized in Table 4-1. The pipe has a specific gravity (with respect to seawater at 64.0 pounds per cubic foot) greater than 1.5. Therefore, the pipe would sink and be stable in the trench.

TABLE 4-1: EMPTY PIPE WEIGHTS FOR THE SINGLE WALL STEEL PIPELINE OPTION

Parameter	Single Wall Steel Pipeline
Pipe OD (inch)	12.75
Wall Thickness (inch)	0.688
Weight in air (pounds/foot)	90.18
Submerged weight (pounds/foot)	32.72
Pipe SG (w.r.t. seawater)	1.57

Note: Pipeline weight includes nominal steel weight, 40 mils of FBE coating, and anodes.

4.2.3 Ice Keel Gouging

General comments on ice keel gouging were made in Section 3.2.4. For the single wall steel pipe alternative, the 3.0-foot-deep, 30-foot-wide ice keel case is the loading event that imposes the greatest strain on the pipeline. The soil displacement and the resulting pipeline movement for this pipeline are shown in Figure 4-2. The corresponding pipeline strain distribution is shown in Figure 4-3.

It can be seen from Table 4-2 that the maximum strains are less than the maximum allowable: 1.8% (tensile allowable strain) and 3.5% (compressive allowable strain), as described in Section 2.11. Therefore, a 7.0-foot depth of cover is adequate for the single wall pipeline with respect to ice keel loading.

TABLE 4-2: MAXIMUM STRAINS IN SUB-ALTERNATIVE A FOR EXTREME ICE KEEL EVENTS

Ice Keel Depth (ft)	Ice Keel Width (ft)	Tensile Strain (%)	Compressive Strain (%)
3.0	30	0.29	1.08
3.0	40	0.19	0.70
3.0	50	0.19	0.69
3.0	60	0.20	0.73
Allowable Strains (%)		1.80	3.50

For sub-alternative B, the zigzag configuration, it is estimated that the locked-in compressive force is reduced to 363 kips due to the pipeline displacing laterally. This reduced compressive force is achieved with an 8° bend angle at every pipe joint. The response to an ice keel event is proportional to the compressive force for the same pipe diameter. Therefore, the strains induced by an ice keel event for a zigzag pipe will be between the results for the single wall system (maximum compressive force of 610 kips) and the pipe-in-HDPE system (zero compressive force). Therefore, to estimate the ice keel strains for this zigzag case, the results for the straight, single wall pipeline system and the single wall inside an HDPE jacket (Chapter 6) are used. The results for the zigzag pipeline system are shown in Table 4-3. The ice keel strains for the zigzag configuration are found by linear interpolation. This procedure is considered reasonable at a conceptual level but would require confirmation during preliminary or detailed design.

TABLE 4-3: MAXIMUM STRAINS IN SUB-ALTERNATIVE B FOR EXTREME ICE KEEL EVENTS

Results for Ice Keel 3.0-feet Deep, 30-feet Wide	**Single Wall Sub-alternative B**
	P eff=363 kips
Max. Tensile Strain (%)	+0.58 [note 1]
Max. Compressive Strain (%)	-0.97 [note 1]

Notes: [1] Linearly interpolated strains.

4.2.4 Upheaval Buckling

General comments on upheaval buckling are presented in Section 3.2.6. The results of calculations indicate that upheaval buckling of a straight, single wall steel pipeline (sub-alternative A) for the Liberty Development cannot be reliably resisted by 7 feet of native backfill. For a 1.5-foot prop height, the native backfill thickness required is about 7.5 feet. The backfill thickness is greater than what can be placed over a pipe at a depth of cover of 7.0 feet.

By using gravel backfill with a density of 60 pounds per cubic foot, a thickness of 5.4 feet is sufficient to prevent upheaval buckling. The preferred option is a combination of a 1-foot-thick single layer of gravel mats and a 5-foot layer of native material completing the trench backfill. This is depicted in Figure 4-4.

The zigzag pipeline, sub-alternative B, with an 8° bend, is allowed to expand laterally. Therefore, the locked-in compressive force is estimated to be half of that present in a straight pipeline. In this case, a 4-foot backfill thickness of native material is sufficient to prevent upheaval buckling.

4.2.5 Thaw Settlement

General comments on thaw settlement were presented in Section 3.2.7. The design thaw settlement for the single wall steel pipeline is 1 foot (see Section 2.7.4). At this conceptual level, no specific finite element analyses of pipe/soil interaction have been performed. Rather, since the maximum differential thaw settlement value of 1 foot is considerably smaller than soil displacements resulting from ice keel scour, the resulting pipeline strains are expected to be smaller and remain well within allowable strain levels.

4.2.6 Strudel Scour

General comments on strudel scour were presented in Section 3.2.8. For this conceptual level report, no specific modeling of pipe/soil interaction through finite element analysis for strudel scour has been performed. However, for the small pipeline span expected, the resulting pipeline stresses would remain much below the allowable stress level.

4.2.7 Cathodic Protection

Sacrificial aluminum anodes would be used to cathodically protect the pipeline for its 20-year design life. A dual-layer FBE coating would be applied to limit anode requirements. The aluminum anodes would be bracelet-type anodes installed at approximately 120-foot intervals (every three pipe joints). The anode mass would be calculated such that current requirements of recommended practices are conservatively met. The CP system would be periodically checked at the shore crossing and at Liberty Island to confirm minimum protection voltages are maintained in accordance with DOT requirements.

4.3 Conceptual Design Selection

4.3.1 Structural Behavior Considerations

The structural behavior of sub-alternatives A and B is summarized in Table 4-4. Sub-alternative B, the zigzag option, allows the pipe to expand laterally, thus decreasing the locked-in compressive force by 50% compared to sub-alternative A. Therefore, ice keel peak compressive strain is less for sub-alternative B than for A, while the tensile strain is greater for sub-alternative B than A.

With respect to upheaval buckling, Table 4-4 indicates that sub-alternative B requires less than 4 feet of native backfill to stabilize the pipe in the presence of a 1.5-foot prop. This is simpler (in terms of backfilling procedures) compared to sub-alternative A. Sub-alternative A requires placement of gravel mats over a prop as determined by a post-lay pipeline survey. It is estimated that less than 25% of the offshore pipeline length would require gravel mat placement.

TABLE 4-4: CONCEPTUAL DESIGN SUMMARY

Load Condition	Pipeline Sub-Alternative	
	A	B
Ice Keel Strain [% of allowable (-) = compressive (+) = tensile]	(-) 31% (+) 16%	(-) 27% (+) 29%
Upheaval Buckling [backfill characteristics]	1-foot gravel mat and 5 feet of native backfill	< 4 feet of native backfill
Thaw Settlement	1 foot	1 foot
Strudel Scour	≈1-foot span	≈1-foot span

4.3.2 Fabrication and Installation Considerations

Table 4-5 summarizes the major activities during pipeline installation and fabrication for each sub-alternative and ranks them. If the sub-alternative is compatible with the activity and can be carried out with relative ease, it receives a grade 3. If more effort is required, the sub-alternative receives grade 2, and if the activity is judged to require much more effort, the grade 1 is assigned. Therefore, the preferred alternative regarding installation and fabrication procedures, based on this high level review, is the one with the highest score.

Some engineering judgement is involved for each score assigned in Table 4-5. For example, for sub-alternative B (zigzag), each pipe joint would have to be bent 8° at its centerline, and therefore it scores 1 in the “Pipe Joint Preparation” entry.

TABLE 4-5: INSTALLATION/FABRICATION SUMMARY

Activity	Pipeline Sub-Alternative	
	A	B
Pipe Joint Preparation	3	1 (due to pre-bend)
Welding	3	1 (due to alignment, because of pre-bend)
Handling	3	2 (because of pre-bend)
Final Pipe Preparation Before Laying in Trench	3	3
Pipe Lay Into Trench	3	2
Backfilling Operations	2	3
Surviving Backfill Operations	3	3
Total Score	20	15

4.3.3 Sub-Alternative Selection

In summary, the overall structural response of sub-alternative B is slightly better than A. On the other hand, fabrication and installation are more straightforward for A compared to B. The fabrication and installation of sub-alternative A are more like conventional on-land installation. Therefore, the remainder of this analysis addresses only sub-alternative A, the straight, single wall pipeline system with a 7-foot depth of cover (Figure 4-5). This section does not preclude the zigzag alternative as being a valid solution; however, for purpose of this study, only one solution is completely reviewed for each alternative.

4.4 Construction

General construction considerations have been presented in Section 3.3, including trenching and installation. This section describes the most suitable method for installing the single wall pipeline system, as well as specific construction aspects. The assumed configuration is summarized in Figure 4-5.

4.4.1 Installation Options

Offshore arctic pipeline installation options are described in Section 3.3 and apply to the single wall steel pipeline alternative.

4.4.2 Construction Method

For the reasons outlined in Section 3.3.10, the most suitable method for installing a single wall steel pipeline for the Liberty Development is by using conventional excavation equipment and off-ice pipe installation techniques. The Liberty Development is close to the Alaskan coastline, in 20 feet of water in a seasonal landfast ice region. Winter trenching was discussed in Section 3.3.6 and winter installation in Sections 3.3.9 and 3.3.10. The reasons for using conventional excavation equipment and off-ice pipe installation techniques are summarized below.

4.4.2.1 Trenching Method

Conventional excavation using backhoes with extended or long-reach booms is considered suitable to excavate a 10.5-foot trench in up to 40 feet of water. This method can either be barge-based or ice-based.

Hydraulic dredging using conventional vessel-mounted equipment can be carried out only during the open water season. These vessels require minimum water depths in which to operate and so could not be utilized along the whole pipeline route. Smaller cutter-suction equipment components have been developed that can be mounted on a backhoe arm. This smaller-scale cutter-suction method could be used for excavation.

Plowing to achieve a depth of cover of 7 feet is considered to be at the limit of what present installation equipment can achieve. This activity would also have to be carried out during open water and would require a marine support vessel capable of supplying the large pull loads to move the plow along the pipeline route. This method requires the pipeline to be installed prior to start of excavation. Preinstalling the pipeline would be achieved either by installing off-ice in winter and leaving the pipeline on the seabed during breakup or by installing the pipeline during open water immediately prior to plowing. Taking both the installation logistics and present capabilities into consideration, this is currently not the most suitable excavation method.

Jetting to a depth of cover of 7 feet is achievable. This method also requires the pipeline to be preinstalled and is suitable for a summer installation scenario for a single pipeline. However, an issue with jetting is the management of the excavated material, which is in a fluidized form and must be returned to the trench to meet the backfill requirements of the design. For these reasons, this excavation method is not considered to be the most suitable for this development.

Mechanical trenching to achieve a depth of cover of 7 feet is considered to be at the limit of what present installation equipment can achieve. Typically, this method is used in open water conditions and is supported by a marine vessel. However, since the mechanical trencher is often self-propelled, it would be feasible to use this technique during winter construction in the floating ice sections. The presently available mechanical trenching equipment for pipelines has water depth limitations in which they can operate. This excavation method is not considered to be the preferred trenching solution for the Liberty Development.

To directionally drill the 6-mile Liberty route, approximately six directional-drill segments would be required, each of which would terminate on the seabed surface. There would therefore be four locations along the seabed where the pipeline would not be protected in a trench. These locations would also be the points where connections are made between the lines and so would be the weakest link of the offshore pipeline. For these reasons, this method is not considered a viable option at this time.

4.4.2.2 Pipeline Installation Method

Use of a lay or reel vessel is feasible; however, scheduling of the required pre-trenching and backfilling activities make this method unattractive. A typical tow or pull method for installing the Liberty pipeline would include:

- Pre-dredging the trench,
- Making up the pipe string either in one 6-mile segment or multiple segment lengths (for example, 1,000 feet long), and
- Pulling the complete pipeline into the trench or pulling the pipeline in stages (partial launch) of 1,000 feet at a time and then welding on the next 1,000-foot string.

If no buoyancy was applied to the pipeline, a complete pull would require a minimum of approximately 500 tons (assuming a coefficient of friction of 1.0) of winch capacity to install 6.12 miles of pipe with a submerged weight of 33 pounds per foot. A towed summer installation using a high-powered tug and pipe flotation buoyancy of approximately 20 pounds per foot would reduce the pull force to approximately 150 tons. Large towing and/or anchor handling vessels would not be able to operate along most of the Liberty pipeline route due to draft limitations. The construction sequence would also require that the whole length of trench be kept open until the pipeline was in place. All the backfill material would have to be temporarily stored until the pipeline installation was completed. This is not considered a very efficient method to install the pipeline system.

Installation of the single wall steel pipeline using off-ice techniques is considered feasible for the Liberty water depths and weight of the pipeline (90 pounds per foot dry weight, 33 pounds per foot submerged weight). This method would be similar to onshore pipe-lowering techniques.

4.4.3 Installation Sequence

A description of the installation sequence as it would apply to the single wall steel pipeline alternative was presented in Section 3.3.10. Equipment requirements and production rates associated with each activity are summarized in the next section on construction costs.

4.4.4 Construction Considerations

Considerations regarding QA/QC, welding and NDE, and temporary storage of excavated material are presented in Section 3.3.10. The quality assurance and quality control associated with the single wall steel pipeline design allows key aspects to be inspected during installation and subsequently monitored during the operational life of the pipeline. The following sections present additional considerations associated with the construction sequence for the single wall pipeline design.

4.4.4.1 Skilled Labor Force and Construction Equipment

The successful fabrication and installation of any engineering design is very dependent upon the available skilled labor force. For the single steel pipe system, the labor force required to install this system is considered to be available. The major construction equipment components are identified in the next section on construction costs.

4.4.4.2 Ice Slot Maintenance During Pipeline Installation

The pipeline installation would closely follow the trenching spread in order to simplify trench spoils handling. The distance behind the trenching spread and the pipeline touchdown point would be approximately 1,000 feet, and the ice slot would have to be kept ice-free.

4.4.4.3 Equipment Required to Lower in Pipeline

It is estimated that four sidebooms would be required to lower the single steel wall pipe system from the surface to the trench bottom.

4.5 Construction Costs

The following section summarizes the basis for the order of magnitude costs required to install the single wall steel pipeline alternative.

4.5.1 Construction Sequence

The pipeline construction sequence was presented in Section 3.4.1 and applies here to the construction of the single wall steel pipe alternative.

4.5.2 Quantities and Rate of Progress

General comments on equipment and material, ice road construction, ice thickening, ice cutting, and ice slotting have been presented in Section 3.4.2. Additional comments are provided below.

4.5.2.1 Trenching

The estimated trench excavation volumes are approximately 460,000 cubic yards, based on a trench which is 10.5 feet deep and 10 feet wide at the bottom (Table 4-6). Side slopes of 2:1 are assumed for the 0- to 8-foot water depths and 3:1 for the remainder of the route. This target trench depth includes a 2-foot overexcavation to ensure that a minimum depth of cover of 7 feet is achieved.

TABLE 4-6: TRENCHING VOLUMES

Water Depth (ft)	Trench Length (ft)	Trench Depth (ft)	Volume (yd^3)
0 – 8	14,877	10.5	179,075
8 – 18	12,473	10.5	201,416
18 – 22	4,964	10.5	80,160
		Total	**460,651**

Trench excavation is a critical operation requiring three trenching spreads each consisting of backhoes, support bridges, spoils handling, spoils transport, and survey equipment. Each trenching spread of two backhoes would work two shifts of 11.5 hours. The rate of progress for each spread and the number of days to complete each zone are summarized below in Table 4-7.

TABLE 4-7: TRENCHING RATES

Water Depth (ft)	Trench Length (ft)	Volume (yd^3)	Productivity (%)	Rate of Progress For Each Spread (ft/hr)	Number of Spreads	Time for Activity, 3 Spreads (days)
0 – 8	14,877	179,075	85	40	2	10
8 – 18	12,473	201,416	75	20	2	19
18 – 22	4,964	80,160	75	5	3	20
				Total		**49**

4.5.2.2 Pipeline Make-Up Site Preparation

The pipeline make-up site would be located on the bottomfast sea ice close to the shore approach in an area measuring approximately 5,000 feet by 750 feet (417,000 square yards).

The preparation of this site would require one spread consisting of bulldozers, cranes, front-end loaders, backhoes and tracked vehicles with augers. It is assumed that one working spread, with a productivity factor of 85%, can prepare 11,260 square yards per day. Using this rate, 416,500 square yards can be prepared in 37 days.

4.5.2.3 Pipe String Make-Up (Welding)

During this activity, 11 pipeline strings of 3,000 feet long each would be constructed, for a total of approximately 808 welds (assuming 40 pipe joints and 6.12 miles of pipe).

For the 12-inch, the completed manual (SMAW) weld would require 6 passes. It is estimated that a spread can produce 50 welds per day or 808 welds in 17 days.

4.5.2.4 Pipe String Transportation

Transporting the 11 pipe strings from the pipeline make-up site to their locations along the Liberty pipeline route would require one spread consisting of sidebooms. It is estimated that this activity can be performed at an advance rate of 0.75 miles per day for a total of 8 days.

4.5.2.5 Pipe String Field Joint Operation

An estimated 11 welds of 6 passes each would be required during the field-joint operation. These welds would be made up using external line-up clamps and would be inspected by X-ray and ultrasonic NDE. This activity could be performed by a small welding spread at a rate of 4 welds per day. However, this operation would last as long as the pipe string transportation activity.

4.5.2.6 Pipeline Installation

The pipeline installation progress rate is theoretically faster than the trenching rate, and therefore, this activity would depend on the duration of trenching. The pipeline can be installed immediately after the trench sections are completed.

Pipeline installation would take 29 days (10 days for water depths of 0-8 feet and 19 days for water depths of 8-18 feet) to advance to the 18-foot isobath. The pipeline in the zone of 18-22 feet of water is assumed to be installed in 6 days because the trenching operations in this zone start before it is reached by the installation spread. It is estimated the total 6.12 miles of single wall pipe installation would be performed in 35 days using one spread consisting of sidebooms and backhoes.

4.5.2.7 Backfilling

Native soil and gravel bags would be used as the backfill material. All excavated material would be placed back in the trench. This activity can be performed much faster than the pipeline can be installed. Since the pipeline can be backfilled immediately after the installation sections are completed, this activity can be performed in 36 days.

The backfill material quantities are estimated assuming 25% coverage of the pipeline by gravel bags (only 30,000 feet of the route is susceptible to upheaval buckling). This equates to approximately 7,500 linear feet of the pipeline covered with gravel mats or bags, requiring 9,000 cubic yards of gravel assuming a single 1-foot layer of gravel mats or bags. This activity would require one spread consisting of loaders, spoil transport trucks, and dozers.

4.5.2.8 Hydrostatic Testing

The hydrostatic pressure-testing of the pipeline is expected to be completed in 5 days.

4.5.2.9 Demobilization

It is estimated that it would take 2 days to demobilize each spread of equipment.

4.5.3 Schedule and Risk

The overall construction for the Liberty pipeline would be performed in winter, from December to April. Construction during winter allows the use of conventional or adapted onshore construction equipment and techniques. A schedule for the single wall steel pipeline option is shown in Figure 4-6. There is a high confidence that this pipeline will be completely installed in this time frame.

4.5.4 Cost Estimate Summary

The different activities associated with construction of the Liberty offshore pipeline using the single wall steel pipe option are presented in Table 4-8. Activities, quantities and progression rates are shown together with the estimated cost for this option. As there is a high confidence that the pipeline will be installed in a single season, a standard contingency of 10% of estimated cost is included in the cost estimate. The total cost estimate of $31 million reflects the budgetary cost that would be estimated to complete this work.

TABLE 4-8: CONCEPTUAL COST ESTIMATE FOR THE SINGLE WALL STEEL PIPE ALTERNATIVE

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1000/day)	Cost (Million $)
Mobilization	Lump Sum			3	1020.0	3.06
Ice Thickening and Road Construction + Maintenance	2.5-inches/day	1	32,314 feet	47	84.0	3.95
Ice Cutting and Slotting	1,000 feet/day	3	32,314 feet	11	29.0	0.96
	0 – 8 feet WD ---> 40 feet/hour/backhoe	2	179,075 cubic yards	10		
Trenching	8 – 18 feet WD ---> 20 feet/hour/backhoe	2	201,416 cubic yards	19	60.0	7.08
	18 – 22 feet WD ---> 5 feet/hour/backhoe	3	80,160 cubic yards	20		
Pipeline Make-Up Site Preparation	11,260 square yards/day	1	416,500 square yards	37	41.0	1.52
Pipe String Make-Up (Welding)	50 welds/day	1	808 welds	17	140.0	2. 38
Pipe String Transportation	0.9 miles/day	1	11 pipeline strings	8	78.0	0.62
Pipe String Field Joint	50 welds/day	1	11 welds	10		0.31
Pipeline Installation	1,500 feet/day	1	32,314 feet	35	43.0	1.51
Backfilling	1,700 feet/day	1	32,314 feet	36	42.0	1.51
Hydrostatic Testing		1		5	84.0	0.42
Demobilization	Lump Sum			2	1020.0	2.04
Material Cost and Transportation	Lump Sum					3.10
Contingency	10%					2.85
					Total	**31**

4.6 Operations and Maintenance

This section presents an operational and maintenance philosophy and recommendations for the offshore section of the single wall steel pipeline system. Table 4-9 summarizes the relationship between the pipeline design and operations and maintenance.

TABLE 4-9: RELATIONSHIP BETWEEN OPERATIONS AND MAINTENANCE AND THE DESIGN

Tasks	Design Aspects
Operations	
Monitoring of Flow	Internal Leak Detection
	Custody Transfer
External Offshore Route Survey	Trench Configuration
	Ice Keel Events
	Strudel Scours Events
	Activities Related to the Design
Shoreline Erosion	Shore Crossing Design
	Trench Configuration
Maintenance	
Cathodic Protection	Cathodic Protection System
Wall Thickness and Internal Damage	Pipeline Corrosion (Internal)
	Pipeline Wall Thickness
Pipeline Configuration	Trench Configuration
	Ice Keel Event
	Strudel Scour Event
	Thaw Settlement
	Thermal Expansion
	Upheaval Buckling
Pipeline Corrosion	Pipeline Corrosion (External)
Pipeline Expansion	Thermal Expansion
Pipeline Shore Approach Geometry Survey	Thaw Settlement

4.6.1 Operations

See Section 3.5.1.

4.6.2 Pipeline Inspection

See Section 3.5.2.

4.6.3 Maintenance

See Section 3.5.3.

4.6.4 Evaluation Criteria and Required Action

See Section 3.5.4.

4.7 Repair

4.7.1 Assumptions and Definitions

See Section 3.6.1.

4.7.2 Repair Techniques

See Section 3.6.2.

4.7.2.1 Repair Technique Evaluation

This section highlights the main points associated with each of the six repair techniques. General comments are presented in Section 3.6.2. This review provides the basis for the recommended repair response for each zone and type of damage.

Welded Repair with Cofferdam

The total amount of backfill that would be removed for this type of permanent repair is approximately 1,150 cubic yards, which is expected to take two to three days. The total time required for the repair is approximately 35 days, which includes mobilization and survey of damage. This repair method would return the single pipe to its original integrity because the welding would be performed and inspected to the same standard as the original pipeline installation.

Hyperbaric Weld Repair

The backfill that would be removed for this type of permanent repair is approximately 1,150 cubic yards, which is expected to take two to three days. The repair time is approximately 35 days. This repair method would return the single wall pipeline to its original integrity because the welding would be performed and inspected to the same standards as the original pipeline installation.

Surface Tie-In Repair

The maximum estimated quantity of soil to be excavated to bring the pipe to the surface is estimated to be 6,490 cubic yards for this type of permanent repair of minor damage in Zone II. When the pipeline is raised to the surface and a section of pipe inserted, the length of pipe to be placed on the seabed would be longer than the axial length of trench that has been excavated. A layover area must be prepared next to the trench and must be excavated to the original trench depth. The additional layover area to be excavated is estimated to be 3,150 cubic yards. The total time for this type of repair is estimated to be 37 days, with 10 to 15 days of this repair time required for excavation. The pipeline is returned to its original integrity as the welding would be performed and inspected to the same original standards and the pipeline reinstated to an as-built, zero-stress condition.

Tow-Out of Replacement String

A 400-foot replacement string would require a maximum estimated 6,480 cubic yards of soil to be excavated for this type of major repair. The time to conduct a bottom tow of a replacement string is estimated to be 40 days. This method can be used as a permanent repair in both zones if a spool piece is welded and as a temporary repair if mechanical connectors are used. Diving requirements are extensive as two tie-ins are required. If welding is used, this repair would reinstate the pipeline to its original integrity. However, mechanical connections are a temporary repair, and the repair does have the same integrity as the original pipeline as-built condition.

Rigid Spool Piece with Mechanical Connectors

The soil to be excavated for a 40-foot spool piece is approximately 1,150 cubic yards for this type of temporary minor repair. The estimated time required for installation of a spool piece is approximately 35 days. This repair method is considered temporary and so is not considered to have the same integrity as the original pipeline as-built condition.

Split Sleeve Repair Method

The soil to be excavated is approximately 850 cubic yards to install a 20-foot split sleeve and conduct this type of temporary minor repair. The total time required to install the split sleeve is estimated to be 25 days. This repair method is considered temporary and so is not considered to have the same integrity as the original pipeline as-built condition.

4.7.2.2 Repair Technique Conclusions

See Section 3.6.2.

4.7.3 Repair Methods for Damage Scenarios

Section 3.6.2 presented types of repairs with regard to the length of pipeline sections that need to be replaced. However, the section did not explicitly relate the size of the repair to the potential damage scenario. For the single wall pipe alternative, there are four categories of damage scenarios:

Category 1: Displaced Pipeline: The damage is non-critical; the pipeline has no leaks or buckle. Such damage would be discovered in routine inspections. If the magnitude of the displacement is such that the pipeline strains are within allowable limits, no real damage has occurred and the pipeline can continue to operate without repair or remedial action, possibly with reduced pressure and throughput. Examples are small bends, pipeline being displaced, etc.

Category 2: Buckle/No Leak: The pipeline damage resulted in a buckle but no leakage occurs.

Category 3: Small/Medium Leak: Such damage is minor and could result from corrosion.

Category 4: Large Leak/Rupture: This is the most severe damage category and could be from an ice keel or other event.

The relationship between these categories and the causes and failure mechanisms will be discussed in the section on failure assessment. Each of these damage categories may require a repair. Figure 4-7 summarizes the categories of damage and the types of repairs.

4.7.4 Recommended Repair Methods

Summer and winter repairs were discussed in Section 3.6.4. Details on which repairs can be conducted when are presented in Figure 4-7. In generating this figure, the "earliest start dates" and "latest completion dates" have been used. The repair techniques for each category of damage are indicated by the notes.

4.8 Leak Detection

4.8.1 Proposed Leak Detection for Single Wall Steel Pipeline

General evaluation and comments on leak detection were presented in Section 3.7. Leak detection for the single wall pipeline would be achieved using two independent systems: the mass balance line pack compensation (MBLPC) system and the pressure point analysis (PPA) system. Conventional leak detection is usually achieved using one of these systems. However, because of the importance placed on leak detection, the Liberty system would include both independent systems. These systems would work in parallel, providing redundancy, and be able to detect leaks as small as approximately 0.15% of the volume of flow.

Supplemental leak detection options for a single wall steel pipeline have also been considered. Through-ice borehole sampling could be carried out but would require deployment of personnel on the ice and assumes that the oil has pooled under the ice at the borehole locations. Remote and field sensing techniques are not feasible or have not advanced to the point where they could reliably be used to detect oil under ice. Leak pressure-testing would require construction and installation of an on-island storage tank to divert production during line shut-in. The sensor technologies investigated showed the greatest promise as a supplemental system.

The LEOS system is favored based on its track record and industry application experience. A description of the system and issues affecting its performance is presented in Section 3.7.

It should be noted that at the present time, the LEOS system is considered the best available technology. By the time the Liberty pipeline is ready to be installed, another system may be considered best available technology. This could partially result from lessons yet to be learned from the Northstar installation.

The MBLPC, PPA, and LEOS systems would be integrated into the pipeline's supervisory control and data acquisition (SCADA) system, which would record all leak detection system parameters simultaneously. Combined, it is expected the systems would detect a large leak within 30 seconds and a small or medium leak (<97.5 barrels per day) within 24 hours. Potential leak volumes and times to detection are discussed further in Section 4.9.

4.8.2 Factors Affecting Leak Detection Performance

Factors affecting leak detection performance are presented in Section 3.7.3. No major issues have been identified which would influence the chosen leak detection system performance. If the system were to become damaged during operation (i.e., from environmental loading), the damaged portion would need to be retrieved and repaired. Alternatively, depending on the cost of repair, a second sensor tube might be plowed in above the pipe, eliminating the need for pipeline retrieval.

4.9 Failure Assessment

In this section, failure analysis for the single wall pipeline system is presented. The initial stage in the process identifies the causes or initiating events that could induce failures, as well as the associated likelihood of occurrence. The process is completed by a review of the likelihood of failure and its consequences (e.g., spill scenarios and the associated cleanup and repair procedures). The background of the failure analysis is summarized in Section 3.8.

4.9.1 Operational Failure Assessment

This section examines initiating events and their causes that may lead to an “incident of damage during operation,” or IDO. Types of damage include leaks, punctures, dents, buckles, collapses, or a displaced pipeline. However, damage does not necessarily require shutdown or repair of the pipeline. For example, assessment of the “displaced pipeline” type of damage may conclude that the damage had not exceeded design limits.

Initiating events that may result in an IDO are listed in Figure 4-8. This figure shows the initiating events as the incoming tree components leading to an IDO. Initiating events I1 to I12 are grouped as:

- *Environmental loading:* initiating events that may potentially lead to damage are seabed ice gouging, subsea permafrost thaw subsidence, and strudel scour.
- *Pipeline failure:* initiating events are those caused by the pipeline functional requirements (e.g., flow pressure, operational temperature, etc.) and the induced stresses and strains. These are upheaval buckling, internal pressure, external pressure, and internal and external corrosion.
- *Third party activity:* initiating events are external to the pipeline operations. These are vessel accidents, anchor dragging, third party construction, and sabotage.

Assessments of these potential initiating events are presented below. Their impact on different categories of IDO are also reviewed.

4.9.1.1 *Quantification of the Incoming Tree for IDO*

The class of events IDO is divided into the four categories presented in Section 4.7.3. In failure assessment, it is important that the analysis of each initiating event reviews the likelihood of the category of the resulting IDO based on evaluation of pertinent evidence. This is discussed below for each initiating event that potentially could lead to an IDO.

4.9.1.2 *Seabed Ice Gouging, Initiating Event I1*

Seabed ice gouge modeling and ice keel loading were discussed in Section 2.9. Equations relating ice gouge depth and its return period are given in the design basis.

The mechanisms of pipeline response to an ice keel event may be any of the four categories cited above, but each with a different likelihood of occurrence. In a Category 1 IDO event, an ice keel displaces the soil around the pipe, thus displacing the pipeline. If the ice gouge depth is equal to or less than the design gouge depth, the resulting strains are well below the allowable strains, no limit state is approached, and operations can continue. A Category 4 (large leak or rupture), however unlikely, would occur only if the ice keel contacts the pipeline. In this case it would be assumed that the ice keel incision depth reaches the pipeline centerline. For the single wall steel pipeline, this depth is equal to 7 feet (depth of cover) plus 0.5 feet (approximate pipeline radius).

Seabed ice scours and the risk these features pose to submarine pipelines have been extensively studied (Lewis et al. 1986; Fleet 1990). A relatively large amount of ice gouge data (20,354 gouges) was gathered on seabed surveys of the Alaskan coast of the Beaufort Sea between Smith Bay and Camden Bay during the 1970s (Weeks et al. 1983). Two surveys for the Liberty project were conducted in 1997 and 1998 (Coastal Frontiers Corporation 1998, 1999), and two others were conducted in the immediate Liberty vicinity (Harding Lawson Associates 1982; McLelland Engineers 1982). Thus, four site-specific data sets are available for statistical review. Other surveys close to the Liberty Development provide data that can be compared to the Liberty-specific data (Braden et al. 1998).

Pipeline resistance or capacity to deform plastically (beyond the yield stress) without reaching a fracture or a local buckle limit state has been well established by multiple cases of independent research (Murphy and Langner 1985; Zimmerman et al. 1995; Corona and Kyriakides 1988). More recently (Nogueira et al. 1999), pipe joints were subjected to a full-scale bend test program in which relatively large strains (5 to 10%) were applied under simulated arctic operational conditions. The pipe and the weld used in this test program have the same material properties and similar dimensions as those of the single wall pipe alternative considered here.

A detailed review of the references cited in the previous paragraphs is beyond the scope of this report. The following evidence has been drawn from the above references:

E1: From the design basis (Chapter 2), the relationship between ice gouge depth, d, and predicted return period, T, for Liberty, where the maximum water depth is 22 feet, is estimated to be (where *d* is in feet, and *T* is in years):

$$d = 0.39 \ln(0.594T)$$

or

$$T = 1.68e^{2.564d}$$

From the above equations, Table 4-10 can be derived.

TABLE 4-10: PROBABILITY OF EXCEEDENCE OF ICE GOUGE DEPTH ALONG LIBERTY ALIGNMENT

d **(ft)**	***T*** **(years)**	***f*** **(1/year)**	**Exceedence Probability over 20-Years = Project Lifetime Damage Frequency**
1.59	100	10^{-2}	0.18
3.0 (design value)	3,600	3×10^{-4}	5×10^{-3}
4.0	48,000	2×10^{-5}	4×10^{-4}
5.0	600,000	2×10^{-6}	3×10^{-5}
7.5	370,000,000	3×10^{-9}	5×10^{-8}

E2: In a location close to Liberty, the Northstar corridor has 12 years of available survey data. In this alignment, the water depths are up to 37 feet, and the predicted 100-year return period ice gouge depth is 3.3 feet. This prediction uses the same statistical methodology as used for Liberty.

E3: Maximum observed ice gouge depth for the alignment described above (see E2) is 2.0 feet.

E4: Maximum observed ice gouge depth for the Liberty alignment is 1.4 feet.

E5: Maximum ice gouge depth decreases with water depth.

E6: The calculated maximum pipeline strain for d = 3.0 feet is 30% of allowable pipeline strain. This calculated strain corresponds to an ice feature with a gouge width to depth aspect ratio of 10. For wider ice gouges (greater aspect ratios), the calculated maximum strains are about 20% of the allowable strain.

E7: All ice gouges observed in the vicinity have an aspect ratio equal to or greater then 10. The percentage of observed ice gouges with an aspect ratio less than 15 is 26%.

E8: Predicted pipeline resistance to fracture due to bending (ultimate design value) at a weld is 3.6% strain, yielding an allowable strain of 1.8% for ice keel events. This ultimate design value of 3.6% assumes the maximum allowable weld defect (1-inch long, 1/8-inch high) is present in the pipe cross-section at the location of the maximum strain fiber.

E9: Full-scale experiments with pipe joints similar to the single wall pipe alternative indicate that a pipeline buckle starts to form at approximately 5% strain and fracture may occur only beyond 10% strain.

E10: An ice gouge with depth greater than 3.0 feet and less than 7.0 feet could possibly form a buckle in the pipe. However, in this case, concurrent conditions are required to induce a fracture failure:

C1: The maximum strained region must occur at a welded joint. The length of the maximum strained region due to an ice keel would be less than 10 feet long. There is a weld every 40 feet. Therefore, C1 has a probability of occurrence of P(C1) = 10/40 = 0.25.

C2: The weld must contain the maximum defect. All welds in the single wall steel pipeline would be subjected to be X-ray and ultrasonic NDE techniques. A maximum defect is unlikely; however, it will be conservatively assumed that 1 in every 20 welds would have the maximum allowable flaw. Therefore, C2 has a probability of occurrence of P(C2) = 1/20 = 0.05.

C3: The maximum allowable defect must be located on the circumference of the pipe such that it occurs at the maximum extreme fiber in tension. The maximum allowable flaw is approximately 1 inch in length, and the tension fiber is a point in the circumference. Therefore, C3 has a probability of occurrence of P(C3) = 1 inch / 3.14 x 12 inch = 0.03.

C4: The extreme event ice keel must be of the minimal aspect ratio. It will be conservatively assumed that this probability is P(C4) = 0.26.

Based on the evidences E1 to E10 above, it will be assumed that a 3-foot-deep ice gouge may cause a Category 1 IDO, a displaced pipeline. If such an event happens, an assessment is warranted to confirm that the pipeline remains integral with minimal ovalization. Therefore, the associated project lifetime damage frequency is given by the right-hand column, second entry on Table 4-10. This is the exceedence probability of 3-foot-deep ice gouges; that is, the probability that at least one ice gouge as deep or deeper than 3.0 feet occurs within the project lifetime. The risk is conservatively increased to the nearest order of magnitude:

Damage frequency (P/L displaced) = $5 \times 10^{-3} \cong \mathbf{10^{-2}}$ incidents per project lifetime.

Based on the evidences E1 to E10 above, it will be assumed that 4-foot-deep ice gouges with an aspect ratio of I5 or less can cause a buckle. Note on Table 4-10 that the probability of occurrence of one or more ice gouges with depth greater than 4 feet is 4×10^{-4} over the project lifetime. From evidence E7, the ratio of ice gouge population with an aspect ratio less than 15 is 0.26. Therefore, the estimated project lifetime damage frequency of buckle is:

Damage frequency (buckle/no leak) = 4 x 10-4 x P(C4) = 4 x 10-4 x 0.26 = 1 x 10-4 ≅ 10-4 incidents per project lifetime.

For an ice gouge event to result in a small or medium leak (that is, a small or medium crack or fracture), a series of conditions are required. This type of damage is conservatively assumed to occur when [a] ice gouges with depth greater than 4 feet of any aspect ratio (4×10^{-4} over the project lifetime) [b] produce the maximum strained region at a welded joint [P(C1) = 0.25], and [c] the welded joint contains the maximum allowable defect [P(C2) = 0.05] which [d] is aligned at the maximum extreme fiber in tension [P(C3) = 0.03]. Therefore, the estimated project lifetime damage frequency of small or medium leak is (conservatively increased to the nearest order of magnitude):

Damage frequency (small/medium leak) = $4 \times 10^{-4} \times 0.25 \times 0.05 \times 0.03 \cong \mathbf{10^{-6}}$ incidents per project lifetime.

The likelihood that an ice gouge event leads to a large leak or rupture is taken directly from Table 4-10 for ice gouges with depth greater than 7.5 feet of any aspect ratio. The basic assumption is that if an ice keel contacts the pipeline, a pipe fracture would occur. Therefore, the estimated project lifetime damage frequency of large leak or rupture is (conservatively increased to the nearest order of magnitude):

Damage frequency (large leak/rupture) = $5 \times 10^{-8} \cong \mathbf{10^{-7}}$ incidents per project lifetime.

The above estimated damage frequencies are shown in the first row (Seabed Ice Gouging) of Table 4-11.

4.9.1.3 Subsea Permafrost Thaw Subsidence, Initiating Event I2

The evidence related to this initiating event is listed below.

E1: The phenomenon of thaw subsidence occurs gradually, over a period of years, as the subsurface temperature increases over the project lifetime.

E2: The maximum settlement is modeled as a total differential settlement, and the maximum strain is found for the length of soil that settles and induces the highest bending strains. In reality, the segment length that actually subsides would rarely match the worst-case span length, and the actual differential settlement would be a fraction of the total potential settlement.

E3: The maximum thaw settlement value is one-third (1 foot - Section 4.2.5) of the maximum ice keel displacement. Therefore, the corresponding pipe strains are likely to be lower than those caused by ice gouging.

E4: Geometry pigs are used to measure the pipeline geometry periodically during the project operational phase. Thus, the pipeline strains would be monitored and preventive action taken if warranted.

Based on the above, it is estimated that Category 4 damage due to this initiating event is extremely unlikely. Therefore, the corresponding frequency assigned is 10^{-8}, which is one order of magnitude lower than the corresponding ice gouge frequency for this category. It is assumed that events which are considered “extremely unlikely” would have an assigned frequency of 10^{-8}.

Although the likelihood of damage occurrence due to thaw settlement is less than that of ice gouging for other damage categories, the same estimated frequency as those presented for ice gouges is conservatively adopted. This is shown in the second row of Table 4-11.

4.9.1.4 Strudel Scour, Initiating Event I3

The evidence related to this initiating event is listed below.

E1: The forces due to an extremely deep strudel scour on top of the pipe are hydrodynamic forces. These forces are not considered high enough to damage the pipe. Fatigue would not occur since the phenomenon happens only on a limited time scale.

E2: The annual probability that a 15-foot-diameter strudel scour at the seabed surface which is 8 feet deep or deeper and occurs over the pipeline is estimated (using the extreme data from four different surveys) to be 0.0021 (see Section 2.8.2). This leads to an estimated 4×10^{-2} occurrence per project lifetime.

E3: If the strudel described on E2 occurs along a straight pipe segment, the pipe would be exposed to minor hydrodynamic loading.

E4: The probability that a 15-foot-long strudel scour forms on the pipe coinciding with a pipe overbend (prop) is a small, second order number.

Based on the above evidence, the estimated damage frequencies for strudel scour will be assigned a probability of occurrence one order of magnitude lower than those for ice keel. These are presented in Table 4-11.

4.9.1.5 Upheaval Buckling, Initiating Event I4

This event could occur if the appropriate backfill is not placed adequately on top of an overbend. In order to mitigate against this potential initiating event, a post-lay survey is planned and gravel mats would be placed on top of overbends that exceed tolerances. Given the low pipeline diameter-to-thickness ratio of 18, which allows relatively high bending capacity without fracture or local buckling, it is highly unlikely that an upheaval buckling event would lead to a large leak or rupture.

The evidences related to upheaval buckling for the single wall alternative are:

E1: Backfill weight used in analysis is the lower bound unconsolidated weight.

E2: Prop height in the analysis is the maximum allowable.

E3: Resistance due to gravel mats is conservatively taken as small.

E4: Post-lay survey would identify overbends.

Based on the above evidence, the estimated frequency of damage due to upheaval buckling will be assigned a probability of occurrence one order of magnitude higher than those for ice keel, except for the displaced pipeline damage category and the large leak and rupture damage categories. These are shown in Table 4-11.

4.9.1.6 Internal Pressure, Initiating Event I5

Initiating Event I5, is Internal Pressure. The damage could result from potential overpressure leading to burst. The evidence related to this event is:

E1: The maximum operating pressure is 1,415 psig, leading to a required pipeline wall thickness of 0.24 inch (at an allowable hoop stress equal to 72% SMYS). The provided pipeline wall thickness is 0.688 inch, which is almost three times that required by ASME 31.4.

E2: Based on the pipe dimensions, the pressure corresponding to a hoop stress equal to SMYS is 6,300 psig. The actual burst pressure is greater than this; thus, burst cannot be achieved under steady-state conditions.

E3: Transients are avoided by established valve closing procedures during operations. Additionally, pressure relieve valves are included in the design.

Based on the above, this is considered to be extremely unlikely, and so the estimated damage frequencies for internal pressure in Table 4-11 are 10^{-8}.

4.9.1.7 External Pressure, Initiating Event I6

At 22-foot water depth, it is extremely unlikely that this initiating event would ever buckle the pipe. Therefore, a frequency of 10^{-8} is assigned for this in Table 4-11.

4.9.1.8 Internal Corrosion, Initiating Event I7

The Liberty oil is non-sour processed crude. It is extremely unlikely that this type of oil would ever cause damage. Therefore, a frequency of 10^{-8} is assigned for this in Table 4-11.

4.9.1.9 External Corrosion, Initiating Event I8

The evidence relating to external corrosion is as follows:

E1: Extra-thick pipe is provided with wall thickness more than three times that required for ASME 31.4, pressure containment.

E2: High-quality, abrasion-resistant, anti-corrosion coating 40 mils thick prevents external corrosion.

E3: Cathodic protection system is conservatively designed.

E4: Cathodic protection system can and would be monitored by checking the potential at each end of the offshore pipeline.

E5: Geometry pigs are planned to be used regularly to check for wall thickness integrity. This would provide advance warning against unexpected external corrosion.

Based on the above, the estimated damage frequencies for internal pressure are shown in Table 4-11. The highest estimated frequency is 10^{-6} occurrences leading to small or medium leaks.

4.9.1.10 Vessel Accidents, Anchor Dragging, Third Party Construction; Initiating Events I9, I10, I11

Typically, these types of initiating events pose some risk to offshore pipelines in the Gulf of Mexico and the North Sea. However, for the Liberty offshore pipeline the possibility of these events is extremely unlikely due to the following evidence:

E1: Pipeline is planned to be completely buried with a 7-foot depth of cover.

E2: Any future third-party construction would be closely monitored and unlikely to happen on top of the offshore alignment.

E3: A vessel sinking on top of the pipeline alignment that has access to these water depths would not be big enough to cause any damage.

Based on the above evidence, these events are considered extremely unlikely. Therefore, the estimated damage frequencies for these causes is assigned 10^{-8} in Table 4-11, with the exception of 10^{-6} occurrences of displaced pipeline due to planned third party construction.

4.9.1.11 Sabotage, Initiating Event I12

Although difficult to quantify, it is hard to imagine that any individual or group could have the means to sabotage the buried offshore pipeline. If sabotage is ever attempted, it would likely be at exposed onshore segments. A probability of 10^{-8} is assigned for sabotage of the offshore segment.

4.9.1.12 Summary

The damage frequency failure assessment can be summarized in Table 4-11. The initiating events are defined as hazards to the pipeline.

The estimated frequency of an IDO in Category 1 (displaced pipeline) is 3% during the project lifetime; however, this type of damage is considered non-critical. Time is available to check and assess the damage and, if required, to initiate a planned repair. The second most frequent damage is buckles without leakage (Category 2). This damage is estimated at a 0.04% project lifetime frequency. The frequencies for small, medium, or large leaks are small.

Table 4-12 shows for each entry of Table 4-11 with a frequency greater than 10^{-8}, when the corresponding damage could occur. This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less severe events; this might result in a large leak or rupture during other times of year. Such an analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear.

4.9.2 Spill Scenarios

4.9.2.1 Potential Oil Loss

Leak detection options have been reviewed in Section 3.7. The recommended supplementary leak detection system for the single wall steel pipeline is the LEOS system. As presented earlier in Section 3.8.4, a guillotine break (Category 4 damage) could potentially yield a loss of 1,576 barrels of oil. Based on a medium (Category 3 damage) leak of 97.5 barrels per day, the volume of oil lost during the reaction time of the LEOS system would be 97.5 barrels (corresponding to a test time of 24 hours for the system). In total, a medium spill scenario might be expected to result in a loss of approximately 125 barrels of oil. A small chronic leak (Category 3 damage) is considered to be 1 barrel per day. Category 1 and Category 2 damage would not result in a spill. These results are summarized in Table 4-13.

TABLE 4-11: INITIATING EVENTS AND RESULTANT DAMAGE FREQUENCY PER CATEGORY

Underlying Main Cause for Initiating Event	Initiating Event	Estimated Damage Frequency (Occurrences per Project Lifetime)			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	10^{-4}	10^{-6}	10^{-7}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-4}	10^{-6}	10^{-8}
	Strudel Scour	10^{-3}	10^{-5}	10^{-7}	10^{-8}
Pipeline Failure	Upheaval Buckling	10^{-2}	10^{-3}	10^{-5}	10^{-7}
	Internal Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Internal Corrosion	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Corrosion	10^{-8}	10^{-8}	10^{-6}	10^{-8}
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		**3×10^{-2}**	**1×10^{-3}**	**1×10^{-5}**	**2×10^{-7}**

TABLE 4-12: WHEN DAMAGE COULD BE REALIZED

Initiating Event	When Potential Damage Could Occur			
	Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Seabed Ice Gouging	June/July Oct./Nov.	June/July Oct./Nov.	Oct./Nov.	Oct./Nov.
Subsea Permafrost Thaw Subsidence	Any Time	Any Time	Any Time	-
Strudel Scour	May/June	May/June	May/June	-
Upheaval Buckling	Any Time	Any Time	Any Time	-
Internal Pressure	-	-	Any Time	-
External Pressure	-	-	-	-
Internal Corrosion	-	-	-	-
External Corrosion	-	-	Any Time	-
Vessel Accidents	Any Time	-	-	-
Anchor Dragging	-	-	-	-
Third Party Construction	Any Time	-	-	-
Sabotage	-	-	-	-

TABLE 4-13: DAMAGE CATEGORIES AND ASSOCIATED SPILL VOLUMES AND FREQUENCY OF PREDICTIONS

Damage Category	Estimated Oil Spill Volume (bbls)	Estimated Damage Frequency During Project Life
1	0	3×10^{-2}
2	0	1×10^{-3}
3	125	1×10^{-5}
4	1,576	2×10^{-7}

4.9.2.2 Spill Scenarios

Spill scenarios were presented in Section 3.8.4. Response time, cleanup capability, cleanup options, environmental impact variables, effectiveness of cleanup, and system down time are discussed in Section 3.8.5.

As shown in Table 4-12, a leak due to Category 4 damage might be expected only in the fall (October-November) of the year. Initial freeze-up could occur the first week of October, and ice movement would be expected to cease by about the middle of November when the ice becomes landfast. During breakup in early July, the ice is assumed to be deteriorated and weak and, for the most part, melts in place. Therefore, ice gouge damage is not assumed to occur during that time of year. Satellite tracking would be used to monitor the drift of any oiled ice. Again referring to Table 4-12, a Category 3 damage scenario could happen any time of the year.

However, as pointed out previously, the joint likelihood of a combination of less severe events has not been examined during this study. Such a study may indicate that more damage windows are possible. Therefore, a response plan would need to be in place that can manage all damage in all seasons.

4.9.3 Cleanup and Repair

The Liberty Development will have an approved oil spill contingency plan demonstrating the capability to clean up an oil spill anytime of year. The volume of oil which could be handled would be significantly larger than anything expected from the pipe.

Cleanup strategies are presented in Section 3.8.5. As discussed above, Category 4 damage might be expected only in the fall, while Category 3 damage could occur any time of the year. Mechanical options might be considered for cleanup of a spill due to Category 4 damage under broken ice, but the most effective strategy would likely involve in-situ burning. If the oiled ice became landfast, conventional winter ice procedures might be used to recover the oil. In any event, cleanup would be carried out as quickly as possible to the satisfaction of Federal and State On-Scene Coordinators to minimize any impact on the environment.

The repair philosophy for the offshore section of the single wall steel pipeline was presented in Section 4.7. The recommended methods of repair, which are dependent on the time of year and damage category, are shown in Figure 4-7. In the case of Category 3 damage, the pipeline has been purged and no further leakage can occur during repair. In the case of Category 4 damage, no secondary spill volume is expected, as precautions would have been taken to ensure no further loss during repair (e.g., purging or plugging the line). The risk of additional oil spill during repair is not considered further in this review.

5. PIPE-IN-PIPE SYSTEM

This section presents the conceptual level design for a pipe-in-pipe carbon steel system. Section 5.1 is an executive summary for this system. The subsequent sections detail the conceptual design.

5.1 Introduction, Summary and Conclusions

5.1.1 Introduction

This pipeline system configuration consists of a steel pipe inside a larger steel pipe. The wall thickness and grade of steel for both pipes are designed to achieve the desired specific gravity and to endure potential displacements when subjected to an extreme environmental loading event. This configuration has been used elsewhere in the offshore pipeline industry primarily for thermal insulation and the installation of multiple lines in a bundle. There are no known precedents for using it to provide secondary containment. As with the single wall steel pipe, the offshore section consists of approximately 6 miles of both the inner and outer pipes fabricated from 40-foot pipe joints manually welded together using shield metal arc welding (SMAW). There would be no subsea valves or fittings, but flanges or bulkheads are typically required for structural integrity.

The outer casing pipe would have an FBE external coating and cathodic protection system. The inner pipe could have an FBE external coating and annular spacers or centralizers, but cannot be cathodically protected. Corrosion control on the outside of the inner pipe and the inside of the outer pipe would rely on the integrity of any coating applied and maintaining an inert environment in the annulus.

This pipeline system would be trenched and requires a minimum depth of cover to protect it against environmental loads such as ice gouge, strudel scour, and upheaval buckling. This pipeline system is illustrated in Figure 5-1.

Two basic sub-alternatives have been studied in connection with pipe-in-pipe pipeline systems:

- Sub-alternative A: Inner pipe: X-52 steel pipe, 12.75-inch OD, 0.688-inch WT; Outer pipe: X-52 steel pipe, 16.00-inch OD, 0.500-inch WT.
- Sub-alternative B: Inner pipe: X-52 steel pipe, 12.75-inch OD, 0.500-inch WT; Outer pipe: X-52 steel pipe, 16.00-inch OD, 0.844-inch WT.

There are some differences in the structural response of the two sub-alternatives with respect to environmental loads.

The pipe-in-pipe sub-alternative A has an outer pipe diameter-to-thickness ratio (D/t) of 32, while the inner pipe has a D/t of 18.53. Therefore, the outer pipe is not as strong and bending resistant as the inner pipe, although the pipe-in-pipe system is designed to safely withstand all arctic environmental loads.

The pipe-in-pipe sub-alternative B has an outer pipe D/t of 18.93. Therefore, the outer pipe of this system is theoretically as strong and bending resistant as the single wall steel pipeline system. In this pipe-in-pipe sub-alternative, the inner pipe wall thickness has been decreased to 0.500 inch.

For these two pipe-in-pipe options there are two further variants:

- Structural bulkheads at Liberty Island and at the shore crossing only, or
- Structural bulkheads every 1/2 mile along the offshore alignment, in addition to bulkheads at Liberty Island and at the shore crossing.

Thus, the pipe-in-pipe system includes four sub-alternatives. The first variant (bulkheads at Liberty Island and shore crossing only) has the potential benefit of a leak detection system through the annulus. The second variant (bulkheads every 1/2 mile) makes a leak detection system through the annulus significantly more complex.

5.1.2 Summary

This section summarizes the structural analysis, construction plan, operations and maintenance, repair philosophy, costs, and failure analysis.

5.1.2.1 Structural Design Summary – Sub-alternative A

In this sub-alternative, the outer pipe has a D/t of 32. This ensures a specific gravity of 1.92, making vertical stability not an issue. However, the total weight of the pipe system in air is 178 pounds per foot, which makes it a heavier option. Such a D/t ratio, combined with the relatively low X-52 grade for the yield stress, ensures good bending ductility and relatively high allowable strains for displacement controlled loading.

This pipe-in-pipe sub-alternative can safely handle environmental loads such as those potentially caused by ice gouge, thaw settlement and strudel scour. For this sub-alternative's upheaval buckling design, native backfill material can be placed on top of the pipeline. This ensures that the pipe would remain in the trench, as installed. Gravel mats are not necessary.

5.1.2.2 Structural Design Summary – Sub-alternative B

In this sub-alternative, the outer pipe has a D/t of 18.9. This ensures a specific gravity of 2.26, making vertical stability not an issue. However, the total weight of the pipe system is 211 pounds per foot, which makes it the heaviest option. Such a D/t ratio, combined with the relatively low X-52 grade for the yield stress, ensures good bending ductility and relatively high allowable strains for displacement controlled loading.

This pipe-in-pipe sub-alternative can safely handle environmental loads such as those potentially caused by ice gouge, thaw settlement and strudel scour. In the design of this sub-alternative against upheaval buckling, the native backfill material can be placed on top of the pipeline to provide adequate resistance. This ensures that the pipe would remain in the trench, as installed, even in the presence of a 2.0-foot prop or crest. Gravel mats are not necessary.

5.1.2.3 Sub-alternative Selection

Both sub-alternatives are safe structurally and can handle all environmental loads. The overall structural response of sub-alternative B is slightly better than A. The installation of sub-alternative B would be slightly more time-consuming than A because of the thicker outer pipe. The remainder of this chapter considers only sub-alternative B (thicker outer pipe) because of the slightly better overall structural response.

5.1.2.4 Construction Summary

The most suitable methodology for installing a pipe-in-pipe system from the island to shore is a winter construction program consisting of conventional excavation equipment and off-ice pipe installation techniques. There is a low confidence level that this installation program would be completed in a single season.

5.1.2.5 Cost and Schedule Summary

The program for the overall construction of this alternative would target completing the construction in a single winter season between December and April. However, based on engineering judgement, there is a low confidence level that this program would be completed in this time frame. It is likely that it would take two seasons to complete this installation sequence. The associated estimated cost for the installation of the pipe-in-pipe system is $61 million, including contingency. The contingency has been assessed based on the level of confidence in completing the installation in a single season.

5.1.2.6 Operations and Maintenance Summary

The envisioned operations and maintenance program for the pipe-in-pipe alternative uses available technology to monitor the condition of the pipeline. This program would monitor most of the design aspects that are considered gradual processes — for example, thaw settlement — and would allow mitigating steps to be taken in a timely manner if required. The program would also identify most events that have occurred between inspections that did not impact the operation of the pipeline but may have affected the pipeline condition, for example, an ice keel passing over the pipeline. The program could not, however, identify mechanical damage to or internal/external corrosion of the outer jacket carrier pipe.

5.1.2.7 Repair Summary

The inner carrier pipe of the pipe-in-pipe alternative can be repaired to its original condition or full integrity during a summer or winter operation. However, the outer jacket pipe cannot be repaired to full integrity. Four permanent repair options are available.

For the localized damage categories, buckle/no leak (Category 2) and small/medium leak (Category 3), affecting less than a 40-foot length of pipe, the recommended permanent repair methods are:

- Summer: Cofferdam.
- Winter: Surface tie-in.

For damage categories that affect pipeline lengths greater than 40 feet (large leak/rupture, Category 4 damage), the recommended permanent repair methods are the same for both seasons:

- Summer: Tow out replacement string with a surface tie-in.
- Winter: Tow out replacement string with a surface tie-in.

5.1.2.8 Leak Detection System Summary

Leak detection for the pipe-in-pipe option would be achieved using three independent systems: a mass balance line pack compensation (MBLPC) system, a pressure point analysis (PPA) system, and a supplemental system. The first two systems would work in parallel, providing redundancy, and would have an accuracy to detect leaks as small as 0.15% of the volume of flow. A supplemental leak detection system, based on periodically monitoring for the presence of hydrocarbon vapors in the annulus, would also be used to detect any leaks from the inner pipe that were below this threshold.

5.1.2.9 Failure Assessment Summary

Damage that does not result in loss of containment is summarized as Category 1 (large displacement) and Category 2 (cross-section buckle/without leak). Damage that does result in loss of primary containment is summarized as Category 3 (small or medium leak) and Category 4 (large leak/rupture).

It is estimated that a Category 1 "incident of damage during operation" (displaced pipeline) has a 2% probability of occurring during the project lifetime. This type of damage is non-critical. Time is available to check and assess the damage, and a planned intervention, if required, could be initiated to correct the condition. Category 2 damage (buckles without leakage) is estimated to have a 0.1% project lifetime frequency. The estimated frequencies for small, medium, or large leaks are very small.

A leak due to Category 4 damage (rupture or large leak) would be realized only during freeze-up. A Category 3 damage scenario (small or medium leak) could happen at any time of the year. For any damage event, cleanup would be carried out. Additional consideration would need to be given to potential secondary spill volume from oil in the annulus during repair and to drying the annulus to prevent corrosion after repair.

This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less severe events; this might result in a large leak or rupture during other times of year. Such an analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear. Therefore, a response plan would need to be in place that could manage all damage in all seasons.

5.1.3 Conclusions

The pipe-in-pipe system chosen to be carried forward for further analysis, sub-alternative B, would meet the functional requirements of flow and pressure for the Liberty Development field.

A configuration with a 5-foot depth of cover and native backfill has been judged as adequate for design while optimizing such variables as constructability, operability, or repairability.

Fabrication and installation of the pipe-in-pipe alternative would be more complicated than the single wall pipeline due to the requirement to keep the pipe annulus dry, the lack of skilled workforce for this type of installation, etc. However, the most suitable method for installing the system is a combination of conventional excavation equipment (backhoes with extended or long-reach booms) to excavate a trench through the ice. The pipeline string is then installed through the ice using techniques similar to overland construction. It is expected that construction could not be completed in a single season.

The estimated cost for the pipe-in-pipe program is $61 million. This cost includes contingency for a second season of construction as there is a low confidence level that this alternative could be fabricated and installed in a single winter season.

Available technology would be used to monitor the pipe as part of the operations and maintenance programs. The inner pipe would not be cathodically protected. The outer pipe cannot be monitored by wall thickness pigging or assessed for internal damage or deformation. Therefore, the integrity of the outer jacket cannot be monitored or inspected.

Leak detection would be achieved using mass balance line pack compensation (MBLPC) and pressure point analysis (PPA). These systems combined would be able to detect a leak greater than 0.15% of the volumetric flowrate. Supplemental leak detection technology is proposed to monitor the annulus of the pipe-in-pipe system. Leaks from the inner pipe greater than 0.15% of the volumetric flowrate would be detected in minutes, while leaks lower than this threshold would be identified within 24 hours.

The probability of a leak from the pipe-in-pipe system is small. The inner pipe can be repaired to full integrity during a summer or winter repair operation. However, the outer jacket pipe cannot be repaired to full integrity. Additionally, it would be difficult to return the annulus to its low-moisture, non-corrosive condition. Procedures would need to be developed to manage the potential for a secondary spill volume from the annulus during repair and to try to achieve a dry annulus to prevent corrosion after repair. In accordance with the approved spill contingency plan, manpower and equipment would be in place to successfully clean up any spill in the event of a leak.

5.2 Structural Design

5.2.1 Flow Analysis

General comments on flow analysis have been made in Section 3.2.2. The combination of gravel backfill as thermal insulation and a –50°F ambient air temperature results in a Liberty Island inlet pressure of 1,276 psig and inlet temperature of 135°F, with a tie-in pressure and temperature of 1,050 psig and 131°F.

5.2.2 Pipeline Installation Stability

General comments on pipeline installation stability are presented in Section 3.2.3. The empty pipe-in-pipe weights are summarized below in Table 5-1.

Both pipe-in-pipe systems have a specific gravity (with respect to seawater at 64.0 pounds per cubic foot) greater than 1.6. Therefore, the pipe would sink and be stable in the trench.

TABLE 5-1: EMPTY PIPE WEIGHTS

Parameter	Pipe-in-Pipe Sub-alternative A	Pipe-in-Pipe Sub-alternative B
Inner Pipe OD (inches)	12.75	12.75
Inner Pipe Wall Thickness (inches)	0.688	0.500
Outer Pipe OD (inches)	16.00	16.00
Outer Pipe Wall Thickness (inches)	0.500	0.844
Weight in Air (pounds/foot)	178	211
Submerged Weight (pounds/foot)	83	113
Pipe SG (w.r.t. seawater)	1.87	2.15

5.2.3 Ice Keel Gouging

General comments on ice keel gouging were made in Section 3.2.4. For the pipe-in-pipe alternative, two cases have been evaluated. The 3.0-foot-deep, 40-foot-wide ice keel case is the loading event that imposes the greatest strain on the pipeline. The soil displacement and resulting pipeline movement for this case are shown in Figures 5-2 and 5-3. The corresponding strain distribution is shown in Figures 5-4 and 5-5.

Tables 5-2 and 5-3 show that the maximum strains in both the inner and outer pipes are below the maximum allowable strains described in Section 2.11. Therefore, 5.0-foot depth of cover is adequate for both pipe-in-pipe options with respect to ice keel loading.

TABLE 5-2: MAXIMUM STRAINS IN A PIPE-IN-PIPE SYSTEM (SUB-ALTERNATIVE A) FOR EXTREME ICE KEEL EVENTS

Ice Gouge Dimensions		**Outer Pipe Strains (D/t = 32)**		**Inner Pipe Strains (D/t = 18.5)**	
Depth (ft)	Width (ft)	Max. Tensile Strain (%)	Max. Compressive Strain (%)	Max. Tensile Strain (%)	Max. Compressive Strain (%)
3.0	30	0.27	0.71	0.22	0.57
3.0	40	0.32	0.79	0.26	0.63
3.0	50	0.21	0.51	0.17	0.41
3.0	60	0.20	0.49	0.16	0.39
Allowable Strains (%)		1.80	1.70	1.80	3.50

TABLE 5-3: MAXIMUM STRAINS IN A PIPE-IN-PIPE SYSTEM (SUB-ALTERNATIVE B) FOR EXTREME ICE KEEL EVENTS

Ice Gouge Dimensions		**Outer Pipe Strains (D/t = 18.5)**		**Inner Pipe Strains (D/t = 25.5)**	
Depth (ft)	Width (ft)	Max. Tensile Strain (%)	Max. Compressive Strain (%)	Max. Tensile Strain (%)	Max. Compressive Strain (%)
3.0	30	0.20	0.40	0.16	0.32
3.0	40	0.38	0.61	0.30	0.49
3.0	50	0.24	0.44	0.19	0.35
3.0	60	0.19	0.36	0.15	0.29
Allowable Strains (%)		1.80	3.50	1.80	2.30

It is important to note that the calculations assumed both the inner pipe and the outer pipe would have the same radius of curvature. While this is a valid approximation of the average structural behavior under bending, the loads between the outer pipe and the inner pipe would be transferred at discrete points along the length where the spacers are located (at approximately 40-foot intervals). The localized load transfer at spacers would magnify pipe bending strain at these locations. Although it is not anticipated that this would bring the maximum strains above the allowable, this localized strain increase would need to be assessed in detailed design.

5.2.4 Upheaval Buckling

Upheaval buckling was discussed in Section 3.2.6. Upheaval buckling potential of the pipe-in-pipe option can be resisted by the native backfill material. For a 1.5-foot prop height, the native backfill thickness required for sub-alternative A is approximately 3.6 feet. A prop height of 2.2 feet could be accommodated by 6 feet of backfill. By using select gravel with a density of 60 pounds per cubic foot, a thickness of 2.5 feet is sufficient to prevent upheaval buckling for an initial prop of 1.5 feet. For sub-alternative A, a minimum backfill thickness of 4.0 feet is adopted. Theoretically, sub-alternative B does not require any backfill for prop heights up to 2.0 feet. However, a minimum backfill thickness of 2.0 feet is considered prudent and is adopted for sub-alternative B. Thus, it would be relatively easy to control upheaval buckling for either sub-alternative.

The pipe-in-pipe system is more resistant than a single wall pipeline to upheaval buckling as it is heavier, has to move more soil to move vertically, and has a reduced axial compressive driving force.

5.2.5 Thaw Settlement

General comments on thaw settlement were presented in Section 3.2.7. The design thaw settlement for the single wall steel pipeline was 1 foot (see Section 2.7.4). Using the pipeline system’s thermal resistance, the external temperatures of the pipe-in-pipe systems have been estimated. The thaw settlement was then estimated using linear interpolation of the 1-foot thaw settlement value for the single wall steel pipeline and the observed nearshore soil conditions. This assumes that the reduction in the rate of thaw bulb growth will limit the amount of thaw-sensitive material contributing to settlement. This results in an estimated design differential settlement of 0.37 feet. At this conceptual level, no specific finite element analyses of pipe-soil interaction have been performed. Rather, since the maximum differential thaw settlement value of 0.37 feet is considerably smaller than soil displacements resulting from ice keel scour, the resulting pipeline strains would likely be smaller. Therefore, the resulting thaw-settlement-induced strains are expected to remain well within allowable strain levels.

5.2.6 Strudel Scour

General comments on strudel scour were presented in Section 3.2.8. For this conceptual level report, no specific modeling of pipe/soil interaction through finite element analysis for strudel scour has been performed. However, for the small pipeline span expected, the resulting pipeline stresses would remain below the allowable stress levels.

5.2.7 Cathodic Protection

Sacrificial aluminum anodes would be used to cathodically protect the outer pipeline for a 20-year design life. A dual-layer FBE coating would be applied to the outer pipe to limit anode requirements. The inner pipe would be externally coated and internally inspected with a smart pig to detect any internal or external corrosion prior to potential leak formation. The annulus of the pipe-in-pipe system must be a non-corrosive environment (low moisture content) to prevent corrosion of the coated inner pipe. This is difficult to achieve and would require additional care during construction and installation of the pipeline. Any residual moisture could be removed only by continually drawing a vacuum on the annulus. The aluminum anodes would be bracelet-type anodes installed at approximately 120-foot intervals (three pipe joints). The anode mass would be calculated such that current requirements of recommended practices are conservatively met. The cathodic protection system would be periodically checked at the shore crossing and at Liberty Island to confirm minimum protection voltages are maintained in accordance with DOT requirements.

5.3 Conceptual Design Selection

5.3.1 Structural Behavior Considerations

The structural behavior of sub-alternatives A and B is basically similar with respect to ice keel loading (Table 5-4). With respect to upheaval buckling, Table 5-4 shows that sub-alternative B requires 2 feet of native backfill to stabilize the pipe in the presence of a 1.5 foot prop. This is simpler (in terms of backfilling procedures) than sub-alternative A.

TABLE 5-4: CONCEPTUAL DESIGN SUMMARY

Load Condition	Pipeline Sub-alternative			
	A		B	
	Outer	Inner	Outer	Inner
Ice Keel Strain [% of allowable (-) = compressive (+) = tensile]	(-) 46% (+) 18%	(-) 18% (+) 14%	(-) 17% (+) 21%	(-) 21% (+) 17%
Upheaval Buckling [backfill characteristics]	3.6 feet of native backfill		2 feet of native backfill	
Thaw Settlement	0.37 foot		0.37 foot	
Strudel Scour Span	≈1 foot		≈1 foot	

The ice keel strains shown in Table 5-4 for sub-alternative B are all less than 25% of allowable strains for a 7-foot cover analysis. A maximum of 2 feet of native backfill are required to prevent the potential for upheaval buckling for sub-alternative B. Therefore, it is judged at the preliminary engineering stage that sub-alternative B can be designed for a depth of cover of 5 feet. This simplifies construction while maintaining structural integrity, but this result would need to be confirmed during detailed design.

5.3.2 Fabrication and Installation Considerations

Table 5-5 summarizes the major activities during pipeline installation and fabrication for each sub-alternative and ranks them. If the sub-alternative is compatible with the activity and it could be completed with relative ease, it receives grade 3. If more effort is required, the sub-alternative receives grade 2, and if the activity is judged to require much more effort, the grade 1 is assigned. Therefore, the preferred alternative is considered to be the one with the highest score.

Some engineering judgement is involved for each score assigned in Table 5-5. For example, for sub-alternative B, the outer pipe weld requires more passes than A and scores 1 in the “Welding” entry. Since sub-alternative B requires only a 2-foot backfill thickness, it scores 3 for “Backfill Operations”, compared to the score of 2 for sub-alternative A.

TABLE 5-5: INSTALLATION/FABRICATION SUMMARY

Activity	**Pipeline Sub-alternative**	
	A	**B**
Pipe Joint Preparation	2	2
Welding	3	1
Handling	2	2
Pipe Lay Into Trench	2	1
Backfilling Operations	2	3
Total Score	11	9

Regarding the pipe-in-pipe bulkhead variants, advantages and disadvantages are presented in Table 5-6. The variant with bulkheads at Liberty Island and at the shore crossing is considered the best option.

TABLE 5-6: ADVANTAGES AND DISADVANTAGES OF BULKHEAD VARIANTS

Bulkhead Location	Advantages & Disadvantages
Liberty Island and Shore Crossing Only	<u>Advantages</u> • Simpler offshore construction • Unobstructed annulus facilitates supplemental leak detection system • In case of an inner pipe leak, oil in annulus may be flushed out <u>Disadvantages</u> • In the case of an inner pipe leak, oil in annulus may spread longitudinally
Every 1/2 Mile	<u>Advantages</u> • In the case of an inner pipe leak, oil in annulus would spread only between the bulkheads <u>Disadvantages</u> • More complicated offshore construction • Obstructed annulus is an impairment to leak detection systems • Bulkheads potentially exposed to high pipe bending strains

5.3.3 Sub-alternative Selection

In summary, the previous sections show that the overall structural response and installation for sub-alternative B are slightly better than for A. Therefore, the pipe-in-pipe system to be carried forward for further analysis is sub-alternative B with a 5-foot depth of cover. Bulkheads are assumed to be used at Liberty Island and the shore crossing only.

5.4 Construction

General construction considerations have been discussed in Section 3.3, including trenching and installation. This section describes the most suitable method for the construction of the pipe-in-pipe system. The assumed configuration is summarized in Figure 5-6.

5.4.1 Installation Options

Offshore arctic pipeline installation options are described in Sections 3.3.9 and 3.3.10 and apply to the pipe-in-pipe option.

5.4.2 Construction Method

For the reasons outlined in Section 3.3.10, the most suitable method for installing a pipe-in-pipe system for Liberty is to use conventional excavation equipment and off-ice pipe installation techniques. Winter trenching is described in Section 3.3.6 and winter installation in Section 3.3.9. The reasons for using conventional excavation equipment and off-ice pipe installation techniques are summarized below.

5.4.2.1 Trenching Method

Pre-excavating with conventional excavation equipment working from an ice-based platform is considered the most suitable method to dig a 9-foot trench. This follows the same reasoning summarized for the single wall steel pipe installation (Section 4.4).

5.4.2.2 Pipeline Installation Method

Similar to the single wall pipe alternative, the use of a lay vessel is feasible; however, scheduling of the required pre-trenching and backfilling activities make this method unattractive. Another disadvantage for a pipe-in-pipe lay vessel installation is the need to prefabricate multiple joint sections (2 to 6 joints long) to be assembled on the lay vessel. If it is not possible to weld the ends of the outer jacket pipe directly together, this weld would incorporate two half-shell pieces of pipe joined with circumferential and longitudinal welds. This type of joint would potentially not have the same integrity as a conventional girth weld between two pipe ends.

Reeling a pipe-in-pipe system of this configuration, though technically feasible, is beyond the capability of currently available reel vessels. The largest pipe-in-pipe system that has been installed by the reeling process to date is an 8-inch inner carrier pipe in a 12-inch outer jacket pipe with an insulation material in the annulus. Another point to note is that the reel capacity would be limited by the weight of the pipe-in-pipe system. It is estimated that the maximum length that could be put on a reel would be approximately 1 mile (approximately 500 tons).

A typical tow or pull method for installing a Liberty pipe-in-pipe system would include:

- Pre-dredging the trench,

- Making up the pipe string either in one 6-mile segment or multiple segment lengths (for example, 1,000 feet long), and
- Pulling the complete pipeline into the trench or pulling the pipeline in stages (partial launch) of 1,000 feet at a time.

Pipeline bundle tow or pull methods are common for pipelines of this length where the outer jacket pipe dimensions are configured so that the submerged weight of the pipeline system is on the order of 10 pounds per foot. Therefore, for the pipe-in-pipe configuration considered here, this method is not considered viable.

Installation of the pipe-in-pipe system using off-ice techniques is considered feasible for the Liberty water depths and weight of the pipeline (210 pounds per foot dry weight, 113 pounds per foot submerged weight). This method is similar to onshore pipe-lowering techniques.

5.4.3 Installation Sequence

A description of a general installation sequence is presented in Section 3.3.10. Deviations from that sequence for the pipe-in-pipe option are described below. Equipment requirements and production rates associated with each activity are summarized in the next section on construction costs.

5.4.3.1 Pipeline Fabrication and Installation

Pipeline fabrication and installation include make-up site preparation, pipe string make-up, transport of strings, pipeline installation, and hydrostatic testing. The work involved for some of these activities is different from what was presented in Section 3.3.10, and these differences are described in the following text.

Mobilize Equipment, Material and Workforce

This activity is the same as presented in Section 3.3.10.

Ice Road Construction and Ice Thickening

There is more construction equipment associated with the pipe-in-pipe alternative, and this would increase the duration and frequency of ice road use. Minor increases in ice road work areas and thickness to support heavier loads may also be required. Therefore, more support activities involving ice road construction and maintenance would be required.

Ice Slotting

This activity is the same as presented in Section 3.3.10.

Trenching

Trench productivity for the pipe-in-pipe system would be faster than the productivity for the single wall pipe alternative, as the target trench depth is estimated to be 1.5 feet shallower. The bottom roughness criteria for the pipe-in-pipe system would have a higher allowable threshold than for the single wall pipe alternative. However, because of the increased diameter, the pipe-in-pipe system would not conform as readily to elevation changes such as in the island approach.

Temporary Storage Site Preparation

This activity is the same as presented in Section 3.3.10.

Pipe String Make-Up (Welding)

In addition to activities presented in Section 3.3.10, the stringing activities for the pipe-in-pipe system would also involve:

Make-up of 1,000-Foot Sections for the 12-inch and 16-inch Pipelines: These activities would include:

- String pipe joints along make-up-site.
- Align and weld pipe joints.
- Non-destructive examination (NDE) with X-ray and ultrasonic equipment to determine that any flaws are smaller than the largest flaw allowed by the limit strain design.
- Field joint coating of weld.

Pipe-in-Pipe Assembly: Upon completion of the 1,000-foot section of 16-inch outer jacket pipe and 12-inch inner carrier pipe, the pipes are aligned so the 12-inch can be pulled into the 16-inch.

- Place temporary shelters at either end of the 16-inch pipe.
- Attach non-metallic spacers to the 12-inch pipe at 10-foot spacing.
- Pass a pull cable from a winch at one end of the 16-inch pipe to the 12-inch pipe at the other end.

- Secure the 16-inch pipe so that when the 12-inch is pulled through the 16-inch, the 16-inch outer jacket does not move.
- Dry the inside of the 16-inch pipe with blowers.
- Once the 16-inch pipe is dry, the 12-inch can be pulled in. As the 12-inch is pulled from its current position into the 16-inch line, it passes through an induction heater in the covered tent area that melts any adhering snow and dries its outer surface.
- Once the 12-inch pipe has been pulled into the 16-inch, both ends should extend 2 or 3 feet beyond the outer jacket. The opening to the annulus at either end is then sealed to keep it dry. The assembled pipe-in-pipe section is stored until it is to be pulled to the side of the trench for installation.

Pipe String Transport and Tie-In Welds

The pipeline strings would be towed via tracked equipment to the side of the trench. The two ends to be joined would be covered with a protective shelter and the temporary annulus seals removed. The two 12-inch sections (the one extending from the 1,000-foot pipe section and the one extending from the pipeline being lowered into the trench) are then aligned using an external line-up clamp. The 12-inch line is then welded by the same procedure used at the pipeline stringing site. On completion of the NDE, the inner carrier pipe weld field joint is coated. External radiography and ultrasonic inspection may be used, but not an internal inspection tool.

On completion of the inner pipe weld and field joint, one option for joining the outer pipe would be to pull the outer pipes together. It may be feasible to develop a special external alignment clamp which has some form of hydraulic ram that could pull the two outer jacket pipes together for these lengths of pipe strings. The system would pull up to 1,000 feet of the outer jacket pipe over the inner 12-inch carrier pipe. Aligning the two outer jacket pipes would also require specialized procedures and beveling techniques. The welding and field joint would be the same as for the 16-inch at the pipeline stringing site except for the NDE. For this field joint, X-ray techniques cannot be used, and only external ultrasonic techniques would be applicable. This is not a normal approach for the connection of outer jacket pipes. The standard approach would be to use a split-sleeve welded connection, but because of the requirement to maintain weld integrity and structural continuity, a direct tie-in girth weld is a preferred solution.

Once the pipe-in-pipe joint is completed, sacrificial anodes would be attached to the outer jacket pipe as required. If an external leak detection system is to be bundled to the pipeline, it would also be attached at this stage.

Pipeline Installation

This activity is the same as presented in Section 3.3.10.

Backfilling the Trench

Once the pipeline is installed in the trench, a survey of the pipeline's vertical configuration would be made to determine whether there were any "high points" (a 1.5-foot change in elevation over 100 feet) along the pipeline. If the vertical variation of the pipeline exceeded these tolerances, the minimum backfill thickness would be increased from 4 feet to 6 feet. If the vertical variance is more severe, then some corrective action such as locally lowering the pipeline would be required.

Hydrostatic Testing and Smart Pigging

Depending on how regulatory requirements are interpreted, a hydrostatic pressure test of the pipe-in-pipe system might include pressure testing of both the inner pipe and the annulus to verify that the pressure criterion is met. Since the medium for hydrostatic testing would be water or a water/glycol mixture, this could not be practically achieved without leaving the annulus flooded at the conclusion of the test. However, an inert-gas pressure test of the annulus may be feasible to ensure the integrity of the outer sleeve.

Demobilize Equipment

This activity is the same as presented in Section 3.3.10.

5.4.4 Construction Considerations

General considerations regarding QA/QC, welding and NDE, and temporary storage of excavated material are presented in Section 3.3.10. The following sections present specific considerations associated with the construction sequence for the pipe-in-pipe.

5.4.4.1 Quality Assurance and Quality Control

General comments on QA/QC presented in Section 3.3.10 apply to the pipe-in-pipe, with additional comments provided below. The quality assurance and quality control associated with the pipe-in-pipe design allows most, but not all, key aspects to be inspected during installation and subsequently monitored during the operational life of the pipeline. With regard to construction, the additional key aspects of the design that should be measured are as follows:

- The 16-inch line pipe would likely be manufactured by the UOE process and would thus contain a longitudinal seam weld. The material properties of the inner seamless 12-inch pipe would be isotropic, whereas the 16-inch pipe would tend to have non-isotropic properties. Isotropic materials are preferred from a limit state design point of view; however, they are not required. Pipe materials specifications and mill inspection would be more involved than for a single 12-inch pipe.

- In the 12-inch-pipeline, all weld imperfections larger than allowable limits would be detected using a combination of X-ray and ultrasonic NDE methods. All imperfections in the 16-inch pipe welds that are constructed at the stringing site prior to the pipe-in-pipe assembly would also be detected using a combination of X-ray and ultrasonic NDE methods. However, the remaining 33 tie-in welds for the 16-inch outer jacket pipe would receive less inspection using external ultrasonic NDE only. X-ray is not possible as the inner pipe obstructs the image.

5.4.4.2 Welding

Comments on welding presented in Section 3.3.10 apply here. If weld cut-outs are required for the pipe-in-pipe system, the sequence to weld the pipes would be more complex and time-consuming than for a single pipe. This would basically be a repeat of the 16-inch pipe string tie-in procedure.

5.4.4.3 Requirement to Maintain Pipe Dry

The pipe-in-pipe assembly sequence would maintain the annulus as dry as possible during construction to avoid corrosion in the annulus. Any residual moisture could be removed only by continually drawing a vacuum on the annulus. This would be difficult to achieve in a field construction setting and would require at least several days to complete the drying. Alternatively, an inert fluid may be pumped into the annulus after construction.

5.4.4.4 Skilled Labor Force and Construction Equipment

The pipe-in-pipe alternative would require a large share of the available labor resources, but the labor force required for installation is considered available. The major construction equipment components are identified in the next section on cost.

5.4.4.5 Ice Slot Maintenance During Pipeline Installation

The pipeline installation would closely follow the trenching spread in order to simplify trench spoils handling. The distance behind the trenching spread and the pipeline touchdown point would be approximately 1,200 feet, and this ice slot would have to be kept ice-free.

5.4.4.6 Equipment Required to Lower in Pipeline

It is estimated that six sidebooms would be required to lower the pipe-in-pipe system from the ice surface to the trench bottom.

5.5 Construction Costs

The following section summarizes the basis for the order of magnitude costs required to install the pipe-in-pipe alternative.

5.5.1 Construction Sequence

The pipeline construction sequence is presented in Section 3.4.1 and applies here with the following differences:

- Pipe-in-Pipe String Make-Up (Welding)
  - Weld up 1,000-foot strings of inner pipe, X-ray/UT.
  - Weld up 1,000-foot strings of outer pipe, X-ray/UT. Dry and cap both ends.
  - Winch inner pipe into outer pipe. Dry and cap both ends. Inner pipe extends beyond outer pipe.
- Pipe-in-Pipe String Field Joint
  - Remove temporary caps. Align and weld inner pipe.
  - Pull outer pipe over inner pipe until the outer pipe is lined up (opposite end of inner pipe exposed).
  - Align and weld outer pipe, UT.
  - Add anodes.

5.5.2 Quantities and Rate of Progress

5.5.2.1 Mobilize Equipment and Material

See Section 3.4.2.

5.5.2.2 Ice Road Construction and Ice Thickening

See Section 3.4.2.

5.5.2.3 Ice Cutting and Slotting

See Section 3.4.2.

5.5.2.4 Trenching

The estimated trench excavation volumes are shown in Table 5-7. The total volume is approximately 354,000 cubic yards based on a 9-foot-deep trench, 10 feet wide at the trench bottom. Side slopes of 2:1 are assumed for the 0- to 8-foot water depths and 3:1 for the remainder of the route. This target trench depth includes overexcavation to ensure the minimum depth of cover is achieved.

FIGURE 5-7: TRENCHING VOLUMES

Water Depth (ft)	Trench Length (ft)	Trench Depth (ft)	Volume (yd^3)
0 – 8	14,877	9	138,852
8 – 18	12,473	9	153,834
18 – 22	4,964	9	61,223
		Total	**353,908**

Trench excavation is a critical operation requiring two or three spreads each consisting of backhoes, support bridges, spoils handling, spoils transport and survey equipment. The rate of progress and days to complete each zone are summarized in Table 5-8.

TABLE 5-8: TRENCHING RATES

Water Depth (ft)	Trench Length (ft)	Volume (yd^3)	Productivity (%)	Rate of Progress for Each Spread (ft/hr)	Number of Spreads	Time for Activity, 3 Spreads (days)
0 – 8	14,877	138,852	85	51	2	8
8 – 18	12,473	153,834	75	26	2	15
18 – 22	4,964	61,223	75	6	3	15
				Total		**38**

5.5.2.5 Pipe-in-Pipe Make-Up Site Preparation

The pipe-in-pipe make-up site would be located on the bottomfast sea ice close to the shore approach in an area measuring approximately 6,000 feet by 800 feet (533,000 square yards). On-site preparation for pipe-in-pipe make-up would require one spread consisting of bulldozers, cranes, front-end loaders, backhoes, and tracked vehicles with augers. One spread, with a productivity factor of 85%, can prepare 11,260 square yards per day. Using this rate of advance, 354,000 square yards can be prepared in 47 days.

5.5.2.6 Pipe-in-Pipe String Make-Up (Welding)

During this activity, 33 pipe-in-pipe strings of 1,000 feet long each would be constructed for a total of approximately 1,616 welds (assuming 40-foot pipe joints and 6.12 miles of inner/outer pipe).

For the 12-inch pipe, the completed manual (SMAW) welds would require 6 passes. It is estimated that a spread can progress at a rate of 50 welds per day for the 12-inch-diameter pipe. For the 16-inch pipe, the weld would probably have 8 to 14 passes. It is estimated that a production line can produce about 26 welds per day for a 16-inch-diameter pipeline with two 10-hour shifts per day. All the pipe string make-up activities could be completed within 48 days.

5.5.2.7 Pipe-in-Pipe String Transportation

Transporting the 33 pipe-in-pipe strings from the pipeline make-up site to their locations along the Liberty pipeline route would require one spread of sidebooms. It is estimated that this activity can position an average of 0.6 miles of pipe string per day at the edge of the ice slot for a total of 10 days.

5.5.2.8 Pipe-in-Pipe String Field-Joint Operations

It is estimated that 66 tie-in welds would be required (two for each of the 33 pipe-in-pipe strings) using a special mechanical line-up clamp. This would pull together and line up outer jacket pipes after the inner pipe is welded, inspected and field-joint coated. One welding spread would perform this activity at an estimated rate of 1 tie-in per day for a total of 33 days.

5.5.2.9 Pipeline Installation

The pipeline installation progress rate is theoretically faster than the trenching rate, and therefore, this activity would depend on the duration of trenching.

Pipeline installation would take 23 days (7 days for water depths of 0 to 8 feet and 11 days for water depths of 8 to 18 feet) to advance to the 18-foot isobath. The zone of 18 to 22 feet of water is assumed to be installed in 6 days because the trenching operations in this zone start before it is reached by the installation spread. It is estimated the total 6.12 miles of pipe-in-pipe installation would be performed in 29 days using one spread consisting of sidebooms and backhoes.

5.5.2.10 Backfilling

Native soil would be used as the main backfill material. All excavated material would be placed back in the trench even though the minimum backfill requirement is 5 feet. This activity would require one spread consisting of loaders, a backhoe, spoil transport trucks, and dozers. The rate of progress of backfilling is dictated by the duration of pipeline installation. It is estimated that this activity would be performed in 30 days.

5.5.2.11 Hydrostatic Testing

The hydrostatic pressure testing of the 12-inch carrier pipe is expected to be completed in 5 days.

5.5.2.12 Demobilization

It is assumed that demobilization can be performed in half the time of mobilization. Thus, this activity would be completed in 15 days.

5.5.3 Schedule and Risk

A contractor or owner might approach this work in several ways. There is always a strong desire to complete a project in the shortest time possible and to plan a contingency for non-completion. If the pipeline can be fabricated and installed within a single winter season, the cost savings are significant and become an incentive to all participants. However, if this is not possible and the pipeline must be abandoned in place for a year, demobilizing and re-mobilizing will increase costs dramatically. The subject is worthy of a detailed schedule risk analysis; unfortunately, the scope of this study precludes a fuller treatment of this subject. Nevertheless, the following is a general discussion of the more important aspects that could affect the schedule and resultant confidence in the cost estimate.

The causes of non-completion within a single season can be many, and with the pipe-in-pipe method, there are several important factors that can affect construction progress.

Schedule risks can be categorized from those that have a high probability with severe consequences that are either manageable or not, to those that have a low probability with little consequence that is either manageable or not.

Weather is a very important (if not the most important) factor in being able to install the line in a single season. Ice roads and the construction ice pad require early and sustained cold weather to be able to achieve the ice thickness required for construction equipment. In a late-start scenario, more equipment may be used to manage the ice production rate. For the pipe-in-pipe, it would likely be necessary to thicken the ice pad in the floating ice section more than for a less heavy pipe. An extra 2 feet of ice thickness may add at least two weeks to the schedule, delaying the timing for construction equipment to be brought onto the ice. Conversely, very cold weather would slow down the rate of production of the pipeline bundle. Materials and pipe string handling becomes very cumbersome, particularly where finesse is required (e.g., insertion of the inner pipe within the outer jacket pipe).

Trenching would be relatively unaffected by the pipeline installation method. In fact, for the pipe-in-pipe, the trench would be shallower, therefore requiring less time to finish. The net effect is to bring the timing for pipe installation and trenching closer together on the critical schedule activities.

Perhaps the greatest risk to the pipe-in-pipe schedule is the “learning curve” that the pipeline installation contractor would need. Aside from the HDD cased-pipe Colville River crossing, local contractors would not be familiar with a long-bundle fabrication sequence and installation with multiple tie-ins on the ice. The differences between the Colville River crossing and a subsea pipeline bundle have been the subject of much discussion, and the off-ice scenario poses a much greater challenge in terms of production rate and quality, and schedule risk. It is important to note though that, given the arctic winter environment, any contractor would require an initial learning period to adjust the bundle fabrication activities and coordinate those with the lay spread. When there are only three months for construction, even a few days delay can have a considerable effect on the overall schedule.

The pipe bundle string fabrication would require its own pipe handling equipment and in numbers (of sidebooms) that would almost match the off-ice installation spread. The amount of pipe handling at the pipe-string make-up yard is considerable (approximately 33 1,000-foot strings). These risks can be managed but would likely result in delays. The effect of cold weather on production cannot be overestimated.

Additionally, the bundle stiffness and bulkhead terminations at each end of the pipeline would have design and construction implications for the shore crossing and island riser.

The net effect of these nuances and the absolute necessity to maintain quality would make a single-season completion unlikely.

There are two schools of thought regarding scheduling. The first is to plan to complete in a single season, with a high probability of needing to abandon the pipe in place and return the following year. The second would be to plan for a first-year pipe-string fabrication and stockpile the pipe-strings until the following year. Then trenching and pipe laying could proceed in tandem the following winter, with a very high probability of success. The costs would be very similar. This discussion serves to highlight the likelihood of increased costs for the bundle pipe installation.

It has been assumed that the construction of the pipe-in-pipe system would be performed in the winter from December to April. Construction during winter allows the use of conventional or adapted onshore construction equipment and techniques. A “one-season” construction schedule for the pipe-in-pipe option is presented in Figure 5-7. There is a low confidence that this installation program will be completed in this time frame. Accordingly, contingency has been added to the budgeted costs.

5.5.4 Cost Estimate Summary

The different activities associated with the construction of the Liberty offshore pipeline using the pipe-in-pipe option are presented in Table 5-9. Activities, quantities and progression rates are shown together with the estimated cost for this option. As there is low confidence that the pipeline would be installed in a single season, a contingency cost is included to account for additional expenditure for a two-season installation plus 10% of the estimate. The total cost estimate of $61 million reflects the budgeted cost that would be estimated to complete this work.

TABLE 5-9: CONCEPTUAL COST ESTIMATE FOR THE PIPE-IN-PIPE ALTERNATIVE

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate (Thousand $/day)	Cost (Million $)
Mobilization	Lump Sum			3	1240	3.72
Ice Thickening and Road Construction + Maintenance	2.5 in/day	1	32,314 feet	56	84	4.7
Ice Cutting and Slotting	800 feet/day	3	32,314 feet	14	29	1.22
Trenching	0 – 8 feet WD ---> 51 feet/hour/backhoe	2	138,852 cubic yards	8	60	5.46
	8 – 18 feet WD ---> 26 feet/hour/backhoe	2	153,834 cubic yards	15		
	18 – 22 feet WD ---> 6 feet/hour/backhoe	3	61,220 cubic yards	15		
Pipe-in-Pipe Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55	2.59
Pipe-in-Pipe String Make-Up (Welding)	50 welds/day for 12.75-in P/L 38 welds/day for 16-in P/L	1	1,616 welds	48	240	11.5
Pipe-in-Pipe String Transportation	0.6 miles/day	1	33 pipeline strings	10	78	0.78
Pipe-in-Pipe String Field Joint	2 welds/day	1	66 welds	33	60	1.02
Pipeline Installation		1	32,314 feet	29	88	2.55
Backfilling		1	32,314 feet	30	42	1.26
Hydrostatic Testing		1		5	84	0.42
Demobilization	Lump Sum			2	920	1.80
Material Cost and Transportation	Lump Sum					4.5
Contingency	10%					4.15
	Additional cost for 2nd season					15.0
					Total	**61**

5.6 Operations and Maintenance

This section presents an operational and maintenance philosophy for the offshore section of the Liberty pipe-in-pipe system. Table 5-10 summarizes the relationship between the operations and maintenance and the design.

TABLE 5-10: RELATIONSHIP BETWEEN OPERATIONS AND MAINTENANCE AND THE DESIGN

Tasks	Design Aspects	
Operations	**Inner Carrier Pipe**	**Outer Jacket Pipe**
Monitoring of Flow	- Internal Leak Detection	- NA
	- Custody Transfer	- NA
External Offshore Route Survey	- Trench Configuration	- Trench Configuration
	- Ice Keel Event	- Ice Keel Event
	- Strudel Scour Event	- Strudel Scour Event
Shoreline Erosion	- Shore Crossing Design	- Shore Crossing Design
	- Trench Configuration	- Trench Configuration
Maintenance	**Inner Carrier Pipe**	**Outer Jacket Pipe**
Cathodic Protection	- NA	- Cathodic Protection System
Wall Thickness and Internal Damage	- Pipeline Corrosion (Internal)	- NA
Pipeline Configuration	- Trench Configuration	- Trench Configuration*
	- Ice Keel Event	- Ice Keel Event*
	- Strudel Scour Event	- Strudel Scour Event*
	- Thaw Settlement	- Thaw Settlement*
	- Thermal Expansion	- Thermal Expansion*
	- Upheaval Buckling	- Upheaval Buckling*
External Corrosion	- Pipeline Corrosion	- NA
Pipeline Expansion	- Thermal Expansion	- Thermal Expansion
Pipeline Shore Approach Geometry Survey	- Thaw Settlement	- Thaw Settlement

*Note: The outer pipe configuration is assumed to follow the inner pipe configuration.

5.6.1 Operation

General comments on operation are presented in Section 3.5.1.

5.6.2 Pipeline Inspection

General comments on pipeline inspection are provided in Section 3.5.2

5.6.3 Maintenance

General comments on maintenance are provided in Section 3.5.3. Differences related to the pipe-in-pipe system are presented below.

5.6.3.1 Monitoring of Cathodic Protection

Anodes are located only on the outer jacket pipe. The annulus of the pipe-in-pipe system must be maintained as a non-corrosive or inert environment (low moisture content) to prevent corrosion of the inner carrier pipe. Therefore, a system would need to be implemented for checking the moisture content of the annulus. The inner carrier pipe would be coated with a durable anti-corrosion coating. However, if the coating were to be damaged or break down, then the only protection against external corrosion is maintaining a non-corrosive or inert environment.

5.6.3.2 Monitoring of Inner Pipe Wall Thickness (Corrosion) and Damage

The wall thickness of the inner carrier pipe would be monitored and assessed for any corrosion, denting, or deformations at periodic intervals listed in Table 3-1 of Section 3.5.3. The outer jacket pipe cannot be monitored by wall thickness pigging or assessed for internal damage or deformation.

5.6.3.3 Monitoring of Pipeline Configuration

The pipeline's geometry would be monitored by inspection pigging the inner carrier pipe and comparing it to the baseline measurement of its as-built configuration. It is assumed that the outer jacket pipe would have the same configuration as the inner carrier pipe, as the pipe-in-pipe design includes spacers whose objective is to maintain the inner carrier pipe concentric with the outer jacket pipe. This assumption may not hold if the system is subjected to extreme bending. Table 3-1 of Section 3.5.3 summarizes the recommended inspection schedule.

5.6.3.4 Monitoring of External Corrosion

External corrosion for the outer jacket pipe would be controlled with a dual-layer FBE pipe coating and a sacrificial-anode cathodic protection system. The inner pipe would not have a cathodic protection system but would be coated. External corrosion of the inner steel pipe would also be controlled by the condition of the annulus, which must remain dry to maintain a non-corrosive environment. Monitoring of the condition of the external surface of the inner carrier pipe would be performed as part of the wall thickness pigging.

5.6.3.5 Pigging Schedule

The inner pipe of the pipe-in-pipe system is capable of being pigged, while the outer pipeline is not. A recommended pigging schedule is discussed in Section 3.5.3. This is a reasonable monitoring program for the inner carrier pipe of the pipe-in-pipe system.

5.6.3.6 Monitoring of Pipeline Expansion

Bulkheads would be installed at the two ends of the offshore section of the pipe-in-pipe system, and pipe-to-pipe spacers would be used at short intervals to force the two pipes to act as one. The island and the shore approaches would incorporate a thermal expansion loop designed to absorb the maximum expected thermal expansion.

The outer jacket pipe is at seabed temperature, while the inner carrier pipe is at the fluid temperature. The inner pipe tries to expand longitudinally but is resisted by the outer jacket pipe and the soil via the bulkheads at either end. The expansion of the pipe-in-pipe system would be less than for a single wall steel pipeline. Thermal expansion would be noted during routine visits to the surfacing point on the island and to the shore crossing.

5.6.3.7 Pipeline Shore Approach Geometry Survey

The pipe-in-pipe annulus would either be air-filled or have a partial vacuum. In either case, the annulus will insulate the outer pipe from the inner carrier, which acts as an insulator. This would reduce the thaw bulb under the pipeline system and is assumed to proportionately reduce thaw settlement. Geometry pigging of the pipeline would measure alignment changes in the offshore pipeline section.

5.6.4 Evaluation Criteria and Required Action

Evaluation criteria and remedial action are discussed in Section 3.5.4 and Table 3-2.

5.7 Repair

5.7.1 Assumptions and Definitions

General comments on repair assumptions and definitions are made in Section 3.6.1. Additional assumptions for the pipe-in-pipe system are:

- Both pipes would require a repair if there was a leak of the inner carrier pipe. It is assumed that an extreme event that ruptures the inner carrier pipe would also rupture the outer pipe. The exceptions are inner carrier pipe over-pressurization (highly unlikely) or corrosion. However, for these two exceptions, the outer pipe would need to be cut away in order to access the ruptured inner carrier pipe, and so subsequently would require a repair.
- If the outer pipe is damaged, but no damage is detected for the inner carrier pipe, the outer pipe must be repaired and the inner pipe inspected for possible damage in order to retain the system integrity.
- After a repair is completed, the annulus would need to be dewatered or inhibited to prevent corrosion. This process may be completed by continually drawing a vacuum on the annulus until it is dry.

5.7.1.1 Offshore Zoning

The offshore pipeline route is divided into zones, which are defined in Section 3.6.1. Those locations of the zones are the same for this option; however, the pipe-in-pipe trench configuration is shallower (5-foot depth of cover).

5.7.1.2 Types of Repair

Types of repair in Section 3.6.1 apply here as well. A larger pipe-in-pipe replacement section (>5 feet) would consist of the outer and inner pipe with spacers in the annulus. The inner carrier pipe would be longer than the outer pipe, with the ends of the inner pipe protruding from the outer pipe ends. This is so that the inner carrier pipe can easily be welded first and then patches or soles can be used to complete the outer pipe.

A smaller pipe-in-pipe replacement section (<5 feet) could consist of an inner carrier pipe with spacers on it and two outer pipe half soles or shells that are wrapped around the inner pipe and would have two arc welds and two length welds.

5.7.2 Repair Techniques

A review of repair techniques has been presented in Section 3.6.2. Variations from these techniques are presented below

5.7.2.1 Repair Technique Evaluation

This section highlights the main points associated with each of the six repair techniques. General comments are presented in Section 3.6.2. The review provides the basis for the recommended repair response for each zone and type of damage.

Welded Repair with Cofferdam

For this permanent repair, the total amount of backfill that would be removed is approximately 1,034 cubic yards, which is expected to take two to three days. The total time required for the repair is approximately 41 days, which includes mobilization and survey of damage. The repair includes the welding of both the inner and outer pipes. The outer pipe would require patches or half soles to complete its permanent weld configuration. This would reduce the integrity of the outer pipe.

Hyperbaric Weld Repair

For this permanent repair, the total amount of backfill that would be removed is approximately 1,034 cubic yards, which is expected to take three to four days. The total repair time is approximately 42 days. The outer pipe would require patches or half soles to complete its permanent weld configuration. This would reduce the integrity of the outer pipe.

Surface Tie-In Repair

For this permanent repair, the maximum estimated quantity of soil to be excavated to bring the pipe-in-pipe system to the surface is 8,500 cubic yards. Due to the increase in the pipe length after the repair, a layover area must be excavated to the original trench depth. This additional layover area will involve approximately 4,000 cubic yards of excavation. The outer pipe would require patches or half soles to complete its permanent weld configuration. This would reduce the integrity of the outer pipe. The total time for this type of repair is estimated to be 47 days, with 15 to 20 days of this time required for excavation.

Tow-Out of Replacement String

For this major repair with a 400-foot replacement pipe-in-pipe string, the maximum estimated quantity of soil to be excavated is 6,480 cubic yards. The required time for conducting a bottom tow of a replacement string is estimated to be 46 days. The outer pipe would require patches or half soles to complete its permanent weld configuration. This would reduce the integrity of the outer pipe.

5.7.2.2 Repair Technique Conclusions

Conclusions regarding repair techniques are discussed in Section 3.6.2. An additional consideration for the pipe-in-pipe system is that each of the repair techniques and equipment requirements increase the repair time when compared to a single pipe. For example, the alignment and welding for repair of the pipe-in-pipe system are estimated to take two to three times as long as the same repair for a single wall steel pipeline system.

5.7.3 Repair Scenarios

The previous section discussed the types of repairs with regard to the length of pipeline sections that need to be replaced. However, it does not explicitly relate the size of the repair to the potential damage scenario. The following four categories of damage scenarios are described in Section 4.7.3:

- Category 1: Displaced Pipeline
- Category 2: Buckle/No Leak
- Category 3: Small/Medium Leak
- Category 4: Large Leak/Rupture

The relationship between these categories and the causes and failure mechanisms is discussed in the section on failure assessment. Each of these damage categories may require a repair. Figure 5-8 summarizes the categories of damage and the types of repairs that would be implemented if required.

5.7.4 Recommended Repair Methods

Summer and winter repairs were discussed in Section 3.6.4. Details on which repairs can be conducted and when are presented in Figure 5-8. In generating this figure, the "earliest start dates" and "latest completion dates" have been used. The repair techniques for each category of damage are indicated by the notes.

5.8 Leak Detection Methods

5.8.1 Leak Detection for a Pipe-in-Pipe System

General evaluation and comments on leak detection are presented in Section 3.7. Leak detection for a pipe-in-pipe option would be achieved using two independent systems: the mass balance line pack compensation (MBLPC) system and the pressure point analysis (PPA) system. Conventional leak detection is usually achieved using one of these systems. However, because of the importance of leak detection, the Liberty system would include both independent systems. These systems would work in parallel, providing redundancy, and be able to detect leaks as small as approximately 0.15% of the volume of flow.

Supplemental leak detection options for a pipe-in-pipe option have also been considered to detect leakage below 0.15% of the volume of flow. Leak detection sensor technology could be applied to the exterior of the outer pipe or to the annulus between the two pipes, depending on the technology considered. The make-up of a pipe-in-pipe-system with no bulkheads is conducive to annulus monitoring by placing a sensor system in the annulus or by periodically monitoring the composition of the air in the annulus. The principle behind the operation of the LEOS system recommended for the single wall steel pipeline can be applied to the annulus of the pipe-in-pipe. Rather than sampling the air in the LEOS collection tube, the air in the annulus of the pipe can be extracted and tested for hydrocarbon vapor. It is assumed that the performance of this system would be as good as the LEOS system proposed for the single wall steel pipeline.

It is possible that if a vacuum system were used, it could also act as an indicator of a leak. If there were a leak in the internal pipe (below the threshold of 0.15%), oil would accumulate at low elevations of the pipe-in-pipe system formed by undulations in the pipe profile. This would result in a change in vacuum pressure once the annulus became flooded. Therefore, by measuring pressure at the vacuum pump, any changes may indicate a leak and flooding of the annulus. This would also be the case if the exterior pipe were to rupture and flood with water. The possibility of using the vacuum system to do this would need to be confirmed in the detailed design stage.

The MBLPC, PPA, and annulus monitoring system could be integrated into the supervisory control and data acquisition (SCADA) system, which would record all leak detection system parameters simultaneously. Combined, it is expected the systems would detect a large leak within 30 seconds and a small leak (less that 0.15% flow) within 24 hours. The assumed system performance does not account for the possibility that the pressure fluctuations in the vacuum could indicate a leak. Potential leak volumes and time to detection are discussed further in Section 5.9.

5.8.2 Factors Affecting Leak Detection Performance

Factors affecting leak detection performance are presented in Section 3.7.3. There are no major issues which would influence the performance of the mass balance and pressure point technologies. These technologies are well established in industry practice. If the integrity of the exterior pipe were lost, a portion of the annulus along the pipeline length would become flooded. This would affect the performance of the supplemental leak detection system and would require pipeline repair even though the integrity of the inner pipeline is still maintained.

5.9 Failure Assessment

5.9.1 Operational Failure Assessment

This section examines initiating events and their causes that may lead to an "incident of damage during operation" (IDO) for the pipe-in-pipe system. The likelihood of each initiating event is discussed below (see Figure 4-9 for a list of initiating events).

5.9.1.1 Seabed Ice Gouging, Initiating Event I1

For the pipe-in-pipe alternative, the depth of cover is 5 feet, compared to 7 feet for the single wall pipeline alternative. This increases the likelihood of fracture and a large leak to 10^{-5} occurrences per project lifetime for the pipe-in-pipe alternative. The probability of gouging could be reduced with deeper burial, but this would further increase costs for this alternative. This type of damage is assumed to happen when an ice gouge is as deep as the pipeline centerline, that is, 5.7 feet. Likelihood of this event is shown in the last row of Table 5-11, which is based on the equations presented in Section 4.9.1.

The four categories of damage are then considered in a manner similar to the analysis in Section 4.9.1. The resulting estimated damage frequencies for an ice gouge initiating event are shown in the first row of Table 5-12. Except for the displaced pipeline damage category, the frequencies have increased when compared to the single wall pipeline.

TABLE 5-11: PROBABILITY OF EXCEEDENCE OF ICE GOUGE DEPTH A LONG LIBERTY ALIGNMENT

D **(ft)**	***T*** **(years)**	***f*** **(1/year)**	**Exceedence Probability over 20-Years = Project Lifetime Damage Frequency**
1.59	100	10^{-2}	0.18
3.0 (design value)	3,600	3×10^{-4}	5×10^{-3}
4.0	48,000	2×10^{-5}	4×10^{-4}
5.7	3,700,000	3×10^{-7}	5×10^{-6}

5.9.1.2 Subsea Permafrost Thaw Subsidence, Initiating Event I2

In this case, the comparatively less backfill to push the pipe down and the higher pipeline system stiffness would make permafrost less likely to cause damage. Therefore, except for the displaced pipeline damage category and the large leak or rupture category, the frequencies have decreased one order of magnitude compared to the single wall pipeline.

5.9.1.3 Strudel Scour, Initiating Event I3

The slightly shallower depth of cover tends to slightly increase the probability of loading due to ice scour, but the stiffer pipe decreases the potential for damage. Therefore, the associated frequencies are the same as those of the single wall pipe system.

5.9.1.4 Upheaval Buckling, Initiating Event I4

This initiating event is less likely to happen for this pipe system compared to the single wall pipe alternative. The vertical resistance that can be generated by the larger pipe diameter moving through the backfill is larger. Also, there is a reduction in the locked-in compressive force and hence a reduction in the driving force. The estimated damage frequencies for upheaval buckling are less than for the single wall pipeline system (see Table 5-12).

5.9.1.5 Internal and External Pressure, Initiating Events I5 and I6

The frequencies for these initiating events are the same as those for a single wall pipeline system.

5.9.1.6 Inner Pipe Corrosion, Initiating Event I7

The potential corrosion of the inner pipe due to oil is considered extremely unlikely and is neglected. External corrosion of the inner pipe due to agents in the annulus is of concern since the inner pipe cannot be cathodically protected and the annulus must be free of corrosive agents. In addition, the integrity of the outer jacket cannot be monitored or inspected. Therefore, Category 3 damage (a small or medium leak into the annulus) is assigned a higher probability of occurrence compared to corrosion of the single wall pipeline.

5.9.1.7 Outer Pipe Corrosion, Initiating Event I8

The safeguards provided to mitigate against outer pipe corrosion are the external FBE coating, the cathodic protection system, and the low moisture content in the annulus. The potential for corrosion of the outer pipe would come from coating damage and from corrosive material in the annulus. Additionally, since the outer pipe cannot be inspected by pigs, an important safeguard is not available. Therefore, the estimated damage frequency in this case is 10^{-4}, which is higher than that for the single wall pipeline.

5.9.1.8 Vessel Accidents, Anchor Dragging, Third Party Construction, Sabotage; Initiating Events I9, I10, I11, I12

The frequencies for these initiating events are the same as those for a single wall pipeline system.

5.9.1.9 Summary

The damage frequency failure assessment is summarized in Table 5-12. The initiating events are defined as hazards to the pipeline.

The estimated frequency of an IDO in Category 1 (displaced pipeline) is 2% during the project lifetime; however, this type of damage is considered non-critical. Time is available to check and assess the damage and, if required, to initiate a planned repair without shutdown.

The second most frequent damage is buckles without leakage (Category 2). This damage is estimated at 0.1% for a project lifetime frequency. The frequencies for small, medium, or large leaks (Category 3 and Category 4) are small. However, these frequencies are higher when compared to the ones for the single wall pipeline. If desired, those frequencies could be lowered by increasing the depth of cover. The corresponding implications are discussed later in Chapter 9.

Table 5-13 shows, for each entry on Table 5-12 with frequency greater than 10^{-8}, when in the year the corresponding damage could occur. This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less severe events; this might result in a large leak or rupture during other times of year. Such an analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear.

TABLE 5-12: INITIATING EVENTS AND RESULTANT DAMAGE FREQUENCY PER CATEGORY

Underlying Main Cause for Initiating Event	**Initiating Event**	**Estimated Damage Frequency (Occurrences per Project Lifetime)**			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	10^{-3}	10^{-4}	10^{-5}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-5}	10^{-7}	10^{-8}
	Strudel Scour	10^{-3}	10^{-5}	10^{-7}	10^{-8}
Pipeline Failure	Upheaval Buckling	10^{-3}	10^{-5}	10^{-8}	10^{-8}
	Internal Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Inner Pipe Corrosion	10^{-8}	10^{-8}	10^{-4}	10^{-8}
	Outer Pipe Corrosion	10^{-8}	10^{-8}	10^{-4}	10^{-8}
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		**2×10^{-2}**	**1×10^{-3}**	**3×10^{-4}**	**1×10^{-5}**

TABLE 5-13: WHEN DAMAGE COULD BE REALIZED

Initiating Event	When Potential Damage Could Occur			
	Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Seabed Ice Gouging	June/July Oct./Nov.	Jun./Jul. Oct./Nov.	Oct./Nov.	Oct./Nov.
Subsea Permafrost	Any Time	Any Time	Any Time	-
Strudel Scour	May/June	May/June	May/June	-
Upheaval Buckling	Any Time	Any Time	-	-
Internal Pressure	-	-	-	-
External Pressure	-	-	-	-
Internal Corrosion	-	-	Any Time	-
External Corrosion	-	-	Any Time	-
Vessel Accidents	Any Time	-	-	-
Anchor Dragging	-	-	-	-
Third Party Construction	Any Time	-	-	-
Sabotage	-	-	-	-

5.9.2 Spill Scenarios

5.9.2.1 Potential Oil Loss

Leak detection options have been reviewed in Section 3.7. The recommended supplementary leak detection system for the pipe-in-pipe system is through annulus monitoring. As presented in Section 3.8.4, a guillotine break (Category 4 damage) could potentially yield a loss of 1,576 barrels of oil. Based on a medium (Category 3 damage) leak of 97.5 barrels per day, the volume of oil lost from the inner pipe during the reaction time of the annulus monitoring system would be 97.5 barrels (corresponding to a test time of 124 hours for the system). In total, a medium spill scenario might be expected to result in approximately 125 barrels of oil escaping from the inner pipe. A small chronic leak (Category 3 damage) is considered to be 1 barrel per day. Depending on the nature of the pipeline failure, the Category 3 damage may or may not result in oil entering the environment. Category 1 and Category 2 damage would not result in a spill. Table 5-14 summarizes the oil spills that would be associated with the different damage categories.

TABLE 5-14: DAMAGE CATEGORIES AND ASSOCIATED OIL SPILL VOLUMES AND FREQUENCY OF DAMAGE PREDICTIONS

Damage Category	Estimated Oil Spill Volume (bbls)	Estimated Damage Frequency During Project Life
1	0	2×10^{-2}
2	0	1×10^{-3}
3[1]	125	1×10^{-4}
3[2]	0	1×10^{-4}
3[3]	125	1×10^{-4}
4	1,576	1×10^{-5}

Notes: [1] Damage caused by corrosion of inner carrier pipe. Oil is contained by the outer jacket pipe.
[2] Damage caused by corrosion of outer pipe resulting in the ingress of seawater to the annulus.
[3] Damage caused by ice keel gouging resulting in release of oil to the environment.

5.9.2.2 Spill Scenarios

Spill scenarios are presented in Section 3.8.4. Response time, cleanup capability, cleanup options, environmental impact variables, effectiveness of cleanup, and system down time are discussed in Section 3.8.5.

As shown in Table 5-13, a leak due to Category 4 damage might be realized only in the fall (October-November) of the year. Initial freeze-up could occur the first week of October and ice movement would be expected to cease by about the middle of November, when the ice becomes landfast. During breakup in early July, the ice is assumed to be deteriorated and weak, and for the most part, would melt in place. Mechanical options might be considered for cleanup of a spill under broken ice, but the most effective strategy would likely involve in-situ burning. Satellite tracking would be used to monitor the drift of any oiled ice. If the oiled ice became landfast, conventional winter ice procedures might be used to recover the oil. Again referring to Table 5-13, a Category 3 damage scenario could happen any time of the year.

However, as pointed out previously, the joint likelihood of a combination of less severe events has not been examined during this study. Such a study may indicate that more damage windows are possible. Therefore, a response plan would need to be in place that can manage all damage in all seasons.

5.9.3 Cleanup and Repair

The Liberty Development will have an approved oil spill contingency plan demonstrating the capability to clean up an oil spill anytime of year. The volume of oil which could be handled would be significantly larger than anything expected from the pipe.

Cleanup strategies are presented in Section 3.8.5. As discussed above, Category 4 damage might be expected only in the fall, while Category 3 damage could occur any time of the year. Mechanical options might be considered for cleanup of a spill due to Category 4 damage under broken ice, but the most effective strategy would likely involve in-situ burning. If the oiled ice became landfast, conventional winter ice procedures might be used to recover the oil. In any event, cleanup would be carried out as quickly as possible to the satisfaction of Federal and State On-Scene Coordinators to minimize any impact on the environment.

The repair philosophy for the offshore section of the pipe-in-pipe option is presented in Section 5.7. The recommended methods of repair, which are dependent on the time of year and damage category, are shown in Figure 5-8. In the case of Category 3 damage, it is assumed the inner pipeline would have been purged and no further leakage would occur during repair. In the case of Category 4 damage, no secondary spill volume from the inner pipe would be expected, as precautions would have been taken to prevent any further loss during repair (e.g., plugging or purging the pipe). The risk of additional oil spill during repair is not considered further in this review.

During detailed design, consideration would need to be given as to how to extract oil or water from the annulus of the pipe-in-pipe system. Water, if left in place, may cause corrosion. Any oil left in the annulus could potentially leak out if the integrity of the outer pipe was lost.

6. SINGLE WALL STEEL PIPE INSIDE HDPE SLEEVE

This section presents the conceptual level design for a single wall, carbon steel pipeline, installed inside a plastic sleeve made of high-density polyethylene (HDPE). Section 6.1 is an executive summary for this system. The subsequent sections detail the conceptual design.

6.1 Introduction, Summary and Conclusions

6.1.1 Introduction

This pipeline system consists of a single wall steel pipe inside a protective HDPE sleeve. The size and grade of the steel pipe would be similar to the single wall steel pipe, which is a 12-inch nominal pipe size with 0.688-inch WT, grade X-52 steel. The HDPE sleeve would provide additional mechanical protection to the pipeline; however, it would not add to structural integrity.

This alternative would have no subsea valves or fittings, but flanges or bulkheads are typically required for structural integrity. This pipeline system (Figure 6-1) would be trenched and requires a minimum depth of cover to protect it against environmental loads such as ice gouge, strudel scour, and upheaval buckling.

Two basic sub-alternatives have been studied in connection with the pipe-in-HDPE pipeline system:

- Sub-alternative A: Inner pipe: X-52 steel pipe, 12.75-inch OD, 0.688-inch WT; annulus filled with polyurethane (PU) foam; HDPE sleeve: 15.25-inch OD, 0.25-inch WT.
- Sub-alternative B: Inner pipe: X-52 steel pipe, 12.75-inch OD, 0.688-inch WT; Air in annulus; HDPE sleeve: 16.25-inch OD, 0.75-inch WT.

There are some differences in the structural response of the two sub-alternatives with respect to environmental loads (Section 6.2).

The pipe-in-HDPE sub-alternative A would have a bond between the steel pipe and the HDPE sleeve via the PU foam. Therefore, the expansion of the inner steel pipe is resisted, resulting in a locked-in compressive force.

However, the HDPE jacket in sub-alternative B is not connected to the inner steel pipe. Therefore, the expansion of the inner steel pipe would be limited only by friction between the steel pipe and the HDPE pipe. The locked-in compressive force due to full restraint would occur only within a short section of pipeline midway between the island and the shore crossing. While this effect is beneficial with respect to bending, the total thermal expansion at Liberty Island and at the shore crossing is estimated to be 13 feet. Large expansion loops are required to safely accommodate this amount of expansion.

6.1.2 Summary

This section summarizes the structural analysis, construction plan, operations and maintenance, repair philosophy, costs, and failure analysis.

6.1.2.1 Structural Design Summary – Sub-alternative A

In this sub-alternative, PU foam fills the annulus between the steel inner pipe and the HDPE sleeve. This design safely resists the design environmental loads such as those caused by ice gouges, thaw settlement, and strudel scour; and gravel mats are not required to maintain vertical stability during operation.

6.1.2.2 Structural Design Summary – Sub-alternative B

In this sub-alternative, the annulus is empty (air-filled) and a 0.75-inch-thick HDPE sleeve surrounds the steel inner pipe. This sub-alternative safely resists the design environmental loads such as those caused by ice gouges, thaw settlement, and strudel scour, and gravel mats are not required to achieve vertical stability.

6.1.2.3 Sub-alternative Selection

While both sub-alternatives safely resist the design environmental loads, sub-alternative B, with a thicker HDPE outer jacket and air in the annulus, is selected for further review in this document due to slightly better structural behavior and a perceived comparatively easier installation. The remainder of this chapter will review this sub-alternative.

6.1.2.4 Construction Summary

The most suitable methodology for installing a pipe-in-HDPE system from the island to shore is a winter construction program consisting of conventional excavation equipment and off-ice pipe installation techniques. There is a low confidence level that this installation program could be completed in a single season.

6.1.2.5 Cost and Schedule Summary

The program for the overall construction of this alternative would target completing the construction in a single winter season between December and April. However, based on engineering judgment, it is likely that this program would not be completed in a single season. The likelihood of a single-season construction for this alternative is greater than for the pipe-in-pipe alternative but less than for the single wall pipe alternative. The estimated cost for the installation of the pipe-in-HDPE system is $44 million, including a contingency based on the level of confidence in completing this installation in a single season.

6.1.2.6 Operations and Maintenance Summary

The envisioned operations and maintenance program for the pipe-in-HDPE alternative uses available technology to monitor the condition of the pipeline. This program would monitor most of the design aspects that are considered to be gradual processes (for example, thaw settlement) and would allow mitigating steps to be taken in a timely manner if required. The program would also identify most events that have occurred between inspections and that did not impact the operation of the pipeline but may have affected the pipeline condition — for example, an ice keel passing over the pipeline. The program would not, however, identify mechanical damage of the outer jacket pipe.

6.1.2.7 Repair Summary

The pipe-in-HDPE system can be repaired to its original condition of full integrity during a summer or winter operation. Three permanent repair options are available.

For the localized damage categories, buckle/no leak (Category 2) and small/medium leak (Category 3), affecting less than a 40-foot length of pipe, the recommended permanent repair methods are:

- Summer: Cofferdam.
- Winter: Surface tie-in.

For damage categories that affect pipeline lengths greater than 40 feet, large leak/rupture (Category 4 damage), the recommended permanent repair methods are the same for both seasons:

- Summer: Tow out replacement string with a surface tie-in.
- Winter: Tow out replacement string with a surface tie-in.

6.1.2.8 Leak Detection System Summary

Leak detection for the pipe-in-HDPE alternative would be achieved using three independent systems: a mass balance line pack compensation (MBLPC) system, a pressure point analysis (PPA) system, and a supplemental system. The first two systems would work in parallel, providing redundancy, and would have an accuracy to detect leaks as small as 0.15% of the volume of flow. A supplemental leak detection system based on periodically monitoring for the presence of hydrocarbon vapors in the annulus would also be used to detect any leaks from the inner pipe that were below this threshold.

6.1.2.9 Failure Assessment Summary

Damage that does not result in loss of containment is summarized as Category 1 (large displacement) and Category 2 (cross-section buckle/without leak). Damage that does result in loss of primary containment is summarized as Category 3 (small or medium leak) and Category 4 (large leak/rupture).

It is estimated that a Category 1 "incident of damage during operation" (displaced pipeline) has a 3% probability of occurring during the project lifetime. This type of damage is non-critical, and time is available to check and assess the damage. A planned intervention, if required, could be initiated to correct the condition. Buckles without leakage (Category 2 damage) is estimated to have a 0.2% project lifetime frequency. Small or medium leaks are estimated to have a 0.1% project lifetime frequency.

A leak due to Category 4 damage (rupture or large leak) would be realized only during freeze-up, while a Category 3 damage scenario (small or medium leak) could happen at any time of the year. Oil pressure on the outer HDPE would depend on the nature of the leak and would need to be further assessed during detailed design. For any damage event, cleanup would be carried out. Additional consideration would need to be given to potential secondary spill volume from oil in the annulus during repair and to drying the annulus to prevent corrosion after repair.

This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less events; this might result in a large leak or rupture during other times of year. Such an analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear. Therefore, a response plan would need to be in place that could manage all damage in all seasons.

6.1.3 Conclusions

Both pipe-in-HDPE sub-alternatives would meet the functional requirements of flow and pressure for the Liberty Development. The structural analysis of the systems indicates that the overall structural response and installation requirements are slightly better for sub-alternative B for the same trench configuration. However, it should be noted that no cases are known where a buried pipe-in-HDPE system has been installed, given the likelihood of pipeline soil displacement such as that from ice keel gouging.

A configuration with a 6-foot depth of cover and native backfill has been judged adequate for design while optimizing other aspects such as constructability, operability or repairability.

Fabrication and installation of the pipe-in-HDPE alternative would be difficult due to the need to keep the pipes dry, the lack of skilled workforce for this type of installation, low pipe specific gravity, etc. However, the most suitable method for installing the system is a combination of conventional excavation equipment (backhoes with extended or long-reach booms) to excavate a trench through the ice. The pipeline string is then installed through the ice using techniques similar to overland construction. There would be a significant risk of damage to the HDPE sleeve during installation. It is unlikely that construction would be completed in a single season.

The estimated cost for the pipe-in-HDPE program is $44 million. This cost includes a partial contingency for a second season of construction as there is a low confidence level that this alternative could be fabricated and installed in a single winter season.

Available technology would be used to monitor the pipe as part of the operations and maintenance programs. The inner pipe would not be cathodically protected. The outer HDPE jacket cannot be monitored by wall thickness pigging or assessed for internal damage or deformation. Therefore, the integrity of the outer jacket cannot be monitored or inspected.

Leak detection would be achieved using mass balance line pack compensation (MBLPC) and pressure point analysis (PPA). These systems combined would be able to detect a leak greater than 0.15% of the volumetric flowrate. Supplemental leak detection technology is proposed to monitor the annulus of the pipe-in-HDPE system. Leaks from the inner pipe greater than 0.15% of the volumetric flowrate would be detected in minutes, while leaks lower than this threshold would be identified within 24 hours.

The probability of a leak from the pipe-in-HDPE system is small. The inner pipeline and outer sleeve can be repaired to full structural integrity during a summer or winter repair operation. However, the annulus may not be returned to its low moisture, non-corrosive condition. Procedures would need to be developed to manage the potential for a secondary spill volume from the annulus during repair and to try to achieve a dry annulus to prevent corrosion after repair. Manpower and equipment would be in place to successfully clean up any spill in the event of a leak.

6.2 Structural Design

6.2.1 Flow Analysis

General comments on the flow analysis have been made in Section 3.2.2. The combination of gravel backfill as thermal insulation and a –50°F ambient air temperature results in a Liberty Island inlet pressure of 1,276 psig and inlet temperature of 135°F, with a tie-in pressure of 1,050 psig and a tie-in temperature of 131.5°F.

6.2.2 Pipeline Installation Stability

General comments on pipeline installation stability are presented in Section 3.2.3. The configuration weights for the empty pipe-in-HDPE systems have been calculated and are summarized below in Table 6-1.

TABLE 6-1: EMPTY PIPE WEIGHTS

Parameter	Pipe-in-HDPE Sub-alternative A	Pipe-in-HDPE Sub-alternative B
Inner Pipe OD (inch)	12.75	12.75
Inner Pipe Wall Thickness (inch)	0.688	0.688
Outer Sleeve OD (inch)	15.25	16.25
Outer Pipe Wall Thickness (inch)	0.250	0.75
Weight in air (pounds/foot)	94.75	103.93
Submerged weight (pounds/foot)	13.57	11.75
Pipe SG (w.r.t. seawater)	1.17	1.13

Note: Pipeline weight includes nominal steel weight, outer sleeve, and annulus insulation.

The pipe-in-HDPE configuration has a specific gravity (with respect to seawater at 64.0 pounds per cubic foot) significantly less than 1.6. Under ideal conditions, a pipeline system would sink and be stable in the trench; however, in this case, the system specific gravity may be less than that of the soil/slurry mixture at the bottom of the trench. Installation procedures would need to be developed to manage the potential instability.

6.2.3 Ice Keel Gouging

General comments on ice keel gouging were made in Section 3.2.4. For the pipe-in-HDPE alternative, two cases have been evaluated. The 3.0-foot-deep, 30-foot-wide ice keel case is the loading event that imposes the greatest compressive strains on the pipeline systems. For tensile strains, the critical load cases vary as indicated in Table 6-2 and 6-3. For the critical compressive loading cases, Figures 6-2 and 6-3 show the soil displacement and the resulting pipeline movements. The corresponding strain distribution is shown in Figures 6-4 and 6-5.

TABLE 6-2: MAXIMUM STRAINS IN A PIPE-IN-HDPE SYSTEM (SUB-ALTERNATIVE A) FOR EXTREME ICE KEEL EVENTS

Ice Gouge Depth (ft)	Ice Gouge Width (ft)	Maximum Tensile Strain (%)	Maximum Compressive Strain (%)
3.0	30	0.29	1.09
3.0	40	0.21	0.76
3.0	50	0.21	0.80
3.0	60	0.30	0.82
Allowable Strains (%)		1.80	3.50

TABLE 6-3: MAXIMUM STRAINS IN A PIPE-IN-HDPE SYSTEM (SUB-ALTERNATIVE B) FOR EXTREME ICE KEEL EVENTS

Ice Gouge Depth (ft)	Ice Gouge Width (ft)	Maximum Tensile Strain (%)	Maximum Compressive Strain (%)
3.0	30	0.77	0.80
3.0	40	0.46	0.48
3.0	50	0.44	0.47
3.0	60	0.48	0.50
Allowable Strains (%)		1.80	3.50

Tables 6-2 and 6-3 show that the maximum strains in both systems are below the maximum allowable strains described in Section 2.11. Therefore, a 6.0-foot depth of cover is adequate for both pipe-in-HDPE sub-alternatives with respect to ice keel loading.

6.2.4 Upheaval Buckling

Upheaval buckling was discussed in Section 3.2.6. Upheaval buckling of the pipe-in-HDPE configuration for the Liberty Development can be resisted by the native backfill material. For a 1.5-foot prop height, the native backfill thickness required for sub-alternative A is approximately 5.8 feet. A prop height of 1.6 feet could be accommodated by 6 feet of backfill. By using select gravel with a density of 60 pounds per cubic foot, a thickness of 4.1 feet is sufficient to prevent upheaval buckling for an initial prop of 1.5

feet. Thus, it would be relatively easy to control upheaval buckling for either sub-alternative. Sub-alternative B would require slightly less backfill thickness.

The pipe-in-HDPE system is more resistant than a single wall pipeline to upheaval buckling as it has more soil to move vertically and has a reduced axial compressive force.

6.2.5 Thaw Settlement

General comments on thaw settlement were presented in Section 3.2.7. The design thaw settlement for the single wall steel pipeline was 1 foot (see Section 2.7.4). Using the pipeline system's thermal resistance, the external temperature of the pipe-in-HDPE system has been estimated. The thaw settlement was then estimated using linear interpolation of the 1-foot thaw settlement value for the single wall steel pipeline and the observed soil conditions. This assumes that the reduction in rate of thaw bulb growth will limit the amount of thaw-sensitive material that results in settlement. This results in an estimated design differential settlement of 0.43 feet. At this conceptual level, no specific pipe/soil interaction finite element analyses have been performed. Rather, since the maximum differential thaw settlement value of 0.43 feet is considerably smaller than soil displacements resulting from ice keel scour, the resulting pipeline strains would likely be smaller. Therefore, thaw-settlement-induced strains are expected to remain well within allowable strain levels.

6.2.6 Strudel Scour

General comments on strudel scour were presented in Section 3.2.8. At this conceptual level, no specific modeling of pipe/soil interaction through finite element analysis for strudel scour has been performed. However, for the small pipeline span expected, the resulting pipeline stresses would remain below allowable stress levels.

6.2.7 Cathodic Protection

The HDPE sleeve provides corrosion protection for the pipeline system as the inner steel pipe and annulus would remain dry. The exterior of the inner pipeline would be coated with a tough anticorrosion coating. During construction, care must be taken to prevent damage to the HDPE sleeve to ensure that the annulus will remain dry. Any damage to the sleeve must be repaired before the pipeline system is installed. The annulus of the pipe-in-HDPE system must be a non-corrosive environment (low moisture content) to prevent corrosion of the coated inner pipe. This is difficult to achieve and would require additional care be taken during construction and installation of the pipeline. Any residual moisture could be removed only by continually drawing a vacuum on the annulus. The inner pipe would be internally inspected with a smart pig to detect any internal or external corrosion.

6.3 Conceptual Design Selection

6.3.1 Structural Behavior Considerations

The structural behavior of sub-alternatives A and B is not the same due to the difference in “locked-in” compressive force (Table 6-4). With respect to upheaval buckling, Table 6-4 shows that sub-alternative A requires 6 feet of native backfill to stabilize the pipe in the presence of a 1.5-foot prop. Sub-alternative B requires no backfill at Liberty Island or at the shore crossing. Backfill requirements increase toward the central part of the offshore alignment to a maximum thickness of 6 feet.

Foam in the annulus gives sub-alternative slightly better thermal properties than sub-alternative B. Since the foam would introduce shear stresses between the steel pipe and the outer jacket, it would lock-in compressive forces in the inner pipe and decrease the amount of expansion at Liberty Island and the shore crossing.

TABLE 6-4: CONCEPTUAL DESIGN SUMMARY

Load Condition	Pipeline Sub-Alternative	
	A	B
Ice Keel Strain [% of allowable (-) = compressive (+) = tensile]	(-) 31% (+) 16%	(-) 23% (+) 43%
Upheaval Buckling [Backfill Characteristics]	6 feet of native backfill	6 feet of native backfill to no backfill required
Thaw Settlement	Better	OK
Strudel Scour Span	≈1 foot	≈1 foot
Expansion at Liberty Island and Shore Crossing	<4 feet	4 to 8 feet

The ice keel strains shown in Table 6-4 for sub-alternative B are all less than 50% of allowable strains for a 7-foot cover analysis. A maximum of 6 feet of native backfill is required to prevent the potential for upheaval buckling for sub-alternative B (only at the center of the offshore pipeline alignment). Therefore, it is judged at the preliminary engineering stage that sub-alternative B can be designed for a depth of cover of 6 feet.

This simplifies construction while maintaining structural integrity, but this result would need to be confirmed during detailed design.

6.3.2 Fabrication and Installation Considerations

Table 6-5 summarizes the major activities during pipeline installation and fabrication for each sub-alternative and ranks them. If the activity for the sub-alternative can be carried out with relative ease, it receives grade 3. If more effort is required, the sub-alternative receives grade 2, and if the activity is judged to require much more effort, the grade 1 is assigned. Therefore, the preferred alternative regarding installation and fabrication procedures, based on this high level review, is the one with the highest score.

TABLE 6-5: INSTALLATION/FABRICATION SUMMARY

Activity	Pipeline Sub-Alternative	
	A	B
Pipe Joint Preparation	2	3
Welding (Steel Pipe and Jacket)	2	3
Handling	2	3
Pipe Lay Into Trench	2	2
Backfilling Operations	2	3
Surviving Backfill Operations	3	3
Total Score	13	17

Some engineering judgement is involved for each score assigned in Table 6-5. For example, for sub-alternative A (with foam), each pipe joint would require the annulus be injected with foam after the inner pipe is welded, yielding a score of 2 for the “Pipe Joint Preparation” entry.

6.3.3 Sub-Alternative Selection

In summary, the previous sections show that the overall structural response and installation for sub-alternative B are slightly better than for A. Therefore, the pipe-in-HDPE system carried forward for further analysis is sub-alternative B: an air-filled annulus with a 0.75-inch-thick HDPE outer casing. The depth of cover selected is 6 feet.

6.4 Construction

General construction considerations have been discussed in Section 3.3, including trenching and installation. This section describes the most suitable method for the construction of the pipe-in-HDPE system. The configuration of the assumed pipe-in-HDPE alternative is summarized in Figure 6-6.

6.4.1 Installation Options

Offshore arctic pipeline installation options have been described in Sections 3.3.9 and 3.3.10 and apply to the pipe-in-HDPE alternative (except possibly reeling).

6.4.2 Construction Method

For the reasons outlined in Section 3.3.10, the most suitable method for installing a pipe-in-HDPE system for Liberty is to use conventional excavation equipment and off-ice pipe installation techniques. Winter trenching is described in Section 3.3.6 and winter installation in Section 3.3.9. The reasons for their selection are summarized below.

6.4.2.1 Trenching Method

Pre-excavating with conventional excavation equipment working from an ice-based platform is considered the most suitable method to dig a 10-foot trench. This conclusion is based on the same reasoning presented for the single wall steel pipe installation.

6.4.2.2 Pipeline Installation Method

As for the single wall pipe alternative, the use of a lay vessel is feasible; however, scheduling of the required pre-trenching and backfilling activities make this method unattractive. Another disadvantage for a pipe-in-HDPE installation is the need to prefabricate multiple joint sections (2 to 6 joints long) to be assembled on the lay vessel. If it is not possible to fuse the ends of the outer jacket pipe directly together, this connection would incorporate two half-shell pieces of HDPE pipe joined with circumferential and longitudinal extrusion welds. This type of joint would potentially not have the same integrity as a butt fusion weld between two pipe ends.

Reeling a pipe-in-HDPE system of this configuration may be difficult and may potentially not be feasible. Issues such as the ability to reel a pipe where the inner pipe is not restrained to be concentric with the outer pipe or the ability to straighten the HDPE pipe after plastically deforming the material may rule out reeling as a installation option.

A typical tow or pull method for installing the Liberty pipe-in-HDPE system would include:

- Pre-dredging the trench,
- Making up the pipe string either in one 6-mile segment or multiple segment lengths (for example, 1,000 feet long), and
- Pulling the complete pipeline into the trench or pulling the pipeline in stages (partial launch) of 1,000 feet at a time.

Pipeline bundle tow or pull methods are common for pipelines of this length where the submerged weight of the pipeline system is on the order of 10 pounds per foot. For the pipe-in-HDPE configuration, it is considered feasible to use this method. However, large towing and/or anchor handling vessels would not be able to operate along most of the Liberty pipeline route due to draft limitations. Backfilling activities could not be initiated until the complete pipeline was in place; therefore, all the backfill material would have to be temporarily stored until the pipeline installation is completed. The construction risk of keeping 6.14 miles of trench open and then installing the pipeline is considered to be too great to allow this installation method to be the preferred option.

Installation of the pipe-in-HDPE using off-ice techniques is considered feasible for the Liberty water depths and weight of the pipeline (104 pounds per foot dry weight, 12 pounds per foot submerged weight). This method is similar to onshore pipe-lowering techniques.

6.4.3 Installation Sequence

A description of a general installation sequence is presented in Section 3.3.10. Deviations from that sequence for the pipe-in-HDPE alternative are described below. Equipment requirements and production rates associated with each activity are summarized in the next section on construction costs.

6.4.3.1 Pipeline Fabrication and Installation

Pipeline fabrication and installation includes make-up site preparation, pipe string make-up, transport of strings, pipeline installation, and hydrostatic testing. The work involved for some of these activities is different from what was presented in Section 3.3.10, and these differences are described in the following text.

Mobilize Equipment, Material and Workforce

This activity is the same as presented in Section 3.3.10.

Ice Road Construction and Ice Thickening

This activity is the same as presented in Section 3.3.10.

Ice Slotting

This activity is the same as presented in Section 3.3.10.

Trenching

Trench productivity for the pipe-in-HDPE system would be similar to the productivity for the single wall pipe alternative. The target trench depth for the pipe-in-HDPE alternative is 10 feet compared with 10.5 feet for the single pipe alternative, resulting in a similar quantity of material to be excavated.

Temporary Storage Site Preparation

This activity is the same as presented in Section 3.3.10.

Pipe String Make-Up (Welding)

In addition to activities presented in Section 3.3.10, the stringing activities would also involve:

Make-Up of 1000-Foot Sections of 12-inch Pipeline: These activities would include:

- String pipe joints along the make-up site.
- Align and weld pipe joints.
- Non-destructive examination (NDE) with X-ray and ultrasonic equipment to ensure flaw sizes are smaller than those dictated by the limit strain design.
- Field joint coating of weld.

Pipe-in-HDPE Assembly: The envisioned assembly of the pipe-in-HDPE is different from the pipe-in-pipe assembly. Though this assembly could probably be carried out in a similar manner to the pipe-in-pipe, there are additional considerations associated with winching the inner pipe into the outer pipe for the pipe-in-HDPE assembly. For example, during the pipe-in-pipe assembly, the outer jacket pipe is set on trestles along its length to keep the outer jacket pipe stationary as the inner pipe is winched into it. These trestles keep it straight. To keep the outer jacket pipe from moving axially as the inner pipe is pulled in, it must be anchored at the winch end. This restraining method means that the outer pipe undergoes compressive loads during the pull-in of the 12-inch inner pipe. Applying the same methodology to the pipe-in-HDPE assembly would induce the same types of loading on the outer HDPE pipe. The ability of the HDPE to resist these compressive loads is not apparent, but it may prove difficult to restrict the induced axial loads within acceptable levels. Variations to this method could be used — for example, anchoring at the other end of the outer jacket pipe so that the loads transferred to the outer HDPE pipe are tensile rather than compressive. These variations may prove feasible. However, for the purpose of this conceptual review, the following assembly sequence is recommended to circumvent any of the axial load issues.

- Move a 1,000-foot section of the 12-inch inner carrier pipe to the assembly area.
- Place protective shelters over the majority of the 12-inch line and dry the external surface.
- Dry sections of the outer HDPE jacket, which could be between 40 and 160 feet in length, at one end of the covered area.
- Raise or hold the 12-inch inner carrier pipe to allow the outer HDPE jacket to slide over it.
- Slide the HDPE pipe over the 12-inch inner carrier pipe and move it to the opposite end.
- Move the first HDPE pipe section to within a few feet of the end of the 12-inch inner pipe string.
- Insert a temporary annulus seal at this end between the inner and outer pipe to ensure that the annulus is kept dry. This seal would be removed prior to tie-in.
- Slide the next section of HDPE pipe over the 12-inch inner carrier so that it is adjacent to the first section.
- Fuse together the two outer HDPE jacket pipes by induction-heating the ends until the HDPE material is molten and pushing the two outer jacket pipes together. The HDPE is then visually inspected; however, key parameters are monitored during the fusion process to assure the quality of the fusion joint.
- Repeat this process until 1,000 feet of the HDPE pipe is assembled over the 12-inch inner carrier.
- Approximately 2 to 3 feet of the 12-inch inner carrier pipe extends beyond the HDPE outer jacket pipe. Insert a temporary annulus seal to keep the annulus dry.
- Store the assembled pipe-in-HDPE section until it is to be pulled to the side of the trench for installation.

Pipe String Transport and Tie-in Welds

Pipe transport and tie-in of the inner pipe would be conducted in the same manner as for the pipe-in-pipe system.

On completion of the inner pipe weld and field joint, one option for joining the outer pipes would be to slide or pull the HDPE pipes together. To execute this operation, it may be feasible to develop a special external alignment clamp which has some form of hydraulic ram that could pull the two outer jacket pipes together for these length of pipe strings. The system would pull up to 1,000 feet of the outer jacket pipe over the inner 12-inch carrier pipe. The two outer jacket pipes would be aligned and then connected in the same manner as the HDPE at the pipeline stringing site. This is not a normal approach for the connection of outer jacket pipes. The standard approach would be to use a split-sleeve connection, but because of the requirement to maintain joint integrity and structural continuity, a direct tie-in fusion joint is the preferred solution.

Once the pipe-in-HDPE joint is completed, if an external leak detection system is to be bundled to the pipeline, it would also be attached at this stage.

Pipeline Installation

This section is the same as presented in Section 3.3.10.

Backfilling the Trench

Once the pipeline is installed in the trench, a survey of the pipeline's vertical configuration would be made to determine whether there were any "high points" (a 1.5-foot change in elevation over 100 feet) along the pipeline. If the vertical variation of the pipeline exceeded these tolerances, the minimum backfill thickness would be increased to greater than 6 feet. If the vertical variance is more severe, then some corrective action such as locally lowering the pipeline would be required. Gravel mounds placed over the pipe every 100 feet would probably be required to maintain the pipe stability during backfilling, given the low specific gravity of the pipe system.

Hydrostatic Testing and Smart Pigging

Depending on how regulatory requirements are interpreted, a hydrostatic pressure test of the pipe-in-HDPE system might include pressure testing of the inner pipe and the annulus to verify that the pressure criteria are met. Since the medium for hydrostatic testing would be water or a water/glycol mixture, this could not be practically achieved without leaving the annulus flooded at the conclusion of the test. However, an inert-gas pressure test of the annulus may be feasible to ensure the integrity of the outer sleeve.

Demobilize Equipment

This activity is the same as presented in Section 3.3.10.

6.4.4 Construction Considerations

General considerations regarding QA/QC, welding and NDE, and temporary storage of excavated material are presented in Section 3.3.10. The following sections present specific considerations associated with the construction sequence for the pipe-in-HDPE system.

6.4.4.1 Quality Assurance and Quality Control

General comments on QA/QC presented in Section 3.3.10 apply to the pipe-in-HDPE, with additional comments provided below. The quality assurance and quality control associated with the pipe-in-HDPE design allows most, but not all, key aspects to be inspected during installation and subsequently monitored during the operational life of the pipeline. With regard to construction, the additional key aspects of the design that should be measured are as follows:

- The HDPE line would be manufactured in a manner similar to that used for onshore gas transmission lines. The properties achieved by this standard process are considered acceptable for the pipe-in-HDPE pipe application.

- The fusion connection method for the HDPE pipe would also achieve the desired material properties using pre-qualified standard techniques. Additional qualification may be required for use in the Arctic.

- Non-destructive inspection methods would not be used for the HDPE pipe. However, as the outer jacket pipe is not the primary carrier of product or necessarily has to be designed for pressure containment, this is considered acceptable.

6.4.4.2 Fusion Jointing Machine

The standard machinery used to join HDPE pipes by a fusion process would have to be adapted for a pipe-in-HDPE system. The standard process requires that the facing unit and heating plate be lowered between the two pipes to be joined without obstruction. Since this is not possible when the inner pipe is present, the fusion jointing machine would need to be redesigned.

6.4.4.3 Requirement to Maintain Pipe Dry

The pipe-in-HDPE assembly sequence would maintain the annulus as dry as possible during construction to avoid corrosion in the annulus. Any residual moisture could be removed only by continually drawing a vacuum on the annulus. As with the pipe-in-pipe alternative, this would be difficult to accomplish. Alternatively, an inert fluid may be pumped into the annulus after construction.

6.4.4.4 Skilled Labor Force and Construction Equipment

The pipe-in-HDPE alternative would require a larger share of the available labor and equipment resources, but the labor force required for installation is considered available. The major construction components are identified in the next section on construction cost.

6.4.4.5 Ice Slot Maintenance During Pipeline Installation

The pipeline installation would closely follow the trenching spread in order to simplify trench spoils handling. The distance behind the trenching spread and the pipeline touchdown point would be approximately 1,200 feet, and this ice slot would have to be kept ice-free.

6.4.4.6 Equipment Required to Lower in Pipeline

It is estimated that four sidebooms would be required to lower the pipe-in-HDPE system from the ice surface to the trench bottom. However, getting the pipeline to touch the bottom of the trench may prove difficult. The low specific gravity of the pipeline (≈1.1) would make it difficult to ensure that the pipe-in-HDPE system would sink in the soil/slurry fluid at the bottom of the trench; the system may rest on top of the soil/slurry. Gravel mounds may be required to hold the pipeline in place (see Section 6.4.4.7 below), and construction procedures would need to be developed that could stabilize the pipeline and control its configuration during backfilling.

6.4.4.7 Backfilling

Backfilling native material over the pipe-in-HDPE pipe would be a very difficult operation. Dropping the backfill material from the ice surface through the water column would likely develop a dense slurry in the trench bottom. This slurry could have a specific gravity greater than that of the pipe-in-HDPE system causing the pipe to float. Additional stabilization would be required and possibly additional consideration to the placement of the backfill. It may be necessary to take steps such as installing gravel mounds at unit spacings — for example, every 100 feet — over the pipe-in-HDPE system prior to backfilling to hold the pipeline in place or placing the backfill using a backhoe and releasing the material only a few feet above the pipeline.

6.5 Construction Costs

The following section summarizes the basis for the order of magnitude costs required to install the pipe-in-HDPE alternative.

6.5.1 Construction Sequence

The pipeline construction sequence was presented in Section 3.4.1 and applies here with the following differences:

- HDPE Pipe Joints (Pipe-in-HDPE strings)
- Pipe-in-HDPE String Make-Up
  - Weld up 1,000-foot strings of inner pipe, cap and X-ray/UT.
  - Slot HDPE pipe strings onto inner pipe and slide down to other string.
- Pipe-in-HDPE String Field Joint
  - Remove temporary seals, align and weld inner pipe.
  - Pull HDPE pipe over inner pipe until the outer pipe is lined up (opposite end of inner pipe exposed).
  - Make HDPE pipe field joint.

6.5.2 Quantities and Rates of Progress

The following section presents the quantities and rate of progress of each activity for the pipe-in-HDPE alternative.

6.5.2.1 Mobilize Equipment and Material

See Section 3.4.2.

6.5.2.2 Ice Road Construction and Ice Thickening

See Section 3.4.2.

6.5.2.3 Ice Cutting and Slotting

See Section 3.4.2.

6.5.2.4 Trenching

The estimated trench excavation volumes for this alternative are shown in Table 6-6. The total volume is approximately 424,000 cubic yards based on a 10-foot-deep trench, 10 feet wide at the trench bottom. Side slopes of 2:1 are assumed for the 0- to 8-foot water depths and 3:1 for the remainder of the route. This target depth includes overexcavation to ensure the minimum depth of cover is achieved.

TABLE 6-6: TRENCHING VOLUMES

Water Depth (ft)	Trench Length (ft)	Trench Depth (ft)	Volume (yd^3)
0 – 8	14,877	10	165,300
8 – 18	12,473	10	184,785
18 – 22	4,964	10	73,541
		Total	**423,626**

Trench excavation is a critical operation requiring two to three spreads each consisting of backhoes, support bridges, spoils handling, spoils transport and survey equipment. Each trenching spread would work two shifts of 11.5 hours. The rate of progress and days to complete each zone are summarized in Table 6-7.

TABLE 6-7: TRENCHING RATES

Water Depth (ft)	Trench Length (ft)	Volume (yd^3)	Productivity (%)	Rate of Progress for Each Spread (ft/hr)	Number of Spreads	Time for Activity, 3 Spreads (days)
0 – 8	14,877	165,300	85	43	2	9
8 – 18	12,473	184,785	75	22	2	18
18 – 22	4,964	73,541	75	5	3	18
				Total		**45**

6.5.2.5 Pipe-in-HDPE Make-Up Site Preparation

It is assumed that the make-up site required for this activity would be similar to that required for the pipe-in-pipe alternative. Thus, the area used for this activity is 533,000 square yards and the preparation time is 47 days.

6.5.2.6 Pipe-in-HDPE String Make-Up

During this activity, 33 pipe-in-HDPE strings of 1,000 feet long each would be constructed for a total of approximately 808 welds of steel pipe and 808 connections for the HDPE pipe (assuming 40-foot pipe joints and 6.12 miles of inner and outer pipe).

It is estimated that a spread can progress at a rate of 50 welds per day for the 12-inch-diameter pipe and 50 welds per day for the 16-inch HDPE pipe. This rate of progress for the 16-inch HDPE pipe can be achieved using approximately 9 HDPE welding machines. Thus, all pipe string make-up activities could be completed in 34 days.

6.5.2.7 Pipe-in-HDPE String Transportation

Transporting the 33 pipe-in-HDPE strings from the pipeline make-up site to their locations along the Liberty pipeline route would require one spread consisting of sidebooms. It is estimated that a spread can transport the pipe strings to the side of the ice slot at an average rate of advance of 0.8 miles of pipe string per day for a total of 10 days.

6.5.2.8 Pipe-in-HDPE String Field-Joint Operations

It is estimated that 66 tie-in welds would be required (33 welds for 12-inch pipe and 33 welds for HDPE pipe). A rate of 3 welds per day is assumed for a duration of 22 days.

6.5.2.9 Pipeline Installation

The pipeline installation progress rate is theoretically faster than the trenching rate, and therefore, this activity would depend on the duration of trenching.

Pipeline installation would take 27 days (8 days for water depths of 0 to 8 feet and 13 days for water depths of 8 to 18 feet) to advance to the 18-foot isobath. The zone of 18 to 22 feet of water is assumed to be installed in 6 days because the trenching operations in this zone start before it is reached by the installation spread. An additional duration of 4 days is added for contingency to manage any flotation issues. It is estimated the total 6.12 miles of pipe-in-HDPE pipe installation would be performed in 37 days using one spread consisting of sidebooms and backhoes.

6.5.2.10 Backfilling

Native soil will be used as the main backfill material. All excavated material would be placed back in the trench even though the minimum backfill requirement is a maximum of 6 feet. This activity would require one spread consisting of loaders, a backhoe, spoil transport trucks, and dozers. The rate of progress of backfilling would be faster than the pipeline installation if the majority of the backfill can be placed by pushing it into the trench from the ice surface. However, if a significant portion of the material had to be placed by a backhoe to maintain the pipeline stability, then the production rate would be significantly reduced. For the cost estimate, this activity is assumed to be dictated by the duration of pipeline installation. It is estimated that this activity would be completed in 44 days.

6.5.2.11 Hydrostatic Testing

The hydrostatic pressure testing of the 12-inch carrier pipe is expected to be completed in 5 days.

6.5.2.12 Demobilization

It is estimated that it would take approximately 2 days for each activity to demobilize from the working area.

6.5.3 Schedule

The overall construction for a pipe-in-HDPE alternative for the Liberty project would be performed during the winter, from December to April. Construction during winter allows the use of conventional or adapted onshore construction equipment and techniques. The recommended schedule for the pipe-in-HDPE alternative is shown in Figure 6-7. There is a low confidence that this installation program will be completed in this time frame. Contingency has been added to the budgeted costs.

6.5.4 Cost Estimate Summary

The different activities associated with the construction of the Liberty offshore pipeline using the pipe-in-HDPE alternative are presented in Table 6-8. Activities, quantities and progression rates are shown together with the estimated cost for this alternative. As there is low confidence that the pipeline would be installed in a single season, a contingency cost is included to account for parts of additional expenditures for a two-season installation plus 10% of the estimate. Only part of the additional cost of a two-season construction program is included as contingency. This is to highlight the relative levels of confidence between completing the pipe-in-HDPE system and the pipe-in-pipe system in a single season (the pipe-in-pipe contingency includes the total additional cost for a two-season construction program). The total cost estimate of $44 million reflects the budgeted cost that would be estimated to complete this work.

TABLE 6-8: CONCEPTUAL COST ESTIMATE FOR THE PIPE-IN-HDPE SUB-ALTERNATIVE

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate (Thousand $/day)	Cost (Million $)
Mobilization	Lump Sum	1		3	1144.0	3.43
Ice Thickening and Road Construction	2.5 in/day	1	6.5 feet	47	84.0	3.95
Ice Cutting and Slotting	1000 feet/day	3	32,314 feet	11	29.0	0.96
Trenching	0 - 8 feet WD ---> 43 feet/hour/backhoe	2	165,300 cubic yards	9	60.0	6.48
	8 - 18 feet WD ---> 22 feet/hour/backhoe	2	184,785 cubic yards	18		
	18 - 22 feet WD ---> 5 feet/hour/backhoe	3	73,541 cubic yards	18		
Pipeline Make-Up Site Preparation	11,260 square yards/day	1	533,000 square yards	47	55.0	2.59
Pipe String Make-Up (Welding)	1) Steel Pipe ---> 50 welds/day 2) HDPE Pipe ---> 50 butt fusions/day	1	1) 808 welds/steel pipe 2) 808 connect/HDPE pipe	34	220.0	7.48
Pipe String Transportation	0.8 miles/day	1	33 Pipeline Strings	10	78.0	0.78
Pipe String Field Joint	1.5 complete tie-ins/day	1	1) 33 welds/steel pipe 2) 33 connect/HDPE pipe	22	31.0	0.68
Pipeline Installation		1	32,314 feet	37	43.0	1.59
Backfilling	1,600 feet/day	1	32,314 feet	44	42.0	1.85
Hydrostatic Testing	Lump Sum	1		5	84.0	0.42
Demobilization	Lump Sum	1		2	1144.0	2.29
Material Cost and Transportation	Lump Sum	1				3.33
Contingency	10%	1				3.6
	A portion of costs for second season	1				5.0
					Total	**44**

6.6 Operations and Maintenance

This section presents an operational and maintenance philosophy for the offshore section of the Liberty pipe-in-HDPE system. Table 6-9 summarizes the relationship between the pipeline design aspects and the operations and maintenance activities.

TABLE 6-9: RELATIONSHIP BETWEEN OPERATIONS AND MAINTENANCE AND THE DESIGN

Tasks	Design Aspects	
Operations	**Steel Inner Carrier Pipe**	**HDPE Outer Jacket Pipe**
Monitoring of Flow	- Internal Leak Detection	- NA
	- Custody Transfer	- NA
External Offshore Route Survey	- Trench Configuration	- Trench Configuration
	- Ice Keel Event	- Ice Keel Event
	- Strudel Scour Event	- Strudel Scour Event
Shoreline Erosion	- Shore Crossing Design	- Shore Crossing Design
	- Trench Configuration	- Trench Configuration
Maintenance	**Steel Inner Carrier Pipe**	**HDPE Outer Jacket Pipe**
Cathodic Protection	- NA	- NA
Wall Thickness and Internal Damage	- Pipeline Corrosion (Internal)	- NA
	- Pipeline Wall Thickness	- NA
Pipeline Configuration	- Trench Configuration	- Trench Configuration*
	- Ice Keel Event	- Ice Keel Event*
	- Strudel Scour Event	- Strudel Scour Event*
	- Thaw Settlement	- Thaw Settlement*
	- Thermal Expansion	- Thermal Expansion*
	- Upheaval Buckling	- Upheaval Buckling*
External Corrosion	- Pipeline Corrosion (External)	- NA
Pipeline Expansion	- Thermal Expansion	- Thermal Expansion
Pipeline Shore Approach Geometry Survey	- Thaw Settlement	- Thaw Settlement*

Note: * The outer HDPE pipe is assumed to have a similar configuration as the inner steel pipe.

6.6.1 Operation

General comments on operation are presented in Section 3.5.1.

6.6.2 Pipeline Inspection

General comments on pipeline inspection are provided in Section 3.5.2.

6.6.3 Maintenance

General comments on maintenance are provided in Section 3.5.3. Differences related to the pipe-in-HDPE system are presented below.

6.6.3.1 Monitoring of Cathodic Protection

The Liberty pipe-in-HDPE system would not have a cathodic protection system, since the HDPE pipe is a non-corrosive material. The annulus of the pipe-in-HDPE system must be maintained as a non-corrosive or inert environment (low moisture content) to prevent corrosion of the inner pipe. Therefore, a system may need to be implemented for checking the moisture content of the annulus. The inner carrier pipe would be coated with a durable anti-corrosion coating. However, if the coating were to be damaged or break down, then the only protection against external corrosion is maintaining a non-corrosive or inert environment.

6.6.3.2 Monitoring of Inner Pipe Wall Thickness (Corrosion) and Damage

The wall thickness of the inner carrier pipe would be monitored and assessed for any corrosion, denting or deformations at periodic intervals listed in Table 3-1 of Section 3.5.3. The outer HDPE jacket cannot be monitored by wall thickness pigging or assessed for internal damage or deformation.

6.6.3.3 Monitoring of Pipeline Configuration

The pipeline’s geometry would be monitored by inspection pigging the inner carrier steel pipe and comparing it to the baseline measurement of its as-built configuration. Since spacers would not be used, the inner carrier steel pipe and the outer HDPE pipe configurations would be similar but not exactly the same. However, the strain criteria for the two different pipes are not the same. If the inner steel carrier pipe is determined to have a 1% strain, the HDPE would be assumed to have a strain of approximately 1.3%. This may be an underestimate. The curvature of the inner pipe may be smaller than the outer because no spacers are present; however, the potential underestimate of strain will be within an order of magnitude. The failure strain for HDPE pipe is approximately 50 times that of steel. Therefore, for any expected event, the strains in the outer HDPE pipe would be a smaller percentage of the failure limit state. Table 3-1 in Section 3.5.3 summarizes the recommended inspection schedule.

6.6.3.4 Monitoring of External Corrosion

External corrosion for the inner steel pipe would be controlled by the condition of the annulus, which must remain dry to maintain a non-corrosive environment. The inner steel pipe would not have a cathodic protection system but would be coated. Monitoring of the condition of the external surface of the inner steel pipe would be performed as part of the wall thickness pigging. The outer HDPE jacket is non-corrosive.

6.6.3.5 Pigging Schedule

The inner pipe of the pipe-in-HDPE system is capable of being pigged, while the outer jacket is not. A recommended pigging schedule is discussed in Section 3.5.3. This is a reasonable monitoring program for the inner pipe of the pipe-in-HDPE system.

6.6.3.6 Monitoring of Pipeline Expansion

For the pipe-in-HDPE system, the inner steel carrier pipe is independent of the outer HDPE pipe. The thermal expansion of the HDPE pipe would be limited by the frictional effects of the soil backfill; however, the inner steel carrier pipe is free to expand. The island and shore approaches would incorporate a thermal expansion loop designed to absorb the maximum expected thermal expansion. The outer HDPE pipe would terminate before the pipeline expansion loops, since the two pipes would be independent of each other. Given the larger thermal expansion by the inner steel pipe and the need to terminate the HDPE sleeve before the expansion loop, a pull tube type approach at both the island and the shore crossing would be required for the pipe-in-HDPE system.

The thermal expansion of the inner carrier would be much larger than for the single wall steel pipeline system. Thermal expansion would be noted during periodic visits to the surfacing point on the island and the shore crossing.

6.6.3.7 Pipeline Shore Approach Geometry Survey

The pipe-in-HDPE annulus would either be air-filled or have a partial vacuum. In either case, the outer annulus will insulate the other pipe from the inner carrier. This would reduce the thaw bulb under the pipeline system and is assumed to proportionately reduce thaw settlement. Geometry pigging of the pipeline would measure alignment changes in the offshore pipeline section.

6.6.4 Evaluation Criteria and Required Action

Evaluation criteria and remedial action are discussed in Section 3.5.4 and Table 3-2.

6.7 Repair

6.7.1 Assumptions and Definitions

General comments on repair assumptions and definitions are made in Section 3.6.1. Additional assumptions for the pipe-in-HDPE system are:

- Both pipes would require a repair if there was a leak of the inner carrier pipe. It is assumed that an extreme event that ruptures the inner carrier pipe would also rupture the outer pipe. The exception is corrosion of the inner carrier pipe. However, for this exception, the outer pipe would need to be cut away in order to access the damaged inner carrier pipe, and so would require a repair.
- If the outer pipe is damaged, but no damage is detected for the inner carrier pipe, the outer pipe must be repaired and the inner pipe inspected for possible damage in order to retain system integrity.
- After a repair is completed, the annulus would need to be dewatered or inhibited to prevent external corrosion of the inner pipe. This process may be completed by continually drawing a vacuum on the annulus.

6.7.1.1 Offshore Zoning

The offshore pipeline route is divided into zones, which are defined in Section 3.6.1. Those locations of the zones are the same for this option; however, the pipe-in-HDPE trench configuration is shallower (6-foot depth of cover).

6.7.1.2 Types of Repair

The types of repair were presented in Section 3.6.1. Minor damage is considered to be localized to a pipeline system segment of 40 feet or less to the outer HDPE. The inner carrier pipe may either remain structurally sound or be damaged to the extent that a short replacement segment is necessary. A pipe-in-HDPE replacement section would consist of the outer and inner pipe with no spacers in the annulus. Since the inner carrier pipe would be longer than the outer pipe, the ends of the inner pipe would protrude. Thus, the inner carrier pipe can be welded first and then half shells used to complete the outer pipe.

6.7.2 Repair Techniques

A review of repair techniques has been presented in Section 3.6.2. Variations from these techniques are presented below.

Applicable repair methods for the pipe-in-HDPE, described in detail in Appendix E, are:

- Welded repair with cofferdam,
- Surface repair, and
- Tow-out of a replacement string.

6.7.2.1 Repair Technique Evaluation

This section highlights the main points associated with each of the three repair techniques. General comments are presented in Section 3.6.2. The review provides the basis for the recommended repair for each zone and type of damage.

Welded Repair with Cofferdam

For this permanent repair, the total amount of backfill that would be removed is approximately 1,150 cubic yards, which is expected to take two to three days. The total time required for the repair is approximately 37 days, which includes mobilization and survey of damage. The repair includes the welding of the inner pipe and fusion (or welding) of the outer HDPE pipe. It is noted that the outer HDPE pipe would require half shells to complete its permanent fused configuration. This would not reduce the integrity of the outer HDPE pipe.

Surface Tie-in Repair

For this permanent repair, the maximum estimated quantity of soil to be excavated to bring the pipe-in-HDPE system to the surface is 6,490 cubic yards. Due to the increase in the pipe length after the repair, a layover area must be excavated to the original trench depth. This additional layover area will involve approximately 3,150 cubic yards of excavation. The outer HDPE pipe would require half shells to complete its permanent fused configuration. This would not reduce the integrity of the outer HDPE pipe. The total time for this type of repair is estimated to be 39 days, with 10 to 15 days of this time required for excavation.

Tow-Out of Replacement String

For this type of major repair with a 400-foot replacement pipe-in-HDPE string, the maximum estimated quantity of soil to be excavated is 6,480 cubic yards. The required time for conducting a bottom tow of a replacement string is estimated to be 42 days. The outer HDPE pipe would require half shells to complete its permanent fused configuration. This would not reduce the integrity of the outer HDPE pipe.

6.7.2.2 Repair Technique Conclusions

Conclusions regarding repair techniques are discussed in Section 3.6.2. Additional considerations for the pipe-in-HDPE system are summarized below.

Permanently repairing the HDPE pipe is completed by either butt fusion, electrofusion, or extrusion welding. Each of these processes is simple, and the end result is a fusion or welded joint which vendors claim is stronger than the HDPE pipe itself.

For the pipe-in-HDPE system, each of the repair techniques and equipment requirements increases the repair time compared to the repair of a single pipe. For example, the alignment and welding for repair of the pipe-in-HDPE system is estimated to take about 1.5 times as long as the same repair for a single wall steel pipeline system.

6.7.3 Repair Scenarios

The previous section discussed the types of repairs with regard to the length of pipeline sections that need to be replaced. However, it does not explicitly relate the size of the repair to the potential damage scenario. The following four categories of damage scenarios are described in Section 4.7.3:

- Category 1: Displaced Pipeline
- Category 2: Buckle/No Leak
- Category 3: Small/Medium Leak
- Category 4: Large Leak/Rupture

The relationship between these categories and the causes and failure mechanisms is discussed in the section on failure assessment. Each of these damage categories may require a repair. Figure 6-8 summarizes the categories of damage and the types of repairs that would be implemented if required.

6.7.4 Recommended Repair Methods

Summer and winter repairs were discussed in Section 3.6.4. Details on which repairs can be conducted and when are presented in Figure 6-8. In generating this figure, the "earliest start dates" and "latest completion dates" have been used. The repair techniques for each category of damage are indicated by the notes.

6.8 Leak Detection Methods

6.8.1 Leak Detection for a Pipe-in-HDPE Sleeve System

General evaluation and comments on leak detection are presented in Section 3.7. Leak detection for a pipe-in-HDPE alternative would be achieved using two independent systems: the mass balance line pack compensation (MBLPC) system and the pressure point analysis (PPA) system. Conventional leak detection is usually achieved using one of these systems. However, because of the importance of leak detection, the Liberty system would include both independent systems. These systems would work in parallel, providing redundancy, and be able to detect leaks as small as approximately 0.15% of the volume of flow.

Supplemental leak detection options for a pipe-in-HDPE alternative have also been considered. Like the pipe-in-pipe system, the make-up of a pipe-in-HDPE system with no bulkheads is conducive to annulus monitoring by placing a sensor system in the annulus or by periodically monitoring the composition of the air in the annulus. The principle behind the operation of the LEOS system selected for the single wall steel pipeline can be applied to the annulus of the pipe-in-HDPE. Rather than sampling the air in the LEOS collection tube, the air in the annulus of the pipe-in-HDPE can be extracted and tested for hydrocarbon vapor. It is assumed that the performance of this system would be as good as the LEOS system proposed for the single wall steel pipeline.

It is possible that if a vacuum system were used, it could also act as an indicator of a leak. If there were a leak in the internal pipe (below the proposed threshold of 0.15%), oil would accumulate at the low elevations due to undulations in the pipe profile. This would result in a change in vacuum pressure once the annulus became flooded. Therefore, by measuring pressure at the vacuum pump, any changes may indicate a leak and flooding of the annulus. This would also be the case if the HDPE sleeve were to rupture and flood with water. The possibility of using the vacuum system to do this would need to be confirmed in the detailed design stage.

The MBLPC, PPA, and annulus monitoring system could be integrated into the supervisory control and data acquisition (SCADA) system, which would record all leak detection system parameters simultaneously. Combined, it is expected the systems would detect a large leak within 30 seconds and a small leak (less that 0.15% flow) within 24 hours. The assumed system performance does not account for the possibility that the pressure fluctuations in the vacuum could indicate a leak. Leak volumes and time to detection are discussed further in Section 6.9.

6.8.2 Factors Affecting Leak Detection Performance

Factors affecting leak detection performance are presented in Section 3.7.3. There are no major issues which would influence the performance of the mass balance and pressure point technologies. These technologies are well established in industry practice. If the integrity of the HDPE sleeve were lost, a portion of the annulus along the pipeline length would become flooded. This would affect the performance of the supplemental leak detection system and would require pipeline repair even though the integrity of the inner pipeline is still maintained.

6.9 Failure Assessment

6.9.1 Operational Failure Assessment

This section examines initiating events and their causes that may lead to an "incident of damage during operation" (IDO) for the pipe-in-HDPE system. The likelihood of each initiating event is discussed below (see Figure 4-9 for a list of initiating events).

6.9.1.1 Seabed Ice Gouging, Initiating Event I1

For the pipe-in-HDPE alternative, the depth of cover is 6 feet, compared to 7 feet for the single wall pipeline alternative. This increases slightly the likelihood of a large leak and fracture (Category 4 damage) for the pipe-in-HDPE alternative. This type of damage is assumed to happen when an ice gouge is as deep as the pipeline centerline, that is, 6.7 feet. The likelihood of this event is shown in the last row of Table 6-10, which is based on the equations presented in Section 4.9.1.

The four categories of damage are then considered in a manner similar to the analysis in Section 4.9.1. The resulting estimated damage frequencies for an ice gouge initiating event are shown in the first row of Table 6-8. Except for the displaced pipeline damage category, the frequencies have increased compared to the single wall pipeline.

TABLE 6-10: PROBABILITY OF EXCEEDENCE OF ICE GOUGE DEPTH ALONG LIBERTY ALIGNMENT

d **(ft)**	***T*** **(years)**	***f*** **(1/year)**	**Exceedence Probability over 20-Years = Project Lifetime Damage Frequency**
1.59	100	10^{-2}	0.18
3.0 (design value)	3,600	3×10^{-4}	5×10^{-3}
4.0	48,000	2×10^{-5}	4×10^{-4}
5.0	621,000	2×10^{-6}	3×10^{-5}
6.7	48,000,000	2×10^{-8}	4×10^{-7}

6.9.1.2 Subsea Permafrost Thaw Subsidence, Initiating Event I2

In this case, there is less backfill to push the pipe down as compared to the single wall steel pipeline. This would make permafrost less likely to cause damage. Therefore, except for the displaced pipeline damage category and the large leak or rupture category, the frequencies have decreased one order of magnitude compared to the single wall pipeline.

6.9.1.3 Strudel Scour, Initiating Event I3

The shallower depth of cover tends to slightly increase the probability of loading due to strudel scour. The outer jacket is not as strong as steel. Therefore, the associated damage frequencies are higher than those of the single wall pipe system (see Table 6-11).

6.9.1.4 Upheaval Buckling, Initiating Event I4

This initiating event is less likely to happen for this pipe system compared to the single wall pipe alternative. The vertical resistance that can be generated by the larger pipe diameter moving through the backfill is larger. Also, there is a reduction in the locked-in axial compression force and hence a reduction in the driving force. The estimated damage frequencies for upheaval buckling are less than for the single wall pipeline system (see Table 6-11).

6.9.1.5 Internal and External Pressure, Initiating Events I5 and I6

The frequencies for these initiating events remain unchanged from those estimated for a single wall pipeline system.

6.9.1.6 Inner Pipe Corrosion, Initiating Event I7

The potential corrosion of the inner steel pipe due to oil is considered extremely unlikely and is not considered. External corrosion of the inner pipe due to agents in the annulus is of concern since the inner pipe cannot be cathodically protected and the annulus must be free of corrosive agents. In addition, the integrity of the outer jacket cannot be monitored or inspected. Therefore, Category 3 damage (a small or medium leak into the annulus) is assigned a higher probability of occurrence compared to the internal corrosion of a single wall pipeline. This probability of occurrence is also greater than that of the pipe-in-pipe system, because the integrity of the outer steel pipe is greater than HDPE, which is more likely to allow moisture into the annulus.

6.9.1.7 Outer Pipe Corrosion, Initiating Event I8

This is not applicable in this system.

6.9.1.8 Vessel Accidents, Anchor Dragging, Third Party Construction, Sabotage; Initiating Events I9, I10, I11, I12

The frequencies for these initiating events remain unchanged from those for a single wall pipeline system.

6.9.1.9 Summary

The damage frequency failure assessment is summarized in Table 6-11. The initiating events are defined as hazards to the pipeline.

The estimated frequency of an IDO in Category 1 (displaced pipeline) is 3% during project lifetime; however, this type of damage is considered non-critical. Time is available to check and assess the damage and if required, to initiate a planned repair**.**

The second most frequent damage is buckles without leakage (Category 2). This damage is estimated at 0.2% project lifetime frequency. The frequency for a small or medium leak (Category 3) is estimated to be 0.1%, and the estimated frequency for large leaks (Category 4) is very small (10^{-6}).

Table 6-12 shows, for each entry of Table 6-11 with a frequency greater than 10^{-8}, when in the year the corresponding damage could occur. This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less severe events; this might result in a large leak or rupture during other times of year. Such an analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear.

TABLE 6-11: INITIATING EVENTS AND RESULTANT DAMAGE FREQUENCY PER CATEGORY

Underlying Main Cause for Initiating Event	Initiating Event	Estimated Damage Frequency (Occurrences per Project Lifetime)			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	10^{-3}	10^{-4}	10^{-6}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-5}	10^{-7}	10^{-8}
	Strudel Scour	10^{-2}	10^{-3}	10^{-5}	10^{-7}
Pipeline Failure	Upheaval Buckling	10^{-3}	10^{-4}	10^{-6}	10^{-8}
	Internal Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Inner Pipe Corrosion	10^{-8}	10^{-8}	10^{-3}	10^{-8}
	Outer Pipe Corrosion	-	-	-	-
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		**3×10^{-2}**	**2×10^{-3}**	**1.1×10^{-3}**	**1×10^{-6}**

TABLE 6-12: WHEN DAMAGE COULD BE REALIZED

Initiating Event	When Potential Damage Could Occur			
	Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Seabed Ice Gouging	June/July Oct./Nov.	June/July Oct./Nov.	Oct./Nov.	Oct./Nov.
Subsea Permafrost Thaw Subsidence	Any Time	Any Time	Any Time	-
Strudel Scour	May/June	May/June	May/June	-
Upheaval Buckling	Any Time	Any Time	-	-
Internal Pressure	-	-	-	-
External Pressure	-	-	-	-
Internal Corrosion	-	-	Any Time	-
External Corrosion	-	-	-	-
Vessel Accidents	Any Time	-	-	-
Anchor Dragging	-	-	-	-
Third Party Construction	Any Time	-	-	-
Sabotage	-	-	-	-

6.9.2 Spill Scenarios

6.9.2.1 Potential Oil Loss

Leak detection options have been reviewed in Section 3.7. The recommended supplementary leak detection system for the pipe-in-HDPE system is through annulus monitoring. As presented earlier in Section 3.8.4, a guillotine break (Category 4 damage) could potentially yield a loss of 1,576 barrels of oil. Based on a medium (Category 3 damage) leak of 97.5 barrels per day, the volume of oil lost from the inner pipe during the reaction time of the annulus monitoring system would be 97.5 barrels (corresponding to a test time of 24 hours for the system). In total, a medium spill scenario might be expected to result in approximately 125 barrels of oil escaping from the inner pipe. A small chronic leak (Category 3 damage) is considered to be 1 barrel per day. Depending on the nature of the pipeline failure, the Category 3 damage may or may not result in oil entering the environment. Category 1 and Category 2 damage would not result in a spill. Table 6-13 summarizes the oil spills that would be associated with the different damage categories.

TABLE 6-13: DAMAGE CATEGORIES AND ASSOCIATED OIL SPILL VOLUMES AND FREQUENCY OF DAMAGE PREDICTIONS

Damage Category	Estimated Oil Spill Volume (bbls)	Estimated Damage Frequency During Project Life
1	0	3×10^{-2}
2	0	2×10^{-3}
3[1]	125	1×10^{-3}
3[2]	125	1×10^{-4}
4	1,576	1×10^{-6}

Note: [1] Damage caused by internal corrosion of inner carrier pipe. Oil is contained by the outer HDPE pipe.

[2] Damage caused by ice keel gouging resulting in release of oil to the environment.

6.9.2.2 Spill Scenarios

Spill scenarios are presented in Section 3.8.4. Response time, cleanup capability, cleanup options, environmental impact variables, effectiveness of cleanup, and system down time are discussed in Section 3.8.5.

As shown in Table 6-12, a leak due to Category 4 damage might be realized only in the fall (October-November) of the year. Initial freeze-up could occur the first week of October and ice movement would be expected to cease by about the middle of November when the ice becomes landfast. During breakup in early July, the ice is assumed to be deteriorated and weak, and for the most part, would melt in place. Mechanical options might be considered for cleanup of a spill under broken ice but the most effective strategy would likely involve in-situ burning. Satellite tracking would be used to monitor the drift of any oiled ice. If the oiled ice became landfast, conventional winter ice procedures might be used to recover the oil. Again referring to Table 6-12, a Category 3 damage scenario could happen any time of the year.

However, as pointed out previously, the joint likelihood of a combination of less severe events has not been examined during this study. Such a study may indicate that more damage windows are possible. Therefore, a response plan would need to be in place that can manage all damage in all seasons.

6.9.3 Cleanup and Repair

The Liberty Development will have an approved oil spill contingency plan demonstrating the capability to clean up an oil spill anytime of year. The volume of oil which could be handled would be significantly larger than anything expected from the pipe.

Cleanup strategies are presented in Section 3.8.5. As discussed above, Category 4 damage might be expected only in the fall, while Category 3 damage could occur any time of the year. Mechanical options might be considered for cleanup of a spill due to Category 4 damage under broken ice, but the most effective strategy would likely involve in-situ burning. If the oiled ice became landfast, conventional winter ice procedures might be used to recover the oil. In any event, cleanup would be carried out as quickly as possible to the satisfaction of Federal and State On-Scene Coordinators to minimize any impact on the environment.

The repair philosophy for the offshore section of the pipe-in-HDPE alternative is presented in Section 6.7. The recommended methods of repair, which are dependent on the time of year and damage category, are shown in Figure 6-8. In the case of Category 3 damage, it is assumed the inner pipeline would have been purged and no further leakage would occur during repair. In the case of Category 4 damage, no secondary spill volume from the inner pipe would be expected, as precautions would have been taken to prevent any further loss during repair (e.g., plugging or purging the pipe). The risk of additional oil spill during repair is not considered further in this review.

During detailed design, consideration would need to be given as to how to extract oil or water from the annulus of the pipe-in-HDPE system. Water, if left in place, may cause corrosion of the inner pipe. Any oil left in the annulus could potentially leak out if the integrity of the outer HDPE sleeve was lost.

7. FLEXIBLE PIPE SYSTEM

This section presents the conceptual level design for a flexible pipe system. Section 7.1 is an executive summary of this system. The subsequent sections detail the conceptual design.

7.1 Introduction, Summary and Conclusions

7.1.1 Introduction

Flexible pipe is a non-bonded pipe made of thermoplastic layers and steel strips. The thermoplastic layers provide containment for internal and external fluids and transmit pressure loads to the steel layers. The steel layers provide mechanical resistance to internal and external loads. A typical cross-section of a flexible pipe is presented in Figures 7-1 and 7-2.

A potential flexible pipe configuration for the Liberty Development would have a 12-inch ID and a 1.47-inch wall thickness. The pipe would consist of layers including an inner interlocked steel carcass, a pressure thermoplastic sheath, two layers of armor wires, fabric tape, and a polyethylene external sheath. The inner interlocked carcass layer protects against collapse due to external loads or pressure buildup within the pipe body. The second layer, polyethylene pressure sheath, provides internal fluid containment. The next two layers are armor layers with rectangular steel wires, which are contra-helically wrapped around the pipe core to ensure resistance to hoop, axial and torsional loads. A high-strength tape layer is applied to prevent opening of the armor wires in cases where the outer sheath is damaged. The final layer is the polyethylene external sheath, which protects the metallic layers and binds the outermost armor layer.

This type of pipe would be supplied in segments on reels. A typical reel is shown in Figure 7-3. Each segment would be approximately 0.75 miles in length. Each section of pipe would terminate with fittings which are designed to be protected from external corrosion. The end fittings would be prepared to allow a butt weld connection between flexible segments.

7.1.2 Summary

This section summarizes the structural design, construction plan, operations and maintenance, repair philosophy, costs, and failure analysis.

7.1.2.1 Structural Design Summary

A flexible pipe alternative would be safe structurally and could handle all environmental loads. There are several commercially available brands of flexible pipe, but they have not been evaluated against one another here. Differences in the brands of flexible pipe would need to be considered during a detailed design phase.

7.1.2.2 Construction Summary

The most suitable methodology for installing a flexible pipeline from the island to shore is a winter construction program of conventional excavation equipment and off-ice pipe installation techniques.

7.1.2.3 Cost and Schedule Summary

It is estimated that the overall construction of this alternative would be performed in a single winter season between December and April. The associated estimated cost for this program is $37 million. There is a high confidence level that this program would be completed in this time frame for approximately this cost.

7.1.2.4 Operations and Maintenance Summary

The envisioned operations and maintenance program for flexible pipe alternative uses available technology to monitor the condition of the pipeline. This program would monitor all of the design aspects that are considered to be gradual processes (for example, thaw settlement) and would allow mitigating steps to be taken in a timely manner if required. The program would also identify all events that have occurred between inspections and that did not impact the operation of the pipeline but may have affected the pipeline condition — for example, an ice keel passing over the pipeline.

7.1.2.5 Repair Summary

The flexible pipeline alternative can be repaired to its original condition or full integrity during a summer or winter operation. Four permanent repair options are available.

For the localized damage categories buckle/no leak (Category 2) and small/medium leak (Category 3), that affects less than a 40-foot length of pipe, the recommended permanent repair methods are:

- Summer: Cofferdam or hyperbaric tie-in.
- Winter: Surface tie-in or hyperbaric tie-in.

For damage categories that affect pipeline lengths greater than 40 feet large, leak/rupture (Category 4), the recommended permanent repair methods are the same for both seasons:

- Summer: Tow out replacement string with a surface tie-in or hyperbaric tie-in.
- Winter: Tow out replacement string with a surface tie-in or hyperbaric tie-in.

7.1.2.6 Leak Detection System Summary

Leak detection for the flexible pipe alternative would be achieved using three independent systems: a mass balance line pack compensation (MBLPC) system, a pressure point analysis (PPA) system, and a supplemental system. The first two systems would work in parallel, providing redundancy, and would have an accuracy to detect leaks as small as 0.15% of the volume of flow. A supplemental leak detection system based on periodically monitoring for the presence of hydrocarbon vapors in the pipe annulus would also be used to detect any leaks in the flexible pipe that were below this threshold.

7.1.2.7 Failure Assessment Summary

Damage that does not result in loss of containment is summarized as Category 1 (large displacement) and Category 2 (cross-section buckle/without leak). Damage that does result in loss of primary containment is summarized as Category 3 (small or medium leak) and Category 4 (large leak/rupture).

It is estimated that a Category 1 "incident of damage" during operation (displaced pipeline) has a 4% probability of occurring during the project lifetime. This type of damage is non-critical, and time is available to check and assess the damage. A planned intervention, if required, could be initiated to correct the condition. Buckles without leakage (Category 2 damage) is estimated to have a 1% project lifetime frequency. The estimated frequency for small or medium leaks is 10^{-3}. The estimated frequency for large leaks is very small.

The leak due to Category 4 damage (rupture or large leak) would be realized only during freeze-up, while a Category 3 damage scenario (small or medium leak) could happen at any time of the year. For any damage event, cleanup would be carried out. During repair, additional consideration would need to be given to a potential secondary spill volume from oil in the annulus and the removal of this oil or any water present.

This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less severe events; this might result in a large leak or rupture during other times of year. Such as analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear. Therefore, a response plan would need to be in place that could manage all damage in all seasons.

7.1.3 Conclusions

A flexible pipe alternative would meet the functional requirements of flow and pressure for the Liberty Development. A configuration of 5-foot depth of cover and native backfill has been judged adequate for design while optimizing other aspects such as constructability, operability, or repairability.

Installation of the flexible pipe alternative would be difficult due to construction considerations such as the limited skilled workforce for this type of installation, pipe low specific gravity, etc. The most suitable method for installing the flexible pipe alternative is a combination of conventional excavation equipment (backhoes with extended or long-reach booms) to excavate a trench through the ice. The flexible pipe would then be unspooled alongside this slot. After sections were welded together at the end connections, the pipeline would be installed through the ice. Care would need to be taken to prevent damage to the outer sheath during lowering in.

The estimated cost for the flexible pipe program is $37 million. There is a high confidence level that this alternative could be completed in a single winter season for approximately this cost.

Available technology would be used to monitor the pipe as part of the operations and maintenance programs. Radiography or eddy current measurement inspection tools (pigs) can be used on flexible pipe to locate defects in both the inner carcass and the hoop strain armor.

Leak detection would be achieved using mass balance line pack compensation (MBLPC) and pressure point analysis (PPA). These systems combined would be able to detect a leak greater than 0.15% of the volumetric flowrate. Supplemental leak detection technology is proposed to monitor the annulus of the flexible pipe system. Leaks from the inner sheath greater than 0.15% of the volumetric flowrate would be detected in minutes, while leaks less than this threshold would be identified within 24 hours.

The probability of a leak from the flexible pipe system is small. The flexible pipe alternative can be repaired to full integrity during a summer or winter repair operation. Procedures would need to be developed to manage the potential for a secondary spill volume from the annulus during repair and to try to achieve a dry annulus to prevent corrosion of the steel armor wires after repair. Manpower and equipment would be in place to successfully clean up any spill in the event of a leak.

7.2 Structural Design

7.2.1 Flow Analysis

General comments on flow analysis have been made in Section 3.2.2. The combination of gravel backfill as a thermal insulation and a -50°F ambient air temperature results in a Liberty Island inlet pressure of 1,285 psig and inlet temperature of 135°F with a tie-in pressure and temperature of 1,050 psig and 131°F.

7.2.2 Pipe Installation Stability

General comments on pipeline stability are presented in Section 3.2.3. Configuration weights for an empty flexible pipe have been calculated and are summarized below in Table 7-1.

TABLE 7-1: EMPTY PIPE WEIGHTS

Parameter	Flexible Pipe Type A
Pipe OD (inch)	14.923
Layers Thickness (inch)	2.933
Weight in air (pounds/foot)	84.4
Submerged weight (pounds/foot)	6.6
Pipe SG (w.r.t. seawater)	1.1

The flexible pipe has a specific gravity (with respect to seawater at 64.0 pounds per cubic foot) of approximately 1.1. Under ideal conditions, a pipeline will sink and be stable in the trench; however, in this case, the pipeline system specific gravity may be less than that of the soil/slurry mixture at the bottom of the trench. Installation procedures would need to be developed to manage the potential instability.

7.2.3 Ice Keel Gouging

General comments on ice keel gouging were made in Section 3.2.4. As with the other pipeline configuration alternatives, an extreme event ice keel design depth of 3.0 feet should be considered as the ice keel loading condition for the flexible pipe alternative. Flexible pipe manufacturers contacted have indicated a minimum operational bend radius of approximately 2.2 to 3.8 meters. As the pipe is flexible, it should be able to accommodate transverse displacements and curvature due to subgouge soil movement, but this would need to be confirmed in detailed design.

The effects of ice gouge over an end fitting or pipe connection would also need to be assessed in the detailed design stage. The number of sections of 12-inch flexible pipe needed for the 6.1-mile Liberty project is estimated to be 8 to 15 pipe lengths; this means that there would be 7 to 14 end fittings or connections. The bending stiffness of an end fitting is quite high compared to the pipe itself. Therefore, at the end fitting interfaces, the pipe would not be able to withstand very large deformation angles. If one uses a garden hose as an analogy, as one bends the hose at a coupling, the flexible hose tends to ovalize and buckle at the coupling. Therefore, the effects of ice gouge on the end fittings would need to be evaluated in detail.

7.2.4 Upheaval Buckling

Upheaval buckling is discussed in Section 3.2.6. For the flexible pipeline system, data on expansion due to temperature and contraction due to pressure are such that a relatively small compressive force (when compared to the single wall pipe) is locked into this system. On the other hand, the bending stiffness is also less, which tends to facilitate pipeline curvature. The net effect is an estimated required native backfill thickness of approximately 4.0 feet.

7.2.5 Thaw Settlement

General comments on thaw settlement are presented in Section 3.2.7. The same concerns for ice keel loading on flexible pipe would apply to thaw settlement. The effects of soil pressure on the pipe in areas of differential settlement would need to be assessed in detailed design. The effects of differential settlement in the area of an end fitting or connection would also need to be looked at in detail.

The design thaw settlement for the single wall steel pipeline is 1 foot (see Section 2.7.4). The estimated design differential settlement for the flexible pipe is almost 1 foot, the impact of which would need to be assessed during the detailed design stage.

7.2.6 Strudel Scour

General comments on strudel scour were presented in Section 3.2.8. At this conceptual level, no specific modeling of pipe/soil interaction through finite element analysis for strudel scour have been performed. However, for the small pipeline span expected, the resulting pipeline stresses are expected to remain much below the allowable stress level.

7.2.7 Corrosion Control

The flexible pipe system's inner and outer most layers are polyethylene sheath liners that prevent corrosive elements from reaching the internal steel layers. The flexible pipe flange end connections would have anti-corrosion coating, as well as possibly a sacrificial anode cathodic protection system. Tools are currently available to pig flexible pipe in order to check the integrity of the layers.

7.3 Conceptual Design Selection

Sub-alternatives of the flexible pipe alternative have not been presented here. There are several commercially available brands of flexible pipe, the differences in which would be considered in detail during a detailed design phase. At this stage, there is no indication that any flexible pipe would perform any better than any other.

7.4 Construction

General construction considerations have been discussed in Section 3.3, including trenching and installation. This section describes the most suitable method for the installation of the flexible pipe system. The configuration of the flexible alternative to be constructed is summarized in Figure 7-4.

7.4.1 Installation Options

Offshore arctic pipeline installation options which could be applied to a flexible alternative have been described in Section 3.3.9 and 3.3.10.

7.4.2 Construction Method

For the reasons outlined in Section 3.3.10, the most suitable method for installing a flexible pipe system for Liberty is to use conventional excavation equipment and off-ice pipe installation techniques. Winter trenching is described in Section 3.3.6 and winter installation in Section 3.3.9. The reasons for using conventional excavation equipment and off-ice pipe installation techniques are summarized below.

7.4.2.1 Trenching Method

The same reasoning summarized for the single wall steel pipe alternative makes mechanical trenching and large-scale hydraulic dredging impractical. Jetting is also not considered a practical option, as it is difficult to collect the excavated material and replace it in the trench as backfill.

Plowing to achieve a depth of cover of 5 feet is within the present capabilities of currently available equipment. The activity would be carried out during open water and would require a marine support vessel capable of supplying the large pull loads to move the plow along the pipeline. The vessel would also have to be able to lift the plow and place it on the seabed — depending on the plow selected, this would require between approximately 100 and 300 tons of force. A vessel that could provide the required pull loads and have a crane that could lift the plow would require a working water depth on the order of 20 feet. Therefore, due to the size of the equipment needed to operate a plow in an open water season and the water depths associated with the Liberty Development (0 to 22 feet), plowing is not considered a feasible option.

Pre-excavating with conventional excavation equipment working from an ice-based platform is considered to be the most suitable method to dig a 9-foot trench. This conclusion is based on the same reasoning presented for the single wall steel pipe installation.

7.4.2.2 Pipeline Installation Method

Reeling a flexible system is the standard method of installation in the offshore industry. However, using standard flexible reeling vessels may not be possible due to minimum working water depth limits of these types of vessels (approximately 15 to 20 feet). Mounting the reels of flexible pipe on a flat-decked transportation barge may be another method of installation from a vessel. Using a flat-decked barge would reduce the minimum working water depths limits and allow the vessel to get closer to shore. This reduces the length of flexible pipe that would have to be pulled from the barge location to the shore crossing. The vessel then would lay away from the shore to the island. As each reel was complete, the vessel would lay the flexible pipe down on the seabed. A second vessel with a full reel on it would then recover the flexible pipe, connect it on the new reel to the end of the recovered pipe, and continue the installation process.

None of the post-trenching techniques of jetting or plowing are considered suitable excavation methods for this application for reasons discussed above. The reeling method is therefore required to install into a pre-dredged trench. This would have to be achieved either with a mechanical winter excavation or a barge-mounted mechanical summer excavation, or a combination of both. A pre-dredged winter trench increases the number of construction seasons and requires the pre-dredged trench to remain stable from April to August. The summer excavation has a shorter construction window and so would require a significant amount of equipment to complete it in one season. Due to the logistical issues of pre-excavating a trench to allow an open-water reel installation, reeling from a vessel is not the preferred installation method.

A typical tow or pull method for installing a flexible pipe for Liberty would include:

- Pre-dredging the trench,
- Making up the pipe string in multiple 2,800-foot-long segments (approximate reel size limit), and
- Pulling the pipeline in stages (partial launch) of 2,800 feet at a time.

Pipeline bundle tow or pull methods are common for a pipeline of this length where the submerged weight of the pipeline system is on the order of 10 pounds per foot. However, there are concerns as to the potential damage to the flexible pipe during installation that are not associated with a steel pipeline installation. Also, large towing and/or anchor handling vessels would not be able to operate along most of the Liberty route due to draft limitations. The construction risk of keeping 6.14 miles of trench open and then installing the pipeline is considered to be too great to allow this installation method to be the preferred option.

Installation of the flexible using off-ice techniques is considered feasible for the Liberty water depths and weight of the pipeline (85 pounds per foot dry weight, 7 pounds per foot submerged weight). This method is similar to onshore pipe-lowering techniques.

7.4.3 Installation Sequence

A description of a general installation sequence is presented in Section 3.3.10. Deviations from that sequence for the flexible pipe alternative are described below. Equipment requirements and production rates associated with each activity are summarized in the next section on construction costs.

7.4.3.1 Pipeline Fabrication and Installation

Pipeline installation includes reel transportation to site, reel storage-site preparation, unspooling of the reels, transport of strings to the side of the trench, welding of individual segments, pipeline installation, and hydrostatic testing. The work involved for some of these activities is different from what was presented in Section 3.3.10, and these differences are described in the following text.

Mobilize Equipment, Material and Workforce

General details were presented in Section 3.3.10. The reels of flexible pipe would be transported by barge to West Dock in the summer prior to construction. It is estimated that approximately 12 reels would be required, each of which would contain 2,800 feet of flexible pipe and would weigh between approximately 150 and 200 tons. The reels would be stored close to West Dock until early winter, when they would be transported by Schuerle trailers (or similar) over gravel roads to the base of the Endicott causeway.

Ice Road Construction and Ice Thickening

This activity is the same as presented in Section 3.3.10.

Ice Slotting

This activity is the same as presented in Section 3.3.10.

Trenching

Trench productivity for the flexible pipe system would be higher than for the other alternatives because of the reduced volume of material to be excavated for the target trench depth of 8.5 feet. A general rule of thumb for trench excavation is that the material to be removed is proportional to the square of the depth of the trench that is to be excavated.

Reel Storage Site Preparation

Construction activities include setup of the material and pipe storage areas. Tracked equipment and graders would be used to produce a level surface from which the flexible would be unspooled.

Unspooling

This commences as soon as the reels are delivered and the site is operational. The unspooling of the flexible pipe from the reels would be carried out on the sea ice close to the shore approach. The activity involves the controlled unspooling of the flexible pipe from the reels to form a single 2,800-foot string that is ready to be towed over the ice to the side of the trench.

Pipe String Transport and Tie-in Welds

During this activity, the flexible strings would be towed via tracked equipment to the side of the trench. Tie-in welds to the previous string would be made and non-destructive examination (NDE) of the welds performed. The welds would be field joint coated with an anti-corrosion material, and a sacrificial anode (if required) would be connected to the joint to protect the connection from external corrosion. If an external leak detection system is to be bundled to the pipeline, it would also be attached at this stage.

Pipeline Installation

This activity is the same as presented in Section 3.3.10.

Backfilling the Trench

Once the pipeline is installed in the trench, a survey of the pipeline's vertical configuration would be made to determine whether there were any "high points" along the pipeline. The vertical variation tolerance for the flexible pipe has not been determined. However, for the purposes of this review, it is assumed that it is similar to that for the single wall pipe alternative (a 1.5-foot change in elevation over 100 feet). If the vertical variance is larger than this, corrective action such as lowering the pipeline would be required. Increasing the backfill thickness to provide additional resistance to vertical movement for larger vertical variances is limited as it cannot be greater than the depth of cover of 5 feet. Gravel mounds placed over the pipe every 100 feet would probably be required to maintain the pipe stability during backfilling, given the low specific gravity of the pipe system.

Hydrostatic Testing and Smart Pigging

This activity is the same as presented in Section 3.3.10.

Demobilize Equipment

This activity is the same as presented in Section 3.3.10.

7.4.4 Construction Considerations

General considerations regarding QA/QC, welding and NDE, and temporary storage of excavated material are presented in Section 3.3.10. The following sections present considerations associated with the construction sequence for a flexible pipe alternative.

7.4.4.1 Quality Assurance and Quality Control

General comments on QA/QC presented in Section 3.3.10 apply to the flexible pipe with additional comments provided below. The quality assurance and quality control associated with the flexible pipeline design allows most, but not all, key aspects to be inspected during installation and subsequently monitored during the operational life of the pipeline. With regard to construction, the additional key aspects of the design that should be measured are:

- The integrity of the 2,800-foot sections of flexible pipe after manufacture can be verified at the factory prior to transport to Alaska and subsequently the North Slope.
- Material properties of the connections between the flexible pipes, achieved by the recommended welding technique required to meet fracture toughness requirements, would be determined via material testing on prequalification welds for 12-inch connections.

7.4.4.2 Skilled Labor Force and Construction Equipment

The successful fabrication and installation of any engineering design and the quality of the final product are very dependent on the available skilled labor force. The labor force required to install the flexible pipe system is considered available. With regards to the flexible pipe fabrication and assembly, many of the skills required are not available in Alaska. The major construction components are identified in the next section on construction costs. The ability to meet air permit regulations regarding emissions for this equipment has not been determined.

7.4.4.3 Ice Slot Maintenance During Pipeline Installation

The pipeline installation would closely follow the trenching spread in order to simplify trench spoils handling. The distance behind the trenching spread and the pipeline touchdown point would be approximately 1,000 feet, and this ice slot would have to be kept ice-free.

7.4.4.4 Equipment Required to Lower in Pipeline

It is estimated that three sidebooms would be required to lower the flexible pipe system from the ice surface to the trench bottom. However, getting the pipeline to touch the bottom of the trench may prove difficult. The low specific gravity of the pipeline ($\approx$1.1) would make it difficult to ensure that the flexible pipe would sink in any soil/slurry fluid at the bottom of the trench. The flexible pipe system may rest on top of the soil/slurry. Gravel mounds may be required to hold the pipe in place (see Section 7.4.4.6 below). Construction procedures would need to be developed that could stabilize the pipeline and control its configuration during backfilling.

7.4.4.5 Transportation

Transportation and maneuvering reels of flexible pipe would be a difficult operation, particularly on the North Slope. For example, to unload the approximately 150- to 200-ton reels of flexible pipe from the material barge at West Dock would not be achieved by a single lift. Procedures would have to be developed to “skid” the reels from the barge onto the dock. Similar issues would be encountered when moving the reels from the base of the Endicott causeway to the reel storage site. An alternative is to pre-load the reels onto the Schuerle trailers or other type of transportation on the materials barge.

7.4.4.6 Backfilling

Backfilling native material over the flexible pipe would be a very difficult operation. Dropping the backfill material from the ice surface through the water column would likely develop a dense slurry in the trench bottom. Since this slurry could have a specific gravity greater than that of the flexible pipe, the pipe would float. Additional stabilization would be required and perhaps more care in the placement of the backfill. It may be necessary to take steps such as installing gravel mounds at unit spacings (every 100 feet) over the flexible pipe prior to backfilling to hold the pipeline in place or placing the backfill using a backhoe and releasing the material only a few feet above the pipeline.

7.5 Construction Costs

The following section summarizes the basis for the order of magnitude costs required to install the flexible pipe alternative.

7.5.1 Construction Sequence

The pipeline construction sequence is presented in Section 3.4.1 and applies here with the following differences:

- Equipment/Material Mobilization
  - Spool flexible pipe onto reels.
  - Barge reels to West Dock in summer.
  - Transport reels to Endicott by land in winter.
- Reel Storage Site Preparation
- Unspooling of Flexible Pipe from Reel
- Flexible Pipe String Transport
- Pipe String Tie-in Welds

7.5.2 Quantities and Rate of Progress

7.5.2.1 Mobilize Equipment and Material

See Section 3.4.2.

7.5.2.2 Ice Road Construction and Ice Thickening

See Section 3.4.2

7.5.2.3 Ice Cutting and Slotting

See Section 3.4.2.

7.5.2.4 Trenching

The estimated trench excavation volumes are shown in Table 7-2. The total volume is approximately 354,000 cubic yards based on an 8.5-foot-deep trench, 10 feet wide at the trench bottom. Side slopes of 2:1 are assumed for the 0- to 8-foot water depths and 3:1 for the remainder of the route. This target trench depth includes overexcavation to ensure the minimum depth of cover is achieved.

TABLE 7-2: TRENCHING VOLUMES

Water Depth (ft)	Trench Length (ft)	Trench Depth (ft)	Volume (yd^3)
0 – 8	14,877	8.5	126,730
8 – 18	12,473	8.5	139,513
18 – 22	4,964	8.5	55,523
		Total	**321,766**

Trench excavation is a critical operation requiring two or three spreads each consisting of backhoes, support bridges, spoils handling, spoils transport, and survey equipment. The rate of progress and days to complete each zone are summarized in Table 7-3.

TABLE 7-3 : TRENCHING RATES

Water Depth (ft)	Trench Length (ft)	Volume (yd^3)	Productivity (%)	Rate of Progress for Each Spread (ft/hr)	Number of Spreads	Time for Activity, (days)
0 – 8	14,877	126,730	85	56	2	7
8 – 18	12,473	139,513	75	28	2	13
18 – 22	4,964	55,523	75	7	3	14
				Total		**34**

7.5.2.5 Spool Site Preparation

It is assumed that a pipeline make-up site preparation area would be the same as for the single wall pipeline alternative. Thus, the area used for this activity would be 417,000 square yards (5,000 feet long and 750 feet wide). It is estimated that this activity can be performed in approximately 37 days.

7.5.2.6 Unspooling and Transportation

The flexible pipe transport would involve approximately 12 pipeline strings of about 2,800 feet each. Each trip would transport the length of pipe contained in one spool from the spool site to a specific area along the Liberty offshore pipeline route. It is assumed that these flexible pipeline strings can be transported to the side of the ice slot at an average rate of 0.9 mile of pipe string per day (unspooling rate is approximately 2 miles/day). Based on this rate, it is estimated that 6.12 miles of flexible pipeline could be transported in 8 days. The unit spread rate for this activity was assumed to be the same as that for the single wall pipeline alternative.

7.5.2.7 Flexible Pipe Field Connection Operations

The flexible pipe connection would be through welded end fittings. Each flexible pipeline string is 2,800 feet long; thus, 11 welds would be required in the offshore section to complete 6.12 miles of pipeline. It is estimated that a welding spread can make 4 welds per day, requiring only 4 days to complete all 11 welds. The transport activity of the flexible pipe limits the duration of this activity. Thus, this activity could be performed in 9 days.

7.5.2.8 Pipeline Installation

The duration of this activity would depend on the duration of the trenching activities. It is assumed that installation of the first two sections of pipeline (water depths of 0 to 8 feet and 8 to 18 feet) would take 20 days. The last section (18- to 22-foot water depths) would be installed in 6 days after the first two sections are completed, since the sections in 8 to 18 feet and 18 to 22 feet are trenched at the same time. An additional contingency of 4 days is assumed to allow for any flotation problems that may be encountered. The entire installation activity can be completed in 30 days. A unit spread rate similar to that of the single wall pipeline alternative is used.

7.5.2.9 Backfilling

Native soil backfill would be used as the main backfill material. Gravel mounds would likely be required every 100 feet to provide stability to the flexible pipeline. All excavated material would be placed back in the trench even though the minimum backfill requirement is a maximum of 5 feet. This activity would require one spread consisting of loaders, a backhoe, spoil transport trucks, and dozers. The rate of progress of backfilling would be faster than the pipeline installation if the majority of the backfill can be placed by pushing it into the trench from the ice surface. However, if a significant portion of the material must be placed by a backhoe to maintain pipeline stability, then the production rate would be significantly reduced. For the cost estimate, this activity is assumed to be dictated by the duration of the pipeline installation. It is estimated that this activity can be completed in 30 days.

7.5.2.10 Hydrostatic Testing

The hydrostatic pressure testing is expected to be finished in 5 days.

7.5.2.11 Demobilization

It would take approximately 2 days for each activity to demobilize their equipment from the working area. The regular unit spread rate is used for those 2 days.

7.5.3 Schedule

The overall construction of flexible pipe alternative for the Liberty project would be performed during the winter season, from December to April. Construction during winter allows the use of conventional or adapted onshore construction equipment and techniques. The recommended schedule for the flexible pipe alternative presented in Figure 7-5.

7.5.4 Cost Estimate Summary

The different activities associated with the construction of the Liberty offshore pipeline using the flexible pipe alternative are presented in Table 7-4. Activities, quantities and progression rates are shown together with the estimated cost for this alternative, which is $37 million.

TABLE 7-4: CONCEPTUAL COST ESTIMATE FOR THE FLEXIBLE PIPE ALTERNATIVE

Activity	Spread Productivity	Number of Spreads	Quantities	Duration (days)	Unit Spread Rate ($1,000/day)	Cost (Million $)
Mobilization	Lump Sum	1		3	910.00	2.73
Ice Thickening and Road Construction + Maintenance	2.5 inches/day	1	32,314 feet	47	84.00	3.95
Ice Cutting and Slotting	1000 feet/day	3	32,314 feet	11	29.00	0.96
Trenching	0 – 8 feet WD ---> 56 feet/hour/backhoe	2	126,730 cubic yards	7	60.00	4.92
	8 – 18 feet WD ---> 28 feet/hour/backhoe	2	139,513 cubic yards	13		
	18 – 22 feet WD ---> 7 feet/hour/backhoe	3	55,523 cubic yards	14		
Spool Site Preparation	11,260 square yards/day	1	416,500 square yards	37	41.00	1.52
Unspool, Flexible Pipe String Transportation.	0.9 miles/day	1	6.12 miles of flexible pipeline	8	78.00	0.62
Flexible Pipe Field Connection	4 welds/day	1	11 welds	9	31.00	0.28
Pipeline Installation (Lowering)		1	32,314 feet	30	43.00	1.12
Backfilling		1	32,314 feet	38	42.00	1.43
Hydrostatic Testing		1		5	84.00	0.42
Demobilization	Lump Sum	1		2	910.00	1.82
Hydrostatic Testing						
Material Cost and Transportation	Lump Sum					13.70
Contingency	10%					3.35
					Total	**37**

7.6 Operations and Maintenance

This section presents an operational and maintenance philosophy for the offshore section of the Liberty flexible pipe system. Table 7-5 summarizes the relationship between the operations and maintenance activities and the design.

TABLE 7-5: RELATIONSHIP BETWEEN OPERATIONS AND MAINTENANCE AND THE DESIGN

Tasks	Design Aspects
Operations	
Monitoring of Flow	- Internal Leak Detection
	- Custody Transfer
External Offshore Route Survey	- Trench Configuration
	- Ice Keel Event
	- Strudel Scour Event
Shoreline Erosion	- Shore Crossing Design
	- Trench Configuration
Maintenance	
Cathodic Protection	- NA
Wall Thickness and Internal Damage	- Pipeline Inner Wall Damage
Pipeline Configuration	- Trench Configuration
	- Ice Keel Event
	- Strudel Scour Event
	- Thaw Settlement
	- Thermal Expansion
External Corrosion	- NA
Pipeline Expansion	- Thermal Expansion
Pipeline Shore Approach Geometry Survey	- Thaw Settlement

7.6.1 Operation

General comments on operation are presented in Section 3.5.1.

7.6.2 Pipeline Inspection

General comments on pipeline inspection are provided in Section 3.5.2.

7.6.3 Maintenance

General comments on maintenance were provided in Section 3.5.3. Differences related to the flexible pipe system are presented below.

7.6.3.1 Monitoring of Cathodic Protection

The Liberty flexible pipe system would have polyethylene liners for the inner- and outermost layers. As part of the leak detection system, the annulus of the flexible pipe would be monitored for moisture. The end connections would have an anti-corrosion coating and may have a sacrificial-anode cathodic protection system. To ensure that the anodes are providing adequate cathodic protection to the end connections, the electric potential would be measured annually at the closest connections to Liberty Island and shore crossing. If a connection in the offshore section is exposed for repair or close inspection, the cathodic protection potential would be measured at the exposed location(s).

7.6.3.2 Monitoring of Pipe Wall Thickness (Internal Corrosion) and Internal Damage

Radiography or eddy current measurement inspection tools (pigs) can be used on flexible pipe to locate defects in both the inner carcass and the hoop strain armor. Monitoring internal damage for the flexible pipe system can also be done by running a video pig at regular intervals to inspect for damage. These would be carried out at the intervals listed in Table 7-6.

Fiber optic cables can be placed in the annulus or structure of the flexible pipe to identify pressure fluctuations or increases in temperature.

7.6.3.3 Monitoring of Pipeline Configuration

The pipeline’s geometry would be monitored by inspection pigging and comparing the results to the baseline measurement of its as-built configuration. Changes to the pipeline’s offshore configuration could potentially be caused by thaw settlement or ice gouging. Table 7-6 summarizes the recommended inspection schedule.

7.6.3.4 Monitoring of External Corrosion

External corrosion of the flexible pipe would not occur since the outer layer is a polyethylene sheath liner. The cathodically protected end connections cannot be monitored for external corrosion but would be coated.

7.6.3.5 Pigging Schedule

The recommended pigging schedule for the flexible pipe system is summarized in Table 7-6. This schedule is not meant to serve as the operations manual for the pipeline but provides typical intervals for the pigging operations and may change based on the preferences of the pipeline operator. The schedule is based on typical pigging schedules that have been performed for other pipelines and on expected performance of the Liberty offshore pipeline.

TABLE 7-6: RECOMMENDED INSPECTION PIGGING SCHEDULE

Pig Inspection	Inspection Schedule
Internal Video and Armor/Sheath Inspection - Pigs would be run in early winter so that any repairs required can be performed during the same winter season.	Startup. Every two years thereafter.
Pipeline Geometry - The purpose of the geometry pigging is to monitor the pipeline configuration offshore.	Baseline pig runs after pipeline construction completed before freeze-up. Once every calendar year for the first five years. Duration between consecutive pig runs would not exceed 18 months during these first five years. Every subsequent two years thereafter. Additional geometry runs would be carried out if severe ice gouges or strudel scours are suspected or observed to have occurred.

7.6.3.6 Monitoring of Pipeline Expansion

General comments on pipeline expansion were presented in Section 3.5.3. For the flexible pipe system, offshore thermal expansion would be limited due to the nature of flexible pipe and the friction effects of the soil backfill. Any thermal expansion would be noted during periodic visits to the surfacing point on the island and to the shore crossing.

7.6.3.7 Pipeline Shore Approach Geometry Survey

General comments on survey of the shore approach were presented in Section 3.5.3. Geometry pigging of the pipeline would measure alignment changes in the offshore pipeline section.

7.6.4 Evaluation Criteria and Required Action

Evaluation criteria and remedial action are discussed in Section 3.5.4. Table 7-7 lists allowable criteria for pipeline anomalies.

TABLE 7-7: PIPELINE EVALUATION AND REMEDIAL ACTION

Anomaly Type	Criteria
Internal Wall Damage	Dealt with on a case-by-case basis. Any wall damage would be detected during scheduled inspection pigging. Action would be determined by the pipeline operator.
Geometry Changes and Misalignment / Displacement	Bending radius is recommended for determining the need for repairs based on the results of consecutive geometry pigging. Minimum bending radius values would be derived from geometry pig measurements. The bending radius would then be used to determine the acceptability of changes to the pipeline's position, between consecutive pig inspections, based on a specified minimum bending radius.
Backfill / Bathymetry Anomalies	Corrective action should be considered once the pipeline has been undermined to the degree that a span has been developed. Such undermining may occur from strudel scour. The pipeline has been evaluated for a maximum span which would not be subject to vibration fatigue. Offshore pipe with less than the required backfill thickness (top of pipe to mudline) should be provided with additional backfill during the next available construction season and referenced for future evaluation surveys. Course of action should be coordinated with geometry pigging results.
Other Anomalies Including Shoreline Erosion	Dealt with qualitatively on a case-by-case basis in a manner that is warranted by inspection survey results. Action would be determined by the pipeline operator in accordance with normal North Slope practice.

As listed in Table 7-7, the bending radius based criteria would be used to assess the need for offshore pipeline re-evaluation or repair when pipeline displacements are detected. Geometry pig measurements would be converted to pipeline curvatures, which would then be compared to the minimum predicted and allowable pipeline bending radii. During the first few years, the yearly change in bending radius would also be determined based on the bending radius change between consecutive pig runs. Depending upon the average rate increase, an assessment can be made as to whether the next pig run should be performed earlier than scheduled or if corrective action is required during the interim.

7.7 Repair

7.7.1 Assumptions and Definitions

General comments on repair assumptions and definitions are presented in Section 3.6.1. An additional assumption for the flexible pipe system follows: After a repair is completed on the flexible pipe system, the annulus would need to be dewatered or inhibited to prevent corrosion. This process may be completed by continually drawing a vacuum on the annulus. This continuous air circulation is similar to what would be done for the purpose of leak detection (see Section 7.8).

7.7.1.1 Offshore Zoning

The offshore pipeline route is divided into zones, which are defined in Section 3.6.1. Those locations of the zones are the same for this option; however, the flexible pipe trench configuration is shallower (5-foot depth of cover).

7.7.1.2 Types of Repair

Types of repair are presented in Section 3.6.1. For a flexible pipe, minor damage is considered to be localized to a segment of 40 feet or less. The pipe may either remain structurally sound or be damaged to the extent that a short replacement segment is necessary. A repair requiring replacement of more than 40 feet of pipe is considered major damage. A length of 40 feet has been arbitrarily selected based on a conventional pipe joint length to allow a basis for comparison.

7.7.2 Repair Techniques

A review of repair techniques has been presented in Section 3.6.2. Variations from the techniques are presented below. Repair methods for the flexible pipe, described in detail in Appendix E, are:

- Welded repair with cofferdam,
- Hyperbaric weld repair,
- Surface repair, and
- Tow-out of replacement string.

7.7.2.1 Repair Technique Evaluation

This section highlights the main points associated with each of the four repair techniques. General comments are presented in Section 3.6.2. The review provides the basis for the recommended repair for each zone and type of damage.

Welded Repair with Cofferdam

For this permanent repair, the total amount of backfill that would be removed is approximately 1,150 cubic yards, which is expected to take two to three days. The total time required for the repair is approximately 37 days, which includes mobilization and survey of damage.

Hyperbaric Weld Repair

For this permanent repair, the total amount of backfill that would be removed is approximately 1,150 cubic yards, which is expected to take three to four days. The total repair time is approximately 37 days.

Surface Tie-In Repair

For this permanent repair, the maximum estimated quantity of soil to be excavated to bring the pipe to the surface is 2,926 cubic yards. Due to the increase in the pipe length after the repair, a layover area must be excavated to the original trench depth. This additional layover area will involve approximately 1,528 cubic yards of excavation. The total time for this type of repair is estimated to be 42 days, with 5 to 10 days of this time being required for excavation.

Tow-Out of Replacement String

For this type of major repair with a 400-foot replacement flexible pipeline string, the maximum estimated quantity of soil to be excavated is 6,480 cubic yards. The required time for conducting a bottom tow of a replacement string is estimated to be 42 days.

7.7.2.2 Repair Technique Conclusions

Conclusions regarding repair techniques are discussed in Section 3.6.2. Additional considerations for the flexible pipe system are summarized below.

Every permanent repair of flexible pipe uses a replacement string. Prior to the repair, a feasibility assessment would be completed to use either a flexible pipe string or a conventional pipe string. The repair would require that the damaged area be cut out and welded end connections added to the mother pipe in the field. Then a flexible pipe repair string with a welded end connection on each end or conventional pipe repair string would be welded to the mother pipe.

A flanged connection repair is considered a temporary repair and would be converted to a welded end connection the following repair season.

For the flexible pipe system, each of the repair techniques and equipment requirements increase the repair time compared to the repair of a single pipe, since the flexible pipe requires an end connection or fitting. For example, actual fitting connection, alignment, and welding for repair of the flexible pipe system is estimated to takes 1.5 times longer than the same repair for a single wall steel pipeline system.

7.7.3 Repair Scenarios

The previous section discussed the types of repairs with regard to the length of pipeline sections that needs to be replaced. However, it does not explicitly relate the size of the repair to the potential damage scenario. The following four categories of damage scenarios were described in Section 4.7.3:

- Category 1: Displaced Pipeline
- Category 2: Buckle/No Leak
- Category 3: Small/Medium Leak
- Category 4: Large Leak/Rupture

The relationship between these categories and the causes and failure mechanisms is discussed in the section on failure assessment. Each of these damage categories may require a repair. Figure 7-6 summarizes the categories of damage and the types of repairs that would be implemented if required.

7.7.4 Recommended Repair Methods

Summer and winter repairs were discussed in Section 3.6.4. Details on which repairs can be conducted and when are presented in Figure 7-6. In generating this figure, the "earliest start dates" and "latest completion dates" have been used. The repair techniques for each category of damage are indicated by the notes.

7.8 Leak Detection Methods

7.8.1 Leak Detection for a Flexible Pipe System

General evaluation and comments on leak detection are presented in Section 3.7. There are additional leak detection options for flexible pipe due to its layered composition. Flexible pipes have an annulus between the inner liner and outer sheath that contains steel armor but can house fiber optics or transmit fluid.

The typical failure mechanism is loss of the integrity of the inner barrier or end fitting seal ring, which allows fluids to enter the annulus. The fluids move along the pipe and are expelled through vent valves without damage to the outer shield. Flexible-pipe suppliers have been working closely with the monitoring industry to develop in-situ integrity monitoring for flexible pipes.

Fiber optic cables can be introduced into the structure of the flexible pipe. The cables can identify curvature variations, pressure fluctuations, or increases in temperature. All of these properties signal the potential loss of fluid containment. In the event the fiber optic cable indicates a potential failure, a video pig can be utilized to view the inner liner.

Some transport (diffusion) of associated gas through the pressure sheath into the annulus occurs in all flexible pipes carrying hydrocarbons. An annulus vent gas system can be used to monitor the gas permeation rates and identify pressure variations resulting from damage to the inner barrier. In the event the inner barrier or seal ring fails, an annulus monitoring system would detect a large increase in pressure or change in gas properties which signals a problem and allows for controlled shutdowns. Such a system can also detect water ingress due to damage to the outer sheath. Each end fitting on the flexible line has vent valves. In order to allow for evaluation at the exposed ends, the vent systems between flexible pipe segments must to be connected.

Leak detection for a flexible pipe alternative would be achieved using two independent systems: the mass balance line pack compensation (MBLPC) system and the pressure point analysis (PPA) system. Conventional leak detection is usually achieved using one of these systems. However, because of the importance of leak detection, the Liberty system would include both independent systems. These systems would work in parallel, providing redundancy, and be able to detect leaks as small as approximately 0.15% of the volume of flow.

Supplemental leak detection options for a flexible pipe alternative have also been considered to detect leakage below 0.15% of the volume of flow. As a supplementary method, it is proposed to monitor the annulus gas of the flexible pipe, as this would require no special make-up or additions to the pipe (i.e., inclusion of fiber optics). A jumper cable would be required from pipe section to pipe section to ensure continuous flow of any annulus gas. Commercial systems are available that can measure the volume and flowrate of vented gas passing through the annulus of the flexible pipe. The systems also incorporate a sampling bottle to enable analysis of gas composition and water content if desired. Continuous and cumulative measurements can reveal changes in the annulus conditions. The system can utilize a built in data logger system, or the data can be forwarded to the SCADA system.

If there were a leak in the inner liner, the amount of fluid entering the annulus would increase. By observing the trend of the data from the vent gas meter, it would be possible to detect a deviation from the baseline rate. The size of the leak would strongly influence the time to detect the leak. It is assumed that the performance of this system would be as good as the LEOS system proposed for the single wall steel pipeline.

The MBLPC, PPA, and annulus monitoring system could be integrated into the SCADA system, which would record all leak detection system parameters simultaneously. Combined, it is expected the systems would detect a large leak within 30 seconds and a small leak (less that 0.15% flow) within 24 hours. Potential leak volumes and time to detection are discussed further in Section 7.9.

7.8.2 Factors Affecting leak Detection Performance

There are no major issues which would influence the performance of the mass balance and pressure point technologies. These are technologies which are well established in industry practice.

Each flexible pipe section must be connected such that there is a continuous annulus and a path for a leak in the liner to be transported to a vent gas meter. The design must be such that the jumper from annulus to annulus does not lose its integrity during installation or backfilling or as the result of environmental loading. A limitation with the system is that the annulus monitoring would not cover the length of pipe comprised of connections.

Alternative monitoring may be required for these short sections and would need to be addressed in detailed design.

7.9 Failure Assessment

7.9.1 Operational Failure Assessment

This section examines initiating events and their causes that may lead to an "incident of damage during operation" (IDO) for the flexible pipe system. The likelihood of each initiating event is discussed below (see Figure 4-9 for a list of initiating events).

7.9.1.1 Seabed Ice Gouging, Initiating Event I1

For the flexible pipe alternative, the depth of cover is 5 feet, compared to 7 feet for single wall pipeline alternative. This increases the likelihood of large leak and fracture to 10^{-5} occurrences per project lifetime for the flexible pipe alternative. This type of damage is assumed to happen when an ice gouge is as deep as the pipeline centerline, that is, 5.7 feet. The likelihood of this event is shown in the last row of Table 7-8, which is based on the equations presented in Section 4.9.1.

TABLE 7-8: PROBABILITY OF EXCEEDENCE OF ICE GOUGE DEPTH ALONG LIBERTY ALIGNMENT

d **(ft)**	***T*** **(years)**	***f*** **(1/year)**	**Exceedence Probability over 20-Years = Project Lifetime Damage Frequency**
1.59	100	10^{-2}	0.18
3.0 (design value)	3,600	3×10^{-4}	5×10^{-3}
4.0	48,000	2×10^{-5}	4×10^{-4}
5.7	3,700,000	3×10^{-7}	5×10^{-6}

For the flexible pipe system, it is assumed that two different load cases could lead to a Category 3 damage: a 4.0-foot-deep ice keel event over the pipe or a 3.0-foot-deep ice keel event happening on top of an end fitting connection. For the 4.0-foot-deep ice keel loading, the damage frequency is 4×10^{-4} taken directly from Table 7-8. For the 3.0-foot-deep ice gouge occurring on top of an end fitting connection, the frequency is estimated as follows:

1. The number of new gouges per mile per year for Liberty is g = 0.097 (Appendix C), which when combined with a 6-mile length and 20-year design life, yields an estimated 12 ice gouge events per project lifetime.

2. It is planned that the flexible pipe be assembled from 12 reeled strings requiring 11 offshore welded end fittings.

3. It is estimated that an ice gouge would bend 40 feet of flexible pipe.

4. The probability of one or more (out of 12) ice gouge events, 3.0 feet deep or deeper, bending one or more of the 11 welds is:

$$P = 40 \text{ feet}/33{,}000 \text{ feet} \times 11 \times 10 \times 5 \times 10^{-3} = 8 \times 10^{-4}.$$

Therefore, adding the estimated damage frequency from a 4.0-foot-deep ice keel (4×10^{-4}) to that from a 3.0-foot-deep ice keel that occurs at an end-fitting weld connection (8×10^{-4}) yields a total probability for a small or medium leak event of 10^{-3} for the flexible pipe system.

For damage Category 1, damage the same frequency as the single wall case is estimated to apply. For Category 2, damage at an intermediate project lifetime damage frequency is estimated.

7.9.1.2 Subsea Permafrost Thaw Subsidence, Initiating Event I2

In this case, the comparatively less backfill to push the pipe down and the flexibility of the system would make permafrost less likely to cause damage. Therefore, except for the displaced pipeline damage category and the large leak or rupture category, the frequencies have decreased one order of magnitude as compared to the single wall pipeline.

7.9.1.3 Strudel Scour, Initiating Event I3

The slightly shallower depth of cover tends to slightly increase the probability of loading due to ice scour. Therefore, the associated frequencies are slightly higher than those for a single wall pipe system.

7.9.1.4 Upheaval Buckling, Initiating Event I4

The estimated damage frequencies for upheaval buckling are the same as those for the single wall pipeline system.

7.9.1.5 Internal and External Pressure, Initiating Events I5 and I6

The frequencies for these initiating events remain unchanged from those of a single wall pipeline system, except for the Category 3 damage due to internal pressure. For the flexible system, there is no additional safety built into the design; therefore, a frequency of 10^{-5} is adopted.

7.9.1.6 Internal Corrosion, Initiating Event I7

The potential corrosion due to oil is considered extremely unlikely.

7.9.1.7 External Corrosion, Initiating Event I8

The frequencies for this initiating event remain unchanged from those of a single wall pipeline system. The integrity of the outer sheath would need to be compromised in order to have corrosion of the steel carcass.

7.9.1.8 Vessel Accidents, Anchor Dragging, Third Party Construction, Sabotage; Initiating Events I9, I10, I11, I12

The frequencies for these initiating events remain unchanged from those of a single wall pipeline system.

7.9.1.9 Summary

The damage frequency failure assessment can be summarized in Table 7-9. The initiating events are defined as hazards to the pipeline.

The estimated frequency of an IDO in Category 1 (displaced pipeline) is 4% during the project lifetime; however, this type of damage is considered non-critical. Time is available to check and assess the damage and, if required, to initiate a planned intervention**.**

The second most frequent damage is buckles without leakage (Category 2). This damage is estimated at 1% for a project lifetime frequency. The frequency for small, medium, or large leaks is small, but these frequencies are higher when compared to the ones for the single wall pipeline. If desired, those frequencies could be lowered by increasing the depth of cover. The corresponding implications are discussed later in Chapter 9.

TABLE 7-9: INITIATING EVENTS AND RESULTANT DAMAGE FREQUENCY PER CATEGORY

Underlying Main Cause for Initiating Event	Initiating Event	Estimated Damage Frequency [Occurrences per Project Lifetime]			
		Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Environmental Loading	Seabed Ice Gouging	10^{-2}	$5x10^{-3}$	10^{-3}	10^{-5}
	Subsea Permafrost Thaw Subsidence	10^{-2}	10^{-5}	10^{-7}	10^{-8}
	Strudel Scour	10^{-2}	10^{-4}	10^{-6}	10^{-8}
Pipeline Failure	Upheaval Buckling	10^{-2}	10^{-3}	10^{-5}	10^{-7}
	Internal Pressure	10^{-8}	10^{-8}	10^{-5}	10^{-8}
	External Pressure	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Internal Corrosion	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	External Corrosion	10^{-8}	10^{-8}	10^{-6}	10^{-8}
Third Party Activity	Vessel Accidents	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Anchor Dragging	10^{-8}	10^{-8}	10^{-8}	10^{-8}
	Third Party Construction	10^{-6}	10^{-8}	10^{-8}	10^{-8}
	Sabotage	10^{-8}	10^{-8}	10^{-8}	10^{-8}
Total		**4×10^{-2}**	**6×10^{-3}**	**1×10^{-3}**	**1×10^{-5}**

Table 7-10 shows for each entry on Table 7-9 with frequency greater than 10^{-8}, when in the year the corresponding damage could occur. This assessment of when potential damage could occur is not based on the joint likelihood of a combination of less severe events; this might result in a large leak or rupture during other times of the year. Such an analysis is beyond the scope of the current study, and if events were combined, then more damage windows may appear.

TABLE 7-10: WHEN DAMAGE COULD BE REALIZED

Initiating Event	**When Potential Damage Could Occur**			
	Category 1 IDO Displaced Pipeline	Category 2 IDO Buckle, No Leak	Category 3 IDO Small, Medium Leak	Category 4 IDO Large Leak, Rupture
Seabed Ice Gouging	June/July Oct./Nov.	June/July Oct./Nov.	Oct./Nov.	Oct./Nov.
Subsea Permafrost Thaw Subsidence	Any Time	Any Time	Any Time	-
Strudel Scour	May/June	May/June	May/June	-
Upheaval Buckling	Any Time	Any Time	Any Time	-
Internal Pressure	-	-	Any time	-
External Pressure	-	-	-	-
Internal Corrosion	-	-	-	-
External Corrosion	-	-	Any Time	-
Vessel Accidents	Any Time	-	-	-
Anchor Dragging	-	-	-	-
Third Party Construction	Any Time	-	-	-
Sabotage	-	-	-	-

7.9.2 Spill Scenarios

7.9.2.1 Potential Oil Loss

Leak detection options have been reviewed in Section 3.7. The recommended supplementary leak detection system for the flexible pipe system is through-annulus monitoring. As presented earlier in Section 3.8.4, a guillotine break (Category 4 damage) could potentially yield a total volume loss of 1,576 barrels of oil. Based on a medium

(Category 3 damage) leak of 97.5 barrels per day, the volume of oil lost from the inner sheath during the reaction time of the annulus monitoring system would be 97.5 barrels (corresponding to a test time of 24 hours for the system). In total, a medium spill scenario might be expected to result in approximately 125 barrels of oil escaping from the inner sheath. A small chronic leak (Category 3 damage) is considered to be 1 barrel per day. Depending on the nature of the pipeline failure, the Category 3 damage may or may not result in oil entering the environment. Category 1 and Category 2 damage would not result in a spill. Table 7-11 summarizes the oil spills that would be associated with the different damage categories.

TABLE 7-11: DAMAGE CATEGORIES AND ASSOCIATED OIL SPILL VOLUMES AND FREQUENCY OF DAMAGE PREDICTIONS

Damage Category	Estimated Oil Spill Volume (bbls)	Estimated Damage Frequency During Project Life
1	0	4×10^{-2}
2	0	6×10^{-3}
3	125	1×10^{-3}
4	1,576	1×10^{-5}

7.9.2.2 Spill Scenarios

Spill scenarios were presented in Section 3.8.4. Response time, cleanup capability, cleanup options, environmental impact variables, effectiveness of cleanup, and system down time are discussed in Section 3.8.5.

As shown in Table 7-10, a leak due to Category 4 damage might be realized in the fall (October-November) of the year. Initial freeze-up could occur the first week of October and ice movement would be expected to cease by about the middle of November when the ice becomes landfast. During breakup in early July, the ice is assumed to be deteriorated and weak and, for the most part, would melt in place. Mechanical options might be considered for cleanup of a spill under broken ice, but the most effective strategy would likely involve in-situ burning. Satellite tracking would be used to monitor the drift of any oiled ice. If the oiled ice became landfast, conventional winter ice procedures might be used to recover the oil. Again referring to Table 7-10, a Category 3 damage scenario could happen any time of the year.

However, as pointed out previously, the joint likelihood of a combination of less severe events has not been examined during this study. Such a study may indicate that more damage windows are possible. Therefore, a response plan would need to be in place that can manage all damage in all seasons.

7.9.3 Cleanup and Repair

The Liberty Development will have an approved oil spill contingency plan demonstrating the capability to clean up an oil spill anytime of year. The volume of oil which could be handled would be significantly larger than anything expected from the pipe.

Cleanup strategies are presented in Section 3.8.5. As presented above, Category 4 damage might be expected only during freeze-up, while Category 3 damage could occur any time of the year. Mechanical options might be considered for cleanup of a spill due to Category 4 damage under broken ice, but the most effective strategy would likely involve in-situ burning. If the oiled ice became landfast, conventional winter ice procedures might be used to recover the oil. In any event, cleanup would be carried out as quickly as possible to the satisfaction of Federal and State On-Scene Coordinators to minimize any impact on the environment.

The repair philosophy for the offshore section of the flexible pipe alternative is presented in Section 7.7. The recommended methods of repair, which are dependent on the time of year and damage category, are shown in Figure 7-6. In the case of Category 3 damage, it is assumed the pipeline would have been purged and no further leakage would occur during repair. In the case of Category 4 damage, no secondary spill volume from the pipe would be expected as precautions would have been taken to prevent any further loss during repair (e.g., plugging or purging the pipe). The risk of additional oil spill during repair is not considered further in this review.

During detailed design, consideration would need to be given as to how to extract oil or water from the annulus of the flexible pipe system. Water, if left in place, may cause corrosion. Any oil left in the annulus could potentially leak out if the integrity of the outer sheath was lost.

8. EVALUATION OF CONTAINMENT CONCEPTS

8.1 Introduction

The primary aim of pipeline design is to engineer a pipe or conduit that will transport a product from one location to another with due consideration to all internal and external influences. All gases and liquids must be pressurized (unless the flow is caused solely by gravity, as in the case of a culvert or channel). A significant part of the design effort is to economically optimize the pipe diameter, wall thickness and material strength, while still safely achieving the design throughput. In the case of steel pipe materials, close attention is paid to protecting the pipe from corrosion. Internal corrosion may be due to the product transported in the line or the unintentional introduction of a corrosive substance at some point during pipeline operation. External corrosion may be due to the surrounding soil or water if the line is buried or installed under water. Generally, steps are always taken to limit corrosion by application of an external corrosion coating, installation of cathodic protection, and if required, the injection of corrosion inhibitors into the product stream during pumping or compression.

Pipeline design codes and standards do not suggest a requirement to provide an outside pipe jacket whose sole purpose is to contain any loss of contents of the pipeline it surrounds. The conditions that might give rise to a loss of product from the inner pipe would also affect the outer pipe. Specific conditions such as the corrosiveness of the transported product are always considered in the design. Pipe-in-pipe systems are widely used, but the outer pipe does not serve as a back-up in the event that something has been omitted in the original design effort. Their prime function is to satisfy installation economics or another design condition, such as to insulate or facilitate installation.

Nevertheless, because questions have been raised regarding the feasibility of coatings, wraps, or oil sorbent materials as containment concepts, this study has examined their possible application to a Liberty offshore pipeline. Additional approaches for product retardation or containment have been addressed beyond the immediate boundary layer of the outermost pipe wall. These, and their practicality, are discussed in the following section.

8.2 Specific Concepts

External coating, outer pipe shrink-wrap, and various types of backfill have been suggested as possible means to contain oil in the event of a leak through the pipe wall. A combination of geotextile wrap around the pipe, or in the trench and over the pipe, as well as a layer of (absorbent) soil, have been suggested as possible containment mechanisms for a pipeline. Many of these strategies have been used successfully on terrestrial projects, such as landfills, reservoirs, ground water contaminant projects, etc., but not for pipelines. However, in underwater and especially in arctic conditions, there are serious fabrication, installation, and functionality issues that must be considered.

Geomembrane liners are typically used as a lining in landfills. This might be considered as a wrap around the pipe (Figure 8-1). It would be very difficult to apply to the pipe. The inside of the material would have to be coated with adhesive during the wrapping process. Field joints and seams would also need to be dealt with manually. The cathodic protection system would likely be compromised because the wrap will shield the pipeline from the anodes. Pipeline installation procedures would be very cumbersome, adding significantly to the installation schedule. It would be very difficult to handle the geomembrane in extreme cold conditions without damaging it during installation. It would also be very difficult to install the pipeline so that there was a geomembrane wrap around a layer (pseudo annulus) of absorbent soil (Figure 8-2). This would likely involve developing specialty construction equipment in order to achieve the desired configuration of liner, soil layer upon which the pipe could be laid, and then covered with a final pass of liner and soil. There also remains the question of how effective or absorbent the soil might be after years of submergence under water.

If the pipeline were to be partially backfilled and then a geomembrane placed over the pipe, the geomembrane would need to be installed with a concave downward shape (Figure 8-3) so that the oil would be contained in the event of a leak. If the membrane was not placed properly (i.e., it was horizontal or concave upward), then oil would escape laterally out from under the cover. Likewise, if the geomembrane placement was not horizontal (it was undulating), then oil might accumulate at a high point and after some time escape laterally (Figure 8-4) out from under the geomembrane. Given the strictly-specified and controlled manner in which landfill-lining geomembranes are placed and backfilled to prevent damage, it appears extremely unlikely that it would be possible to successfully place a geomembrane with the submarine pipelines for the purpose of containment.

There are a number of oil sorbent materials commercially available for cleaning up oil floating on water. Placing this material around the pipe may be difficult as oil sorbent material floats. It would, therefore, need to be contained within a fabricated bag, net or cover which could be placed around or over the pipe (Figure 8-5). The majority of products available are biodegradable (e.g., wood or peat), and therefore, their effectiveness over time would likely deteriorate. Although the manufacturers claim that these types of materials will repel water and absorb oil, they also state the materials may float only for several days when unsaturated with oil, which suggests that they will eventually absorb water. Other products on the market will bond with any trace metals in the water and relatively quickly lose their ability to absorb oil if trace metals are present. The fabrication and installation practicality issues with this type of system are difficult and complex.

8.3 Summary

Alternative containment concepts for a buried offshore pipeline have been considered. In summary, it is felt that these containment concepts are not feasible for the following reasons:

- It would be difficult, if not impossible, to properly apply an external wrap to the pipeline and ensure its integrity is maintained.
- The use of these alternative containment concepts would likely require the design and construction of specialty application and construction equipment.
- Alternative containment designs may affect the performance of other systems such as cathodic protection.
- There is a high probability that a system applied to the pipeline would not survive installation of the pipeline into the trench.
- There would be no means to verify the integrity of any containment design after installation or during operation.
- An attempt to contain the oil with a system placed over the pipe would cause oil to channel longitudinally along the pipe. This would worsen the situation in the event of a leak as there would be a greater amount of contaminated material to remove and dispose of (the aerial extent of the leak has increased).
- If a system could successfully be installed, the effectiveness of the system after years of submergence under water is unknown.

The engineering design of any pipeline system would be such that it would be designed not to leak, and thus, designing additional containment would contradict the concept of “engineering design”.

9. COMPARISON OF ALTERNATIVES

This section compares the four pipeline system alternatives based on key differences in the review findings for each alternative. These differences determine the optimum pipeline solution for system functionality, system integrity and environmental impact.

The first section of this comparison reviews the relative differences among the alternatives with respect to system configuration, cost, installation, and operations. The second section reviews the relative differences among the alternatives with respect to operational risk of different types of damage, consequences of damage to the environment, and cleanup and repair response capabilities. Conclusions are summarized in the final section.

9.1 Configuration, Cost, Installation, and Operations Comparison

Table 9-1 summarizes the main differences in alternative system configurations, cost, schedule, installation, and operations and maintenance identified in the preceding chapters. Table 9-1 is discussed in the following sections.

9.1.1 Configuration

The four alternative configurations reviewed meet the pipeline system design criteria. The first part of Table 9-1 summarizes the differences between the configurations that have subsequent implications in other areas associated with the alternative.

9.1.1.1 Depth of Cover, Excavation Volume and Trenching Duration

The depth of cover required to protect the pipeline alternative dictates the trench configuration and the volume of material to be excavated. The amount of material to be excavated affects both the trenching productivity and potentially the amount of sediment suspended in the water column. The excavated material quantity range is 322,000 cubic yards to 461,000 cubic yards, a difference of 140,000 cubic yards of trench excavation. This corresponds to a range in minimum duration of the trenching activity of 9 days when considering the first section will be excavated at the start of February and that two sections in the deeper water will be parallel operations starting in mid-February. Therefore, even though there is a difference in volume of trench excavation, the impact on the construction program is small.

9.1.1.2 Gravel Backfill

Gravel is required for trench backfilling with three of the four alternatives. For the single wall pipe alternative, the gravel is required where pipe configurations do not meet the vertical configuration tolerances. This has been estimated as 9,000 cubic yards, which will be installed in gravel mat units each containing approximately 4 cubic yards of gravel. For the pipe-in-HDPE and flexible pipe alternatives — with specific gravities of 1.1 and 1.2, respectively — gravel is required to maintain stability of the pipeline in the bottom of the trench. Gravel mounds of approximately 30 cubic yards placed at 100-foot spacings are considered adequate to stabilize the pipelines. This results in a gravel requirement of approximately 10,000 cubic yards.

9.1.1.3 Pipeline Expansion

At the island and shore crossing, each pipeline alternative will expand due to the difference between installation and operating temperatures and pressures. The amount of expansion is dependent upon the system configuration. For three of the alternatives, this is considered to be less than 0.5 feet and can be accommodated using rigid steel pipeline offsets. However, the predicted expansion for the pipe-in-HDPE alternative could be as large as 13 feet. An expansion loop to accommodate this amount of expansion would require a large island surface area or a flexible pipe spool piece.

9.1.1.4 Number of Welds/Connections

This line item is included in Table 9-1 to identify the number of connections/welds associated with each system. The differences in the number of welds itself is not of concern, but the weld process used at the different connecting locations (coating yard, pipeline make-up site, or on-ice tie-in), and the integrity of each is important. The tie-in welds, made beside the trench, connect long strings of pipe together using external line-up clamps; and the pipe-in-pipe alternative tie-in NDE is not as complete as at the make-up site. The tie-in welds for the proposed construction method may, therefore, be more susceptible to potential flaws and should be minimized.

9.1.2 Cost and Schedule

Budget cost estimates range from $31 million to $61 million, including the base case cost plus a contingency value. The contingency value is estimated based on the confidence associated with meeting the proposed schedule. For the pipe-in-pipe and the pipe-in-HDPE alternatives, there is a high likelihood that an additional construction season will be required to complete these more complex construction programs. Therefore, the contingency includes a portion of the additional season construction costs. This is a standard approach to determining budgeted cost estimates for construction projects.

Section 5.5.3 discussed the relatively low confidence for constructing the pipe-in-pipe and pipe-in-HDPE alternatives in a single season. It is based on construction experience (relevant examples quoted) for new and reasonably complex construction procedures requiring specialized skills sets and extensive quality assurance.

9.1.3 Installation

The main installation differences and considerations associated with the different alternatives are identified in Table 9-1.

The ice thickness requirements are largest for the pipe-in-pipe alternative in order to manage the additional loads that will be placed on the ice close to the trench by additional sideboom equipment and pipe string weight. Increasing the ice thickness increases the time to complete the ice roads and work platform, and delays the start of trenching and pipeline installation operations.

The relative quantities of equipment that will be required to install each pipeline system have been assessed relative to a single wall pipeline. The basis for the equipment quantities estimate is the unit mobilization cost summarized for all the spreads that are to be used during field construction.

The construction considerations also highlight concerns regarding installation of each system alternative summarized in the associated alternative chapter.

9.1.4 Operations and Maintenance Concerns

The main difference in maintenance of the pipeline systems is that monitoring cannot be accomplished in all structural components of some alternatives. It is not presently feasible to monitor the integrity of the outer jacket pipe of both the pipe-in-pipe and pipe-in-HDPE alternatives. Post-failure monitoring could be achieved for these two systems using the annular leak detection system to detect the presence of water and hydrocarbon. However, no preventive monitoring of the outer jacket pipe can be performed for these systems.

TABLE 9-1: DIFFERENCES BETWEEN ALTERNATIVES RELATED TO CONFIGURATION, COST, SCHEDULE, INSTALLATION, OPERATIONS AND MAINTENANCE

Description	Pipeline Alternative			
	Single Wall	**Pipe-in-Pipe**	**Pipe-in-HDPE**	**Flexible Pipe**
Configuration				
Depth of Cover (feet)	7	5	6	5
Excavation Volume (1000 yds^3)	461	354	424	322
Relative Excavation Volume (%)	100	77	92	70
Duration of Trenching Activity (days)	33	26	30	24
Gravel Backfill (yds^3) [Does not include 50% contingency]	9000 (in gravel mats)	0	10000 (30 yds^3 every 100 feet)	10000 (30 yds^3 every 100 feet)
Pipe Specific Gravity	1.6	2.2	1.2	1.1
Pipeline Expansion (feet)	<0.5	<0.5	13	<0.5
Number of Welds/ Connections	808 welds 11 of the welds are tie-in welds	1616 welds 66 welds are tie-in welds	808 welds, 808 fusions 66 connections are tie-in connections	13 connections 11 of the connections are tie-in connections
Cost				
Budgetary Cost ($ millions)	31	61	44	37
Relative Cost (%)	100	195	140	120
Schedule				
Estimated Schedule Bases	Single Winter Season	Single Winter Season	Single Winter Season	Single Winter Season
Likelihood of Requiring an Additional Season to Complete Construction (%)	10	80	60	10
Installation				
Ice Thickness (feet)	8.5	10.5	8.5	8.5
Relative Quantity of Construction Equipment per Season (%)	100	120	115	90
Considerations	1. Identification of vertical pipeline profiles that do not meet the design criteria	1. Pipe-in-pipe assembly logistics 2. Assurance of dryness of 12-in. pipe prior to pipe-in-pipe assembly 3. Achieving pull-in of 12-in. to outer jacket 4. Handling of pipe-in-pipe system (210 pounds/foot) and large stiffness 5. Requirement for a thicker ice platform	1. Assurance of dryness of 12-in. pipe prior to pipe-in-HDPE assembly 2. Execution of pipe-in-HDPE assembly 3. Maintaining pipeline stability in the trench 4. First application of the HDPE of this type	1. Logistics for transportation and handling heavy reels 2. Maintaining pipeline stability in the trench
Operation & Maintenance Concerns	1. Conventional operations	1. Monitoring of the outer pipe integrity	1. Monitoring of the outer pipe integrity	1. Monitoring of flexible cross-section

9.2 Operational Risk and Consequences of Failure Comparison

The operational risk of damage for each pipeline system alternative is compared in this section based on the analysis performed in the previous chapters.

Table 9-2 presents, for all four pipeline system alternatives, the estimated damage frequency and the subsequent environmental oil spill in barrels of oil per damage category. The damage consequences are discussed and compared first, and the estimated damage frequencies are discussed and compared next.

9.2.1 Damage Consequences: Volume of Oil Spilled into the Environment

This section presents a discussion of the volume of oil potentially spilled into the environment, which is the damage consequence of most concern. By definition, there is no oil spilled into the environment for Category 1 and Category 2 damage. These two damage categories are therefore not discussed in detail. However, it should be noted that in addition to oil spills, another consequence of damage is repair of the pipeline. Repair means bringing the system to the original level of integrity, and in this case all damage categories are important.

The repair aspect of damage consequence is not explicitly addressed in this section, but the main repair concerns are summarized in the last row of Table 9-2. It can be clearly seen that the system that would be most likely successfully repaired is the single wall pipeline alternative. The remainder of this section explains and compares the environmental oil spill damage consequence.

For a small or medium leak (Category 3) where both the internal and external (if present) pipes fail, the maximum volume of oil spilled into the environment is 125 barrels. It is assumed that each of these alternatives would have a LEOS or similar supplemental leak detection system. For more details on the volumes to be analyzed and reaction times, see the leak detection Sections 4.8, 5.8, 6.8, and 7.8.

The analyses of the previous paragraph assumes the maximum oil spill threshold that PPA and mass balance cannot detect 0.15% of maximum flow (which at 65,000 barrels per day equals 97.5 barrels per day) plus reaction time to be able to detect the leak. This analysis assumes that for leak rates greater than this threshold, PPA and mass balance would be able to detect the leak quickly and the pipeline system would be shut in within minutes.

TABLE 9-2: OPERATIONAL DAMAGE FREQUENCY AND CONSEQUENCES OF FAILURE COMPARISON BETWEEN SYSTEMS

Alternative	Single Wall	Pipe-in-Pipe	Pipe-in-HDPE	Flexible Pipe
Category 1: damage freq. (project life) – env. oil spill volume	3×10^{-2} - 0 barrels	2×10^{-2} - 0 barrels	3×10^{-2} - 0 barrels	4×10^{-2} - 0 barrels
Category 2: damage freq. (project life) – env. oil spill volume	1×10^{-3} - 0 barrels	1×10^{-3} - 0 barrels	2×10^{-3} - 0 barrels	6×10^{-3} - 0 barrels
Category 3: damage freq. (project life) – env. oil spill volume	1×10^{-5} - 125 barrels	1×10^{-4} [1] - 125 barrels	1×10^{-4} [1] - 125 barrels	1×10^{-3} [1] - 125 barrels
Category 4: damage freq. (project life) – env. oil spill volume	2×10^{-7} - 1,567 barrels	1×10^{-5} - 1,576 barrels	1×10^{-6} - 1,576 barrels	1×10^{-5} - 1,576 barrels
Repair concerns	1. Typical arctic marine site access constraints, relatively easy system to repair	1. Clean up annulus in case of any leaks 2. Heavy pipe difficult to handle and lift out of trench 3. In case of repair difficult to bring to original integrity	1. Clean up annulus in case of any leaks 2. In case of repair difficult to bring system to original integrity	1. In case of leak, repair requires field end terminations and spool piece

Note: [1] Pipeline failure is by ice gouging causing both inner and outer containment to fail and release oil to the environment.

The double pipe systems are redundant systems requiring a small and medium leak (Category 3) into the environment to first leak through the inner pipe and then through the outer pipe. One failure mechanism that may lead to an environmental oil spill is a simultaneous corrosion of both pipes, which is extremely unlikely. However, if both pipes fracture simultaneously, due to an ice keel event, for example, the estimated volume of oil spilled remains 125 barrels.

For Category 4 damage (large leak or rupture), it is estimated that the maximum oil spill is 1,576 barrels (see Section 3.8.4). This spill volume is again a consequence of leak detection and reaction time, with the addition of oil drainage, volume expansion, and water intrusion in the line. Given that the inner diameter pressures are virtually the same for all systems, this Category 4 damage is the same for all alternatives.

9.2.2 Damage Frequencies: Likelihood of Oil Spills

In this section, the damage frequencies estimated for each of the pipeline system (see Table 9-2) are discussed. Material presented in Section 3.8 and in Sections 4.9.1, 5.9.1, 6.9.1, and 7.9.1 for each of the pipeline system alternatives is relied upon for this assessment. This helps to minimize repetition and cross-referencing to streamline the discussion to the main factors influencing the damage frequency and corresponding failure mechanisms.

9.2.2.1 Category 1 Damage Frequency: Displaced Pipeline

For the single wall pipeline system, the estimated project lifetime frequency of this potential damage is 3%. The initiating events that control this estimated frequency are seabed ice gouging, permafrost thaw subsidence, and upheaval buckling, with 1% estimated for the frequency of each.

For the pipe-in-pipe system, the estimated frequency of this potential damage is 2%. The initiating events that are controlling this estimated frequency are seabed ice gouging and permafrost thaw subsidence. There is very little upheaval buckling potential for the pipe-in-pipe system. Although the shallower depth of cover of 5 feet would make strudel scour more likely to affect this system (when compared to the single wall pipe system), the added stiffness of the pipe-in-pipe acts as an added safeguard against potential damage.

For pipe-in-HDPE, the estimated frequency of this potential damage is 3%. The initiating events that are the controlling this estimated frequency are seabed ice gouging, permafrost thaw subsidence, and strudel scour. There is less upheaval buckling potential for this system due to the decrease in locked-in compressive force for most of the route. However, strudel scour is an increased factor since the pipe has a depth of cover of 6 feet, without the benefit of increased pipe stiffness.

For flexible pipe, the estimated frequency of this potential damage is 4%. All the above discussed initiating events contributes to this frequency: seabed ice gouging, permafrost thaw subsidence, strudel scour, and upheaval buckling.

9.2.2.2 Category 2 Damage Frequency: Buckle/No Leak

For the single wall pipeline system, the estimated frequency of this potential damage is controlled by the upheaval buckling initiating event. For the pipe-in-pipe system, the estimated frequency of this potential damage is controlled by seabed ice gouging. For pipe-in-HDPE and flexible pipe, the estimated frequency of this potential damage is controlled by seabed ice gouging and strudel scour. Each alternative has an estimated frequency of the same order of magnitude (10^{-3}).

9.2.2.3 Category 3 Damage Frequency: Small or Medium Leak

The single wall pipeline system has the smallest estimated frequency for this potential damage: 10^{-5} occurrences per project lifetime. The initiating event that controls this damage frequency is upheaval buckling.

For the pipe-in-pipe system, the estimated frequency for the small and medium leak damage is 10^{-4}. This is due to seabed ice gouging only; corrosion of the inner pipe and corrosion of the outer pipe would cause damage only if the occurrence is simultaneous. This is a second order effect and is considered extremely unlikely.

For pipe-in-HDPE, the estimated frequency of this potential damage is 10^{-4}, again caused by seabed ice gouging, which also is the main contributor to a damage frequency of 10^{-3} for the flexible pipe case.

9.2.2.4 Category 4 Damage Frequency: Large Leak or Rupture

The single wall pipeline system has the smallest estimated frequency for this potential damage: $2x10^{-7}$ occurrences per project lifetime. The initiating events that control this damage frequency are seabed ice gouging and upheaval buckling. This small project lifetime damage frequency indicates that this damage is highly unlikely for this pipeline system.

For the pipe-in-pipe system, the estimated frequency of the large leak or rupture is 10^{-5}. This is due to seabed ice gouging only. This damage frequency indicates that this type of damage is very unlikely.

For pipe-in-HDPE, the estimated frequency of this potential damage is 10^{-6}, again caused by seabed ice gouging, which also is the main contributor to an estimated damage frequency of 10^{-5} for the flexible pipe case.

9.2.3 Comparative Risk of Environmental Oil Spills

Risk is the product of the damage frequency times the consequence of interest, in this case, oil spilled into the environment. The definition of risk is discussed in detail in Section 3.8. This section presents an analysis of the environmental oil spill risk for all the pipeline system alternatives.

Table 9-3 shows the risk in barrels of oil spilled into the environment for all alternatives is negligible. The single wall pipeline alternative poses the lowest risk to the environment. The pipe-in-pipe and pipe-in-HDPE show a relative risk 9 to 18 times greater that the risk posed by the single wall system. Flexible pipe shows an estimated relative risk of approximately two orders of magnitude higher than the risk of a single wall pipeline system.

TABLE 9-3: RISK (BARRELS) OF OIL SPILL INTO ENVIRONMENT FOR DIFFERENT ALTERNATIVES

Alternative	Single Wall	Pipe-In-Pipe	Pipe-In-HDPE	Flexible Pipe
Risk (bbls) [1]	1.6×10^{-3}	2.8×10^{-2}	1.4×10^{-2}	1.4×10^{-1}
Relative risk [2]	1	18	9	88

Notes:

[1] Risk = frequency x consequences, in units of the consequence
Example: Single wall risk = $(1 \times 10^{-5}) \times 125$ bbls + $(2 \times 10^{-7}) \times 1{,}567 = 1.6 \times 10^{-3}$ bbls

[2] Relative risk = system risk divide single wall pipe system risk

The shallower depth of cover for the pipe-in-pipe system is the main factor increasing the risk of oil spilled into the environment. In order to bring the pipe-in-pipe system alternative to about the same level of risk as the single wall, the depth of cover needs to be increased to 7 feet. This would have the effect of lowering the damage frequency for Category 3 (small or medium leak) to 10^{-6} occurrences per project lifetime, and the damage frequency of Category 4 (large leak or rupture) to 10^{-7}. Therefore, a pipe-in-pipe system with a 7-foot depth of cover would have a risk of 2.8×10^{-4} barrels of oil spilling into the environment, which is about 6 times less risk as the currently evaluated single wall pipeline system.

Increasing the pipe-in-pipe depth of cover from 5 to 7 feet has an increased cost that can be estimated with the information given in this report at about $10 million. It is estimated that the risk posed to the currently proposed single wall pipeline system can be further lowered with less expenditure.

9.3 Conclusions

The different configurations of the alternatives have different implications on the construction and installation program. For example, the single wall pipeline is to be buried in a deeper trench, whereas the pipe-in-pipe alternative has a very intensive make-up assembly and requires more equipment. On balance, the pipe-in-pipe and pipe-in-HDPE alternatives are considered to be much more difficult than the single wall or flexible alternatives to construct. Correspondingly, the pipe-in-pipe and pipe-in-HDPE alternatives are more expensive and will most likely require an additional construction season when compared to the single wall and flexible alternatives.

Monitoring of the pipeline's integrity during operation is required to allow preventive maintenance to be implemented. The single wall pipe alternative is the only solution that allows all the design aspects to be monitored during operation.

The absolute risk of oil spilled into the environment is lowest for the single wall pipeline system. The main conclusion of this risk analysis is that the safeguards provided to the single wall pipeline system — (a) depth of cover; (b) trench backfill material and procedures; (c) pipe wall thickness (low D/t); (d) cathodic protection system, anodes and coating; (e) routine geometry pig inspections; and (f) leak detection systems — provide a total system reliability that minimizes the risk of environmental oil spills to negligible levels. The single wall pipeline system is also the system that is relatively easier to repair. Therefore, the single wall pipeline system is the best system for this application.

The double wall systems, including both pipe-in-pipe and pipe-in-HDPE, are the second best. Their risk of oil spills is more than an order of magnitude greater than the single wall pipe, but the risk is still very small and acceptable. Given the higher risk, cost and the difficulty of repair, these systems are less suitable than the single wall pipeline system for this application. The risk could be decreased by increasing the depth of cover (burial depth); however, the cost would increase further.

The flexible pipe system has a risk of oil spill approximately two orders of magnitude greater than the single wall pipeline. This risk is still relatively low and can be decreased by increasing its burial depth. However, if the depth of cover is increased, the extra difficulties for installation with heavy reels, and the possible repair of 2,800-foot segments, make this alternative unattractive. This system is not recommended to this application.

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11. GLOSSARY OF TERMS

Term	Definition
AAC	Alaska Administration Code.
Annulus	The void between the outside of the inner pipe and inside of the outer pipe.
ANSI	American National Standard Institute.
API	American Petroleum Institute.
API Gravity	Gravity (weight per unit of volume) of crude oil or other liquid hydrocarbon as measured by a system recommended by the API.
ARP	Average Return Period.
ASME	American Society of Mechanical Engineers.
Backfill	Soil placed over the trenched pipeline system.
Backfill thickness	The depth from the backfill surface to the top of the pipe buried below.
Boston Square Analysis	Qualitative categorization of likelihood of occurrence and its manageability using a matrix format.
Bottom Fast Ice	Ice which is grounded.
BOPD	Barrels of Oil Per Day
Buckle	Flattening or excessive ovalization of the pipe cross section.
Bundle Make-up	The process of coupling together pipe strings.
BPXA	British Petroleum Exploration Alaska.
Breakdown	Degradation of material due to elements.
Bulkhead	Structural section used to structurally connect the outer jacket pipe to the inner carrier pipe for pipe-in-pipe arrangements.
Cathodic Protection (CP)	A means of corrosion prevention where by electrons are supplied to the pipeline from an external source such as a sacrificial anode.
CDF	Cumulative Distribution Function - Statistical term that defines how a variable is distributed cumulatively.
CFR	Code of Federal Regulations
Clamps	Internal or external device for aligning pipe ends for welding.
Clamshell	Hoe attachment capable of removing dirt vertically.
Cofferdam	A structure consisting of sheet piling and supports which is placed on the seabed and pumped dry.
Demobilization	The process of removing all equipment, facilities and personnel from site.

Term	Definition
Design Life	For this project, the pipeline system and its components are designed for a 20-year design life. However, the operational life of the pipeline may be extended beyond its design life by demonstration of its integrity.
Dielectric	A non-conductor of direct electric current.
DOC	Depth Of Cover – Distance from the original undisturbed seabed to the top of the buried pipe.
DOT	Department of Transportation.
Endicott	Process facility west of Liberty Development.
Engineering Failures	There are a number of pipeline conditions that would be considered to be engineering failures. The associated consequence is not necessarily oil spilled to the environment. Examples of these conditions are: *Serviceability Limit State* A potentially undesirable pipeline condition. A serviceability condition is generally within the limits of the design criteria, however it may need close monitoring and perhaps future corrective action. This condition is unlikely to require immediate shutdown of the pipeline system. *Ultimate Limit State (ULS)* A pipeline condition characterized by a deformation of the pipeline, which disrupts the normal operation of the pipeline system without creating a leak. It will likely require the shutdown of the pipeline system in order to take the necessary corrective action. The following examples will describe this situation: local buckling or cross-section collapse without fracture, upheaval buckling leading to pipeline exposure, excessive corrosion leading to wall thickness reduction, pipeline dent due to excessive bending. *Ultimate Limit State with Leak* Worst case scenario of a pipeline failure condition resulting in fracture/rupture of the pipeline and the consequent leaking.
EOR	Enhanced Oil Recovery – The application of secondary and tertiary methods (i.e. waterflooding, gas lift etc.) to recover oil after a well's original rate of production has diminished.
ERW	Electric Resistant Welding – Welding technique normally used during pipe manufacture.

Term	**Definition**
ESD Valve	Emergency Shut Down Valve – Valve used to stop the operation of the pipeline.
Extreme Event	An event beyond that which the pipeline was defined for.
Failure Analysis	Analysis performed on the pipeline system to determine the possible occurrence of a pipeline failure.
Failure Assessment Categories	Category 1 Damage – Displaced Pipeline (no leaks or buckle). Category 2 Damage – Buckles without leak. Category 3 Damage – Small to medium leak. Category 4 Damage – Rupture or large leak.
FEA	Finite Element Analysis – Computer based method used to model and analyze complex mediums.
FBE	Fusion Bonded Epoxy – a type of protective coating that helps prevent corrosion or damage to the pipeline.
FEIS	Final Environmental Impact Statement.
Flexural Rigidity	The product of Young's Modulus (E) and Second Moment of Area (I) – EI quantifies the stiffness of the pipeline.
Geometry Pig	Type of smart pig that is used to determine the condition of the internal profile of the pipeline.
GPR	Ground Penetrating Radar.
Gravel Mat	Mat of composite material filled with gravel. For Liberty single pipe solution it is used to avoid upheaval buckling.
Guillotine Break	Complete rupture or shearing of the pipeline.
Hazard	An initiating event which could cause damage to the pipeline.
HPDE	High-Density Polyethylene Polymer (thermoplastic material).
H_s	Significant Wave Height.
Hydrodynamic	Forces generated as a consequence of a moving fluid.
Hyperbaric Welding Chamber	Enclosure that permits "dry welding" of pipeline on the seafloor. Any sea water is displaced with breathing-gas mixtures for the diver welders, permitting them to work in the dry but high pressure atmosphere.
Hyperbolic Spring	Assumed force-displacement response of soil loading on the pipeline.
Ice Gouge	Gouge in the seabed that is formed by irregular ice keels making periodical contact with the seabed.
Ice Keel	Irregular ice blocks that shift beneath the floating sea ices and periodically come in contact with the seabed.

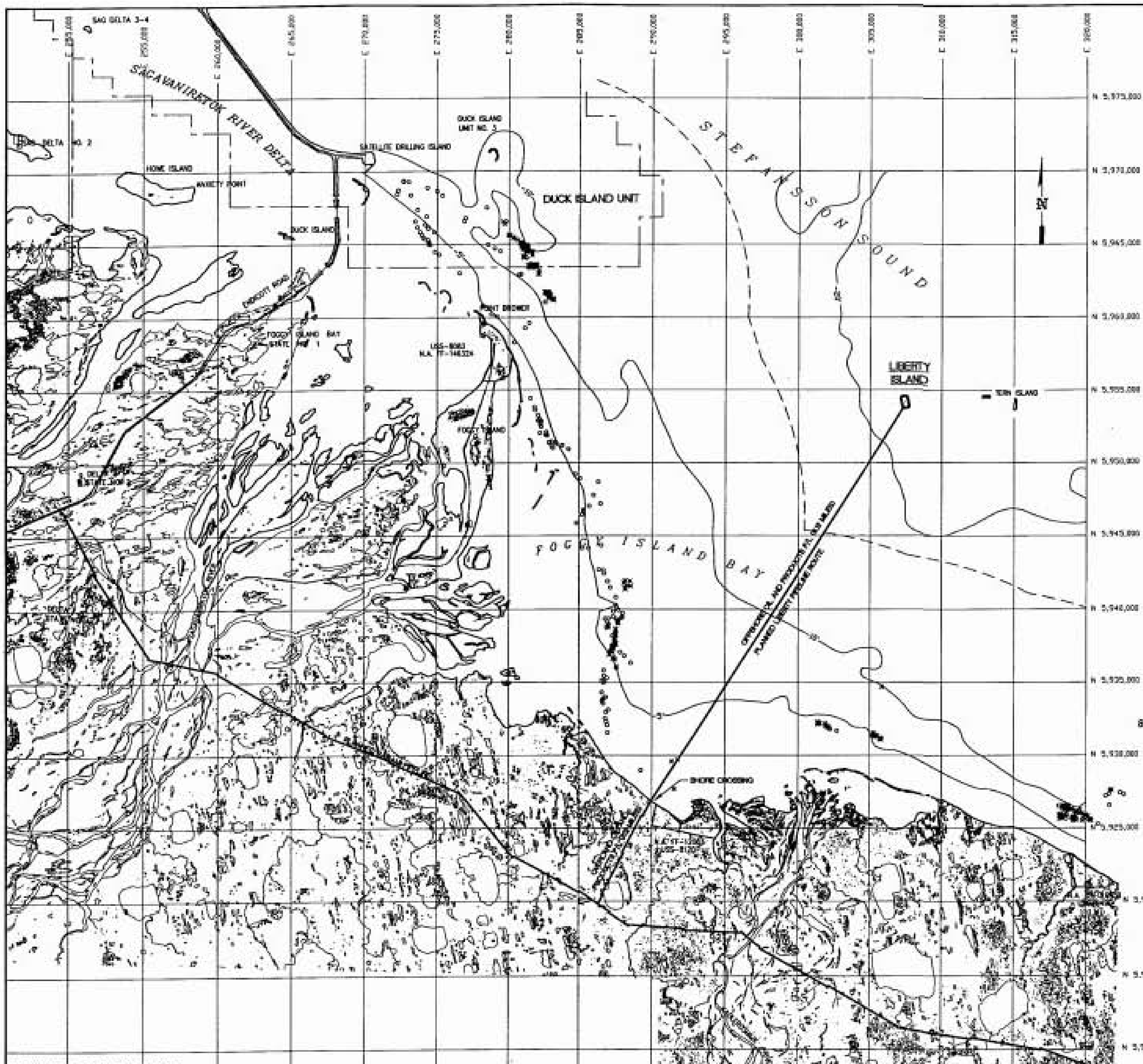
Term	Definition
Ice Ride-Up	Condition occurring when ice flow is resisted by some physical obstruction – the ice “rides-up” over the obstruction.
IDO	Incident of Damage during Operation.
Inner Carrier	Internal pipeline of a pipe-in-pipe system – This pipeline transports the fluid.
Isobath	Contour line on a map that identifies areas with the same water depth.
Isotropic	Properties are the same in every direction.
Joint	Length of pipe
Kinematic Hardening Plasticity	A type of material behavior model.
Landfast Ice	Ice which forms and remains fast along the coast.
Latent Heat	Amount of heat released or absorbed when a substance change its physical phase with no change in temperature.
LACT	Lease Automatic Custody Transfer.
LEOS	Siemens leak detection system for oil pipeline.
Liberty Island	A planned man-made island to be located off the Northern coast of Alaska just east of the Sag River Delta in Foggy Island Bay.
Locked-In Axial Compressive Force	Axial compressive force which occurs when a pipeline tries to expand due to thermal effects but is prevented from doing so.
Material Non-Linearity	Non-linear behavior of a material.
MAOP	Maximum Allowable Operating Pressure – The rating of the pipeline system for the pressure conditions it will be exposed to.
MBLPC	Mass Balance Line Pack Compensation – A method of leak detection in a pipeline system.
MLLW	Mean Low Level Water – Standard reference water level elevation.
NDE	Non Destructive Examination – Describes techniques used to determine weld defects without directly interfering with pipe material.
MSL	Mean Sea Level - Standard reference water level elevation.
OD	Outside Diameter.
Ovalization	Parameter that quantifies the out of the roundness of the pipeline.
Outer jacket	External steel pipe of a pipe-in-pipe system or outer HDPE pipe of a pipe-in-HDPE system.

Term	Definition
Owner	Company for whom pipeline is being built.
PDF	Probability Distribution Formula – Statistical method describing the distribution of a physical property.
Permafrost	Persistence of ground temperature below 0°F for over two years.
Pig Trap	A pressure containing system that allows pigs to be launched or received into or from the pipeline ends.
Pipe-in- HDPE	Pipeline system alternative for oil/gas transmission characterized by placing a steel pipeline inside a plastic (high-density polyethylene) pipeline.
Pipe-in-Pipe	Pipeline arrangement for oil/gas transmission characterized by placing a steel pipeline (inner carrier) inside another steel pipeline (outer jacket) concentrically.
PPA	Pressure Point Analysis – A method of leak detection in a pipeline system.
Pipe String	Several pipe joints welded together.
Probability Density Function (PDF)	A mathematical expression of probability.
psig	Pounds per square inch gauge.
QA/QC	Quality Assurance/Quality Control
Redundancy	Components beyond which are necessary.
Resistivity	A materials resistance to electric current.
Riser Casing	A large diameter cylinder that provides a protective void in which a riser (vertical pipe) can be placed. The riser casing enables pipe movement without passive soil resistance being mobilized.
Risk Analysis	Numerical quantification of the probability of a certain event occurring. This review can be performed on the pipeline system to determine the likelihood of events occurring and assessing whether design modifications are required to reduce this probability.
Route alignment	Selected route for the laying of the pipeline.
ROW	Right-of-Way - A permit required by law to build and operate a pipeline.
Sacrificial Anode	A block of nonferrous metal connected to the pipeline at regular intervals. The anode establishes a weak electric current that flows to the pipeline, thus reversing the flow of current that is associated with corrosion.

Term	Definition
SCADA	Supervisory Control And Data Acquisition.
Shore crossing	Area on the route alignment where the offshore pipeline becomes an onshore pipeline – transition of the pipeline from below water to above ground.
Sideboom	A tractor with a side operating crane.
Single Beam Fathometer	A device to measure bathymetry.
Slip Joint	A joint which can accommodate slippage or axial movement.
Smart Pig	Instrumented internal inspection device that is used to determine the condition of the pipeline. Smart pigs, by travelling through the pipeline, can detect erosion, pitted areas, out-of-round spots and incipient cracks. It is launched at one end of the pipeline and received at the other end.
SMAW	Shield Metal Arc Welding - A type of welding procedure used in the pipeline industry.
Sole	Pipe shell used in pipeline repair.
Soil Survey	Geological program to determine the soil conditions along the route alignment.
Spacer	Applies to pipe-in-pipe system – ensures the inner carrier pipe is concentric relative to the outer jacket pipe.
Span Length	Distance between two points along a pipeline where the pipeline is unsupported.
Specific Gravity	Ratio of the density of a component or material to the density of water at a given temperature.
Split Sleeve	A sleeve for repair which is split to accommodate installation.
Spool Piece	Length of pipe used to replace the section of pipeline removed during repair.
Storm Surge	Sea level rise due to major storm.
Stove Pipe	A method of pipeline construction where one pipe is slipped inside a second pipe.
Strain	Any forced change in the dimensions of a body.
Strudel Scours	This describes when a river overflows the sea ice sheet at the river delta, and the overflooding water finds holes or cracks in the ice to the seawater below. This flow tends to have enough velocity to displace the sea floor sediment thus scouring the seabed.
Surface Tie-in	The process of lifting both pipeline ends to surface and joining them .
Submerged Weight	Weight of a component (e.g. pipeline) when submerged in water.

Term	Definition
Thaw Bulb	Thawed bulb-shaped zone of soil underneath the pipeline formed by the pipeline operating at temperatures higher than the original soil temperature.
Thaw Settlement	Settlement of the soil in ice bounded permafrost due to the warm pipeline temperature thawing the soil.
Thermal Conductivity	The ability of a substance to transfer heat.
Thermal Expansion Loop	Section of pipe that is designed to deflect and therefore absorb the thermal expansion and contraction associated with pipeline operation.
T_{PEAK}	Period associated with the peak wave.
Tonne	2204 lbs (1000 kg).
UOE	Describes method of bending plate of steel into a U-shape, then into a rough O-shape, welded at the seam and then Expanded by a hydraulic die into a circular pipe.
UT	Ultrasonic Testing (NDE method).
Upheaval Buckling	A condition of vertical movement of a pipeline from its installed position due to forces induced by the operating temperature pressure effects.
UTM	Universal Transverse Mercator – A geographic coordinate system.
Vertical Riser	Section of pipe that achieves vertical transition in elevation.
Virtual Anchor	The effect of restraint of a pipeline due to friction between the pipe and the soil.
VPE	Cross linked high density polyethylene.
Water Head	Height of water column that can exert a hydrostatic pressure.
Worst Case Load	For this project, this term refers to the design load case for a particular environment loading (e.g., due to ice gouge) or functional loading (e.g., due to internal pressure), which constitutes an extreme event, typically with a return period of one hundred years.
WT	Wall thickness of pipe.
Zig-Zag Pipe	Pipeline configuration where each pipe joint has a bend of approximately 8 degrees – this allows lateral expansion and thus reduces the magnitude of compressive forces locked into the pipeline.

APPENDIX A
DRAWINGS



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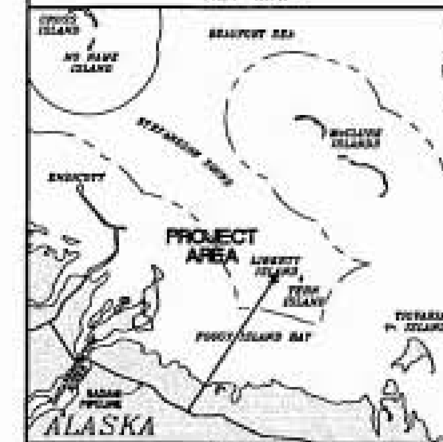
KEY MAP



NOTES

1. THIS MAP IS BASED ON DIGITAL MAP FILES PROVIDED BY BP CARTOGRAPHY AND IS THE PROPERTY OF BP EXPLORATION (ALASKA) INC.
2. TRANSVERSE MERCATOR PROJECTION, ALASKA COORDINATE SYSTEM 1927, ZONE 3, CLARKE 1866 SPHEROID. GRID UNITS ARE IN FEET.
3. WATER DEPTHS IN FEET BELOW MLLW.

LEGEND

- WATER DEPTHS (IN FEET BELOW MLLW)
- UNIT BOUNDARY
- TERRITORIAL SEA LINE (3 NAUTICAL MILES)
- ROAD
- STRUDEL SCOUR LOCATION (IN SEABED)
- STRUDEL HOLE LOCATION (IN ICE)

SCALE (STATUTE MILE)

0 1/2 1 1 1/2 2 3

REFERENCE DRAWINGS	NO.	DATE	REVISION	BY	CHK	APPD	NO.	DATE	REVISION	BY	CHK	APPD	APPROVAL
	0A	8-15-97	ISSUED FOR REVIEW	JEC	JBS	CAL							
	0B	2-15-98	ISSUED FOR DESIGN SUMMARY	KGC									

ENGINEERING RECORD		DATE
DRAWN BY:	JEC	7-15-97
DESIGNED BY:		
DESIGN CHECKED:		
APPROVED BY:		
APPROVED BY:		
WORK PKG:		
SCALE: AS NOTED		

BP EXPLORATION

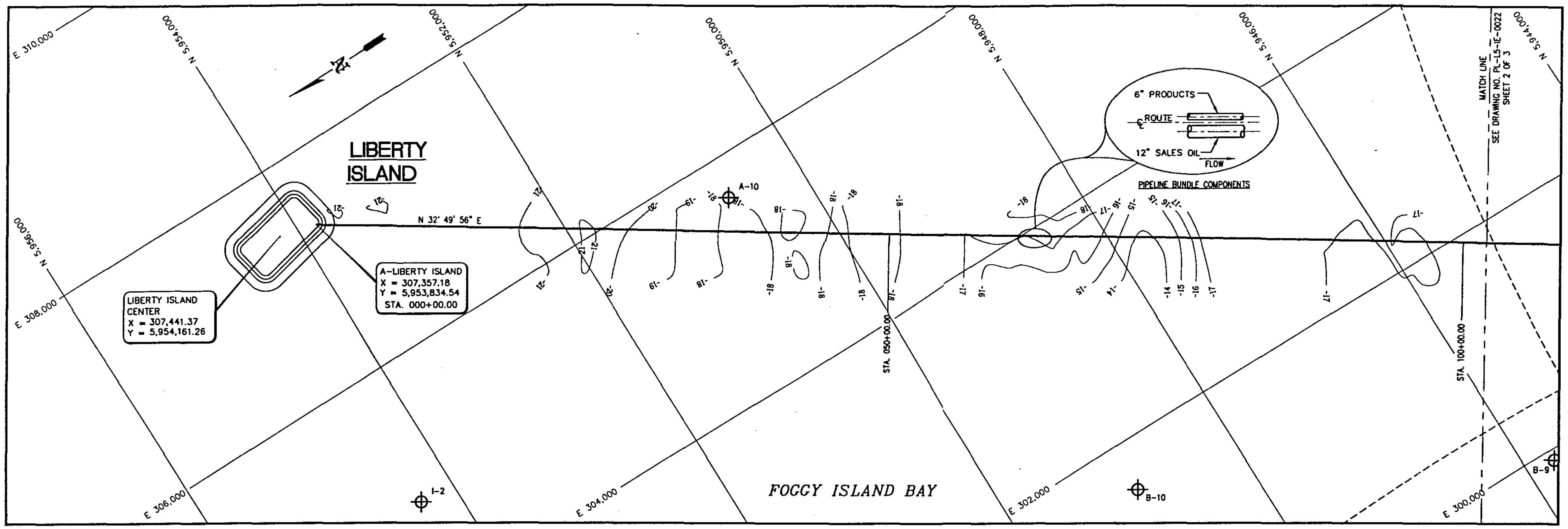
INTEC ENGINEERING

LIBERTY

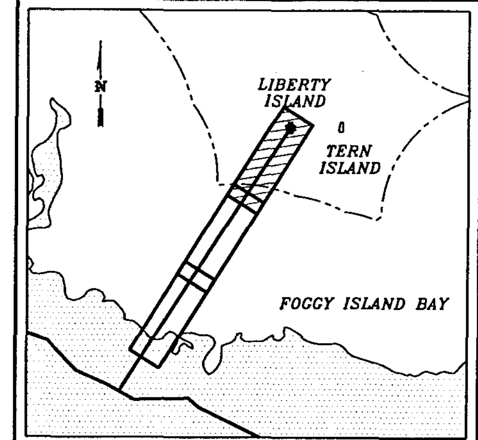
TITLE OF DRAWING

PIPELINE GENERAL ARRANGEMENT

PROJECT & MODULE I.D.	DRAWING NUMBER	SHEET
L I B - G E N	P L - L 5 - I E - 0 0 0 2 - 0 B	0 0 1
PROJECT / MODULE	DISC. / FAC. / CONT I.D. / SEQUENCE NO. / REV.NO.	OF 1



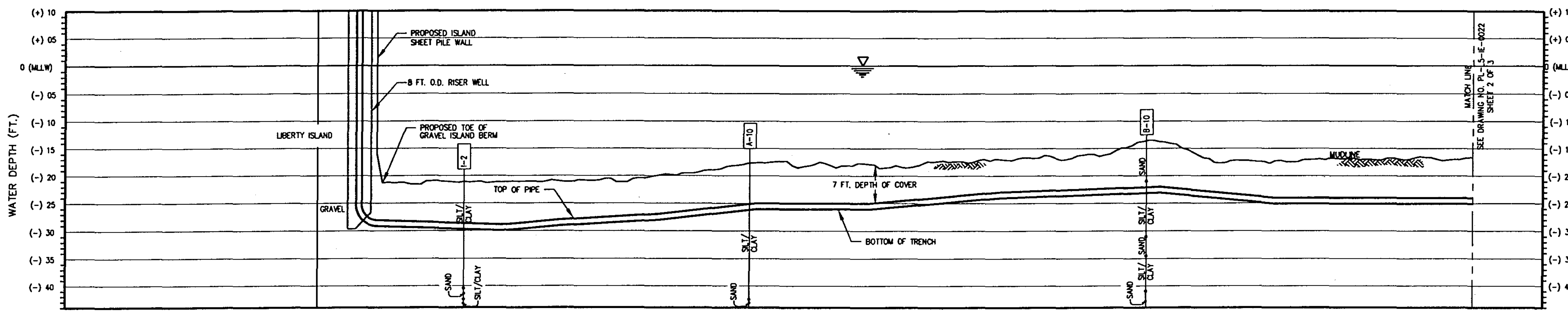
KEY PLAN



PTS.	X	Y	STATION	DESCRIPTION
A	307,357.18	5,953,834.54	000+00.00	LIBERTY ISLAND
PI-1	289,849.43	5,926,701.37	322+91.33	PI-1
B	289,834.59	5,926,673.02	323+23.33	SHORE CROSSING

NOTES

1. TRANSVERSE MERCATOR PROJECTION, ALASKA COORDINATE SYSTEM 1927, ZONE 3, CLARKE 1866 SPHEROID. GRID UNITS ARE IN FEET.
2. WATER DEPTHS ARE IN FEET BELOW MLLW.
3. PIPELINE DEPTH OF COVER IS THE DISTANCE FROM THE TOP OF PIPE TO ORIGINAL SEABED, REGARDLESS OF THE AMOUNT OF BACKFILL OVER THE PIPE. SEE DWG PL-L5-IE-0028 FOR BACKFILL REQUIREMENTS.
4. BATHYMETRY FROM 1997 CFC SURVEY (PRELIMINARY DATA).



LEGEND

- PROPOSED PIPELINE ROUTE
- B-10 — 1997 BOREHOLE SAMPLE LOCATION
- APPROXIMATE TERRITORIAL SEA LINE (3 NAUTICAL MILES)
- B-10 — BOREHOLE TAG
- SOIL STRATIGRAPHY DEMARCATION LIMIT
- N/A — BOREHOLE DEPTH LIMIT

SCALE (FEET)

0 500 1000 1500

PROFILE: HORIZ. = 1 IN. = 500 FT.
VERT. = 1 IN. = 10 FT.

STA. 000+00.00 LIBERTY ISLAND — STA. 102+00.00 MATCH LINE

SALES OIL		
PIPE SIZE AND GRADE	SEE DRAWING No. PL-L5-IE-0041	12.75-IN. O.D. x 0.688-IN. W.T. API 5L GRADE X-52 (OFFSHORE PIPE SPEC.)
PIPE COATING	SEE DRAWING No. PL-L5-IE-0041	FBE (40 MILS. THK.)
DRY/SUBMERGED WEIGHT (EMPTY)	SEE DRAWING No. PL-L5-IE-0041	89.9 LB./FT. / 32.4 LB./FT.
ANODE WEIGHT AND SPACING	SEE DRAWING No. PL-L5-IE-0041	56.0 LB. @ 240 FT.
DEPTH OF COVER	SEE DRAWING No. PL-L5-IE-0041	7 FT.

PRODUCTS		
PIPE SIZE AND GRADE	SEE DRAWING No. PL-L5-IE-0041	6.625-IN. O.D. x 0.432-IN. W.T. API 5L GRADE X-52 (OFFSHORE PIPE SPEC.)
PIPE COATING	SEE DRAWING No. PL-L5-IE-0041	FBE (40 MILS. THK.)
DRY/SUBMERGED WEIGHT (EMPTY)	SEE DRAWING No. PL-L5-IE-0041	29.2 LB./FT. / 13.5 LB./FT.
ANODE WEIGHT AND SPACING	SEE DRAWING No. PL-L5-IE-0041	20.5 LB. @ 240 FT.
DEPTH OF COVER	SEE DRAWING No. PL-L5-IE-0041	7 FT.

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CONSTRUCTION DETAILS

REFERENCE DRAWINGS		NO.	DATE	REVISION	BY	CHK	APPD	NO.	DATE	REVISION	BY	CHK	APPD	APPROVAL
PL-L5-IE-0022	OFFSHORE ALIGNMENT PLAN AND PROFILE SHEET 2 OF 3	0A	8-18-97	ISSUED FOR REVIEW	KGC	JBS	GAL							
PL-L5-IE-0023	OFFSHORE ALIGNMENT PLAN AND PROFILE SHEET 3 OF 3	0B	2-26-98	ISSUED FOR DESIGN SUMMARY	KGC	JBS	GAL							
		0C	3-11-98	REVISED PROFILE PANEL	KGC	JBS	GAL							

ENGINEERING RECORD		DATE
DRAWN BY:	KGC	7-25-97
DESIGNED BY:		
DESIGN CHECKED:		
APPROVED BY:		
APPROVED BY:		
WORK PKG:		
SCALE: 1 in. = 500 ft.		

BP EXPLORATION

INTEC ENGINEERING

LIBERTY

TITLE OF DRAWING:

OFFSHORE ALIGNMENT PLAN AND PROFILE SHEET 1 OF 3

PROJECT & MODULE I.D.		DRAWING NUMBER					SHEET
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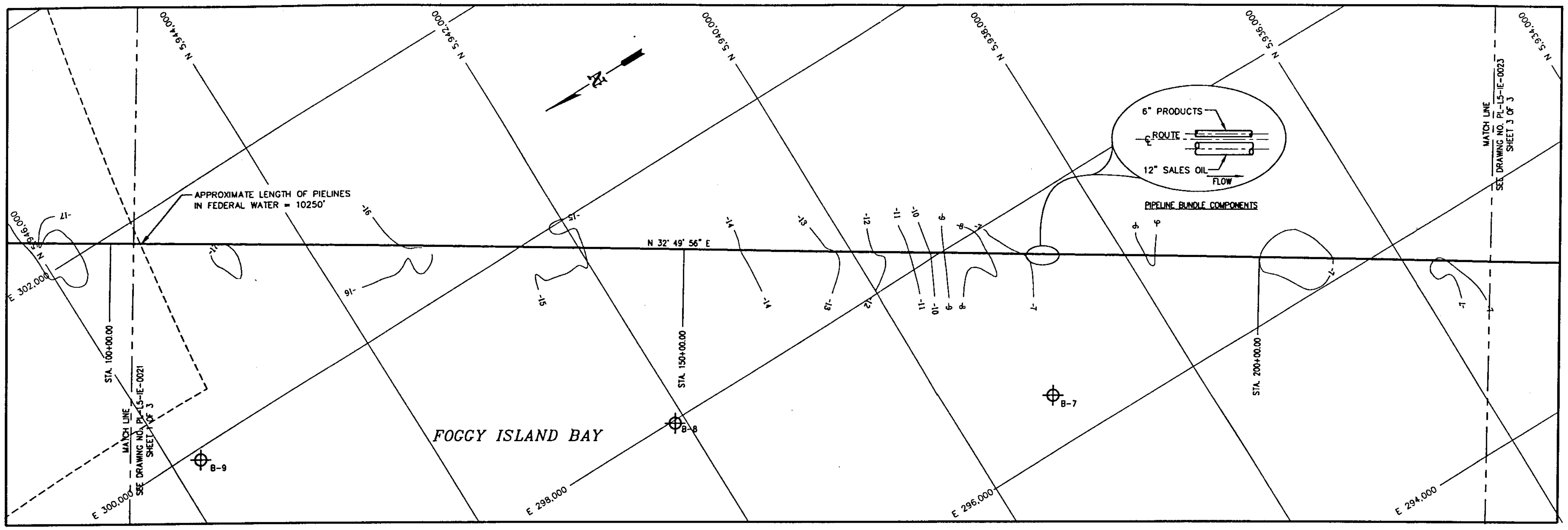
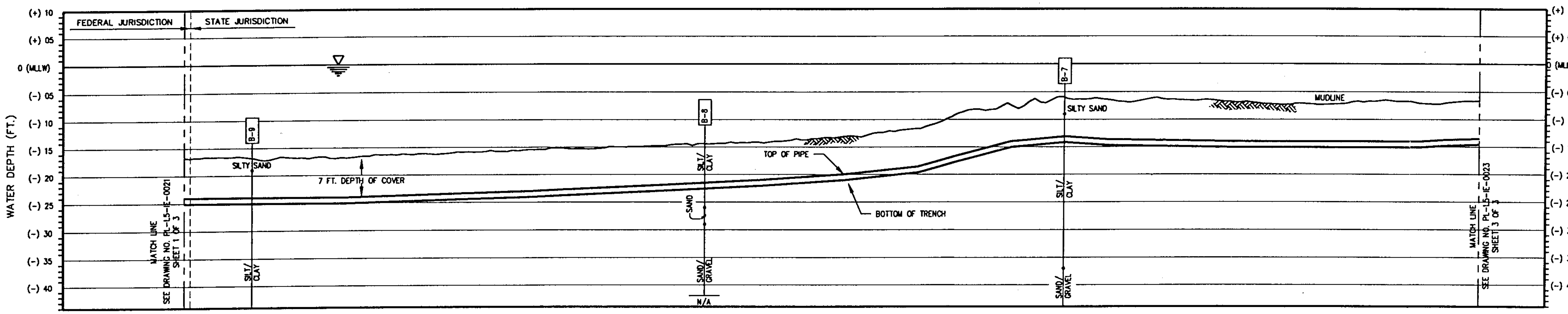
PROJECT	MODULE	DISC.	FAC.	CONT.I.D.	SEQUENCE NO.	REV.NO.	





STA. 102+00.00 MATCH LINE | STA. 102+50.00 | STA. 220+00.00 MATCH LINE

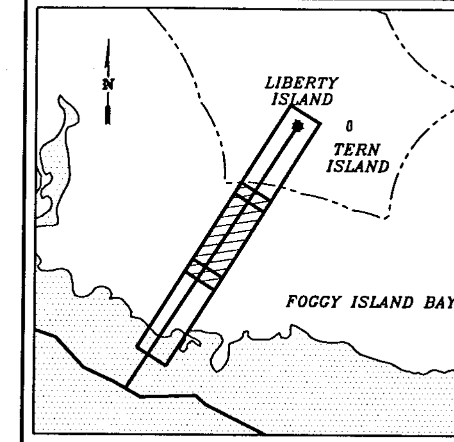
SALES OIL	
PIPE SIZE AND GRADE	12.75-IN. O.D. x 0.688-IN. W.T. API 5L GRADE X-52 (OFFSHORE PIPE SPEC.)
PIPE COATING	FBE (40 MILS. THK.)
DRY/SUBMERGED WEIGHT (EMPTY)	89.9 LB./FT. / 32.4 LB./FT.
ANODE WEIGHT AND SPACING	56.0 LB. @ 240 FT.
DEPTH OF COVER	7 FT.

PRODUCTS	
PIPE SIZE AND GRADE	6.625-IN. O.D. x 0.432-IN. W.T. API 5L GRADE X-52 (OFFSHORE PIPE SPEC.)
PIPE COATING	FBE (40 MILS. THK.)
DRY/SUBMERGED WEIGHT (EMPTY)	29.2 LB./FT. / 13.5 LB./FT.
ANODE WEIGHT AND SPACING	20.5 LB. @ 240 FT.
DEPTH OF COVER	7 FT.

CONSTRUCTION DETAILS

FILE: 8512-022D.DWG OCT 1, 1998 1:14 PM JAS

KEY PLAN



PTS.	X	Y	STATION	DESCRIPTION
A	307,357.18	5,953,834.54	000+00.00	LIBERTY ISLAND
PI-1	289,849.43	5,926,701.37	322+91.33	PI-1
B	289,834.59	5,926,673.02	323+23.33	SHORE CROSSING

NOTES

1. TRANSVERSE MERCATOR PROJECTION, ALASKA COORDINATE SYSTEM 1927, ZONE 3, CLARKE 1866 SPHEROID. GRID UNITS ARE IN FEET.
2. WATER DEPTHS ARE IN FEET BELOW MLLW.
3. PIPELINE DEPTH OF COVER IS THE DISTANCE FROM THE TOP OF PIPE TO ORIGINAL SEABED, REGARDLESS OF THE AMOUNT OF BACKFILL OVER THE PIPE. SEE DWG PL-L5-IE-0028 FOR BACKFILL REQUIREMENTS.
4. BATHYMETRY FROM 1997 CFC SURVEY (PRELIMINARY DATA).

LEGEND

- PROPOSED PIPELINE ROUTE
- B-10 1997 BOREHOLE SAMPLE LOCATION
- APPROXIMATE TERRITORIAL SEA LINE (3 NAUTICAL MILES)
- B-10 BOREHOLE TAG
- SOIL STRATIGRAPHY DEMARCATION LIMIT
- N/A BOREHOLE DEPTH LIMIT

SCALE (FEET)

0 500 1000 1500

PROFILE: HORIZ. = 1 IN. = 500 FT.
VERT. = 1 IN. = 10 FT.

REFERENCE DRAWINGS	
PL-L5-IE-0021	OFFSHORE ALIGNMENT PLAN AND PROFILE SHEET 1 OF 3
PL-L5-IE-0023	OFFSHORE ALIGNMENT PLAN AND PROFILE SHEET 3 OF 3

NO.	DATE	REVISION	BY	CHK	APPD
0A	8-18-97	ISSUED FOR REVIEW	KGC	JBS	GAL
0B	2-26-98	ISSUED FOR DESIGN SUMMARY	KGC	JBS	GAL
0C	3-11-98	FEDERAL AND STATE JURISDICTIONS SHOWN AND REVISED PROFILE PANEL	KGC	JBS	GAL

APPROVAL

ENGINEERING RECORD		DATE
DRAWN BY:	KGC	7-25-97
DESIGNED BY:		
DESIGN CHECKED:		
APPROVED BY:		
APPROVED BY:		
WORK PKG:		
SCALE: 1 in. = 500 ft.		

BP EXPLORATION

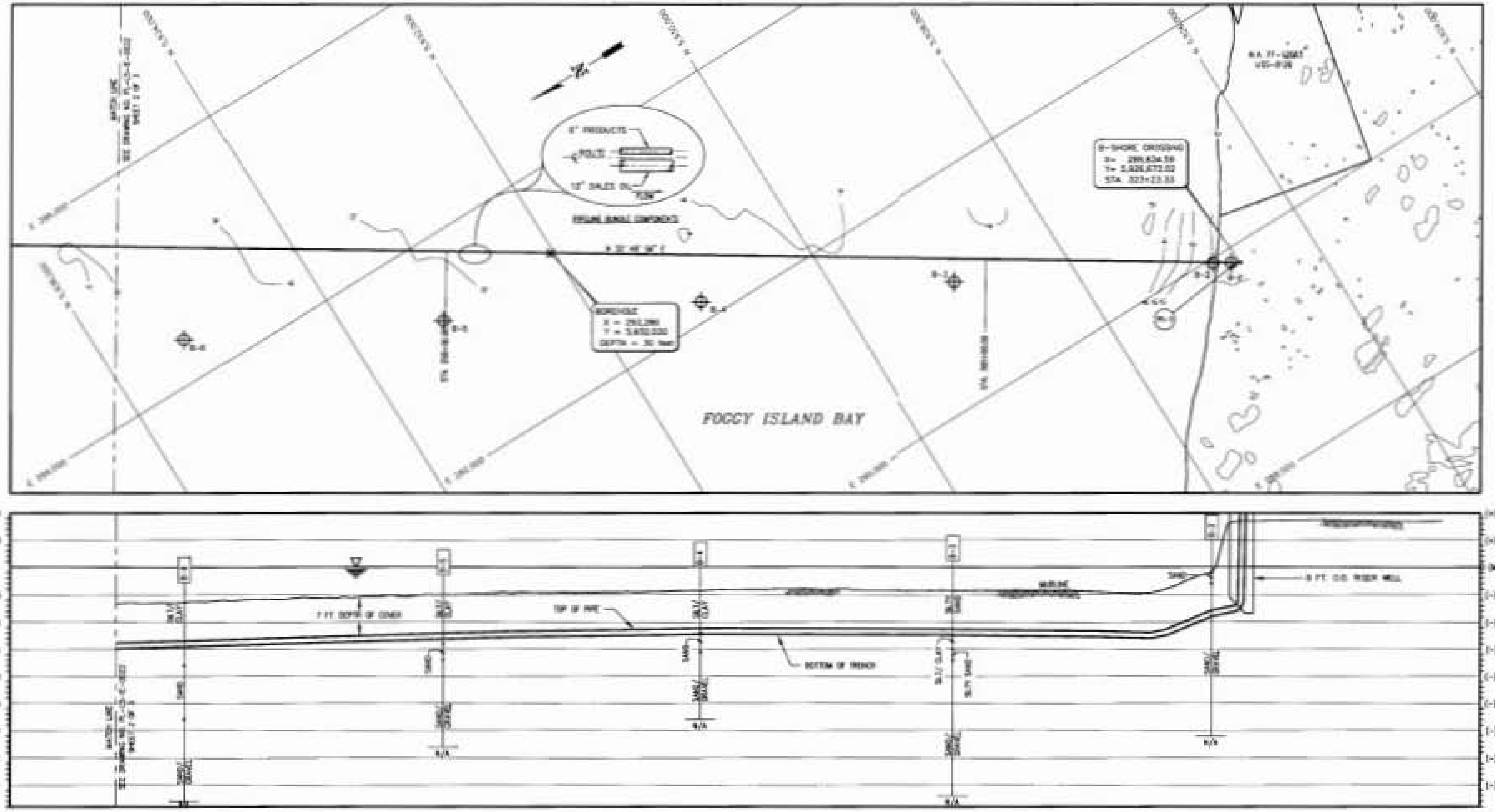
INTEC ENGINEERING

LIBERTY

TITLE OF DRAWING:

OFFSHORE ALIGNMENT PLAN AND PROFILE SHEET 2 OF 3

PROJECT & MODULE I.D.	DRAWING NUMBER	SHEET
L I B - G E N	P L - L 5 - I E - 0 0 2 2 - 0 C	0 0 1 OF 1
PROJECT / MODULE	DISC. / FAC. / CONT.I.D. / SEQUENCE NO. / REV.NO.	



SALES OIL

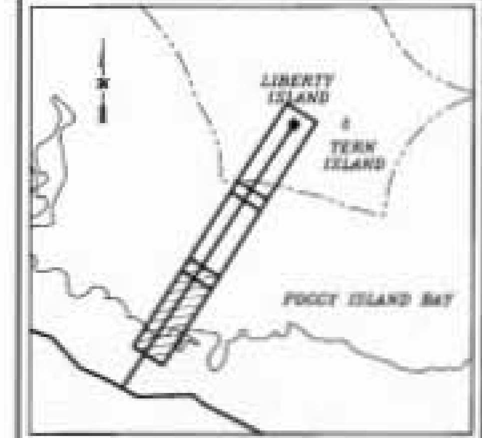
PIPE SIZE AND GRADE	12.75-IN. O.D. x 0.688-IN. W.T. API 5L GRADE X-52 (OFFSHORE PIPE SPEC) — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
PIPE COATING	TBE (40 MILS. THK) — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
DRY/SUBMERGED WEIGHT (EMPTY)	89.9 LB./FT. / 32.4 LB./FT. — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
ANODE WEIGHT AND SPACING	56.0 LB. @ 240 FT. — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
DEPTH OF COVER	7 FT. — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA

PRODUCTS

PIPE SIZE AND GRADE	8.625-IN. O.D. x 0.432-IN. W.T. API 5L GRADE X-52 (OFFSHORE PIPE SPEC) — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
PIPE COATING	TBE (40 MILS. THK) — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
DRY/SUBMERGED WEIGHT (EMPTY)	39.2 LB./FT. / 13.5 LB./FT. — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
ANODE WEIGHT AND SPACING	20.5 LB. @ 240 FT. — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA
DEPTH OF COVER	7 FT. — SEE DWG. PL-L5-IE-0050 FOR PIPELINE SHORE CROSSING DATA

CONSTRUCTION DETAILS

KEY PLAN



NOTES

1. TRANSVERSE MERCATOR PROJECTION, ALASKA COORDINATE SYSTEM 1927, ZONE 3, CLARKE 1866 SPHEROID. GRID UNITS ARE IN FEET.
2. WATER DEPTHS ARE IN FEET BELOW MLLW.
3. PIPELINE DEPTH OF COVER IS THE DISTANCE FROM THE TOP OF PIPE TO ORIGINAL SEABED, REGARDLESS OF THE AMOUNT OF BACKFILL OVER THE PIPE. SEE DWG PL-L5-IE-0020 FOR BACKFILL REQUIREMENTS.
4. BATHYMETRY FROM 1997 OTC SURVEY (PRELIMINARY DATA).

LEGEND

- PROPOSED PIPELINE ROUTE
- 1997 BOREHOLE SAMPLE LOCATION
- APPROXIMATE TERRITORIAL SEA LINE (3 NAUTICAL MILES)
- BOREHOLE TAG
- SOIL STRATIGRAPHY DEMARCATION LIMIT
- BOREHOLE DEPTH LIMIT

SCALE (FEET)

0 500 1000 1500

PROFILE: HORIZ. = 1 IN. = 500 FT.
VERT. = 1 IN. = 10 FT.

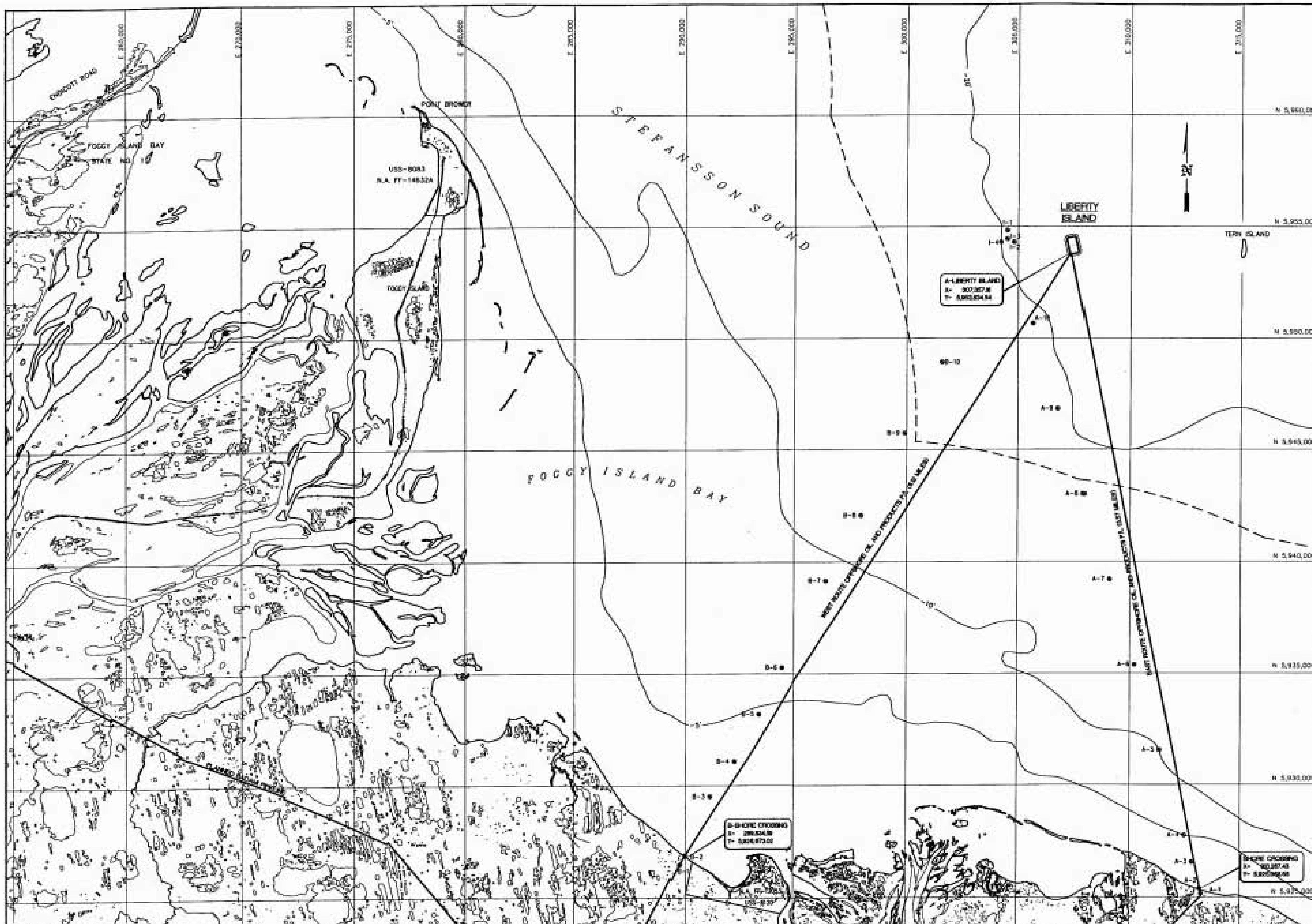
BP EXPLORATION

INTEC ENGINEERING

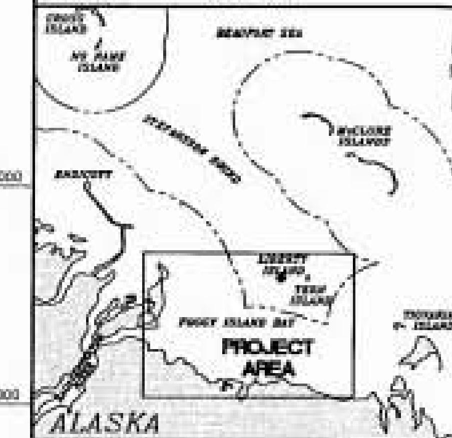
LIBERTY

OFFSHORE ALIGNMENT
PLAN AND PROFILE
SHEET 3 OF 3

PROJECT & MODULE I.D.	DRAWING NUMBER	SHEET
L I B - G E N	P L - L 5 - I E - 0 0 2 3 - 0 C	0 0 1 OF 1



KEY MAP



NOTES

1. THIS MAP IS BASED ON DIGITAL MAP FILES PROVIDED BY BP CARTOGRAPHY AND IS THE PROPERTY OF BP EXPLORATION (ALASKA) INC.
2. TRANSVERSE MERCATOR PROJECTION, ALASKA COORDINATE SYSTEM 1927, ZONE 3, CLARKE 1866 SPHEROID. GRID UNITS ARE IN FEET.
3. WATER DEPTHS IN FEET BELOW MLLW.

LEGEND

- PROPOSED LIBERTY PIPELINE ROUTES
- A-7 — 1997 BOREHOLE SAMPLE LOCATION
- -20' — BATHYMETRY FROM NOAA CHART 16061, BASED ON 1949 - 1950 SOUNDINGS.
- TERRITORIAL SEA LINE (3 NAUTICAL MILES)
- ROAD

REFERENCE DRAWINGS		NO.	DATE	REVISION	BY	CHK	APPD
PL-L5-IE-0003	PIPELINE GENERAL ARRANGEMENT	0A	8-18-97	ISSUED FOR REVIEW	JES	JBS	CAL
		0B	2-26-98	ISSUED FOR DESIGN SUMMARY	KGC	JBS	CAL

NO.	DATE	REVISION	BY	CHK	APPD	APPROVAL

ENGINEERING RECORD		DATE
DRAWN BY:	JEG	3-22-97
DESIGNED BY:		
DESIGN CHECKED:		
APPROVED BY:		
APPROVED BY:		
WORK PKG:		
SCALE: 1 IN. = 2000 FT.		

BP EXPLORATION

INTEC ENGINEERING

LIBERTY

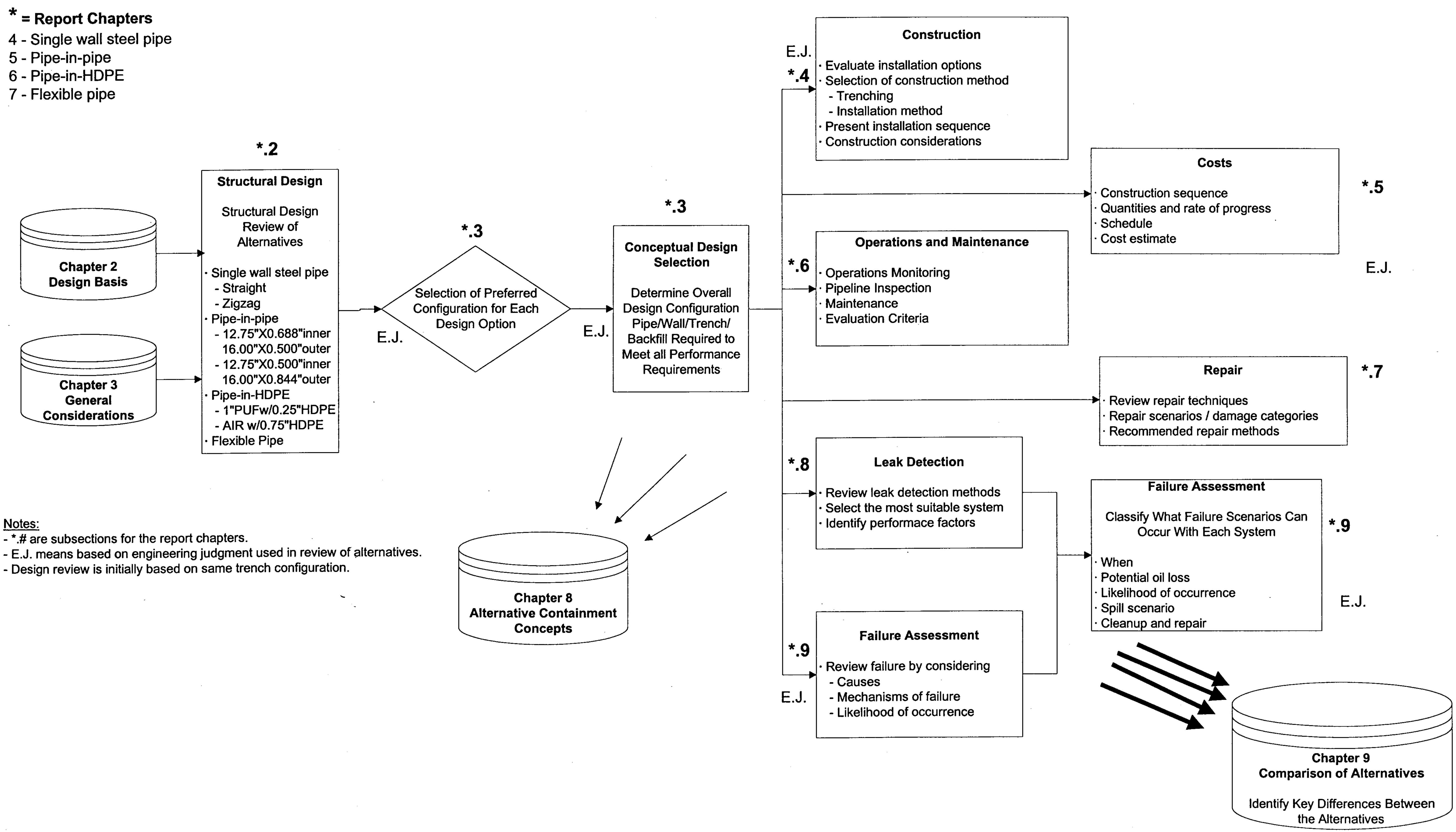
TITLE OF DRAWING:

OFFSHORE PIPELINE ROUTE OPTIONS

PROJECT & MODULE I.D.		DRAWING NUMBER					SHEET	
LIB	GEN	PL	L5	IE	0010	0B	001	
PROJECT	MODULE	DISC.	FAC.	CONT.I.D.	SEQUENCE NO.	REV.NO.	OF	1

APPENDIX B
FIGURES

Figure 1-1: Flowchart Summarizing Report Structure



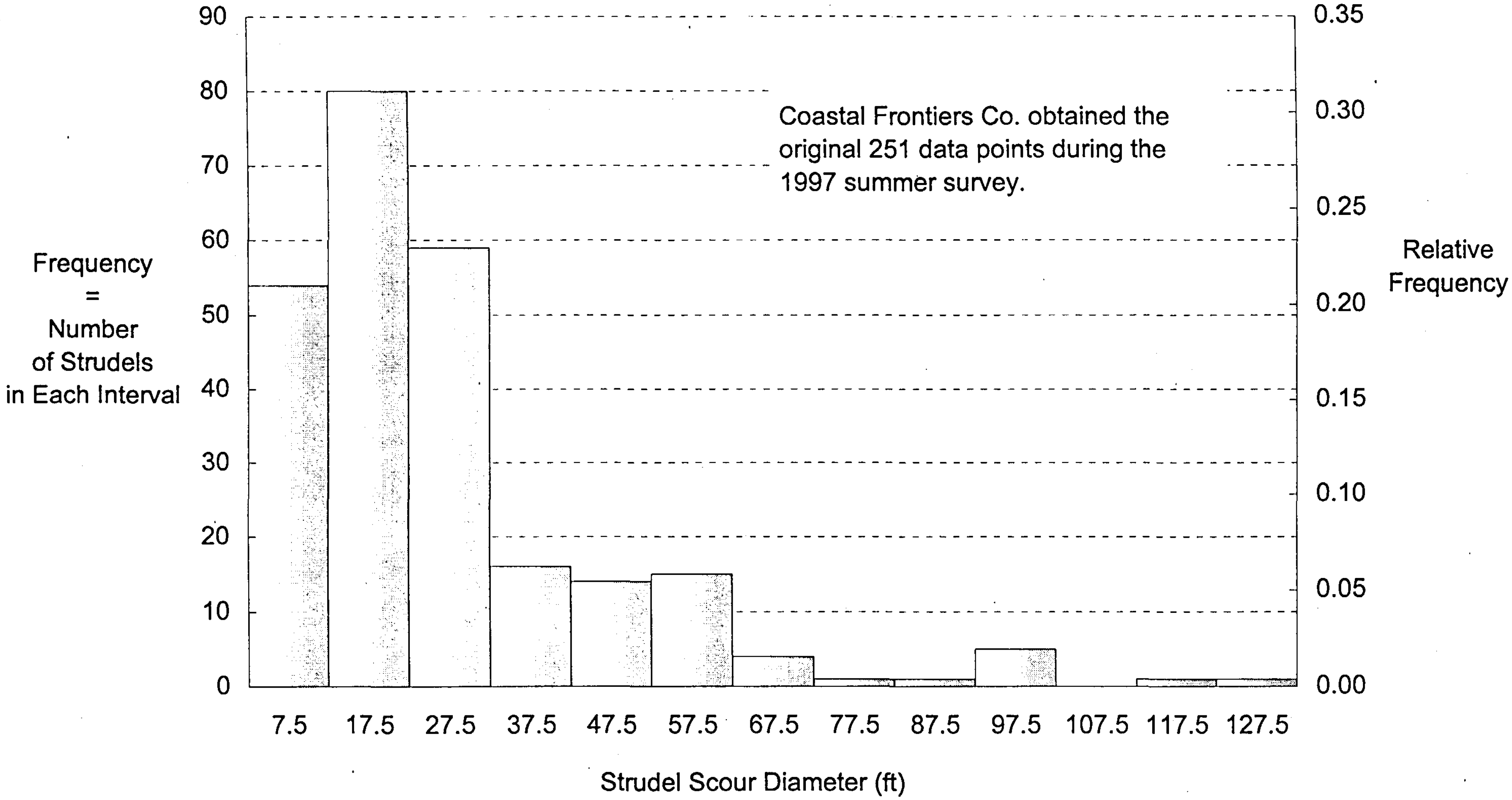


Figure 2-1: Histogram of Strudel Diameters in the Vicinity of Liberty Pipeline Route

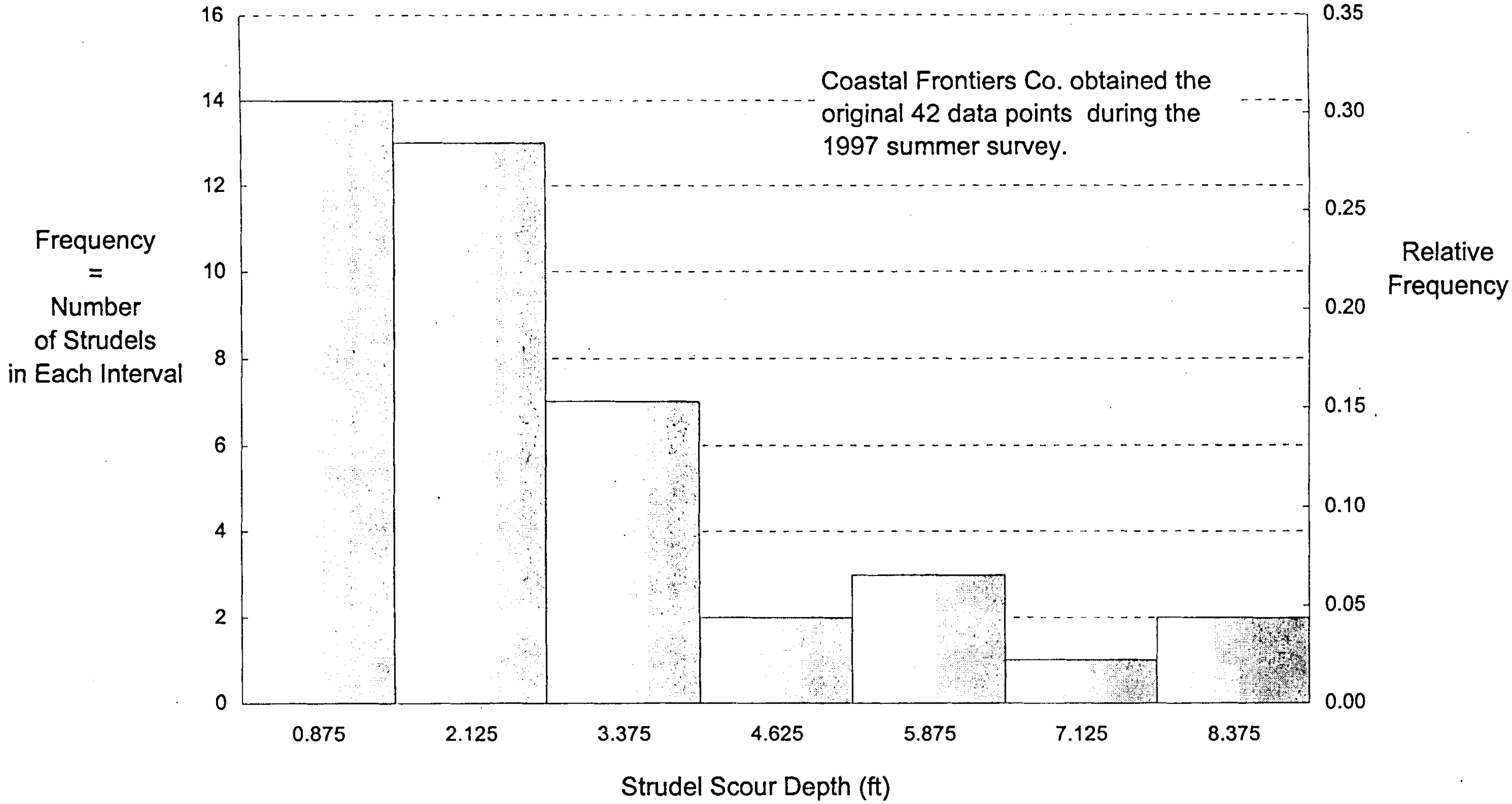
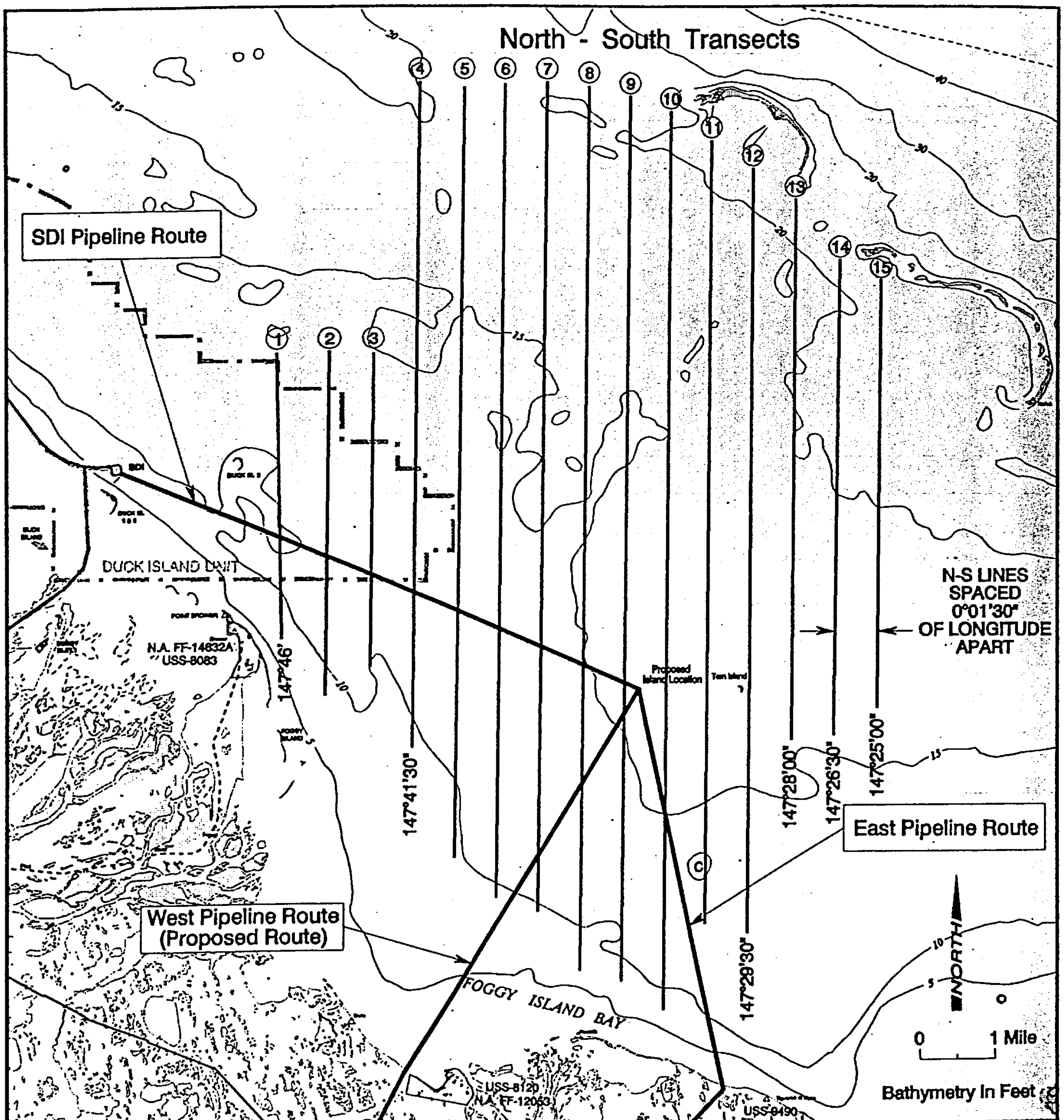


Figure 2-2: Histogram of strudel depths in the vicinity of Liberty pipeline route



Notes : (1) Map is based on U.S.G.S. quad Beechy Point (B-2, B-1, A-2, and A-1), and on the Unit Operator's Facility Maps.

(2) Scale is 1" = 2 Miles.

(3) Horizontal Datum is NAD 27.

FIGURE 2-3: 1997 PIPELINE ROUTE SURVEY LOCATION MAP.

bs13407a.dgn

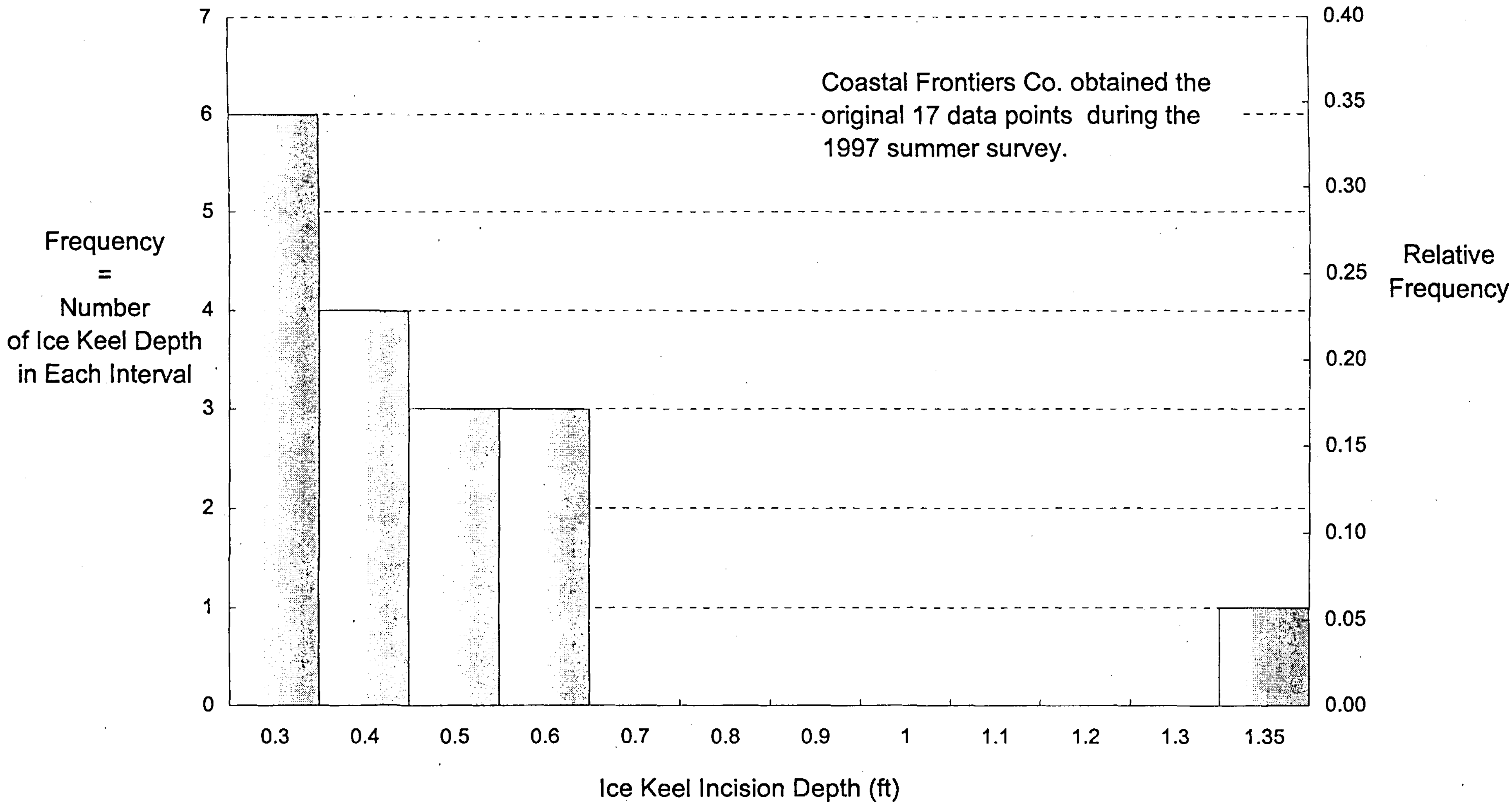


Figure 2-4: Histogram of ice keel depths in the vicinity of Liberty pipeline route

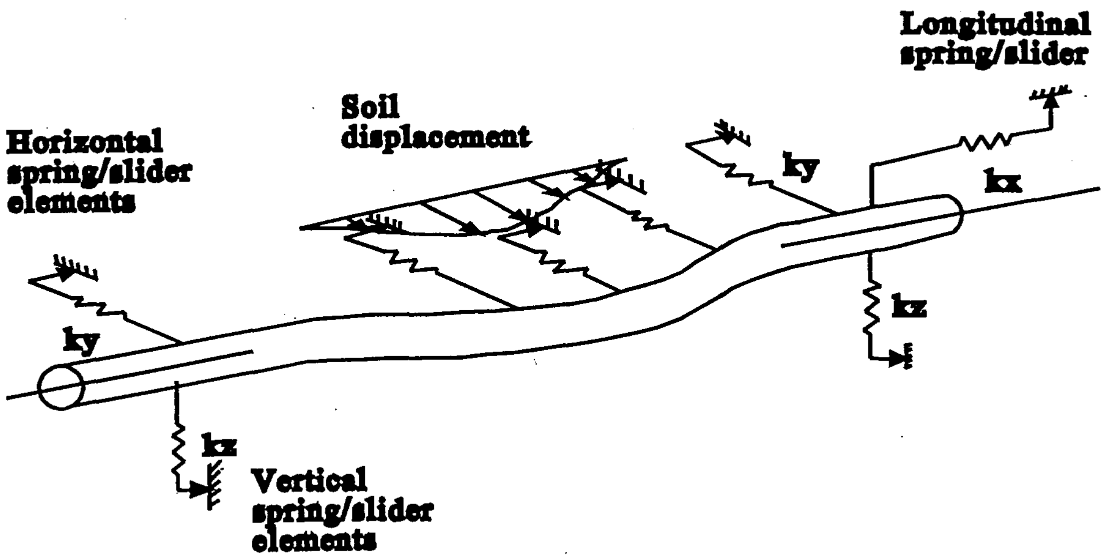


FIGURE 2-5 – SCHEMATIC REPRESENTATIONS OF SOIL REACTIONS.

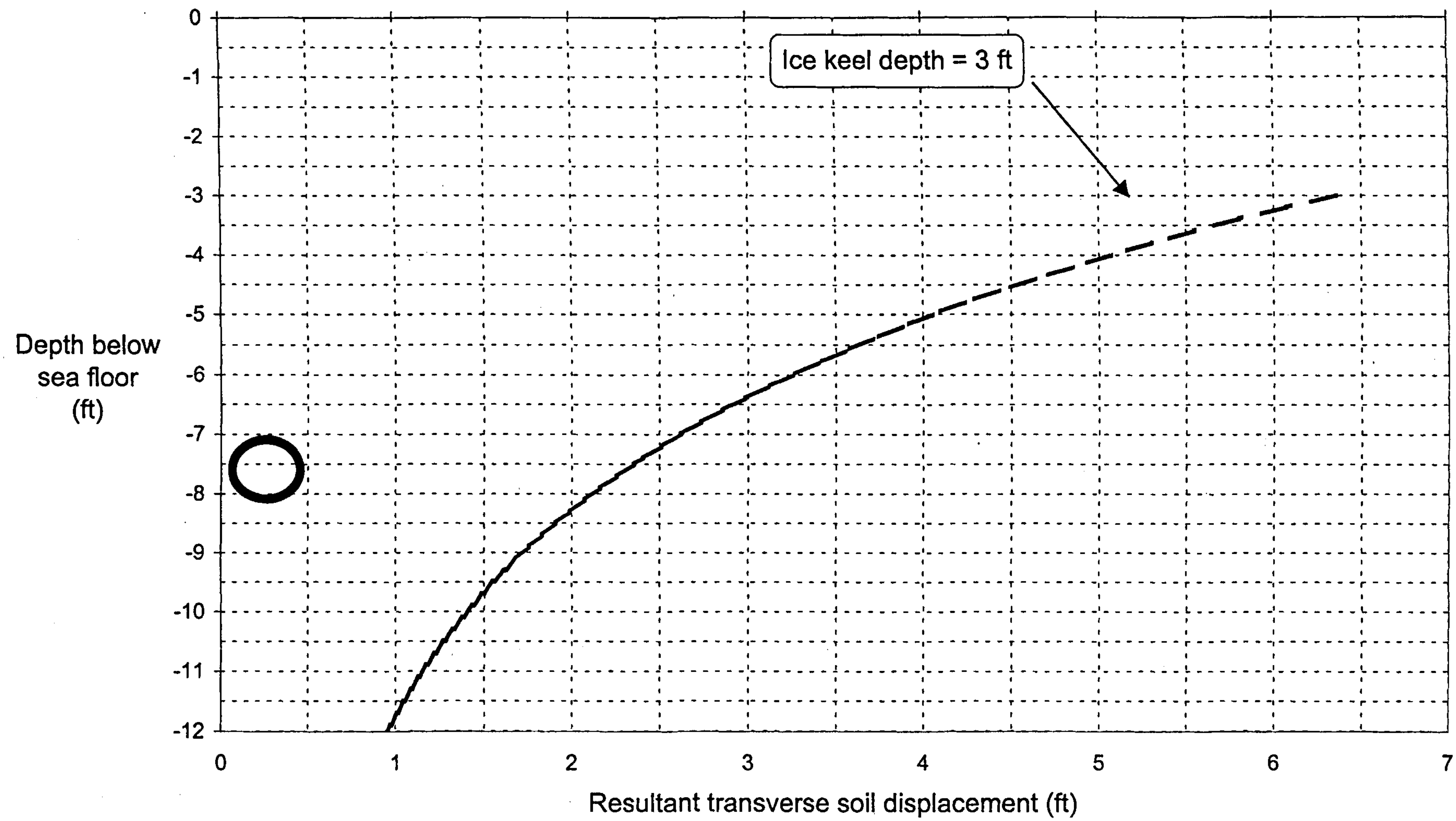


Fig. 2.6: Resultant soil displacements vs. depth below sea bed for 30-ft wide, 3-ft deep ice keel.

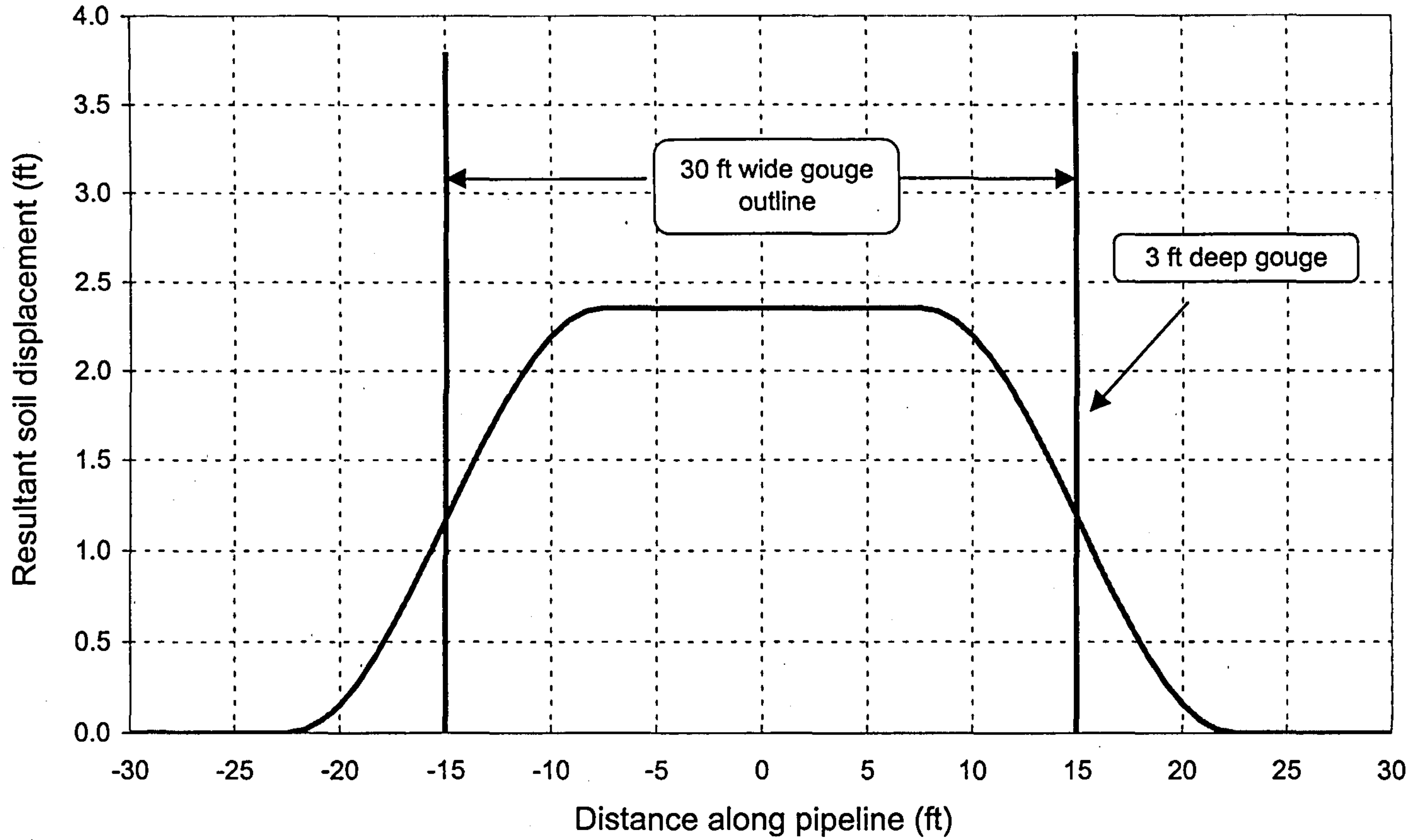


Fig. 2.7: Soil displacements variation along pipeline length for 30-ft wide, 3-ft deep ice keel.

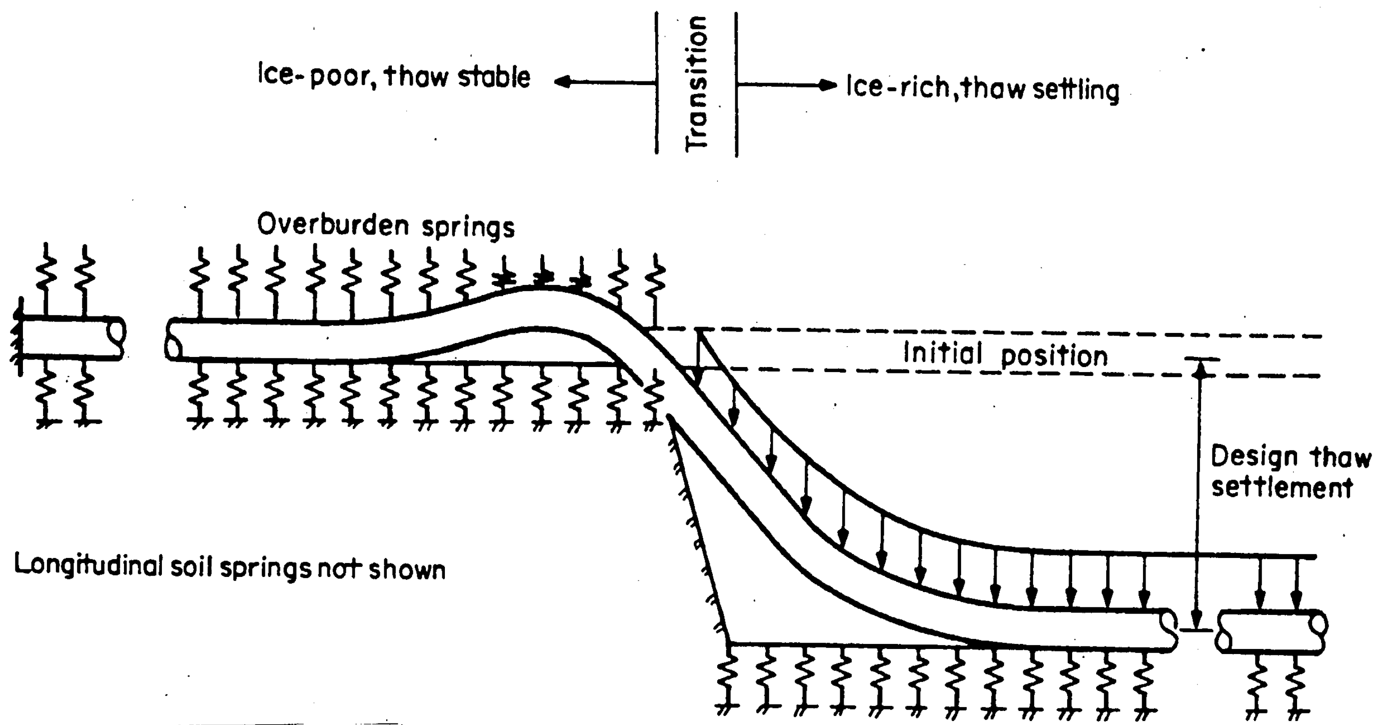


Fig 2-8: Differential Thaw Settlement Condition (after Nixon et al. 1984).

INTEC ENGINEERING

CALCULATION NUMBER

Project BPXA Liberty Job No. H-0851.02

Subject Strudel Scour Sheet

Signature Date

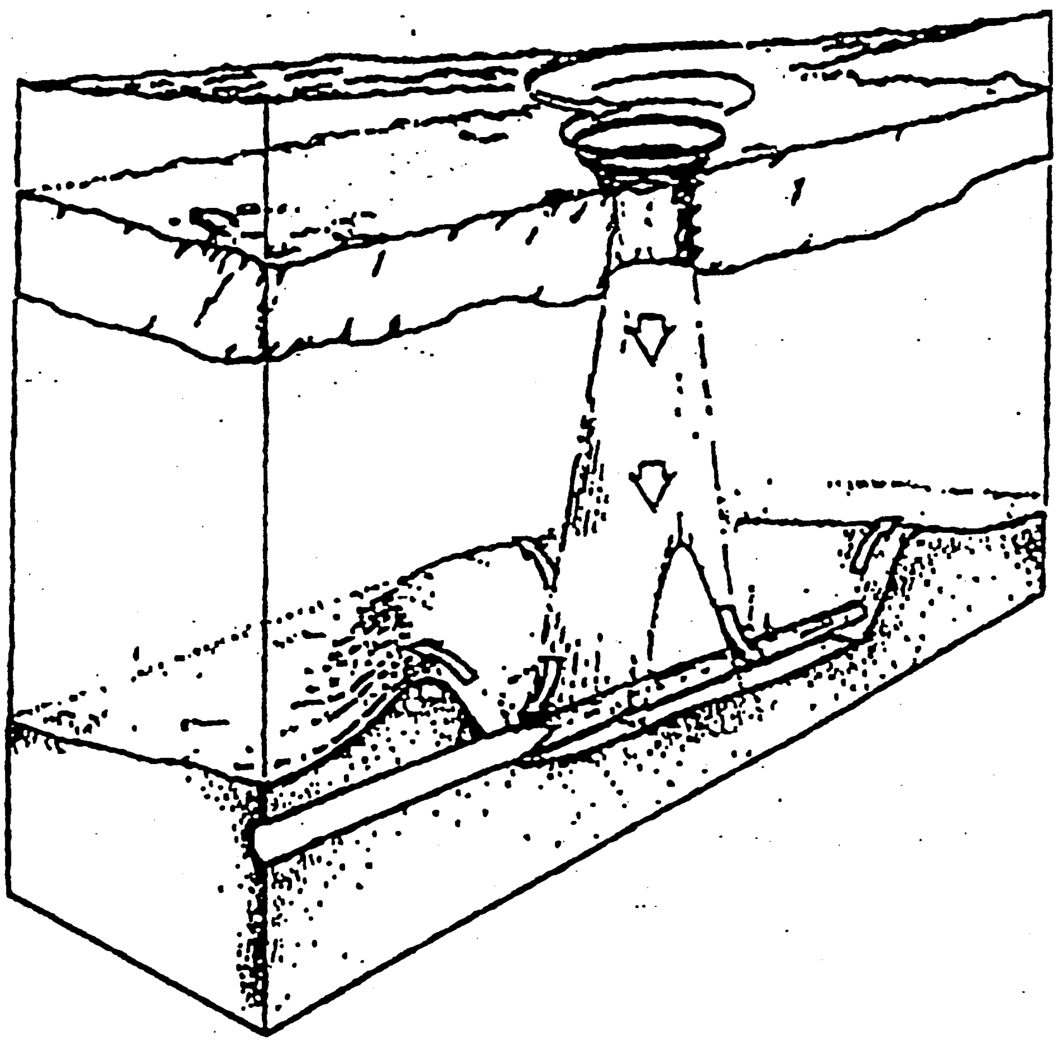
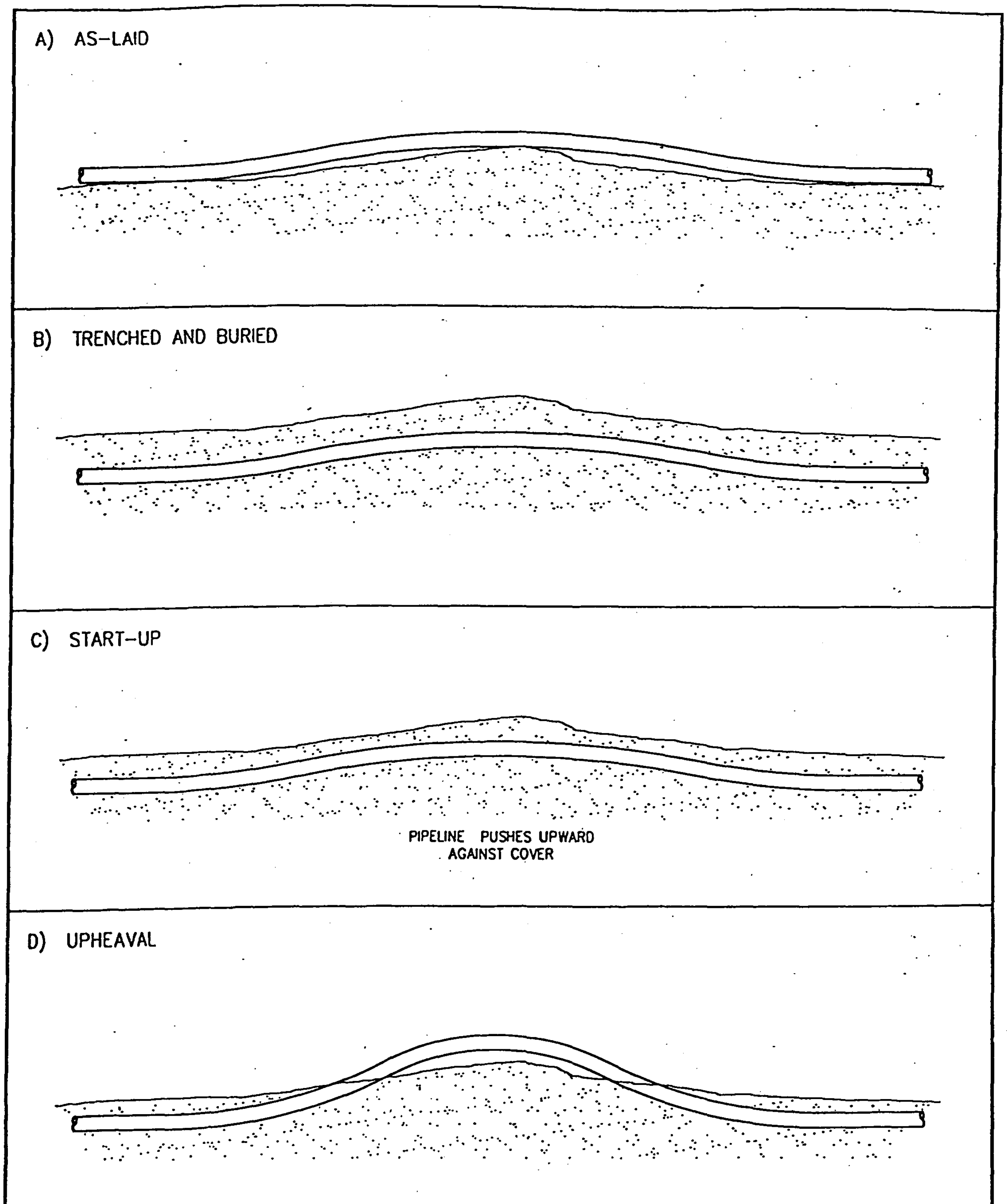


Figure 2-9: Strudel Scour Loading Buried Offshore Pipeline



BP EXPLORATION (Alaska) INC.

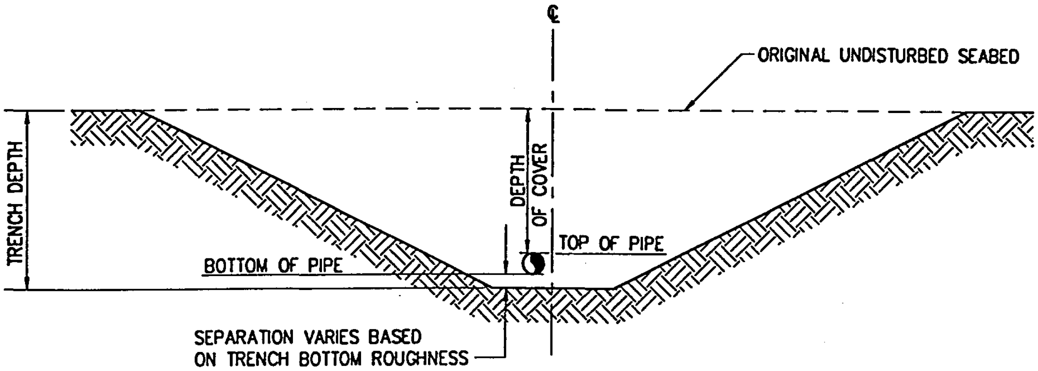
INTEC ENGINEERING

LIBERTY PIPELINE PROJECT

SEQUENCE OF LAYING, TRENCHING AND UPHEAVAL

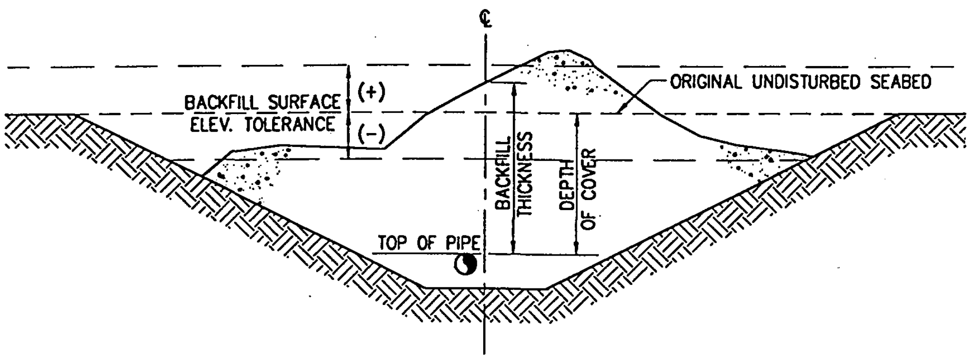
DRAWN BY	DATE	JOB NO.	
KGC	3-26-98	H-851.02	Figure 2-10

CAD FILE: 8512-25A.DWG MAR 26, 1998 10:58 AM KGC



TRENCH CONFIGURATION IMMEDIATELY FOLLOWING PIPELAY

SCALE: NONE



TRENCH CONFIGURATION IMMEDIATELY FOLLOWING BACKFILLING

SCALE: NONE

NOTES:

1. SEA ICE NOT SHOWN FOR CLARITY.

BP EXPLORATION (Alaska) INC.	INTEC ENGINEERING			
BPXA LIBERTY PIPELINES	PIPELINE TRENCHING AND BACKFILLING			
	DRAWN BY JEG	DATE 7-3-97	JOB NO. H-660.3	Figure 3.1
CAD FILE: 6603514A.DWG FEB 9, 1998 10:36 AM JEG				

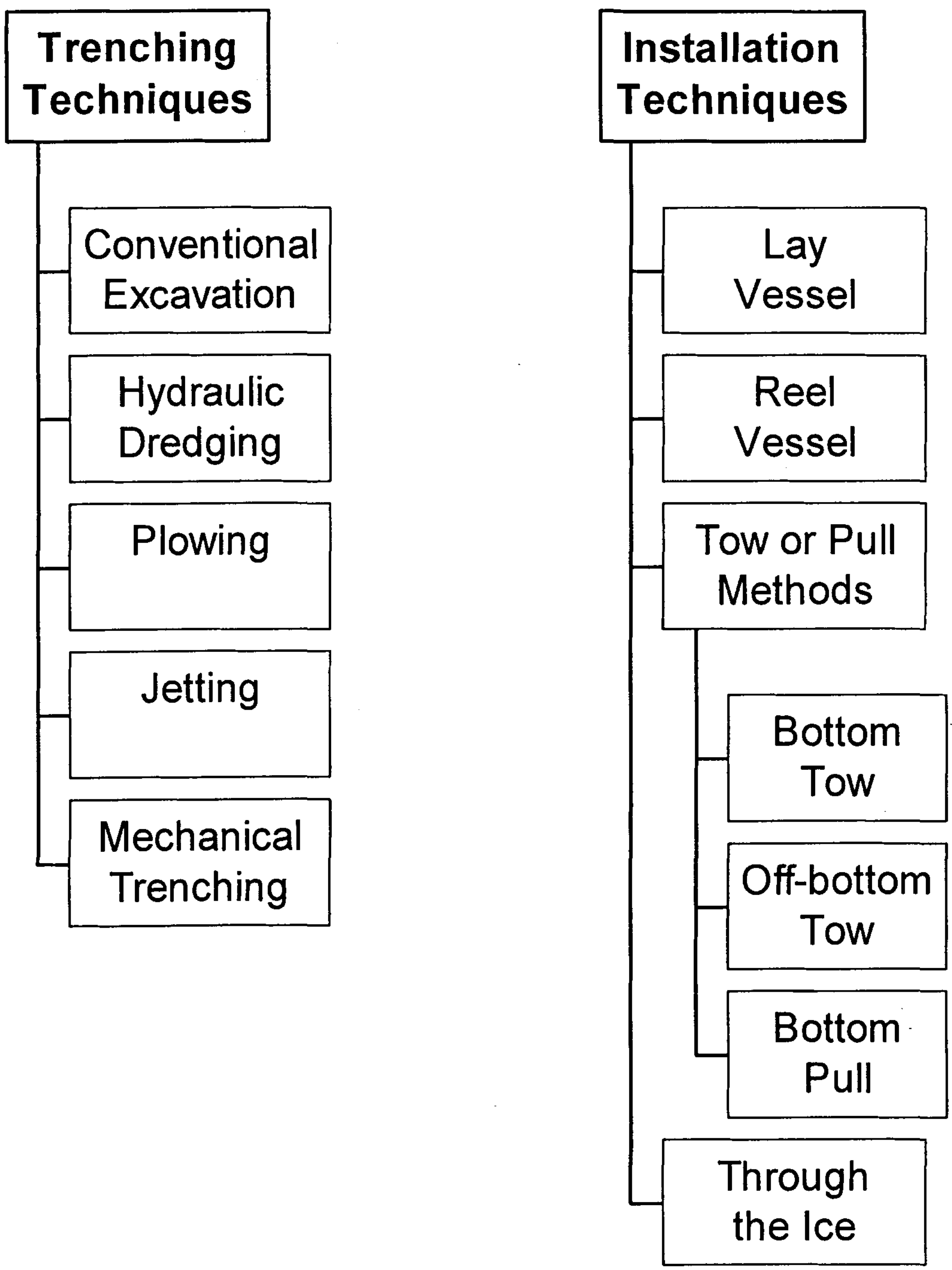
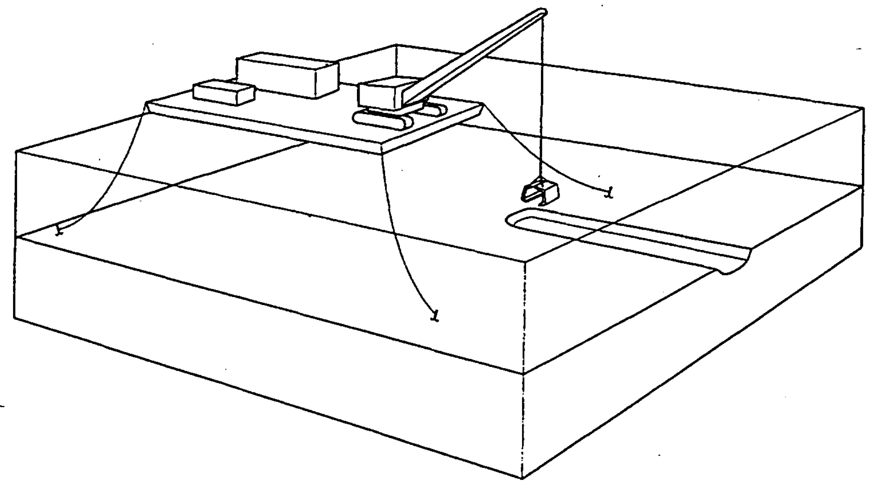


Figure 3.2 Trenching and pipeline installation techniques used for offshore pipeline construction

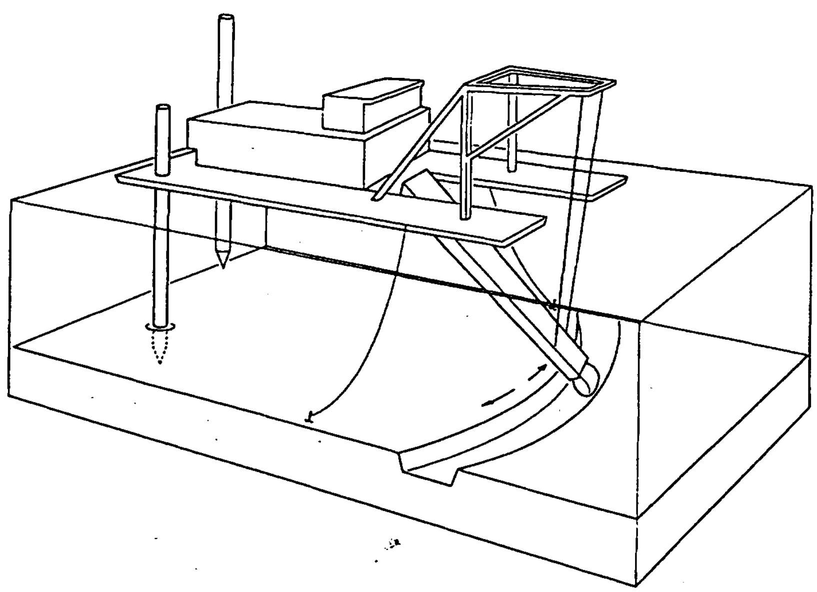
CLAM SHELL ON BARGE

[TYPICAL BARGE DIMENSIONS 200 ft x 60 ft x 20 ft (LENGTH x BEAM x DRAFT)]



CUTTER SUCTION DREDGE

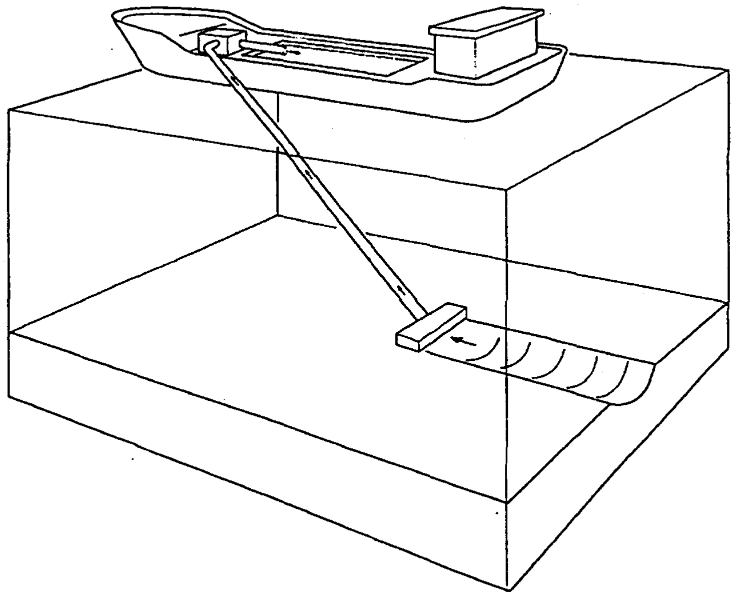
[TYPICAL VESSEL DIMENSIONS 200 ft x 60 ft x 15 ft (LENGTH x BEAM x DRAFT)]



BP EXPLORATION (Alaska) INC.	INTEC ENGINEERING
LIBERTY PIPELINE PROJECT	CONVENTIONAL EXCAVATION AND CUTTER SUCTION HYDRAULIC DREDGING TECHNIQUES
CAD FILE: 8512-3-8.DWG SEP 13, 1999 12:47 PM KGC	DRAWN BY KGC · DATE 9-13-99 · JOB NO. H-851.02 · Figure 3.3

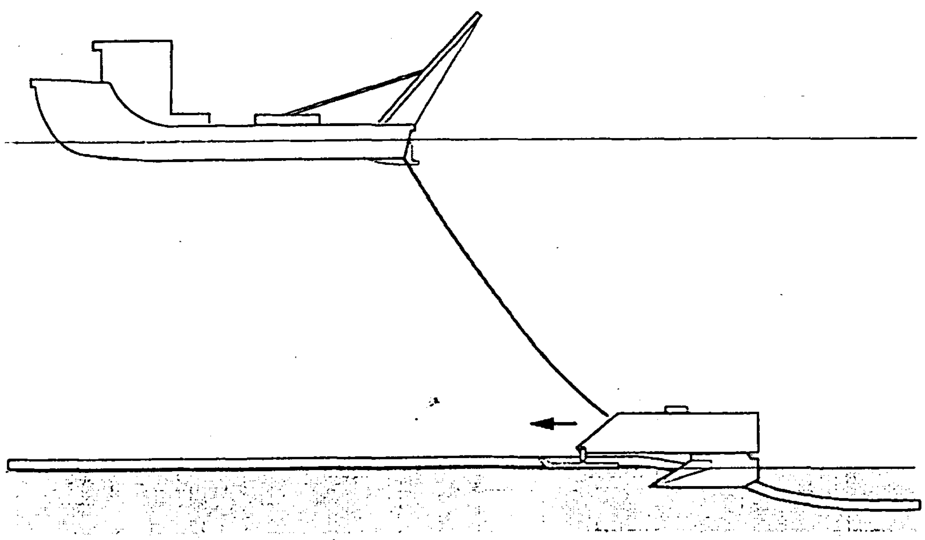
TRAILING SUCTION DREDGE

[TYPICAL VESSEL DIMENSIONS 400 ft x 80 ft x 30 ft (LENGTH x BEAM x DRAFT)]



PIPELINE PLOW

[TYPICAL VESSEL DIMENSIONS 200 ft x 60 ft x 20 ft (LENGTH x BEAM x DRAFT);
PLOW DIMENSIONS 50 ft x 25 ft x 20 ft]



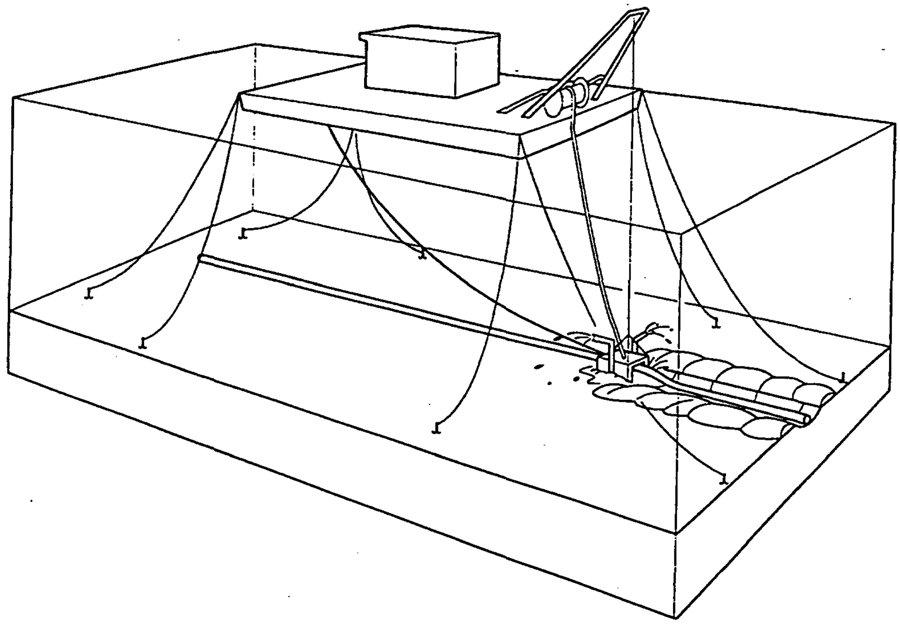
BP EXPLORATION (Alaska) INC.	INTEC ENGINEERING
LIBERTY PIPELINE PROJECT	TRAILING SUCTION HOPPER HYDRAULIC DREDGING AND PLOWING TECHNIQUES

DRAWN BY	DATE	JOB NO.	
KGC	9-13-99	H-851.02	Figure 3.4

CAD FILE: 8512-3-9.DWG SEP 13, 1999 12:59 PM KGC

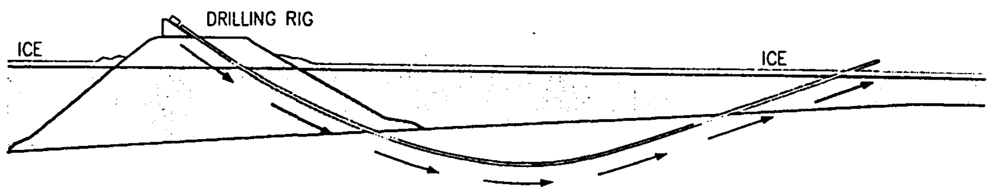
BURIAL BY JETTING

[TYPICAL BARGE DIMENSIONS 400 ft x 120 ft x 20 ft (LENGTH x BEAM x DRAFT)]

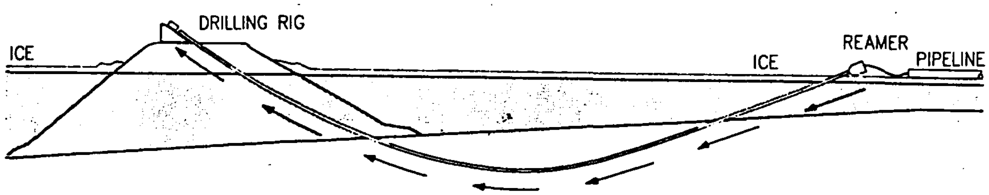


DIRECTIONAL DRILLING

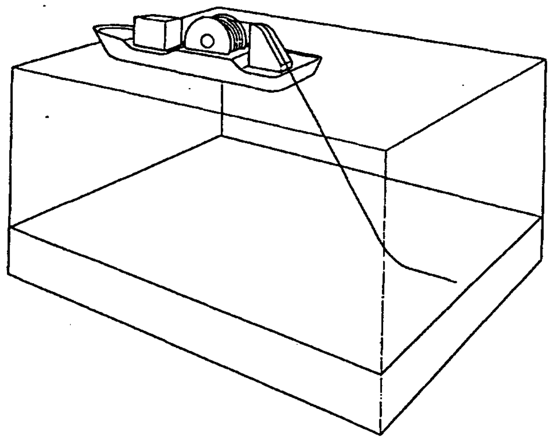
1. DRILLING OF PILOT HOLE



2. PULLING OF REAMER AND PIPELINE



BP EXPLORATION (Alaska) INC.	INTEC ENGINEERING			
LIBERTY PIPELINE PROJECT	JETTING AND DIRECTIONAL DRILLING TECHNIQUES			
	DRAWN BY KGC	DATE 9-13-99	JOB NO. H-851.02	Figure 3.5
CAD FILE: 8512-3-10.DWG SEP 13, 1999 1:04 PM KGC				

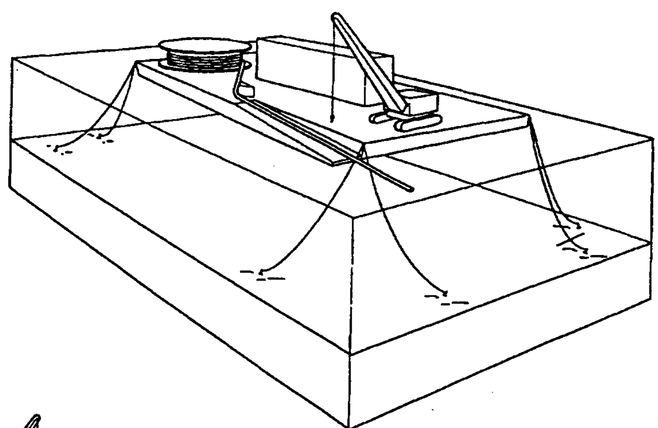


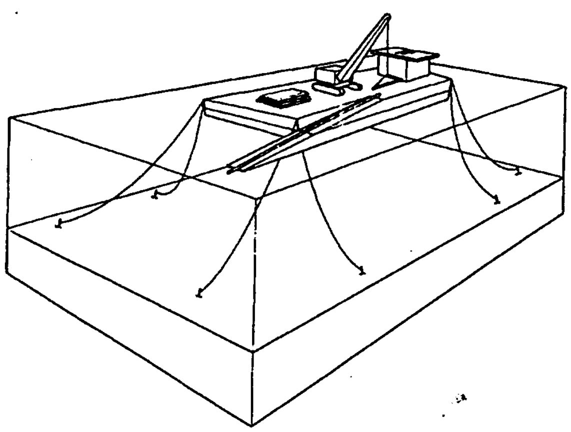
REEL SHIP

[TYPICAL VESSEL DIMENSIONS
400 ft x 70 ft x 30 ft
(LENGTH x BEAM x DRAFT)]

REEL BARGE

[TYPICAL BARGE DIMENSIONS
300 ft x 60 ft x 20 ft
(LENGTH x BEAM x DRAFT)]





PIPELINE LAY BARGE

[TYPICAL BARGE DIMENSIONS
200 ft x 60 ft x 12 ft
(LENGTH x BEAM x DRAFT)]

BP EXPLORATION (Alaska) INC.

INTEC ENGINEERING

LIBERTY PIPELINE PROJECT

CONVENTIONAL OFFSHORE REELING AND LAY VESSELS

DRAWN BY	DATE	JOB NO.	
KGC	9-13-99	H-851.02	**Figure 3.6**

CAD FILE: 8512-3-11.DWG SEP 13, 1999 1:14 PM KGC

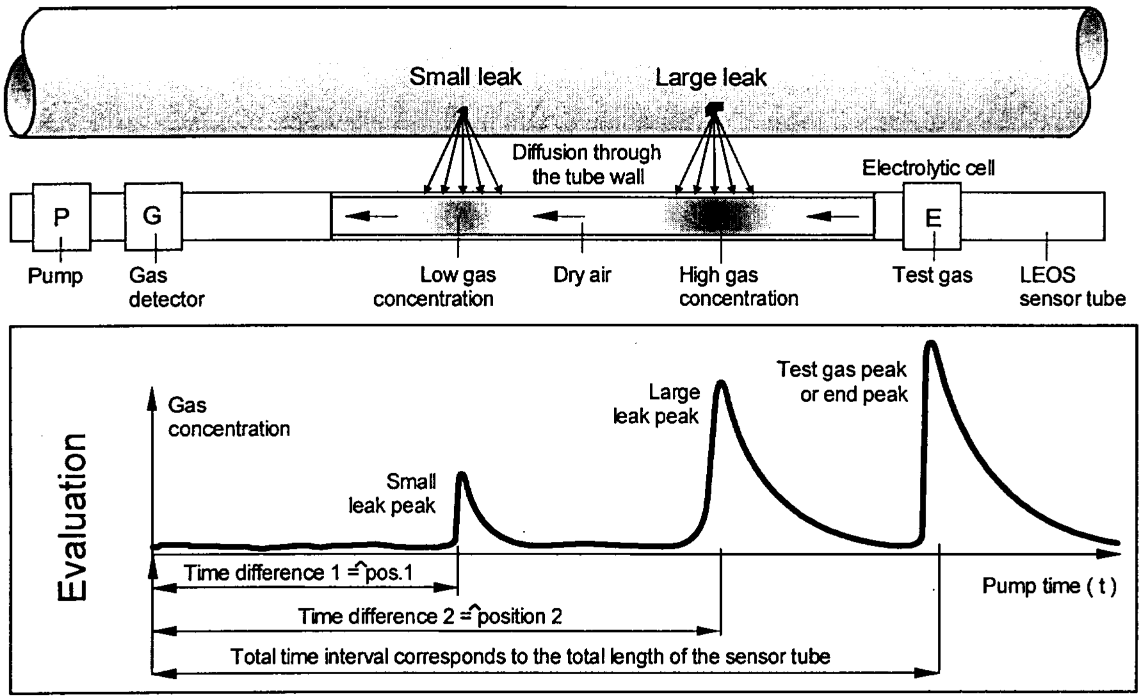
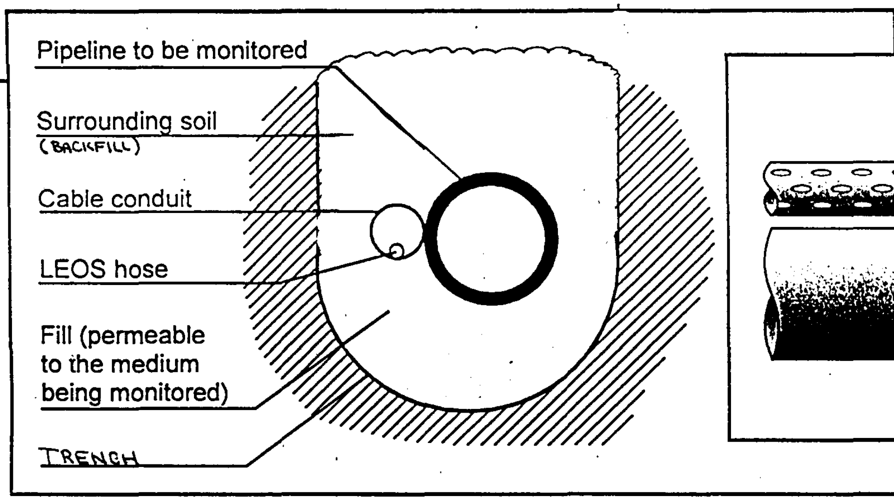
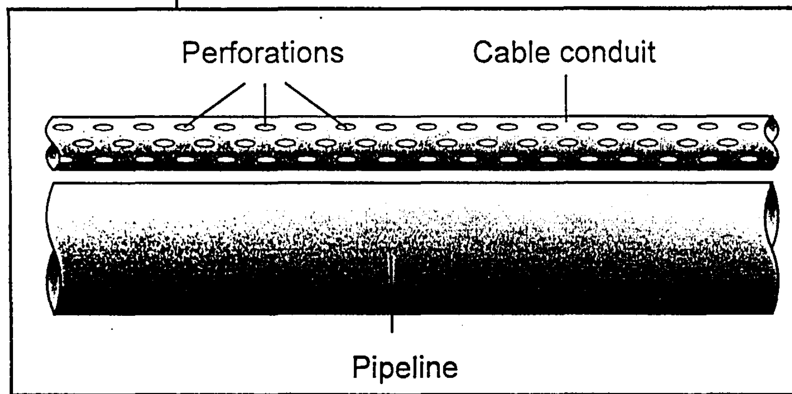


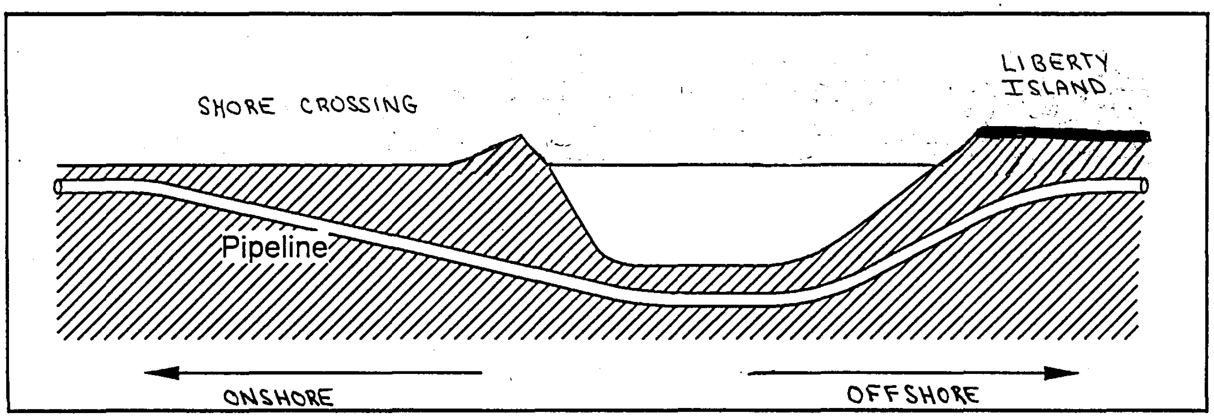
Figure 3-7: Principle of Operation – Siemens LEOS

Figure 3-8: Pipeline and LEOS System Installed under a Body of Water

Laying of Sensor Hose under a Body of Water







LEOS (Leak Detection and Location System) (NTS)

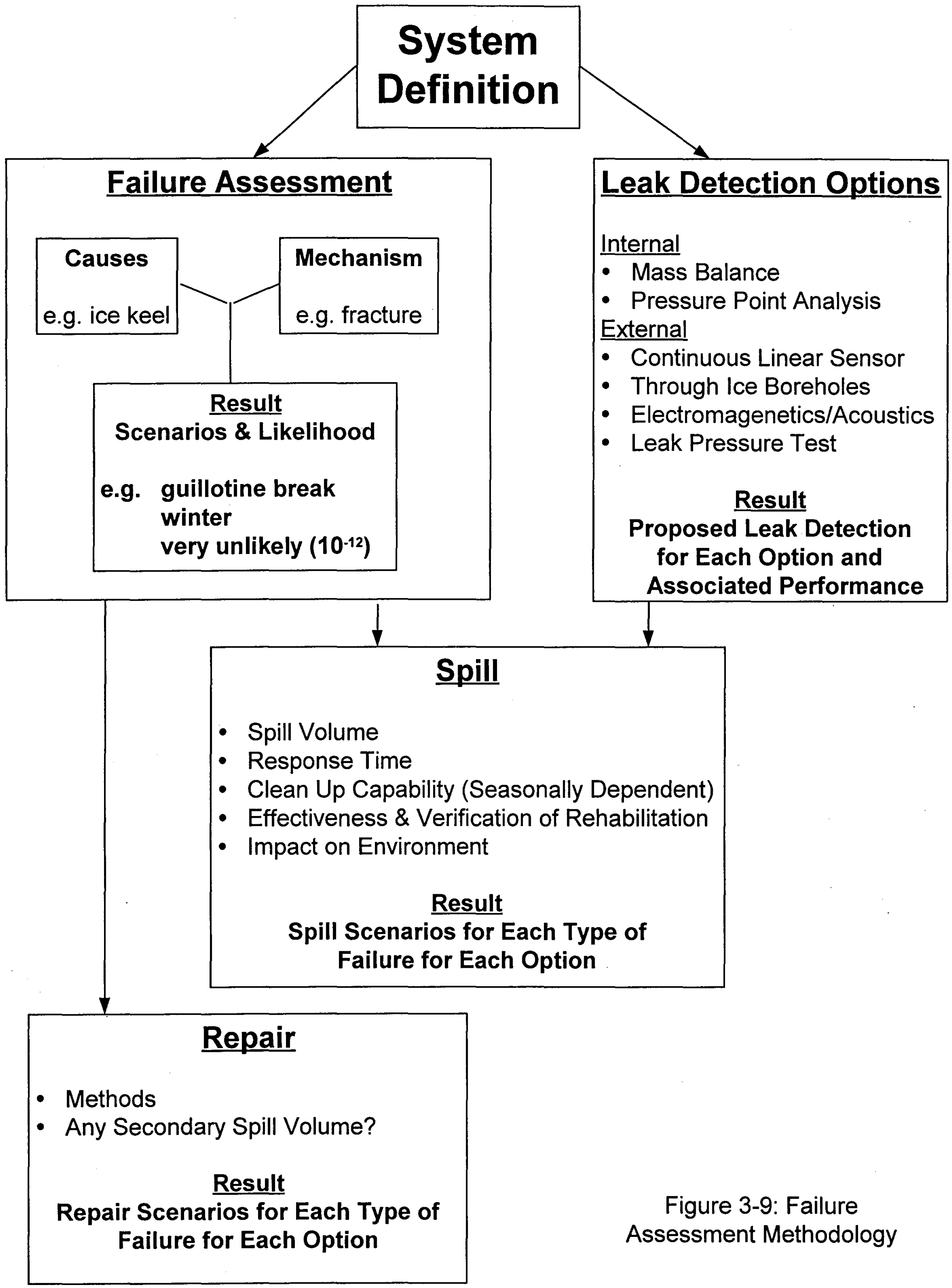
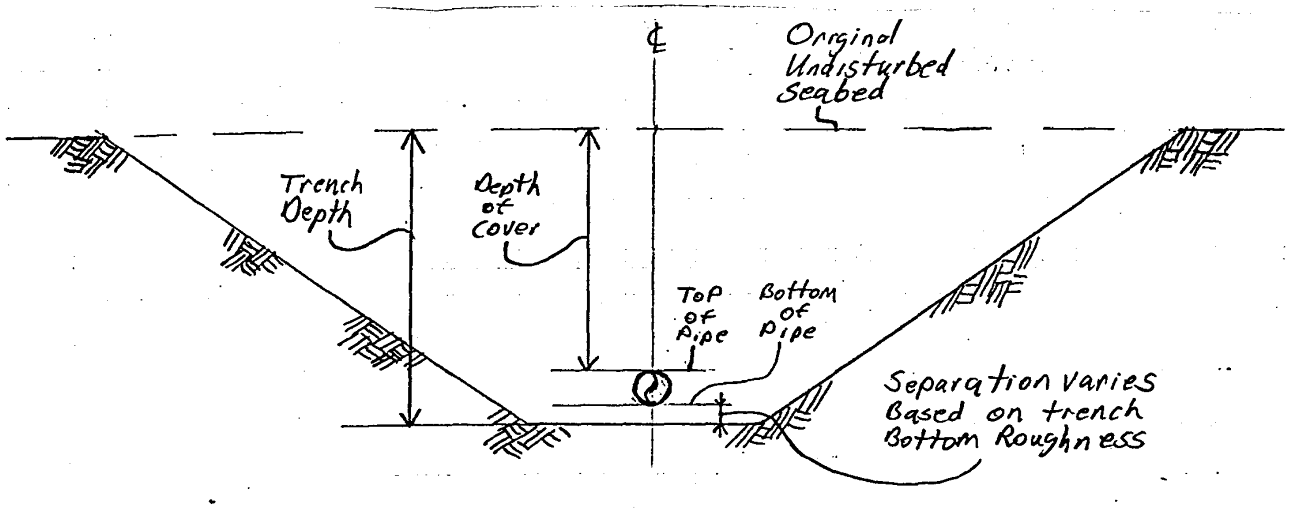
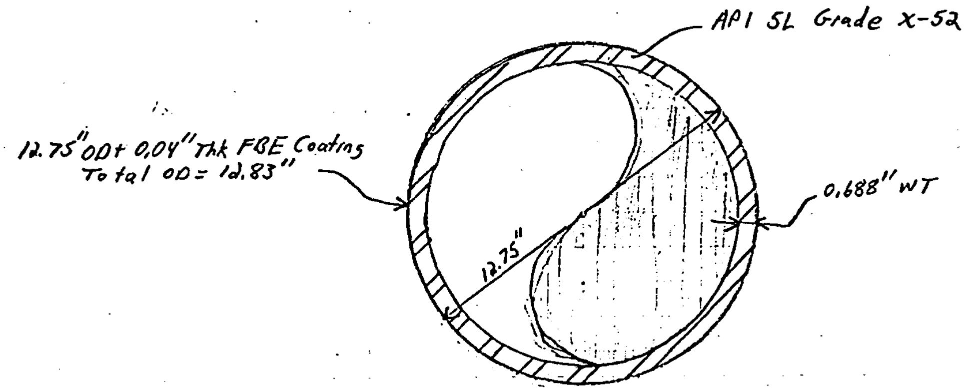


Figure 3-9: Failure Assessment Methodology



Trench Configuration



Note: Sacrificial Half Bracelet 'Anodes' Spaced at 120 ft intervals with Typical Dimentions will be installed on top of Pipe to Facilitate roller Passage.

Pipe Details

Figure 4.1 – Single wall Steel pipeline Configuration

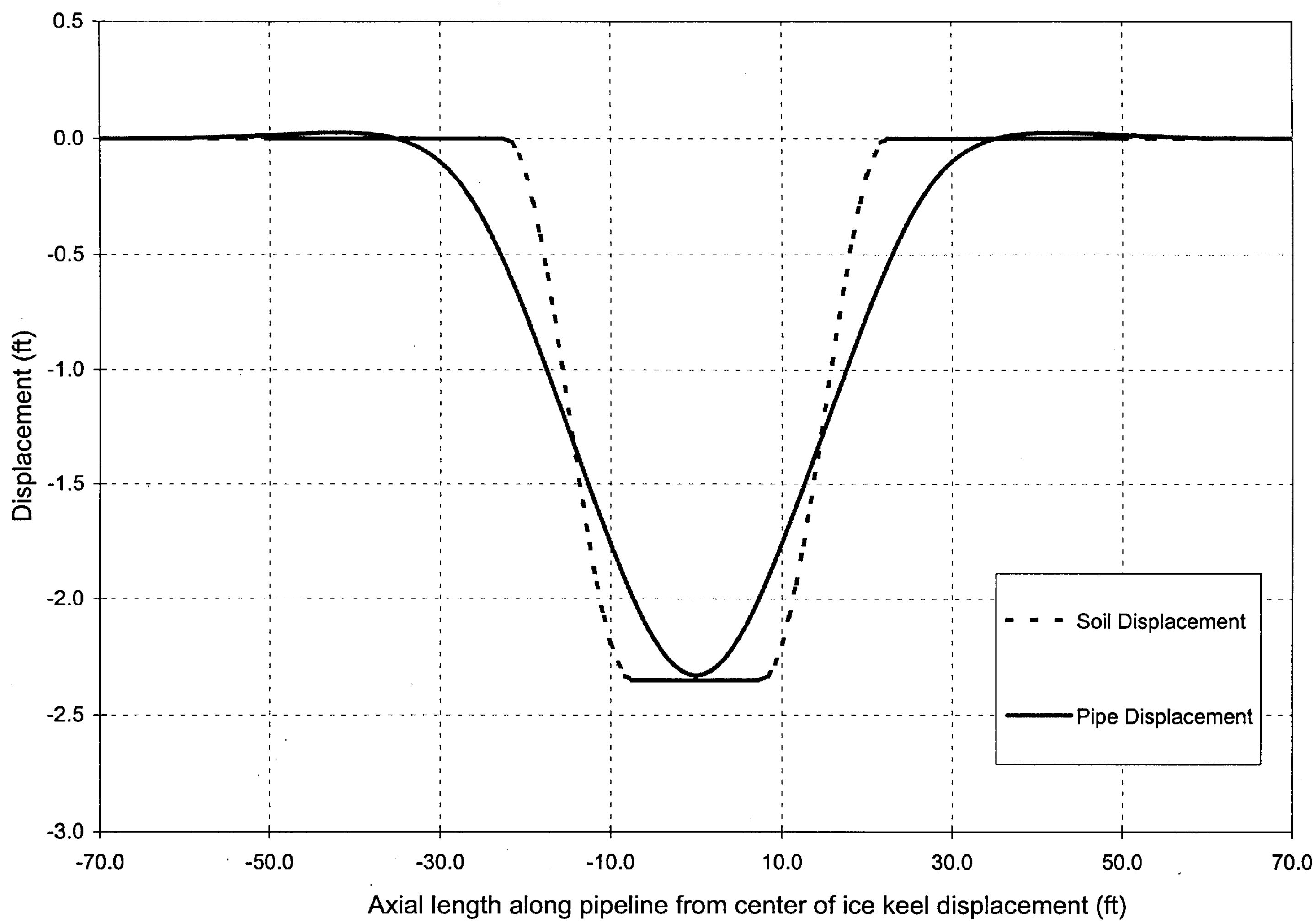


Figure 4.2 : Single wall steel pipe 12.75" OD, 0.688" WT
Pipe displacement within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi
keel: 3.0 ft deep, 30 ft wide

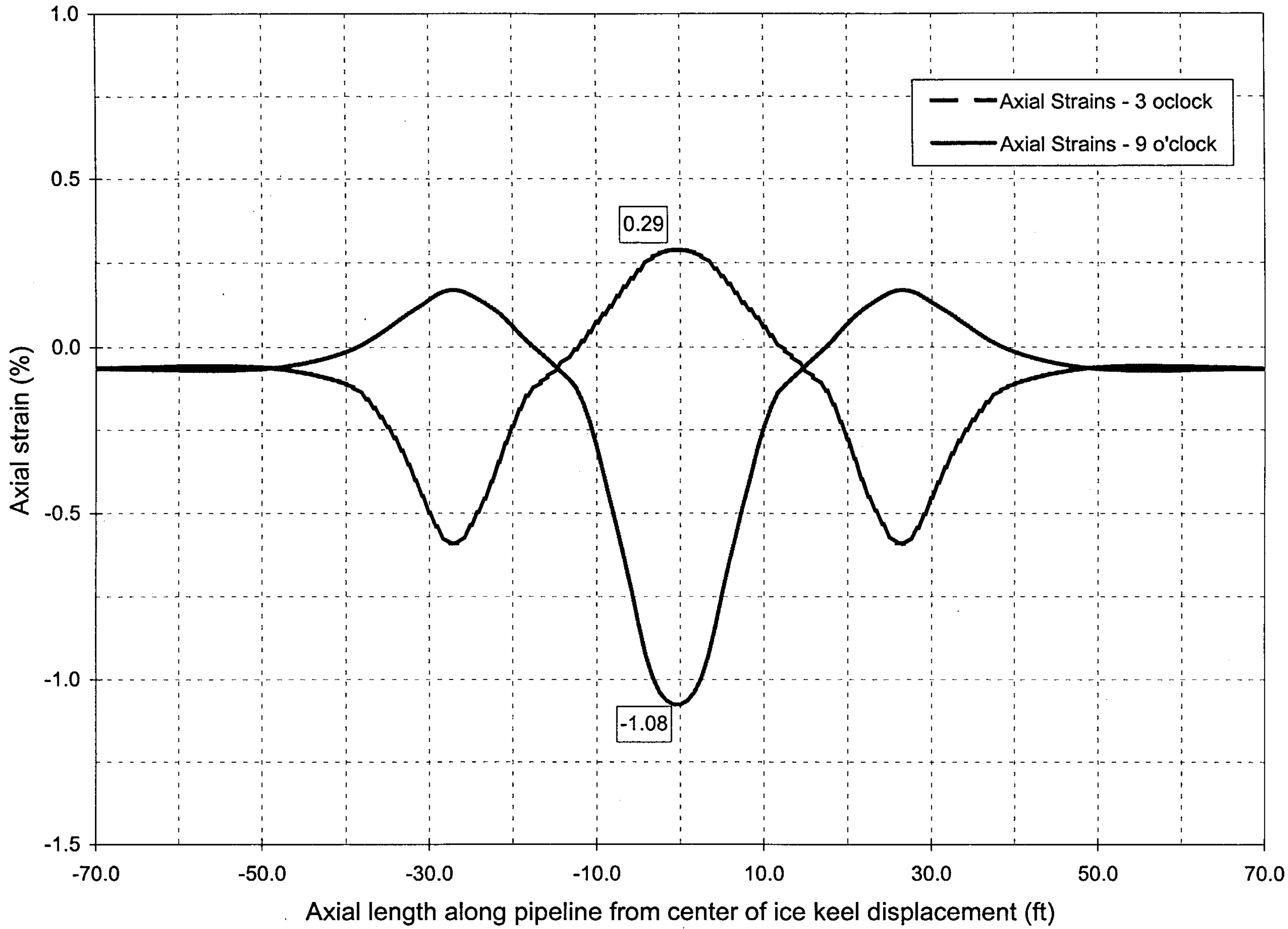


Figure 4.3 : Single wall steel pipe 12.75" OD, 0.688" WT
Axial Strain within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi
keel: 3.0 ft deep, 30 ft wide

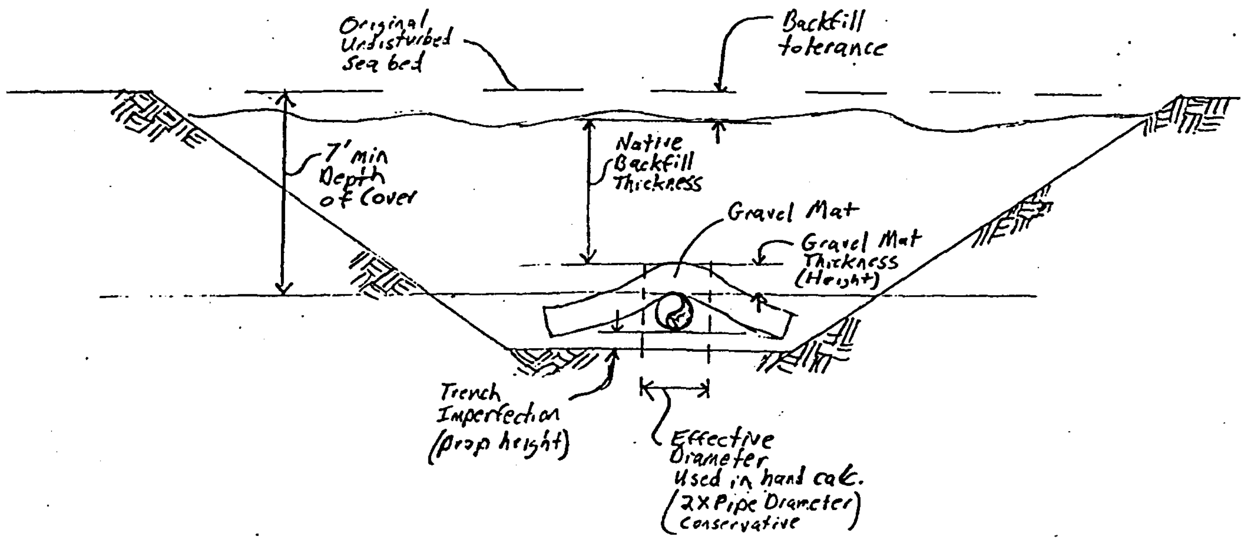


Figure 4.4: Trench Cross-section of Gravel Mat and Native Backfill Combination

- Depth of cover, DOC = 7 ft
- Target Trench Depth, TTD = 10.5 ft
- Backfill:

  Generally 7ft native backfill

  At high points: 1-foot gravel mat, plus

  5-foot native backfill
- Pipe:

  12.75-in OD,

  0.688-in WT,

  D/t = 18.5

  dry weight = 90 lb/ft

  SG = 1.6

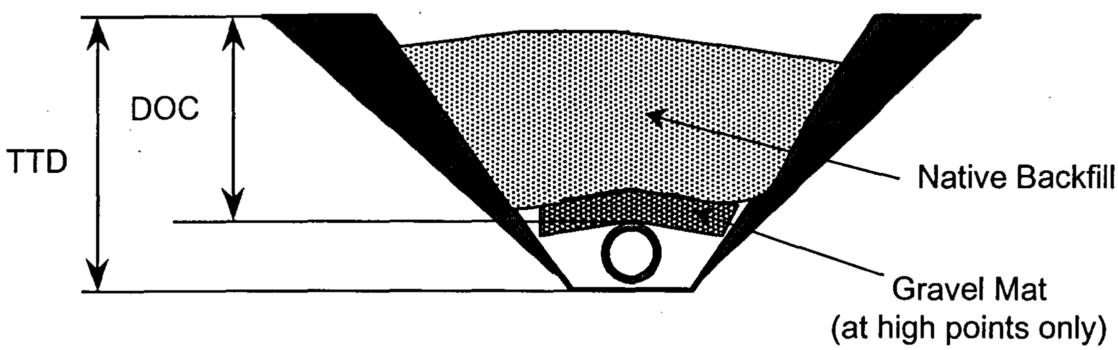
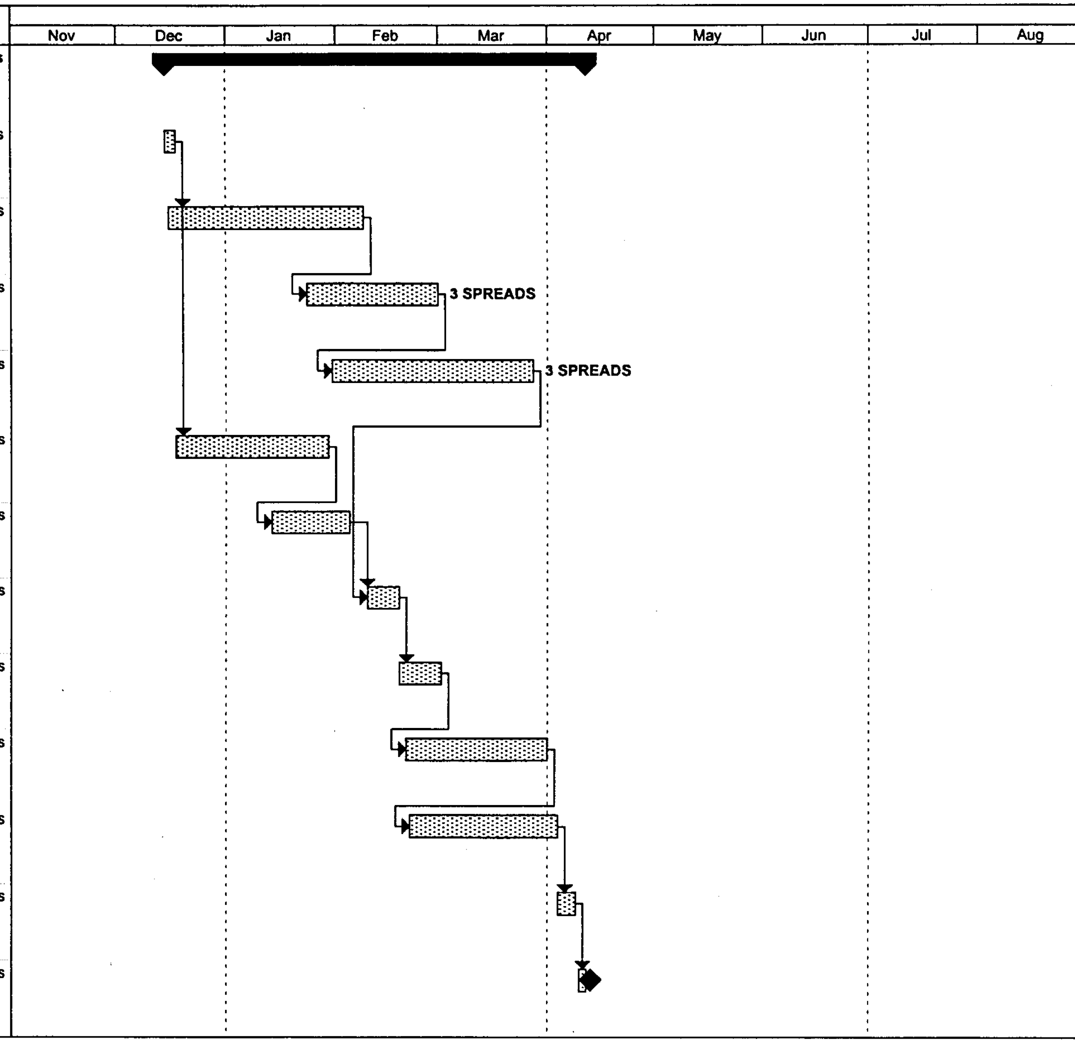


Figure 4.5 Single Wall Steel Pipeline Selected Configuration

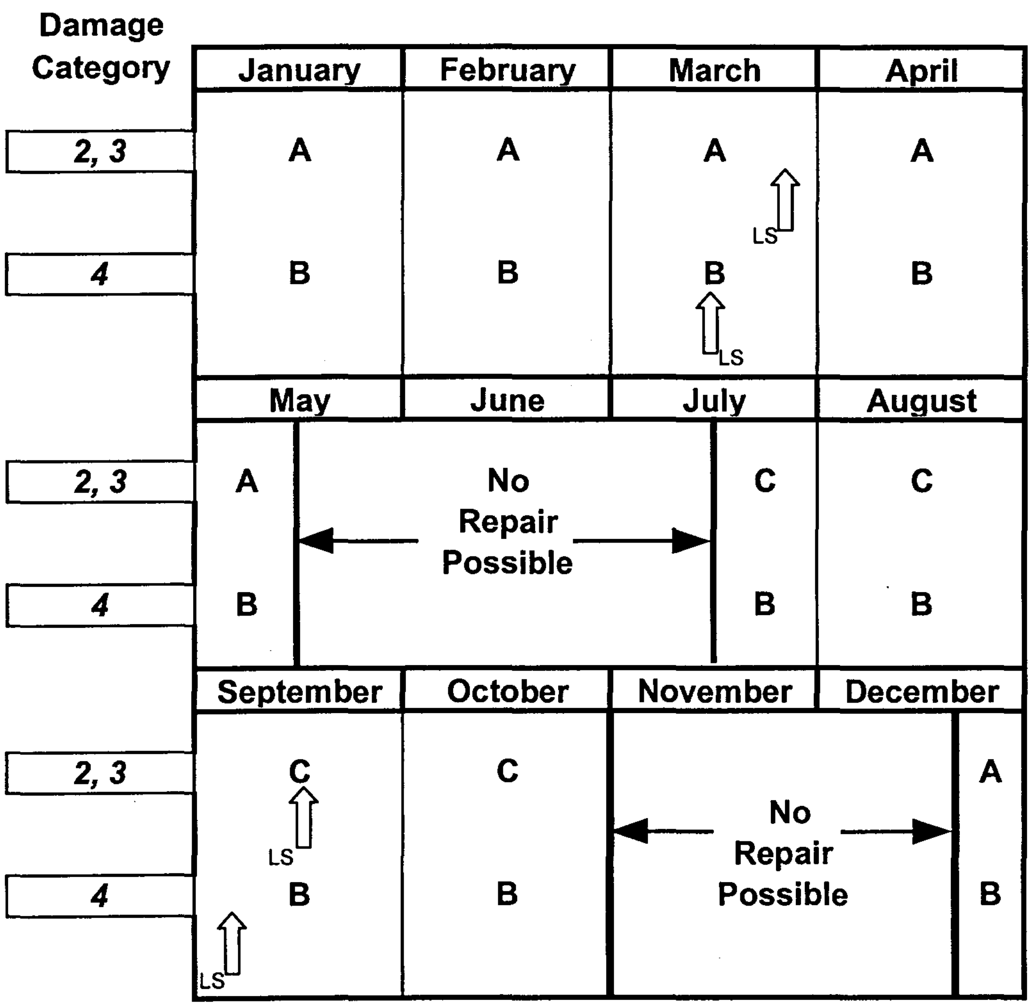
FIGURE 4.6 CONSTRUCTION SCHEDULE - SINGLE WALL STEEL PIPE OPTION

ID	Task Name	Duration
1	**Offshore Pipeline Construction**	**102 days**
2	Mobilization Equipment/Material	3 days
3	Ice Thickening and Ice Road Construc	47 days
4	Ice Cutting and Slotting	32 days
5	Trenching	49 days
6	Pipeline Make-up Site Preparation	37 days
7	Pipe String Make-Up (Welding)	19 days
8	Pipe String Transportation	8 days
9	Pipe String Field Joint	10 days
10	Pipeline Installation	35 days
11	Backfilling	36 days
12	Hydrostatic Testing	5 days
13	Demobilization Equipment	2 days



Project: construction schedule_SP
Date: Fri 10/22/99

Task | Milestone | Summary



Notes:

LS indicates the timing for the "latest start date" for that repair.

A - Surface repair or hyperbaric tie-in.

B - Tow replacement string with subsurface tie-in or hyperbaric tie-in.

C - Cofferdam or hyperbaric tie-in.

Damage Category 2 - Buckle / No Leak.

Damage Category 3 - Small / Medium Leak.

Damage Category 4 - Large Leak / Rupture.

Conditions after repair will result in full integrity of the pipe.

Figure 4-7: Recommended Repair Methods

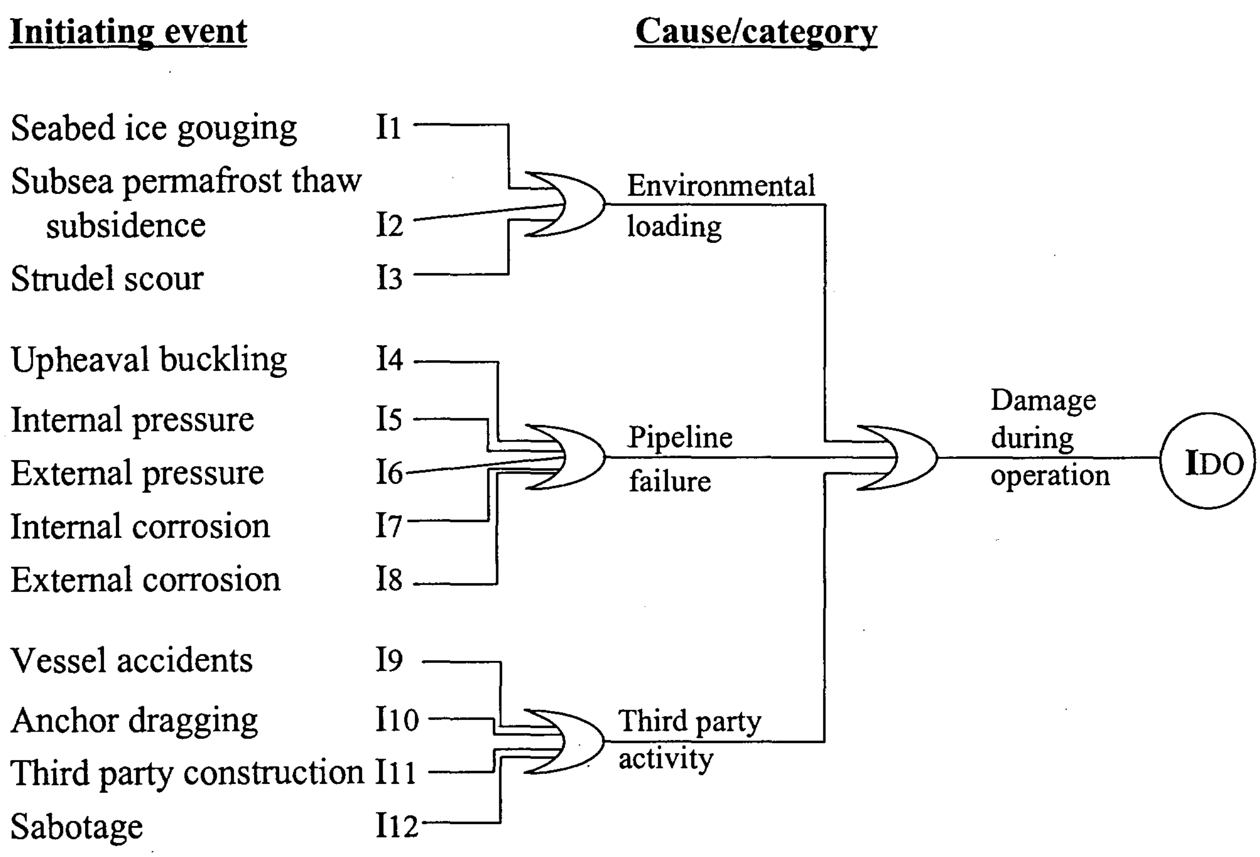
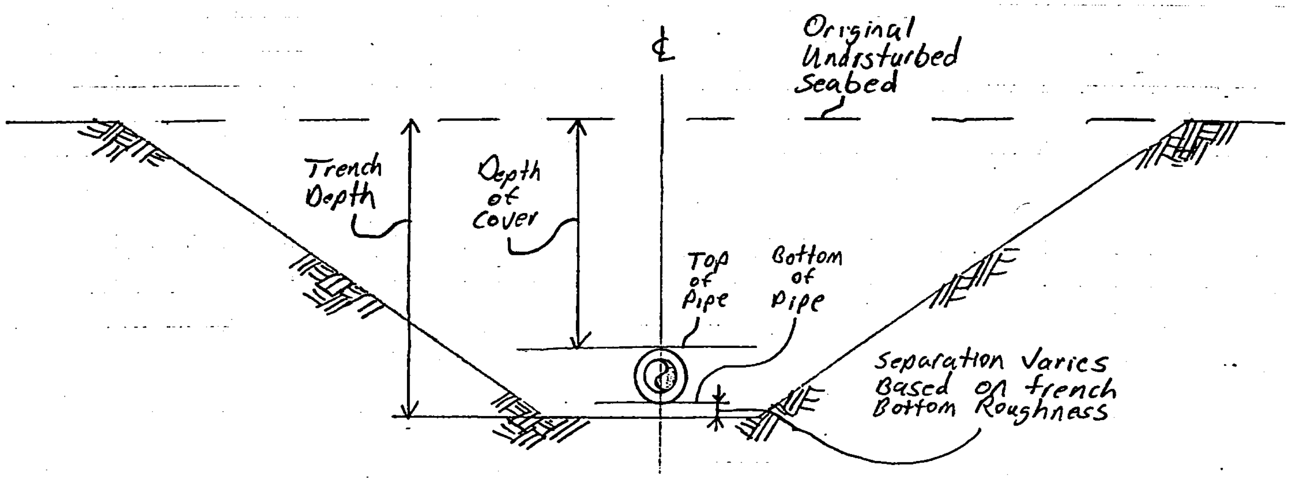
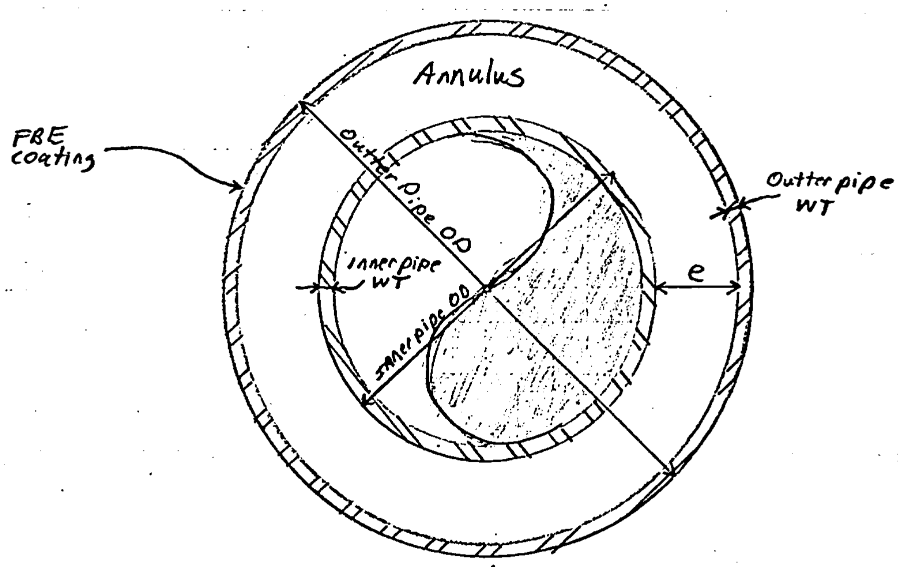


Figure 4-8: Incoming tree resulting in event IDO, "Damage during operation"



Trench Configuration



Pipe Details

Figure 5.1 – Pipe-in-Pipe Configuration

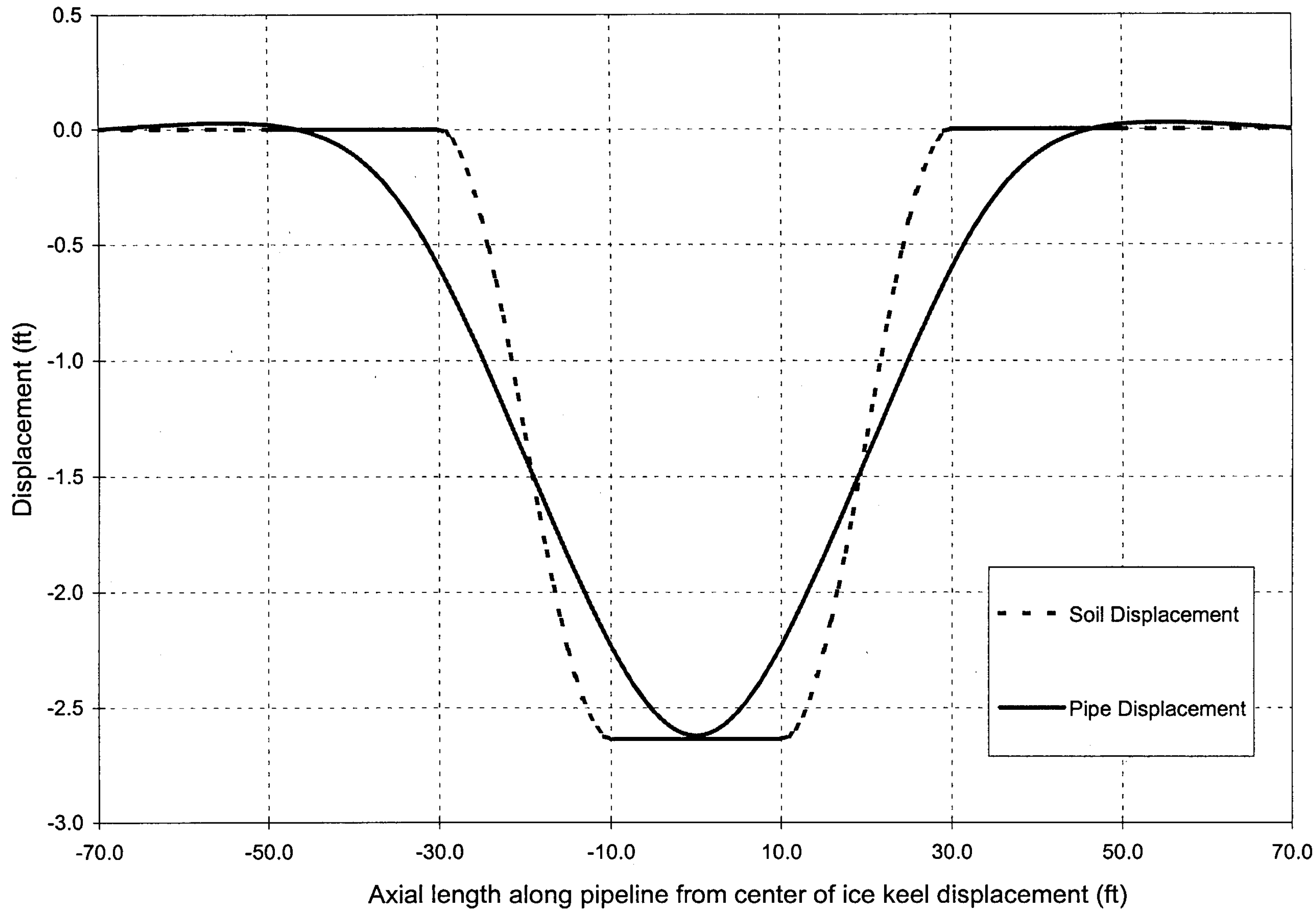


Figure 5.2 : Pipe-in-Pipe 12.75" OD, 0.688" WT & 16.00" OD, 0.500" WT
Pipe displacement within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi
keel: 3.0 ft deep, 40 ft wide

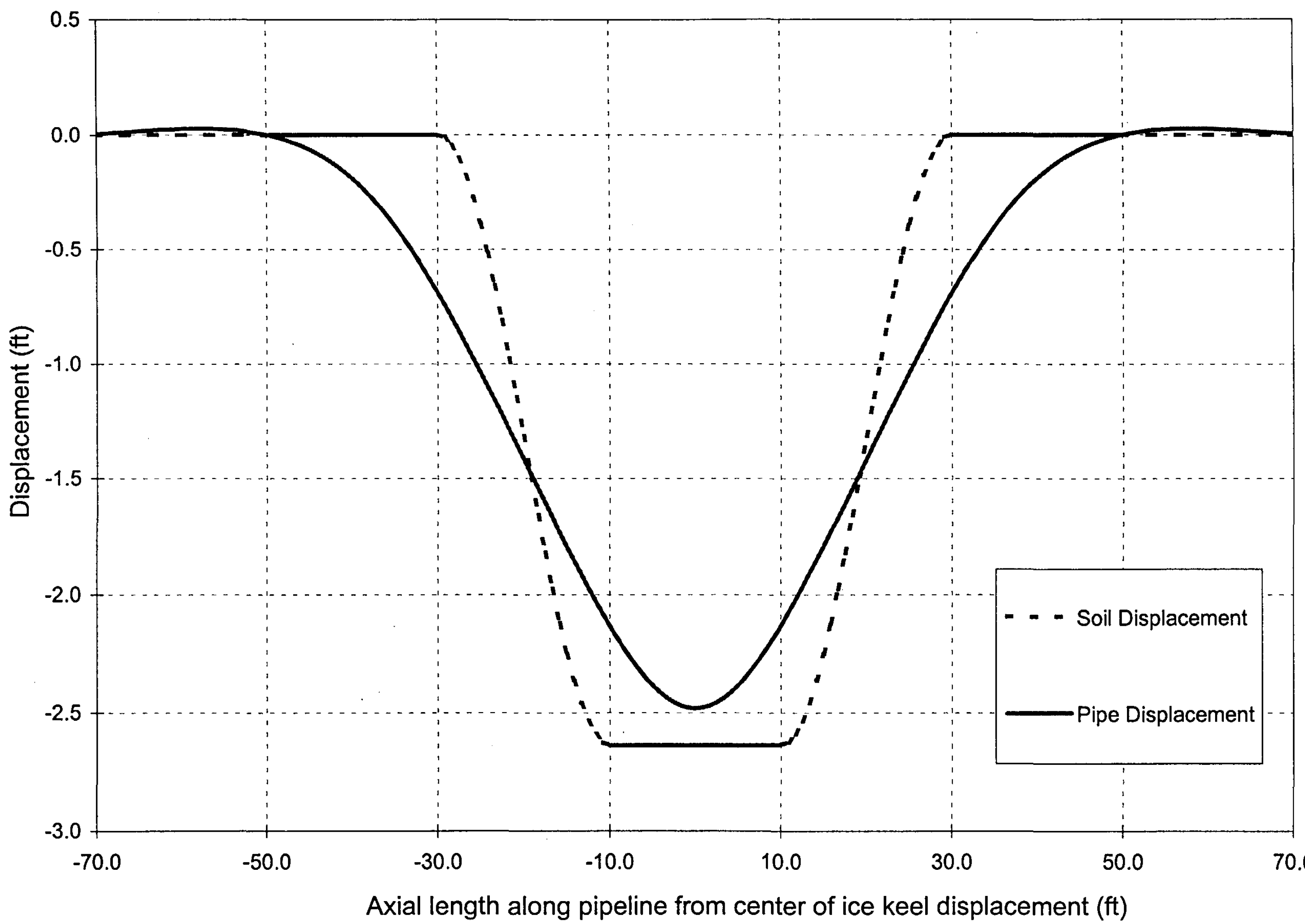


Figure 5.3 : Pipe-in-Pipe 12.75" OD, 0.500" WT & 16.00" OD, 0.844" WT
Pipe displacement within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi
keel: 3.0 ft deep, 40 ft wide

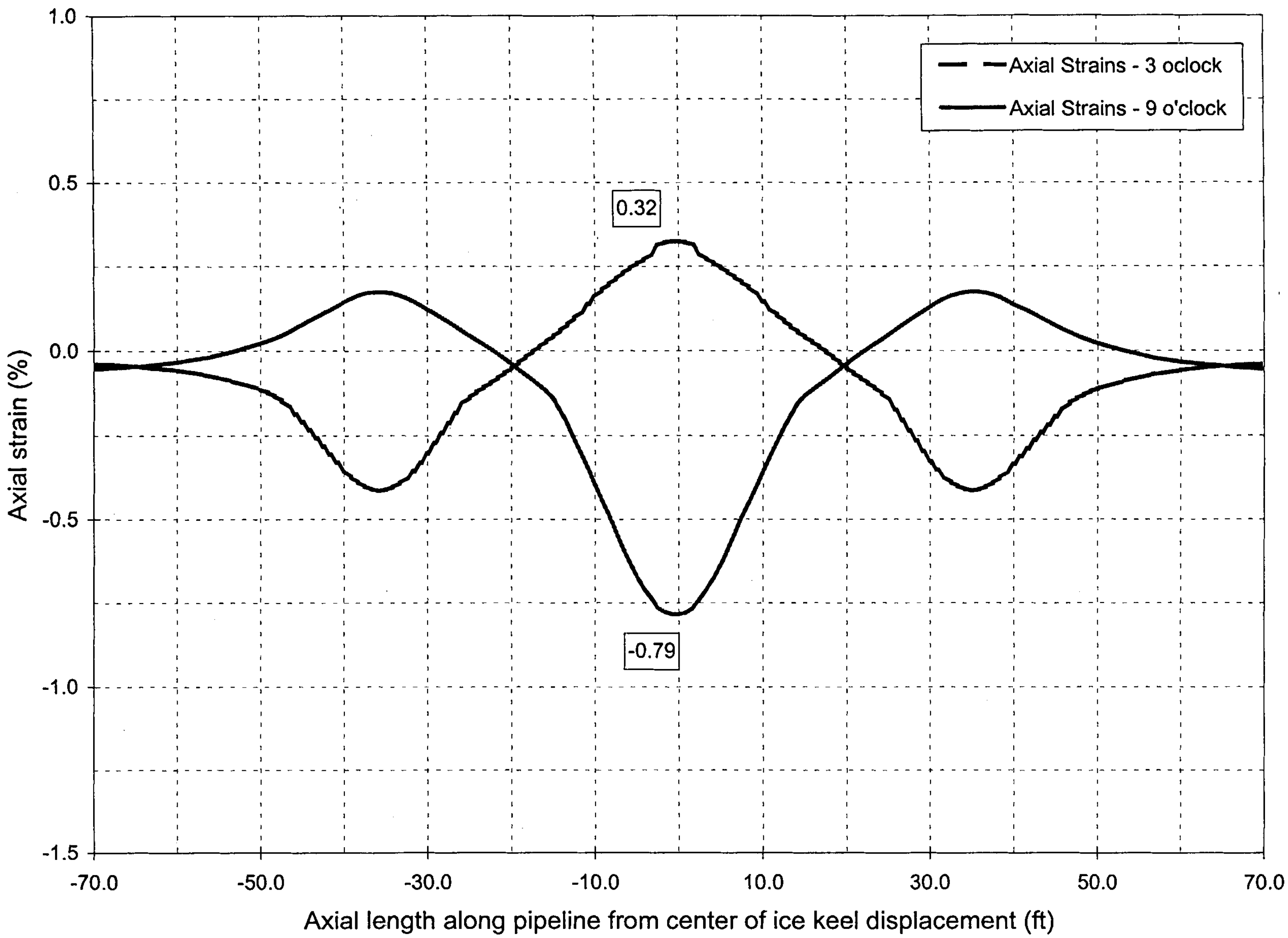


Figure 5.4 : Pipe-in-Pipe 12.75" OD, 0.688" WT & 16.00" OD, 0.500" WT
Axial Strain within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi
keel: 3.0 ft deep, 40 ft wide

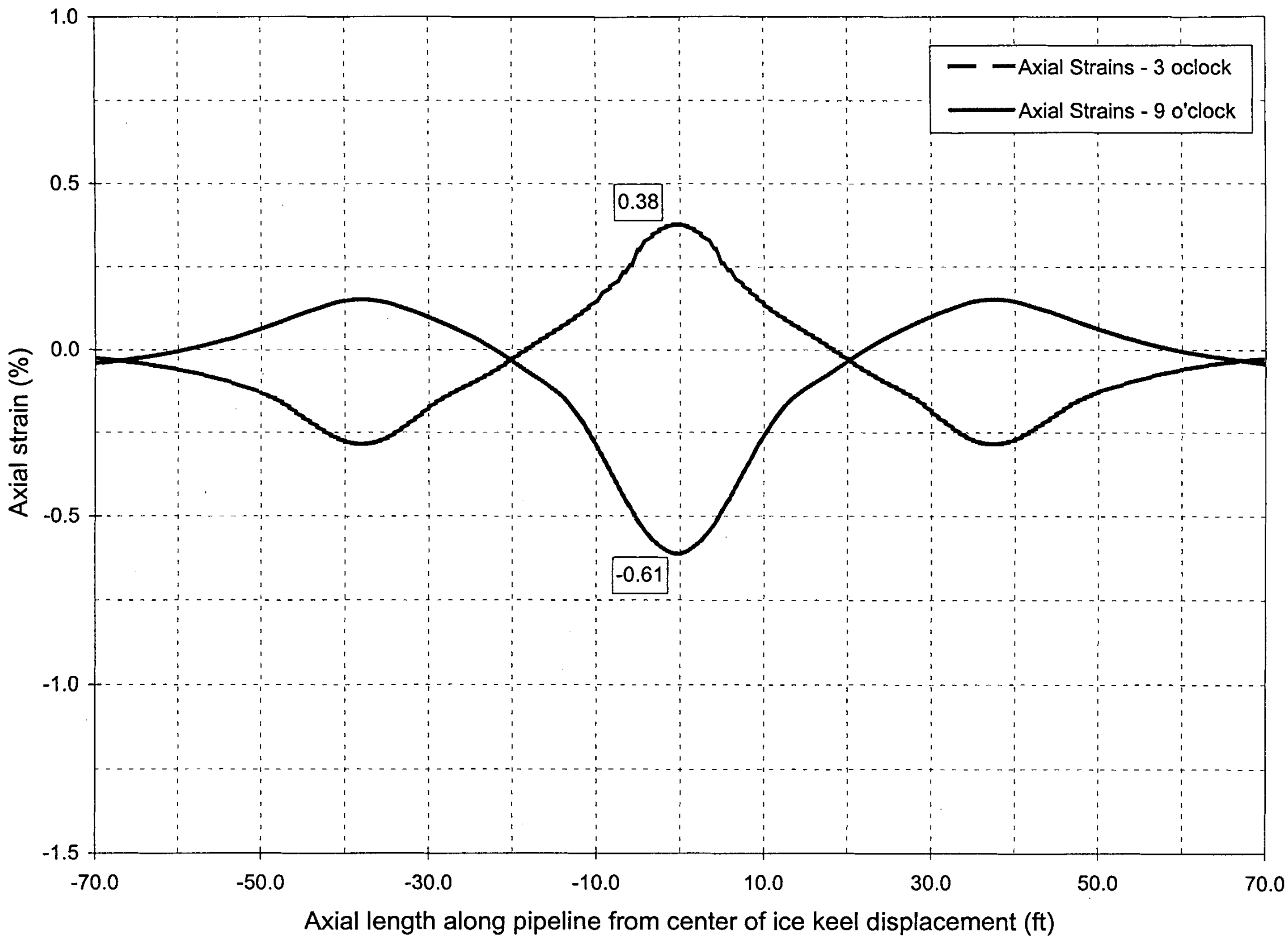


Figure 5.5 : Pipe-in-Pipe 12.75" OD, 0.500" WT & 16.00" OD, 0.844" WT
Axial Strain within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi
keel: 3.0 ft deep, 40 ft wide

- Depth of cover, DOC = 5 ft
- Target Trench Depth, TTD = 9 ft.
- Backfill:

  4-foot native backfill
- Outer Pipe:

  16.00-in OD, 0.844-in WT

  D/t = 18.5
- Inner Pipe:

  12.75-in OD,

  0.50-in WT

  dry weight = 210 lb/ft

  SG = 2.2

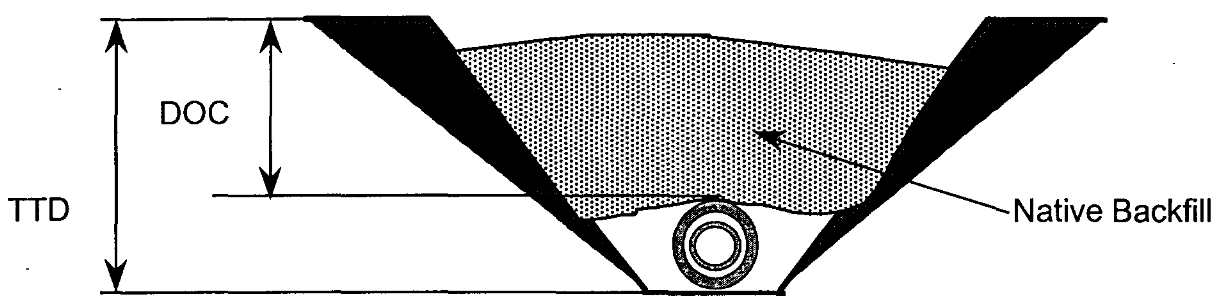
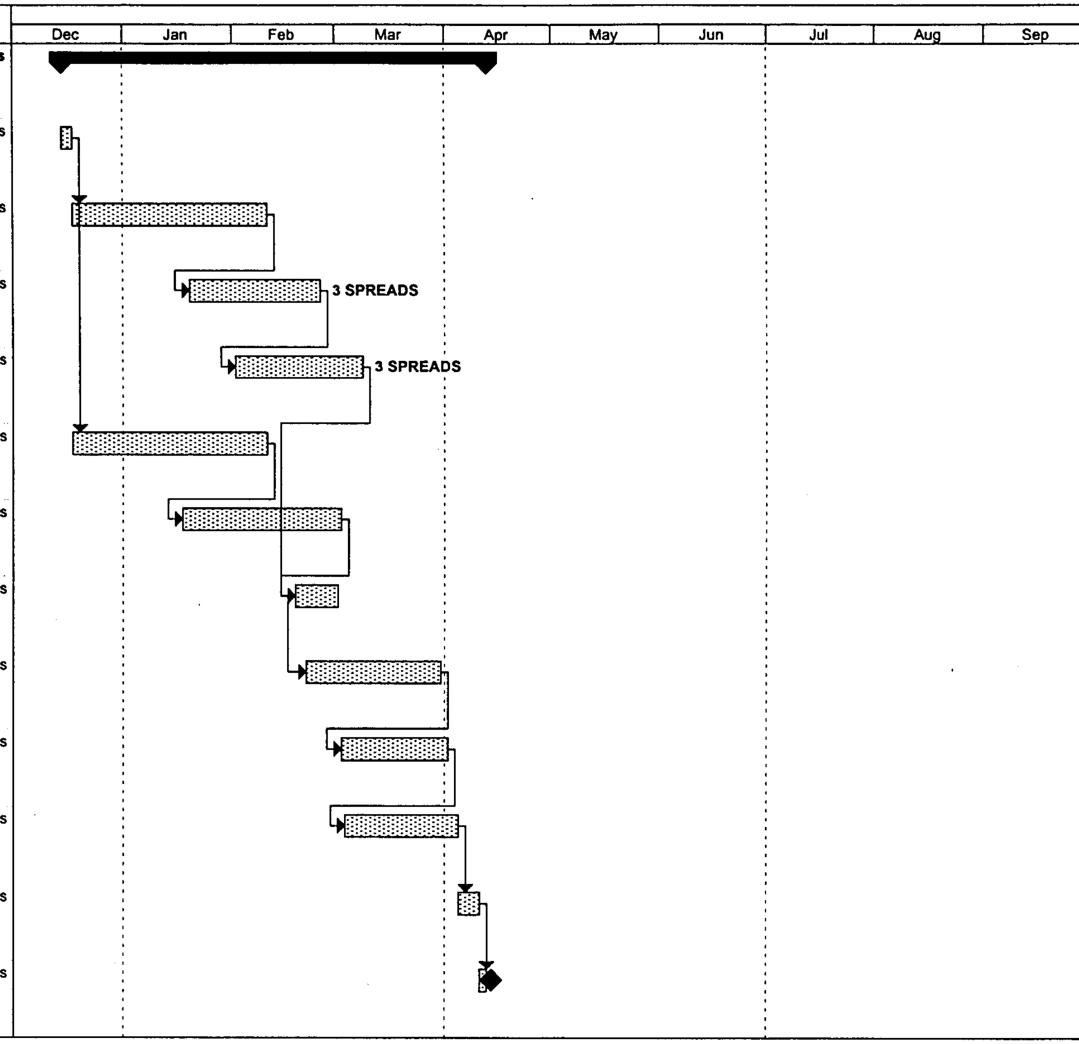


Figure 5.6 Pipe-in-Pipe Selected Configuration

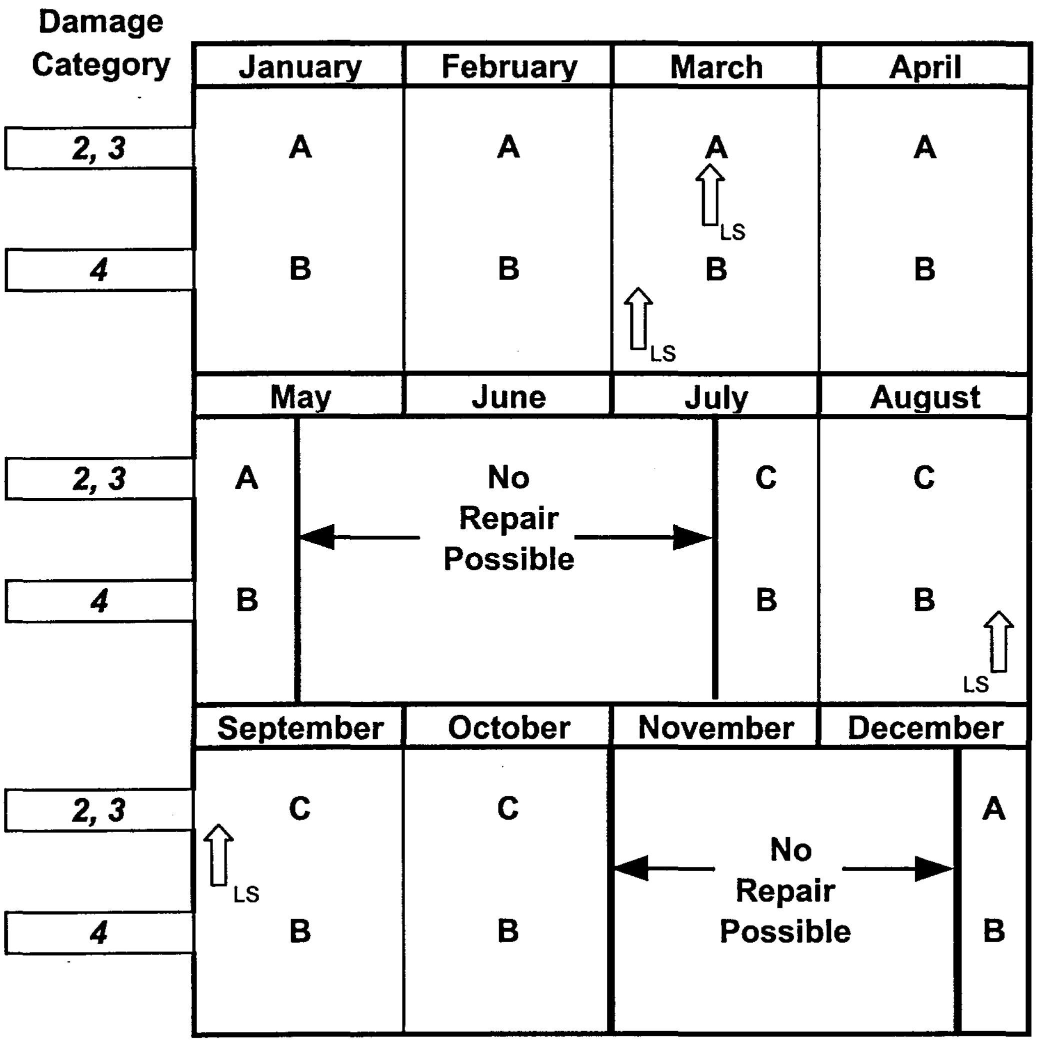
FIGURE 5.7 CONSTRUCTION SCHEDULE - PIPE-IN-PIPE OPTION

ID		Task Name	Duration
1		**Offshore Pipeline Construction**	**103 days**
2		Mobilization Equipment/Material	3 days
3		Ice Thickening and Ice Road Construction	47 days
4		Ice Cutting and Slotting	32 days
5		Trenching	31 days
6		Pipeline Make-Up Site Preparation	47 days
7		Pipe String Make-Up (Welding)	39 days
8		Pipe String Transportation	10 days
9		Pipe-in-Pipe String Field Joint	33 days
10		Pipeline Installation	26 days
11		Backfilling	27 days
12		Hydrostatic Testing	5 days
13		Demobilization Equipment	2 days



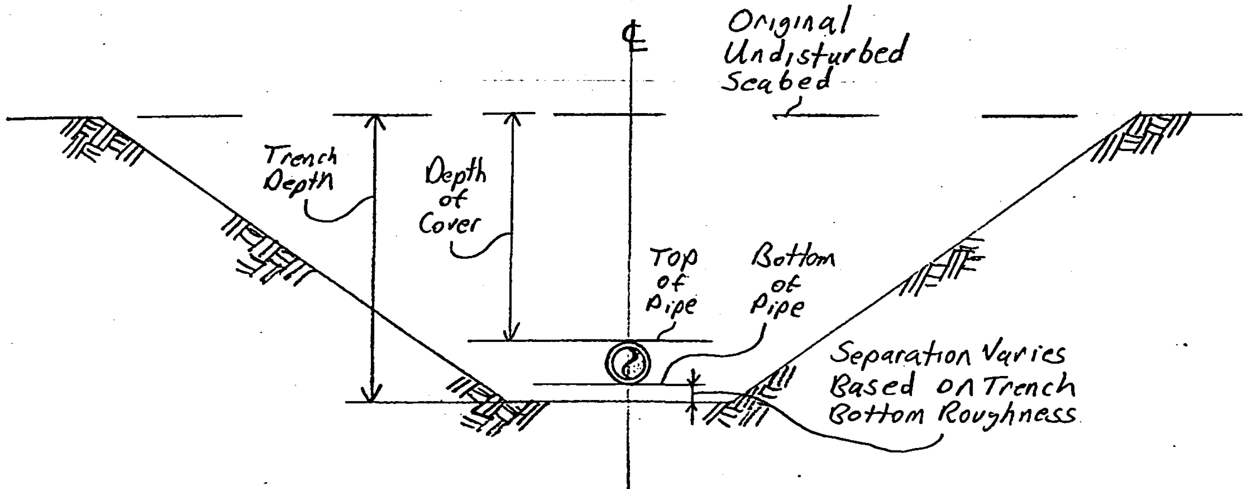
Project: construction schedule_SP
Date: Fri 10/08/99

Task Milestone Summary

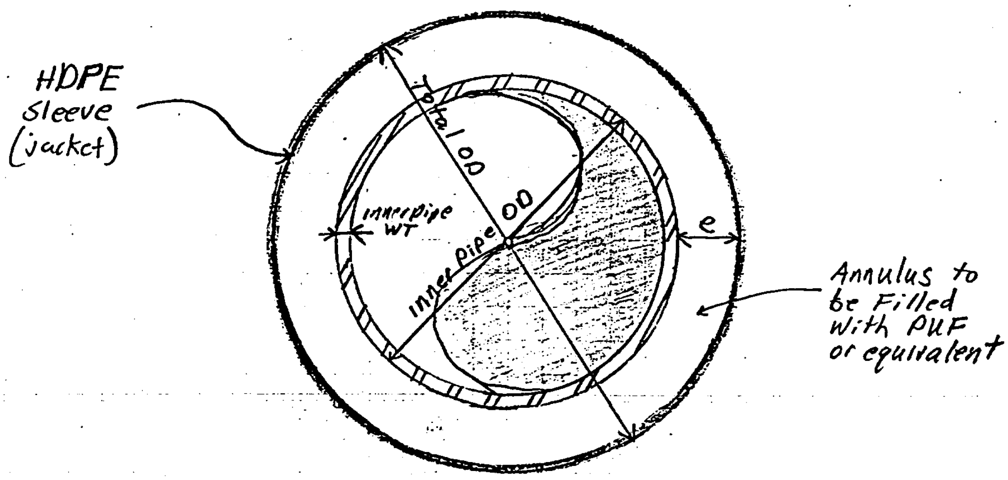


Notes: LS indicates the timing for the "latest start date" for that repair.
A - Surface tie-in.
B - Tow replacement string with surface tie-in.
C - Cofferdam.
Damage Category 2 - Buckle / No Leak.
Damage Category 3 - Small / Medium Leak.
Damage Category 4 - Large Leak / Rupture.
Conditions after repair will result in full integrity of the inner pipe and reduced integrity of the carrier pipe.

Figure 5-8: Recommended Repair Methods



Trench Configuration



Pipe Details

Figure 6.1 – Single Wall Steel Pipe Inside HDPE Sleeve Configuration

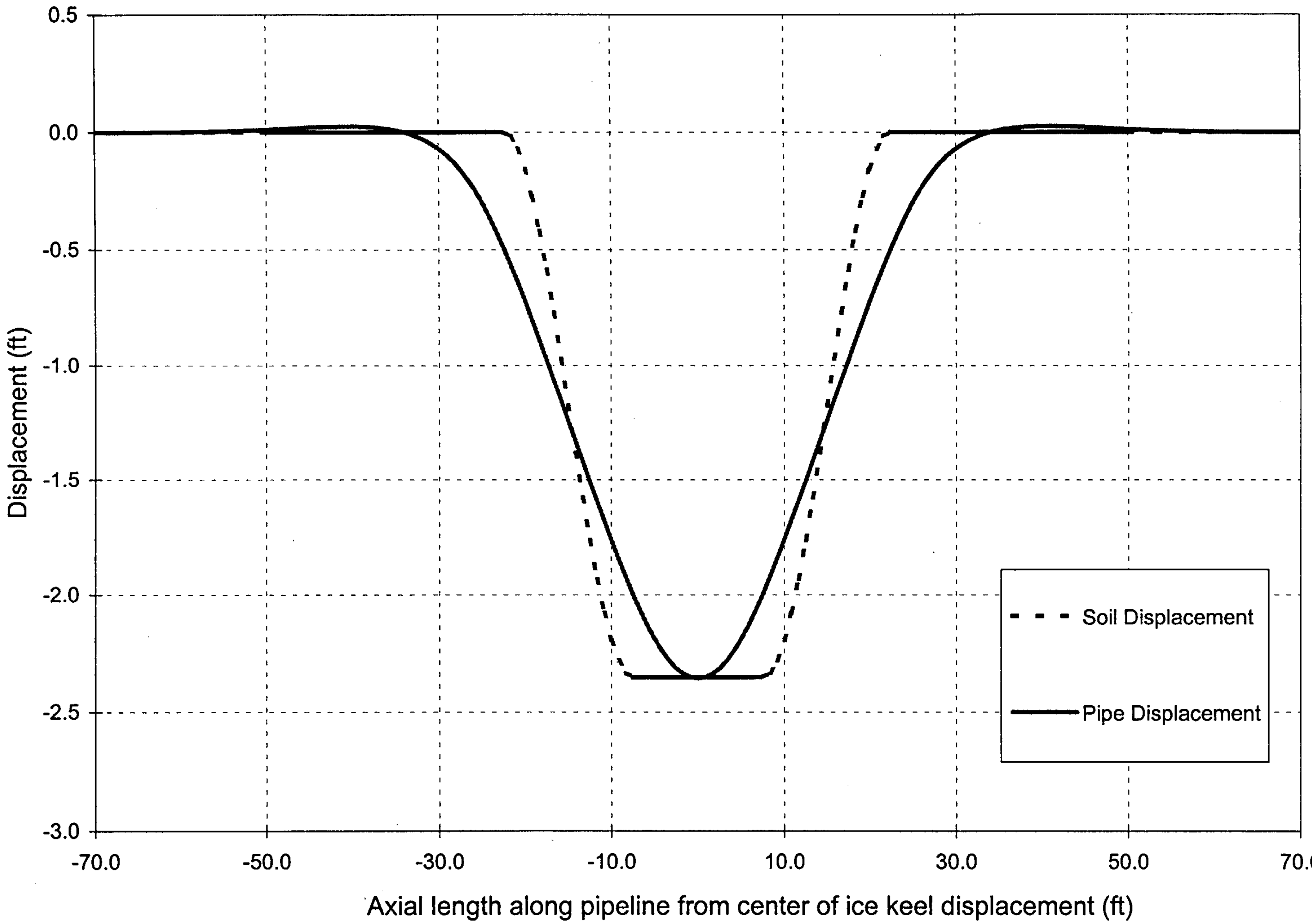


Figure 6.2 : Pipe-in-HDPE 12.75" OD, 0.688" WT, w/ 1"PUF & 0.25"HDPE
Axial Strain within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi
keel: 3.0 ft deep, 30 ft wide

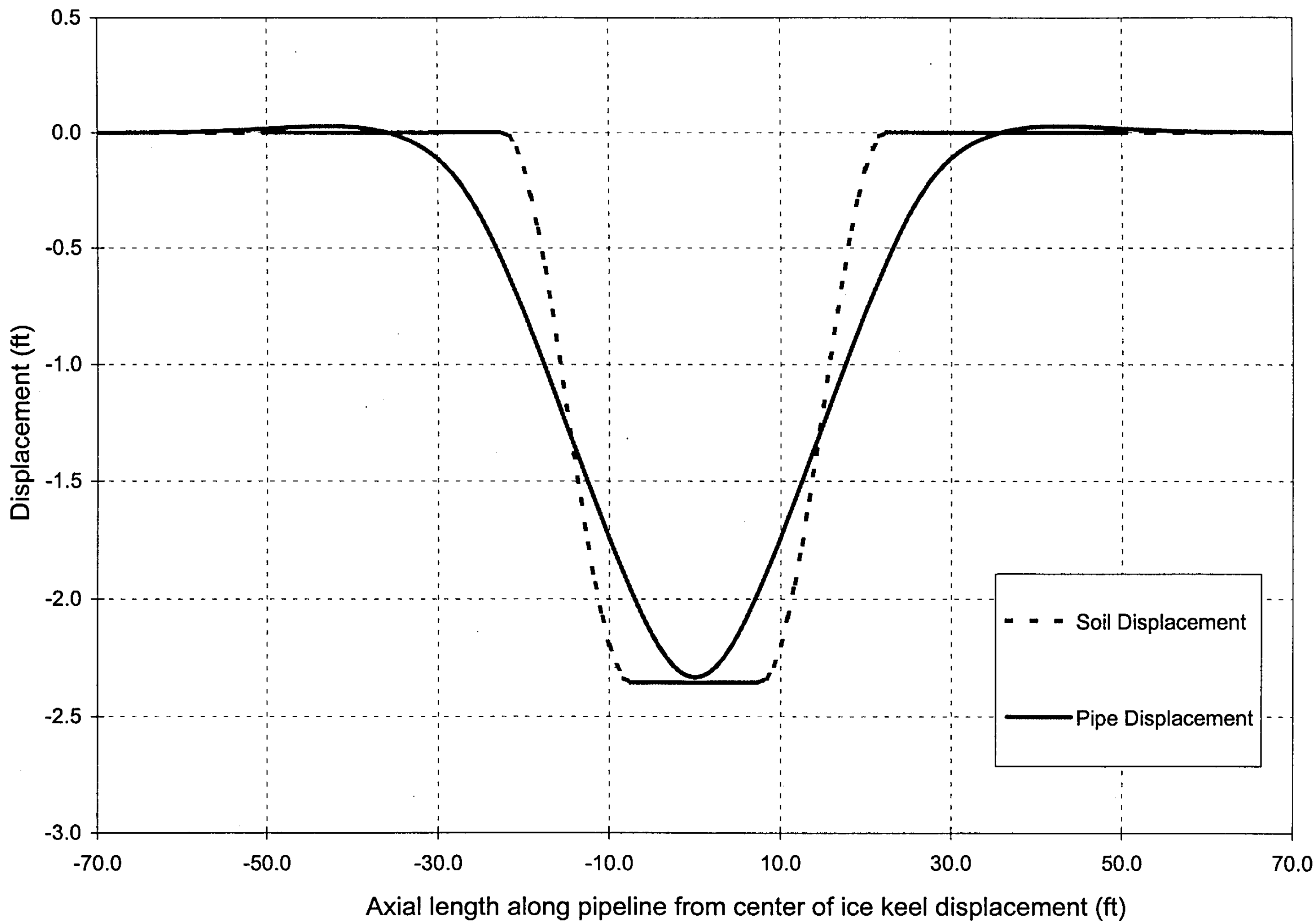


Figure 6.3 : Pipe-in-HDPE 12.75" OD, 0.688" WT, w/ 0.75" HDPE
Axial Strain within ice-keel zone - 7 ft pipe cover, Pressure = 1415 psi
keel: 3.0 ft deep, 30 ft wide

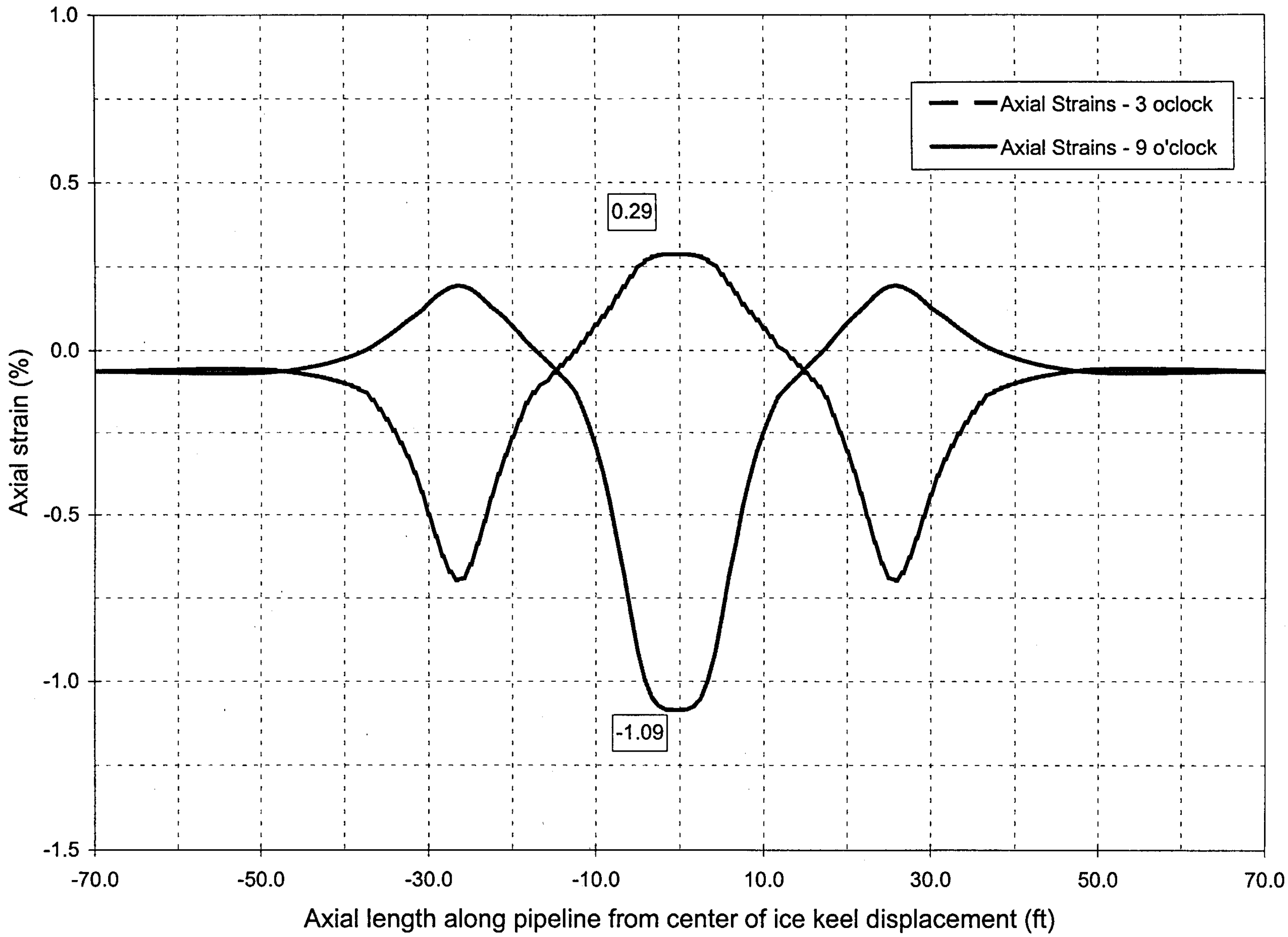


Figure 6.4 : Pipe-in-HDPE 12.75" OD, 0.688" WT, w/ 1"PUF & 0.25"HDPE Axial Strain within ice-keel zone - 7 ft pipe cover, DT=120°F, Pressure = 1415 psi keel: 3.0 ft deep, 30 ft wide

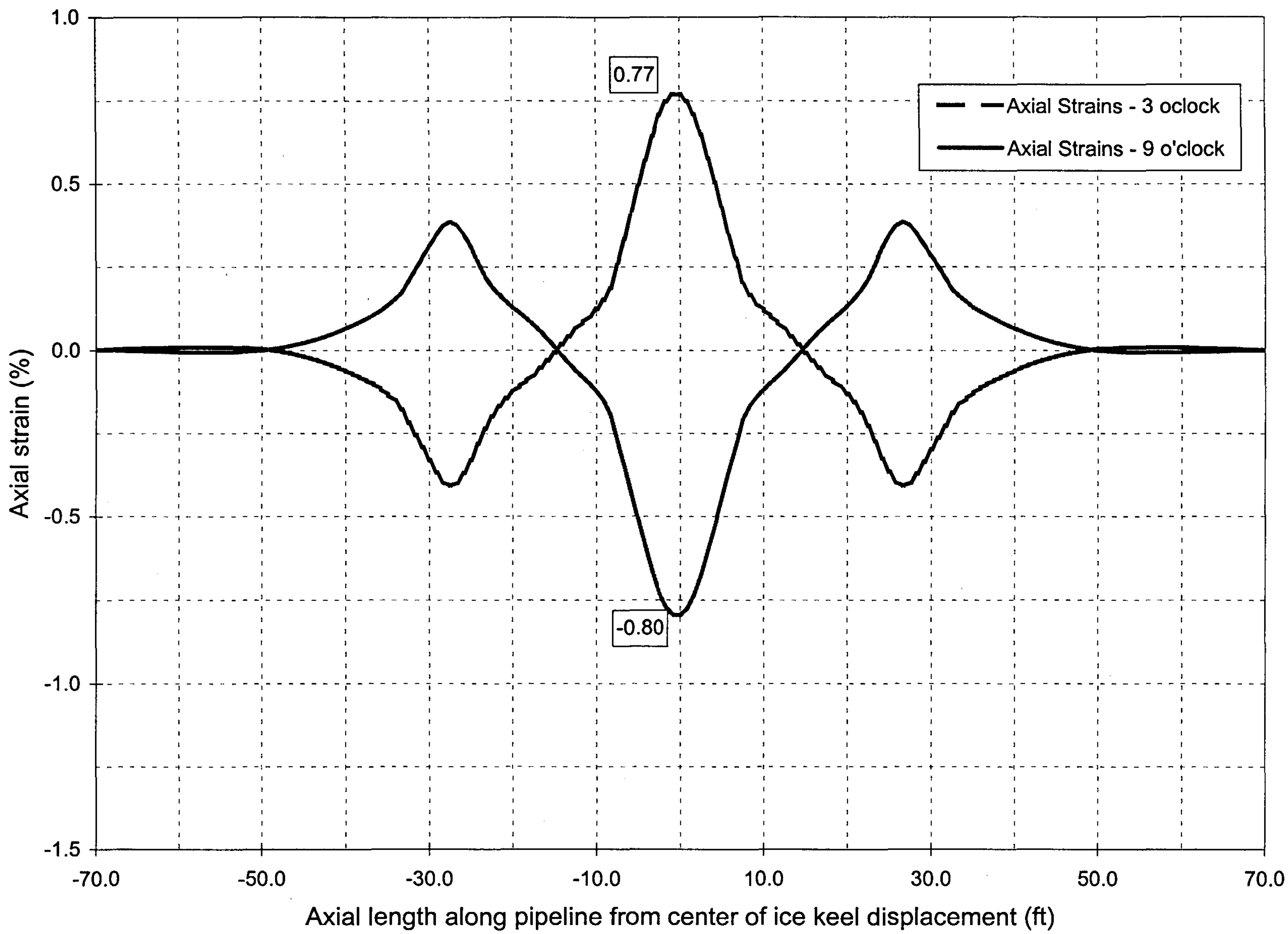


Figure 6.5 : Pipe-in-HDPE 12.75" OD, 0.688" WT, w/ 0.75" HDPE Axial Strain within ice-keel zone - 7 ft pipe cover, Pressure = 1415 psi keel: 3.0 ft deep, 30 ft wide

- Depth of Cover, DOC = 6 ft
- Target Trench Depth, TTD = 10 ft.
- Backfill:

  0- to 5-foot native backfill required
- Outer HDPE Pipe:

  16.50-in OD,

  0.75-inch WT
- Inner Steel Pipe:

  12.75-in OD,

  0.688-in WT

  dry weight = 95 lb/ft

  SG = 1.2

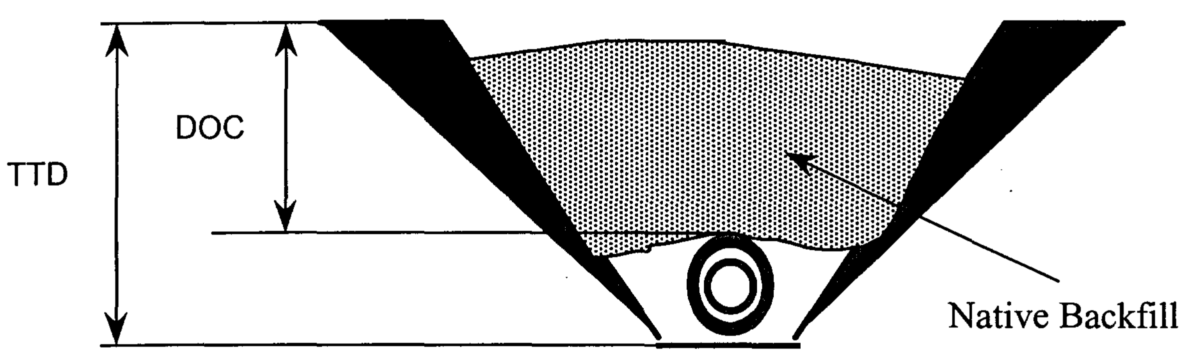
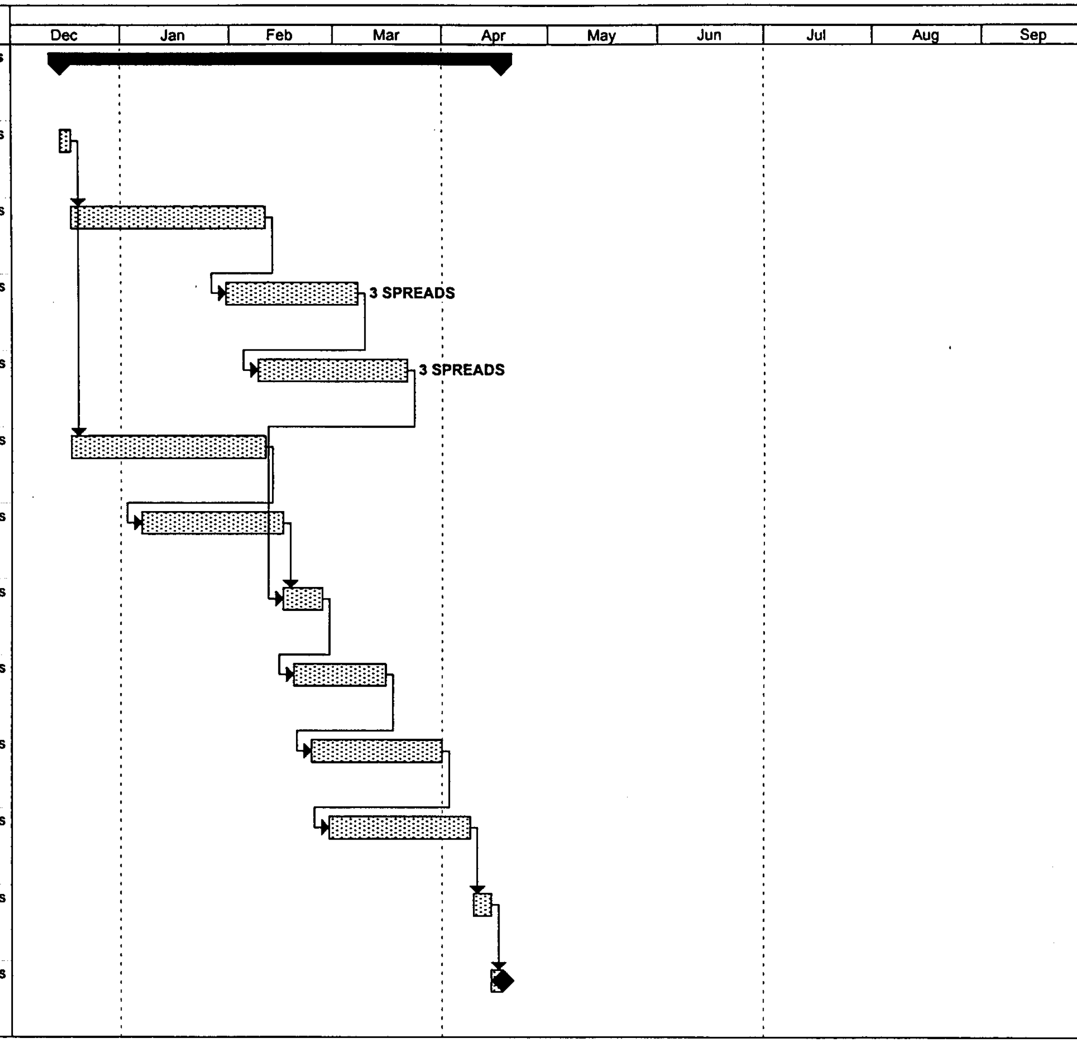


Figure 6.6 Pipe-in-HDPE Selected Configuration

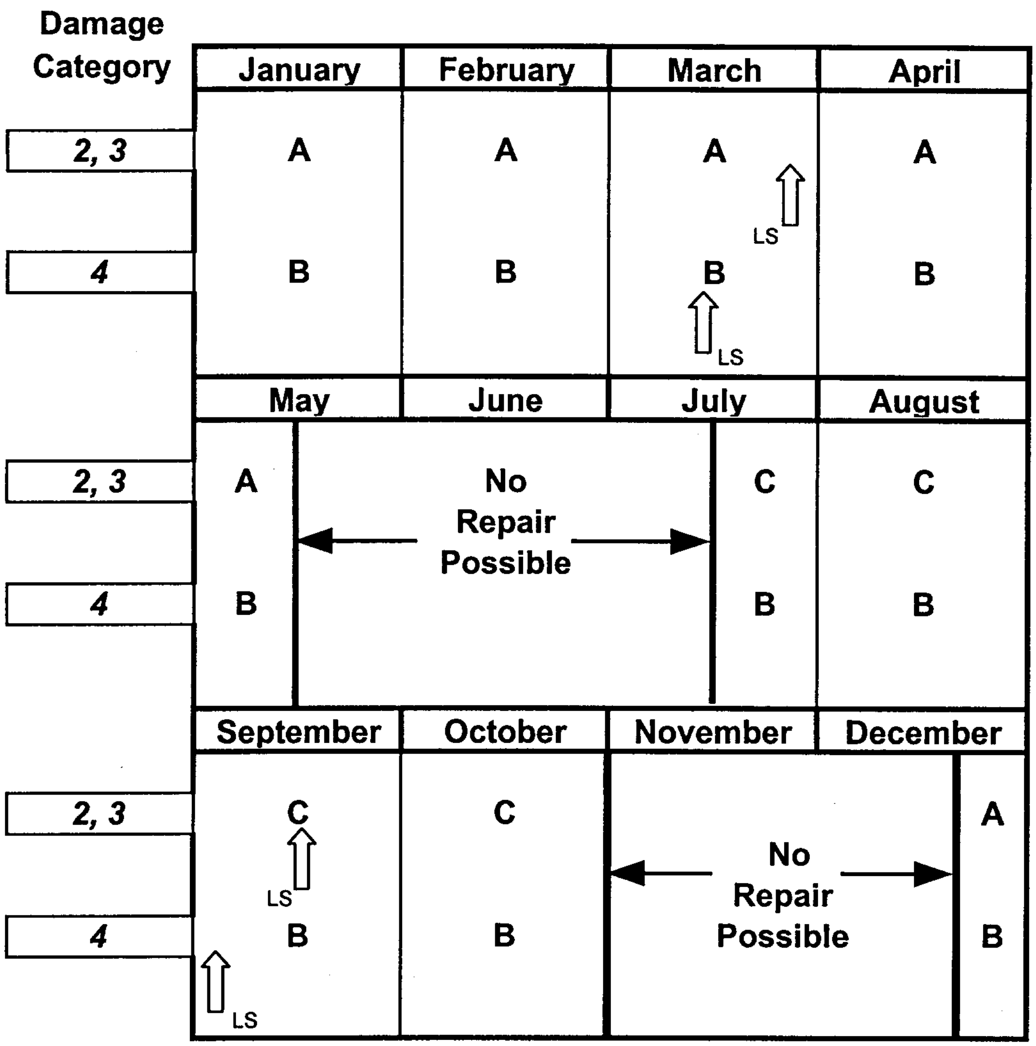
FIGURE 6.7 CONSTRUCTION SCHEDULE - PIPE-IN-HDPE OPTION

ID	Task Name	Duration
1	**Offshore Pipeline Construction**	107 days
2	Mobilization Equipment/Material	3 days
3	Ice Thickening and Ice Road Construction	47 days
4	Ice Cutting and Slotting	32 days
5	Trenching	36 days
6	Pipeline Make-Up Site Preparation	47 days
7	Pipe String Make-Up (Welding)	34 days
8	Pipe String Transportation	10 days
9	Pipe String Field Joint	22 days
10	Pipeline Installation	32 days
11	Backfilling	35 days
12	Hydrostatic Testing	5 days
13	Demobilization Equipment	2 days



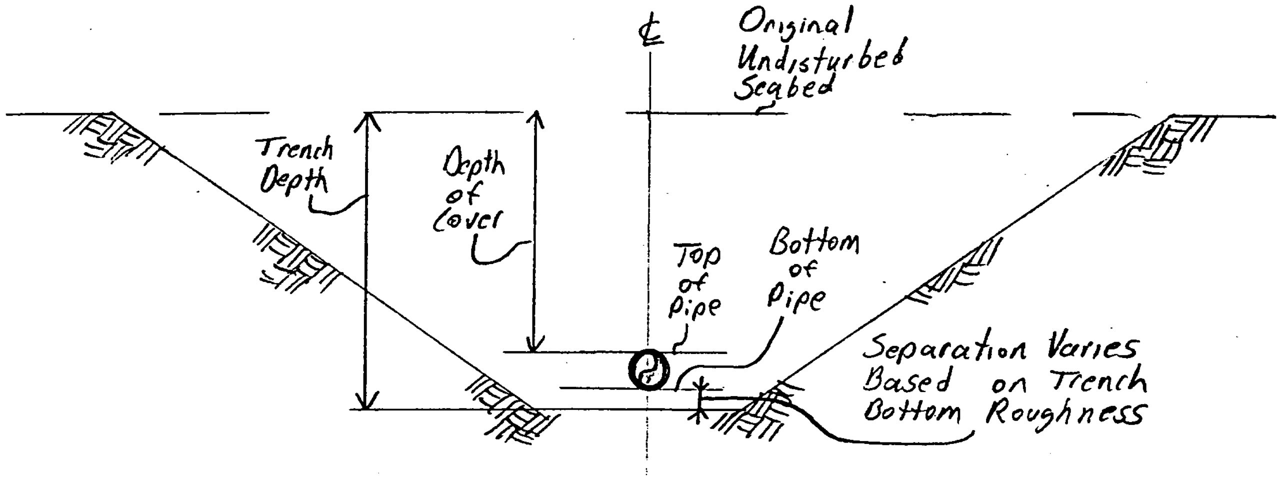
Project: construction schedule_SP
Date: Thu 10/14/99

Task | Milestone | Summary

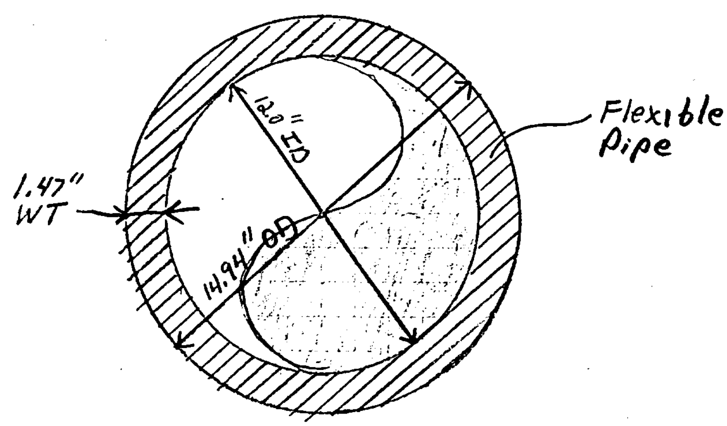


Notes: LS indicates the timing for the "latest start date" for that repair.
A - Surface Repair.
B - Tow replacement string with surface tie-in.
C - Cofferdam.
Damage Category 2 - Buckle / No Leak.
Damage Category 3 - Small / Medium Leak.
Damage Category 4 - Large Leak / Rupture.
Conditions after repair will result in full integrity of the pipe.

Figure 6-8: Recommended Repair Methods



Trench Configuration



Pipe Details

Figure 7.1 – Flexible Pipe Configuration

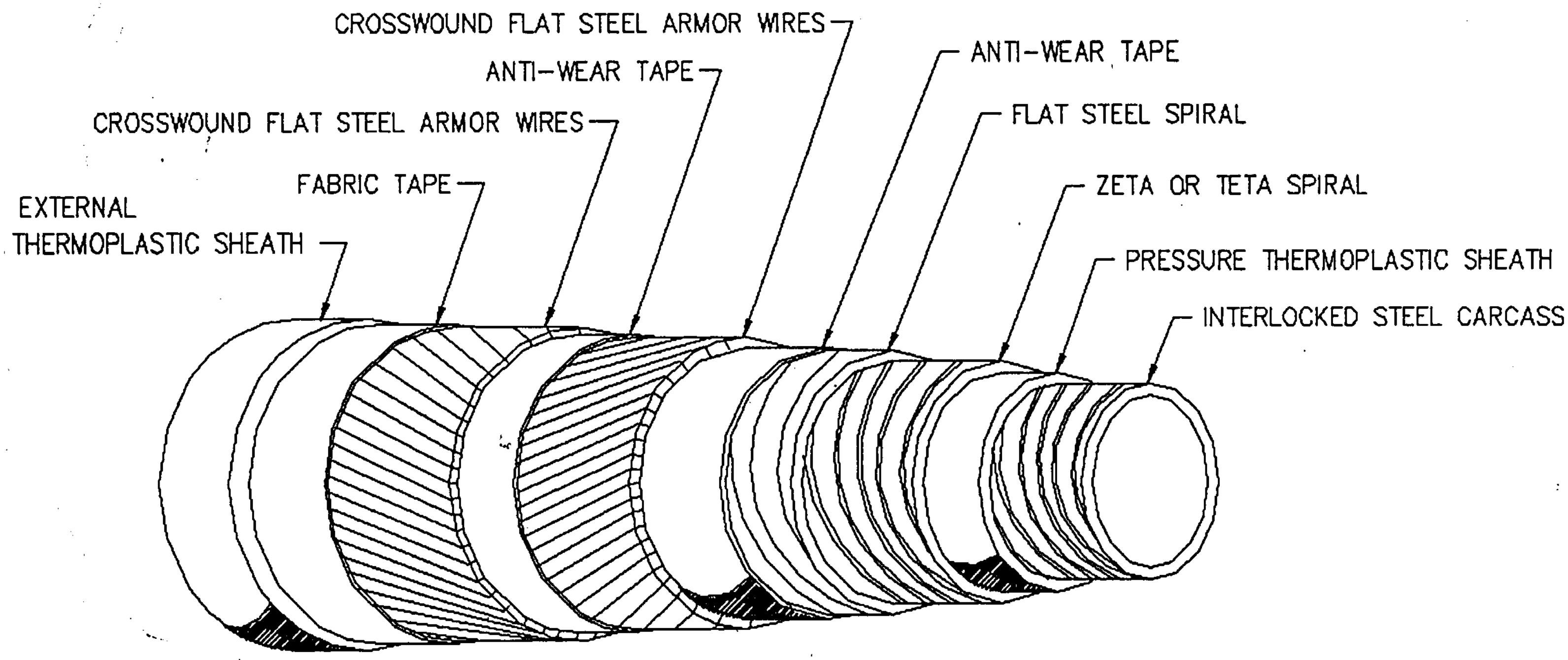


Figure 7.2 : Flexible pipe cross section with layer description

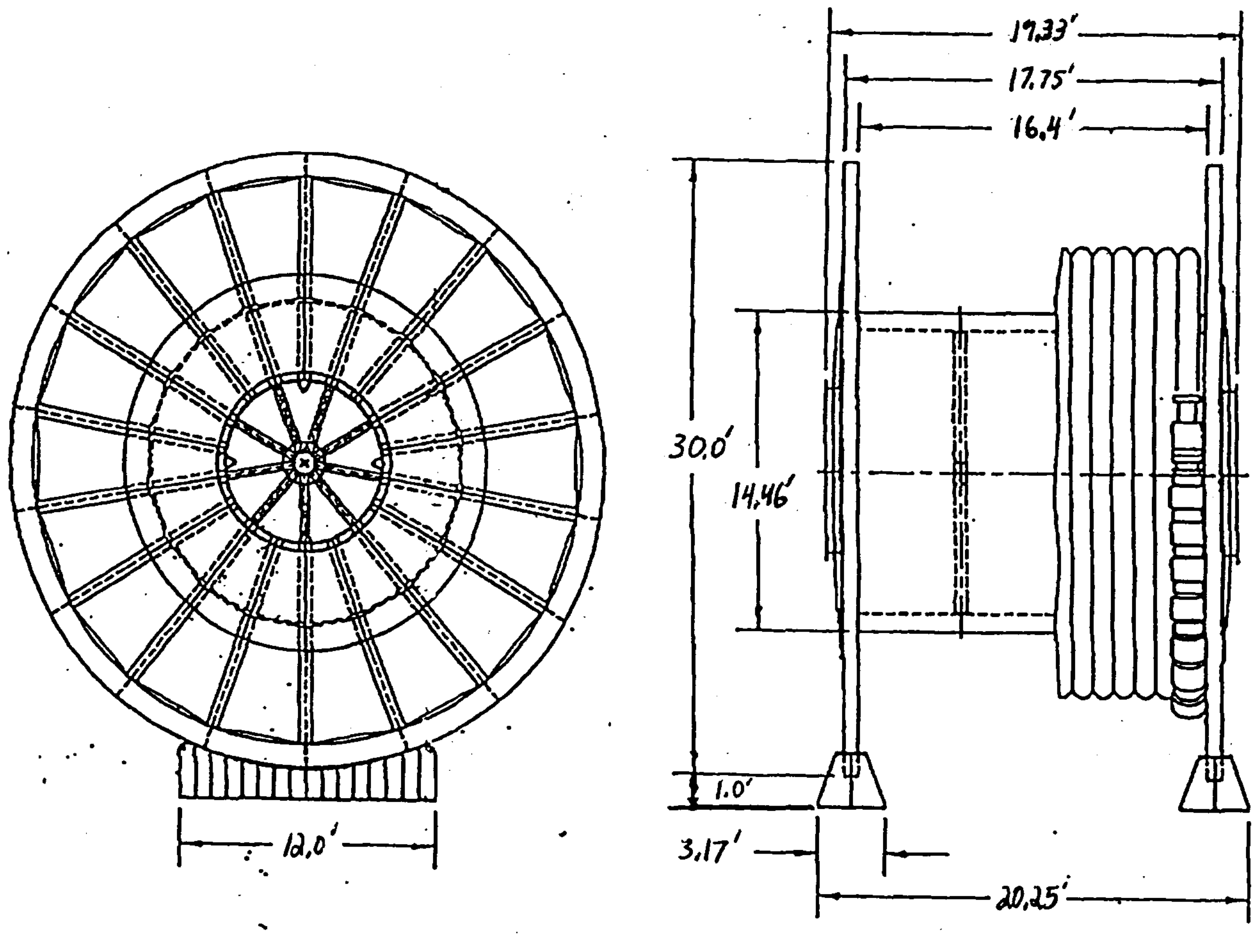


Figure 7.3: Typical reel for flexible pipe

- Depth of cover, DOC = 5 ft
- Target Trench Depth, TTD = 8.5 ft
- Backfill:

  4-foot native backfill required
- Flexible Pipe:

  16.00-in OD,

  weight = 85 lb/ft

  SG = 1.1

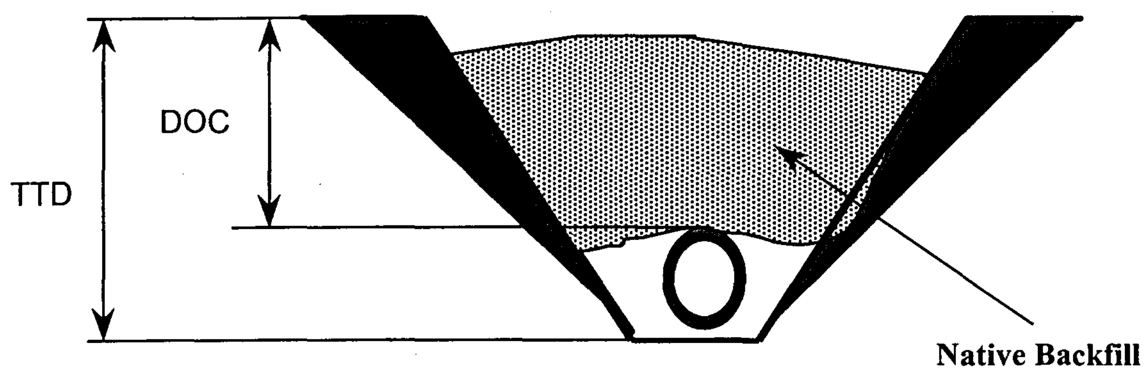
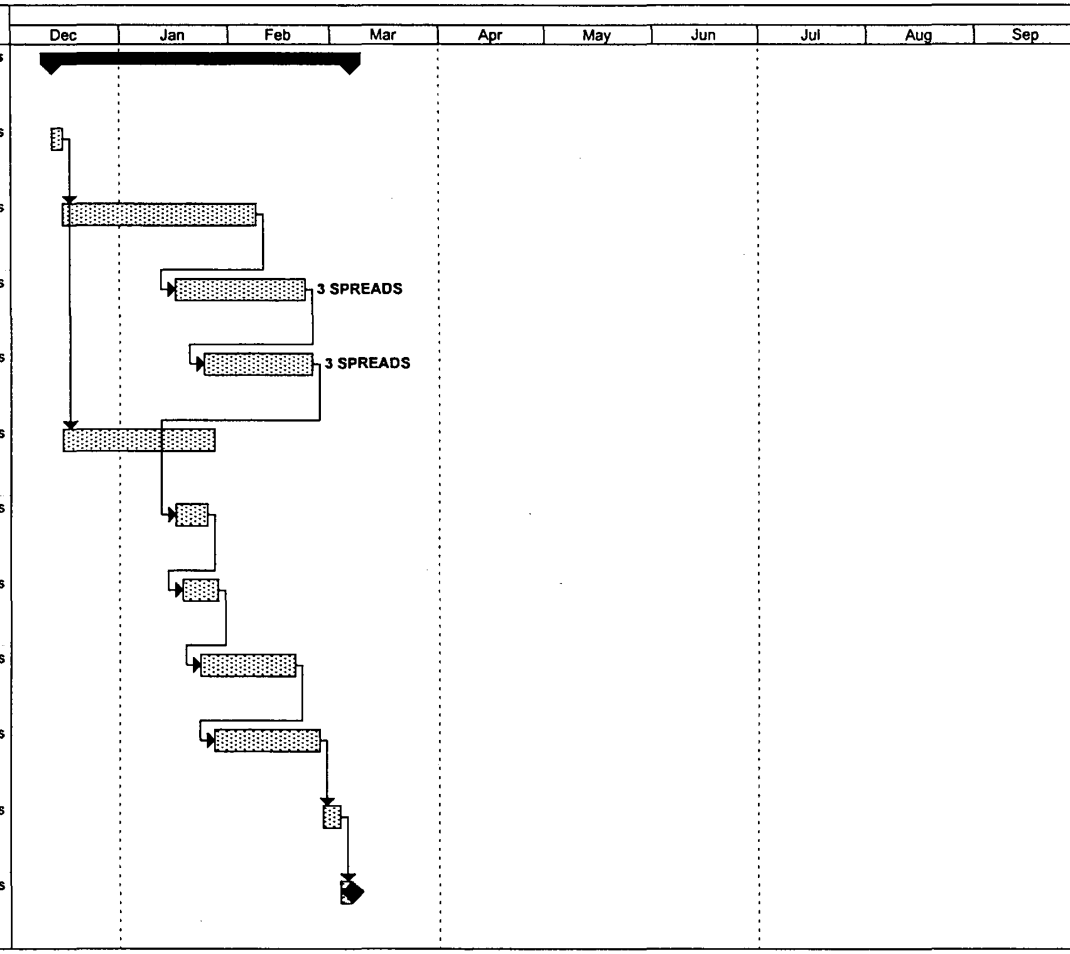


Figure 7.4 Flexible Pipe Selected Configuration

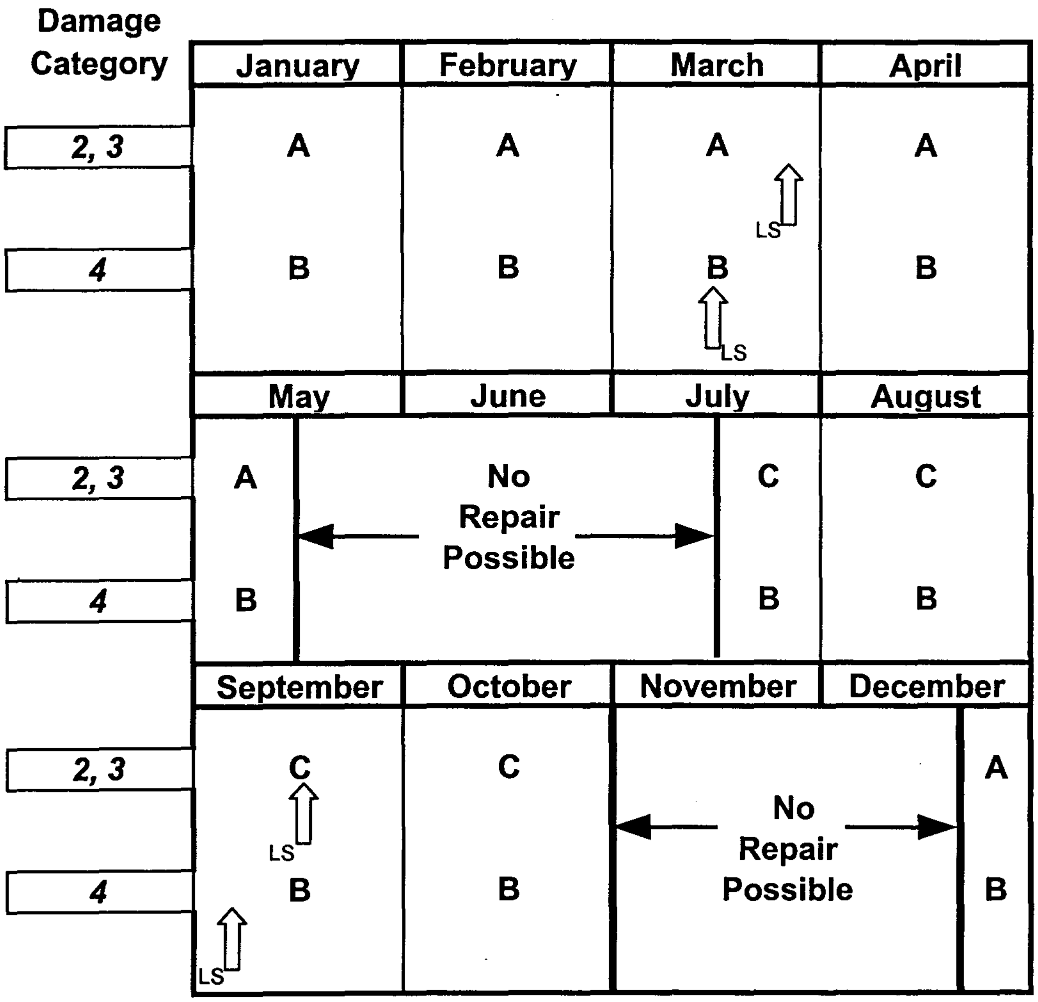
FIGURE 7.5 CONSTRUCTION SCHEDULE - FLEXIBLE PIPE OPTION

ID	Task Name	Duration
1	**Offshore Pipeline Construction**	73 days
2	Mobilization Equipment/Material	3 days
3	Ice Thickening and Ice Road Construction	47 days
4	Ice Cutting and Slotting	32 days
5	Trenching	27 days
6	Spools Site Preparation	37 days
7	Unspooling, Flexible Pipe StringTransport	8 days
8	Flexible Pipe String Connection	9 days
9	Pipeline Installation	24 days
10	Backfilling	26 days
11	Hydrostatic Testing	5 days
12	Demobilization Equipment	2 days



Project: construction schedule_SP
Date: Thu 10/14/99

Task | Milestone | Summary



Notes: LS indicates the timing for the "latest start date" for that repair.
A - Surface repair or hyperbaric tie-in.
B - Tow replacement string with subsurface tie-in or hyperbaric tie-in.
C - Cofferdam or hyperbaric tie-in.
Damage Category 2 - Buckle / No Leak.
Damage Category 3 - Small / Medium Leak.
Damage Category 4 - Large Leak / Rupture.
Conditions after repair will result in full integrity of the pipe.

Figure 7-6: Recommended Repair Methods

INTEC ENGINEERING

CALCULATION NUMBER

Project ______ Job No. ______

Subject ______ Sheet ______

Signature ______ Date ______

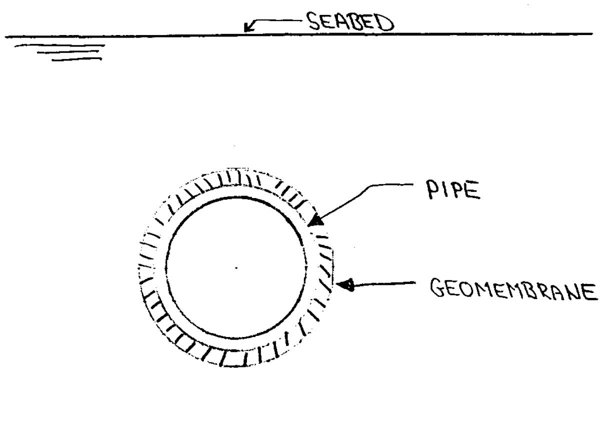


FIGURE 8.1 - PIPE WRAPPED WITH GEOMEMBRANE

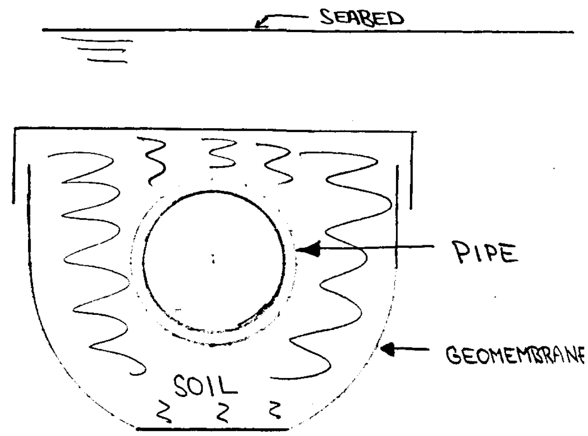


FIGURE 8.2 - GEOMEMBRANE WRAP AROUND A LAYER OF SOIL

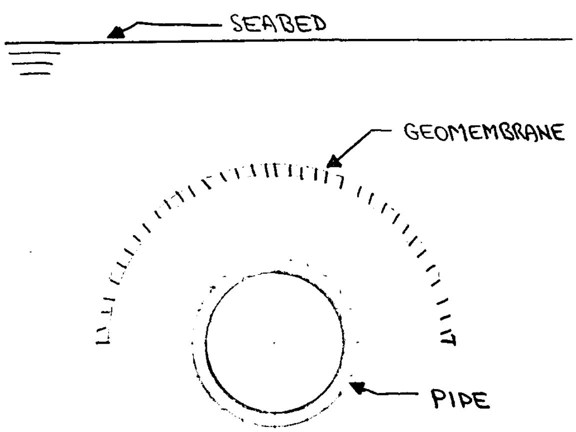


FIGURE 8.3 - GEOMEMBRANE COVER OVER PIPE

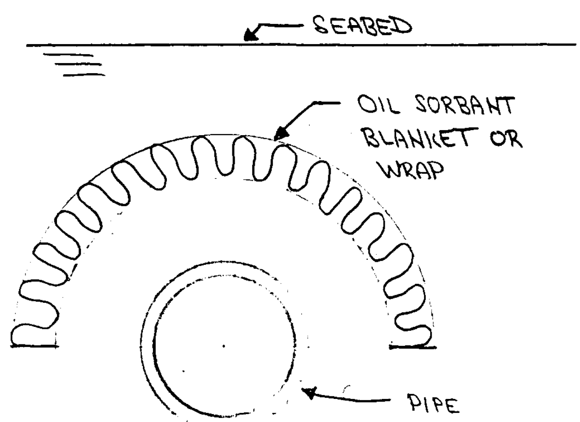


FIGURE 8.5 - OIL SORBANT BLANKET OR WRAP OVER PIPE

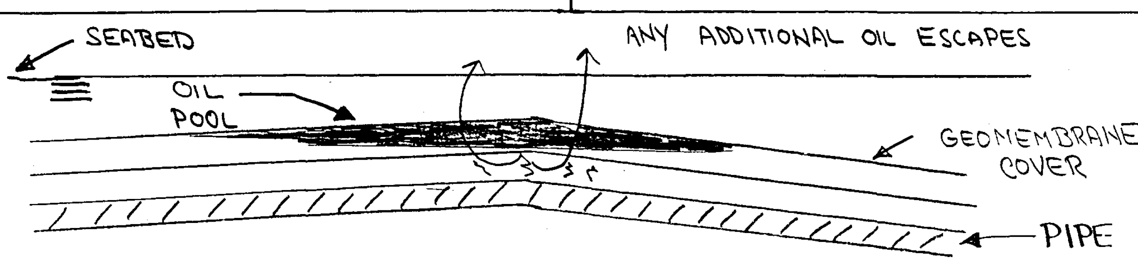


FIGURE 8.4 - OIL ESCAPING FROM UNDER GEOMEMBRANE COVER

APPENDIX C

STATISTICAL ANALYSIS OF ICE GOUGE FIELD DATA

Statistical Analysis of Ice Gouge Field Data

Statistical analysis of two ice gouge data sets have been conducted. These data sets were obtained by Coastal Frontiers Corporation during the summers of 1997 (shown in Figure 2-3) and 1998 and are specific to the Liberty project (Coastal Frontiers Corporation 1998, 1999). They were conceived and executed to examine the proposed pipeline alignment and surrounding area.

Analysis of the 1998 CFC Survey Data

Data from the 1998 survey (Coastal Frontiers Corporation 1999) has been analyzed and presented in Table C-1. The lowest limit of the ice gouge depth class is defined as 0.25 ft with a class range of 0.1 ft. Therefore, the first class is from 0.25 to 0.35 ft. The second depth class is from 0.35 to 0.45 ft, and so on. The minimum ice gouge depth reported is 0.6 ft, the maximum is 0.3 feet deep, with an average depth of 0.475 ft, and a median depth of 0.5 ft.

TABLE C-1: FREQUENCY DISTRIBUTION FOR ICE GOUGE DEPTHS FROM 1998 SURVEY DATA

Class Limits (ft)	Class center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of Exceedence
0.25						1.0000
	0.3	1	0.2500	1	0.2500	
0.35						0.7500
	0.4	0	0.0000	1	0.2500	
0.45						0.7500
	0.5	2	0.5000	3	0.7500	
0.55						0.2500
	0.6	1	0.2500	4	1.0000	
0.65						0.0000
Number of observations = 4						
Average depth = 0.475 ft						
Median depth = 0.5 ft						

Graphical Gouge Depth Calculation

The exceedence probability function (EPF) that best fit the data is given by:

$$EP_D = e^{-4.1589(x-0.282)} \qquad \text{(C-1)}$$

The probability of exceedence vs. class limits (first and last columns of Table C-1) are plotted in Figure C-1. From the gouge depth probability density function presented in this figure, the cutoff depth is calculated to be 0.282ft. Lambda (1/ft) is take from the least squares fit of the exponential plot to be $\lambda = 4.1589$.

The annual ice gouge recurrence rate, g, (new gouges per mile per year) is calculated to be 0.055. The annual ice gouge recurrence rate is based on assuming all 4 gouges observed in approximately 72 statute survey miles during 1998 were new gouges. This is a conservative estimate. In fact, one gouge was identified as an old gouge from the 1997 summer survey.

The pipeline length is conservatively taken as 6.12 miles. This length includes a portion of the route protected by deep burial within the Liberty Island and the shallow/above water portions of the shore crossing.

The gouge trend angle is conservatively estimated to be 90 degrees (perpendicular to the pipeline route) and the gouge depth return period is taken to be 100 years.

The extreme gouge depth calculation results in a design ice gouge of 1.13 ft.

Analytical Gouge Depth Calculation

The average incision depth, d_{bar}, has been calculated to be 0.475 ft. The cutoff depth is taken to be the lower bound of the class depth interval below which no gouges were observed, c = 0.25. Lambda (1/ft) can be calculated for a negative exponential probability distribution, as $\lambda = 1/(d_{bar}-c) = 4.4444$.

Again, the annual ice gouge recurrence rate, the pipeline length, the gouge trend angle, and the gouge depth return period are taken to be 0.055 new gouges per mile per year, 6.12 miles, 90 degrees, and 100 years respectively.

The gouge depth calculation results in a design ice gouge of 1.04-ft.

Analysis of the 1997 CFC Survey Data

Table C-2 was obtained by sorting the 1997 ice gouge data set (Coastal Frontiers Corporation 1998) by scour depth. In this case, the lowest limit of the ice gouge depth class is defined as 0.25 ft with a class range of 0.1 ft. The minimum ice gouge depth reported is 0.3 ft, the maximum is 1.4 feet deep, with an average depth of 0.476 ft, and a median depth of 0.4 ft.

TABLE C-2: FREQUENCY DISTRIBUTION FOR ICE GOUGE DEPTHS FROM 1997 SURVEY DATA

Class Limits (ft)	Class center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of Exceedence
0.25						1.0000
	0.3	6	0.3529	6	0.3529	
0.35						0.6471
	0.4	4	0.2353	10	0.5882	
0.45						0.4118
	0.5	3	0.1765	13	0.7647	
0.55						0.2353
	0.6	3	0.1765	16	0.9412	
0.65						0.0588
	0.7	0	0.0000	16	0.9412	
0.75						0.0588
	0.8	0	0.0000	16	0.9412	
0.85						0.0588
	0.90	0	0.0000	16	0.9412	
0.95						0.0588
	1.00	0	0.0000	16	0.9412	
1.05						0.0588
	1.10	0	0.0000	16	0.9412	
1.15						0.0588
	1.20	0	0.0000	16	0.9412	
1.25						0.0588
	1.30	0	0.0000	16	0.9412	
1.35						0.0588
	1.40	1	0.0588	17	1.0000	
1.45						0.0000
Number of observations = 17						
Average depth = 0.476 ft.						
Median depth = 0.4 ft						

<u>Graphical Gouge Depth Calculation</u>

The exceedence probability function (EPF) that best fit the data is given by:

$$EP_D = e^{-2.5629(x+0.027)} \quad \text{(C-2)}$$

The probability of exceedence vs. class limits (first and last columns of Table C-2) are plotted in Figure C-2. The cutoff depth is calculated from the gouge depth probability density function in Figure C-2 and results in c = -0.027. Note that the negative value for c will be replaced by c = 0.00 for use in calculating extreme gouge depths. Substituting c = 0.00 gives 100% of gouges ≥ 0-ft deep. Lambda is taken from the least squares curve fit of the exponential plot and is calculated to be $\lambda = 2.5629$ (1/ft).

The annual ice gouge recurrence rate is calculated to be 0.097 new gouges per mile per year. The annual ice gouge recurrence rate is based on assuming all 17 gouges observed in approximately 175 statute survey miles during 1997 were new gouges. This is a conservative estimate.

The pipeline length is conservatively taken as 6.12 miles. This length includes a portion of the route protected by deep burial within the Liberty Island and the shallow/above water portions of the shore crossing.

The gouge trend angle is conservatively estimated to be 90 degrees (perpendicular to the pipeline route) and the gouge depth return period is taken to be 100 years.

The extreme gouge depth calculation results in a design ice gouge of 1.59 ft.

Analytical Gouge Depth Calculation

The average incision depth, d_{bar}, has been calculated to be 0.476 ft. The cutoff depth is taken to be the lower bound of the class depth interval below which no gouges were observed, c = 0.25. Lambda (1/ft) can be calculated for a negative exponential probability distribution as $\lambda = 1/(d_{bar}-c) = 4.4248$.

The annual ice gouge recurrence rate, the pipeline length, the gouge trend angle, and the gouge depth return period are taken to be 0.097 new gouges per mile per year, 6.12 miles, 90 degrees, and 100 years respectively.

The gouge depth calculation results in a design ice gouge of 1.17 ft.

Combined 1997 & 1998 Data Sets

Combined data from the 1997 and 1998 surveys have been analyzed and results are presented in Table C-3. Again, in this case, the lowest limit of the ice gouge depth class is defined as 0.25 ft with a class range of 0.1 ft. Overall, the minimum ice gouge depth is 0.3 ft, the maximum is 1.4 ft deep, with an average depth of 0.45 ft, and a median depth of 0.5 ft.

TABLE C-3: FREQUENCY DISTRIBUTION FOR ICE GOUGE DEPTHS FROM 1997/98 SURVEY DATA

Class Limits (ft)	Class center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of Exceedence
0.25						1.0000
	0.3	7	0.3333	7	0.3333	
0.35						0.6667
	0.4	4	0.1905	11	0.5238	
0.45						0.4762
	0.5	5	0.2381	16	0.7619	
0.55						0.2381
	0.6	4	0.1905	20	0.9524	
0.65						0.0476
	0.7	0	0.0000	20	0.9524	
0.75						0.0476
	0.8	0	0.0000	20	0.9524	
0.85						0.0476
	0.90	0	0.0000	20	0.9524	
0.95						0.0476
	1.00	0	0.0000	20	0.9524	
1.05						0.0476
	1.10	0	0.0000	20	0.9524	
1.15						0.0476
	1.20	0	0.0000	20	0.9524	
1.25						0.0476
	1.30	0	0.0000	20	0.9524	
1.35						0.0476
	1.40	1	0.0476	21	1.0000	
1.45						0.0000
Number of observations = 21						
Average depth = 0.476 ft						
Median depth = 0.4 ft						

Graphical Gouge Depth Calculation

The exceedence probability function (EPF) that best fit the data is given by:

$$EP_D = e^{-2.8464(x-0.011)} \qquad \text{(C-3)}$$

The probability of exceedence vs. class limits (first and last columns of Table C-3) are plotted in Figure C-3. From the gouge depth probability density function presented in this figure, the cutoff depth is calculated to be 0.011 ft. Lambda (1/ft) is taken from the least squares fit of the exponential plot to be 2.8464 (1/ft).

The annual ice gouge recurrence rate, g, (new gouges per mile per year) is calculated to be 0.076. The annual ice gouge recurrence rate is based on the average rate from 1997 and 1998.

The pipeline length is conservatively taken as 6.12 miles. This length includes a portion of the route protected by deep burial within the Liberty Island and the shallow/above water portions of the shore crossing.

The gouge trend angle is conservatively estimated to be 90 degrees (perpendicular to the pipeline route) and the gouge depth return period is taken to be 100 years.

The 100-year gouge depth calculation results in a design ice gouge of 1.36-ft.

Analytical Gouge Depth Calculation

The average incision depth, d_{bar}, has been calculated to be 0.476 ft. The cutoff depth is taken to be the lower bound of the class depth interval below which no gouges were observed, c = 0.25 ft. Lambda (1/ft) can be calculated for a negative exponential probability distribution as $\lambda = 1/(d_{bar}-c) = 4.4248$.

The annual ice gouge recurrence rate is 0.076 new gouges per mile per year, the pipeline length is 6.12 miles, the gouge trend angle is 90 degrees, and the gouge depth return is 100 years.

The 100-year gouge depth calculation results in a design ice gouge of 1.12-ft.

Design Ice Gouge Depth

Standard analysis techniques have been used to analyze two years of data specific to the Liberty pipeline route. The negative exponential function has been found to give a good fit to observed seabed gouge depth data and forms the basis for the Liberty pipeline extreme gouge depth predictions. The maximum gouge depth is calculated using a general methodology recommended by API RP 2N (Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions, 1995).

The following table summarizes the results for a 100-year ARP ice keel incision depth:

TABLE C-4: 100 YEARS ARP ICE KEEL DEPTH

Data Set	Graphical Method	Analytical Method
1997	1.59 ft	1.17 ft
1998	1.13 ft	1.04 ft
1997 & 1998Combined	1.36 ft	1.12 ft

Analysis of the 1997 ice gouge data suggests that the design ice gouge (100-year ARP) be 1.59 feet. The 1998 survey data indicated a maximum gouge incision depth of 1.13 feet. Combined, the data sets suggest a design depth of 1.36 feet. Note that in all cases, the graphical method predicts a deeper extreme gouge depth than the analytical method and may be conservatively applied.

An ice gouge depth of 3.0 feet has been conservatively assumed in pipeline design for the analysis of pipeline bending strains due to ice keel gouging. During the Northstar design (INTEC Engineering 1997), analysis of ice gouge data suggests a 100-year ARP maximum gouge depth of approximately 3.3 feet. The Liberty Island site will be subjected to smaller ice features than Northstar due to the comparatively large amount of land and shoal area shielding. Other ice gouge observations (Harding Lawson Associates 1982; McLelland Engineers 1982; Weeks et al. 1983; Reimnitz and Ross 1979; Watson Company 1998a; 1998b) suggest a maximum gouge depth of 2.3 feet or less.

The design scour depth of 3-ft is 2.21 times deeper (221%) than the combined data set value of 1.36-ft. The average return period for a 3.0-ft deep design ice gouge is estimated to be greater than 10,000 years.

Subgouge Deformation Formulations

The maximum vertical and horizontal soil displacements occur at the ice keel base, where stresses and strains in the soil are highest. The derived functions with distance along the pipeline (y), and depth beneath the gouge base (z) are all related to the magnitude of horizontal soil displacement u(0,0,0) at the gouge base. The C-CORE centrifuge results are used to obtain this value, and this “scales” all of the soil (and pipe) displacements in the ensuing analysis. In the following, the x-axis is parallel to the direction of ice motion, y is parallel to the pipe, and z is depth. Woodworth-Lynas et al. (1996) have proposed that the maximum horizontal soil deformation ought to be related to the square root of the gouge depth, D and the breadth of the gouging keel, B, from considerations of geometric similarity. The maximum horizontal displacement at the mid point of the keel, u(0,0,0), can be estimated from:

$$u(0,0,0) = 0.6\ \mathrm{SQRT}\ (BD) \qquad \text{(C-4)}$$

where B = gouge width (in direction parallel to pipeline) and D = gouge depth.

The vertical and horizontal soil movements were observed to decrease with depth beneath scour, z according to the functions provided below.

Vertical Displacements

$v(0,0,z) / D = \exp\{-0.333\ z/D\}$ for clay soils .... (C-5)
$v(0,0,z) / D = 0.441 \exp\{-0.687\ z/D\}$ for sands .... (C-6)

Horizontal Displacements

$u(0,0,z) / u(0,0,0) = \exp\{-0.667\ z/D)$ for clay soils.. (C-7)
$u(0,0,z) / u(0,0,0) = 1.10 \exp\{-0.755\ z/D)$ for sands... (C-8)

After analyzing observed vertical and horizontal soil deformations from several centrifuge tests, the variation of vertical and horizontal soil displacement, u, across the direction of ice movement (parallel to pipe) was found to be approximately represented by the following formulations.

Vertical Displacement Distribution along the pipeline:

1 if $y/B<0.25$............................. (C-9)
$v(0,y,z) / v(0,0,z) = 0.5\{1+\cos(2y/B-0.5)\pi\}$ if $0.25<y/B<0.75$.................... (C-10)
0 if $y/B>0.75$........................... (C-11)

Horizontal Displacement Distribution along the pipeline:

1 if $y/B<0.25$........................... (C-12)
$u(0,y,z) / u(0,0,z) = 0.5\{1+\cos(2y/B-0.5)\ \pi\}$ if $0.25<y/B<0.75$.................... (C-13)
0 if $y/B>0.75$........................... (C-14)

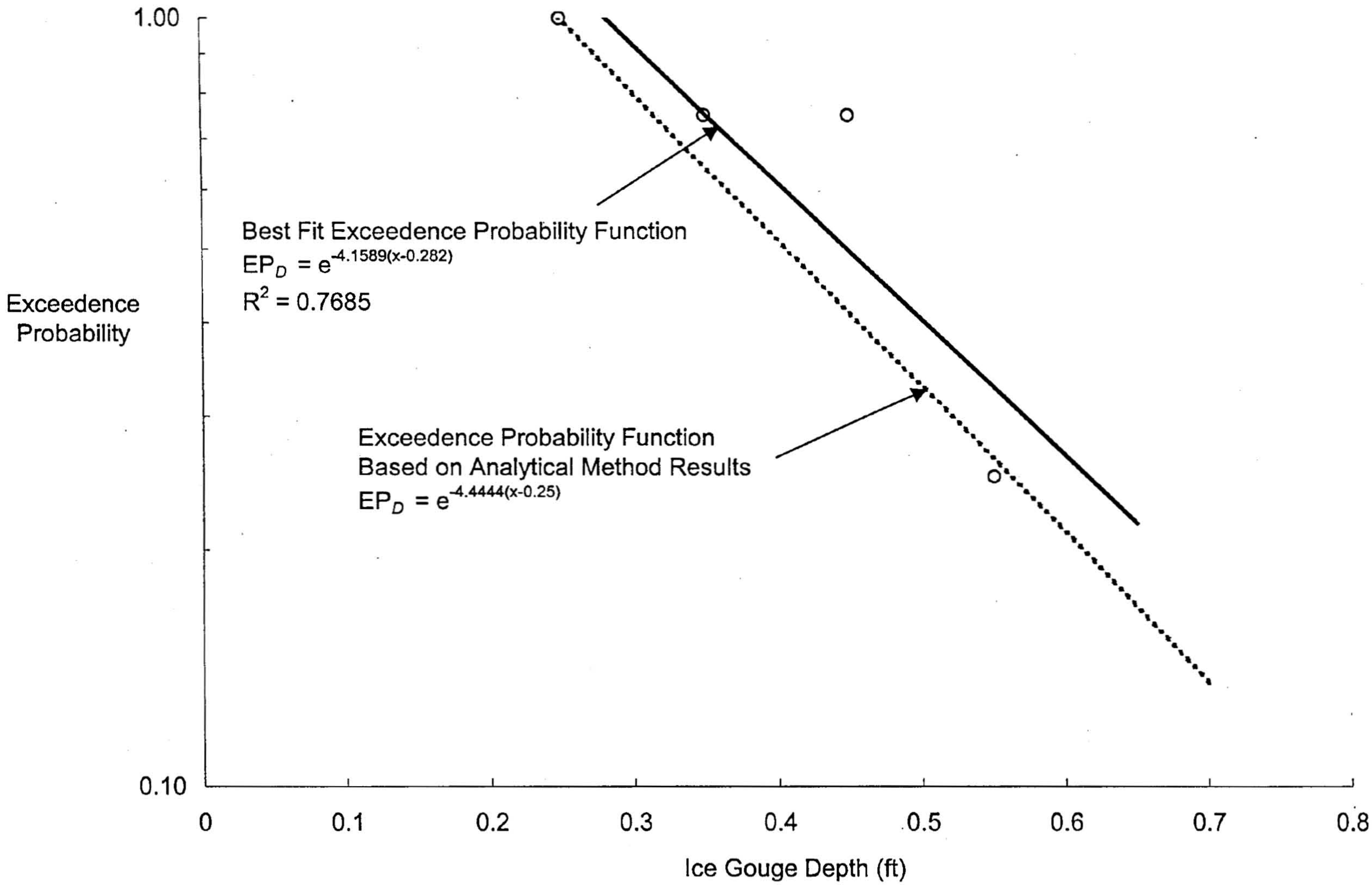


Figure C-1: Exceedence Probability Function for the 1998 Ice Keel data set

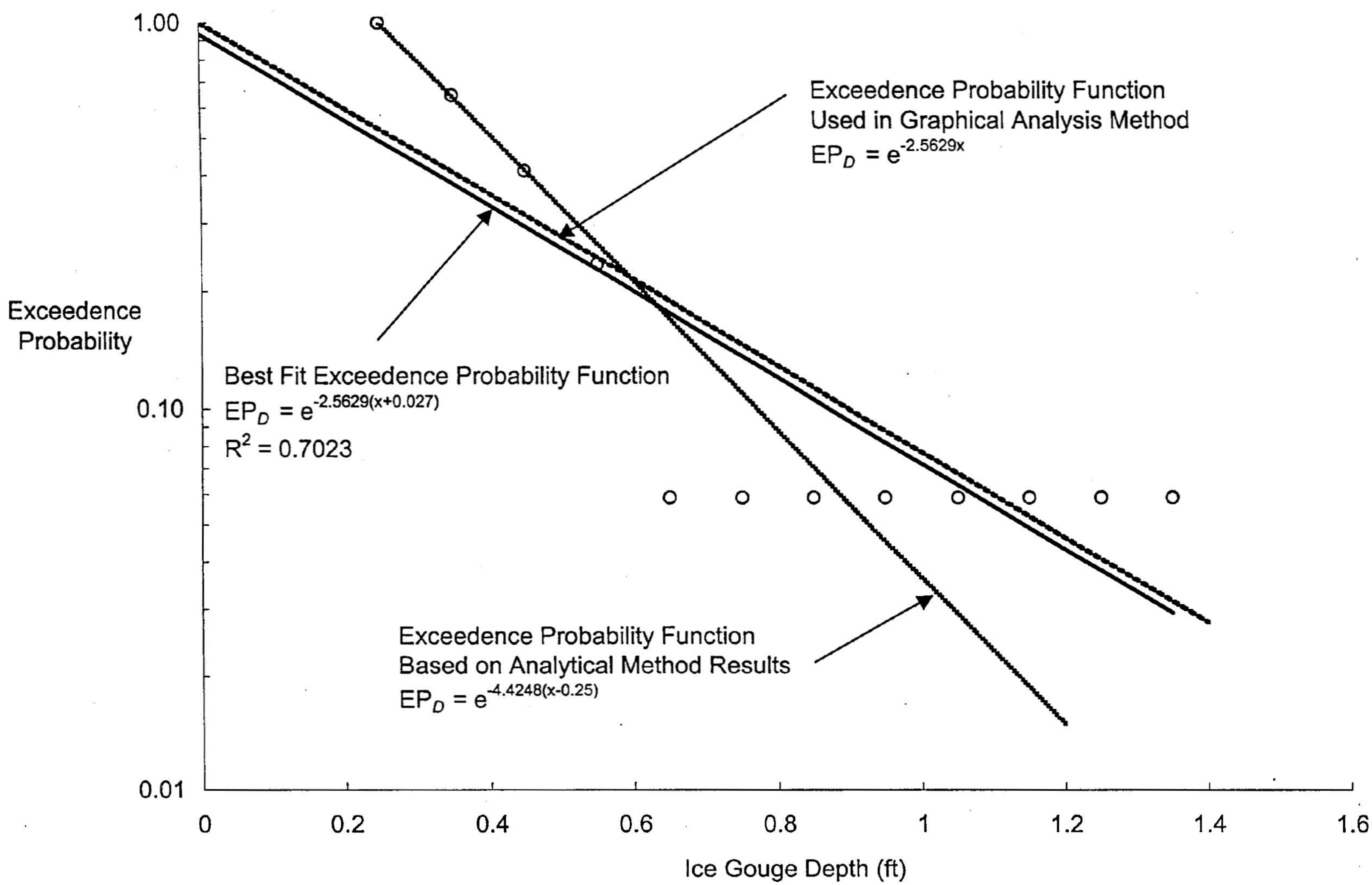


Figure C-2: Exceedence Probability Function for the 1997 Ice Keel data set

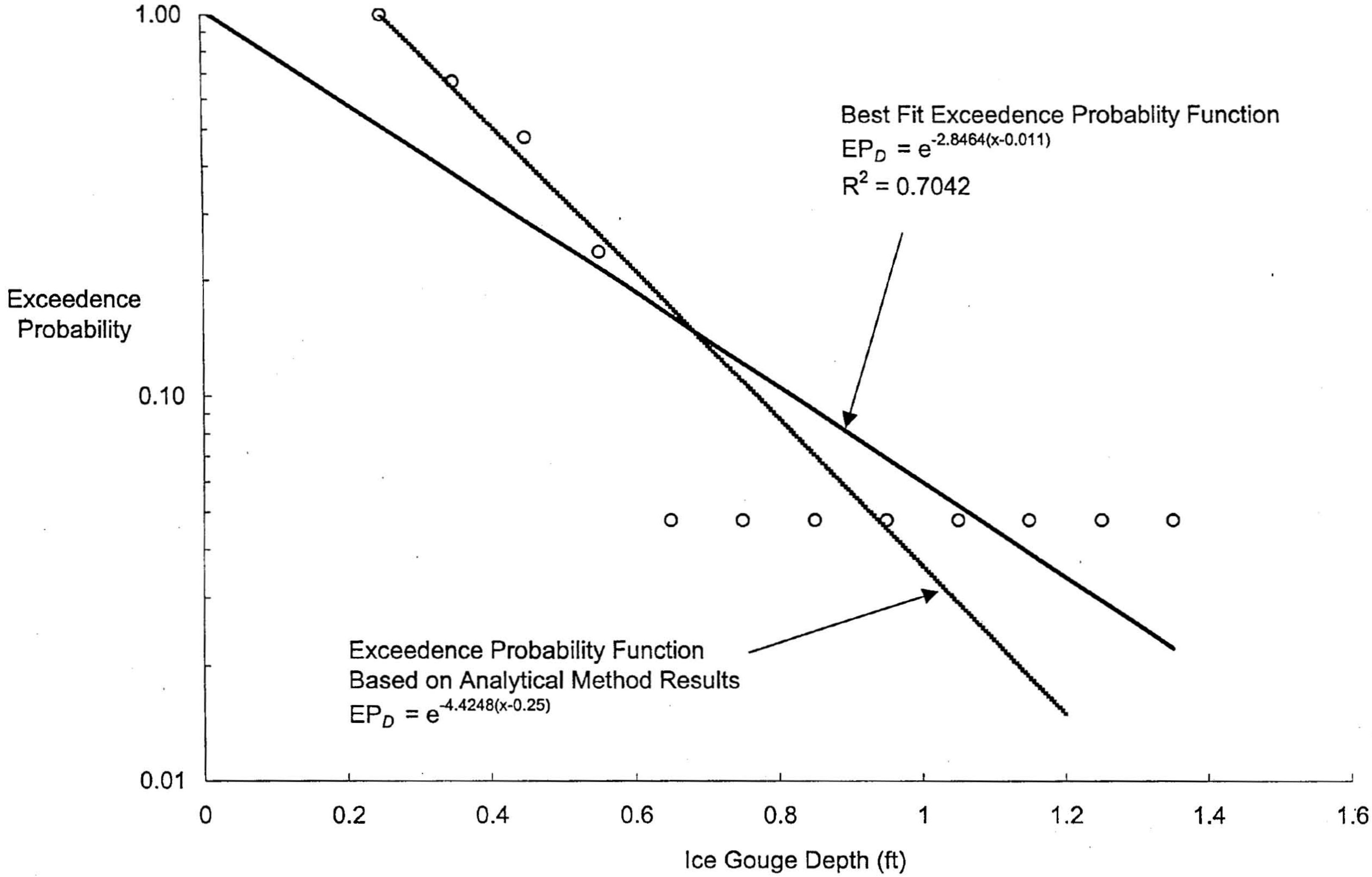


Figure C-3: Exceedence Probability Function for the 1997 & 1998 combined Ice Keel data sets

APPENDIX D

STATISTICAL ANALYSIS OF STRUDEL SCOUR FIELD DATA

Analysis of the 1998 Data Set

Strudel Scour Depth

Table D-1 was obtained by sorting the 1998 strudel scour data set (Coastal Frontiers Co. 1999) by scour depth and excluding the strudel observations for which depth was not recorded. The depth class lowest limit is defined as 0.25 ft, with a class range of 1.25 ft. Therefore, the first class is from 0.25 ft to 1.5 ft. The second depth class is from 1.5 ft to 2.75 ft, and so on. The minimum strudel scour depth reported is 0.4-ft deep, the maximum is 3.5-ft deep, with an average depth of 1.13 ft, and a median depth of 1.0 ft.

TABLE D-1: FREQUENCY DISTRIBUTION FOR DEPTH OF STRUDEL SCOURS OBSERVED IN 1998

Class Limits (ft)	Class center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of exceedence
0.25						1.0000
	0.875	13	0.7222	13	0.7222	
1.50						0.2778
	2.125	4	0.2222	17	0.9444	
2.75						0.0556
	3.375	1	0.0556	18	1.0000	
4.00						0.0000
	4.625	0	0.0000	18	1.0000	
5.25						0.0000
	5.875	0	0.0000	18	1.0000	
6.50						0.0000
	7.125	0	0.0000	18	1.0000	
7.75						0.0000
	8.375	0	0.0000	18	1.0000	
9.00						0.0000
Number of observations = 18						
Average depth = 1.13 ft						
Median depth = 1.0 ft						

The exceedence probability function (EPF) that best fit Table D-1 data is given by:

$$EP_D = e^{-1.156(D-0.3)} \quad \text{(D-1)}$$

The probability of exceedence vs. class limits (first and last columns of Table D-1) are plotted in Figure D-1.

Equation D-1 provides a continuous function for the probability of exceedence of strudel depths. For example, a strudel scour with a depth greater than or equal to 8 ft has an exceedence probability of 0.014 %.

Strudel Scour Diameter

Coastal Frontiers Corporation (1999; 1998) reports the maximum horizontal dimensions of strudel scours. Such maximum horizontal dimensions are conservatively treated herein as diameters. Therefore any beneficial aspect ratio is ignored and in effect the circumscribed circle to each strudel is used as an independent variable. The term "diameter" is used from this point forward, and the symbol H is used for it in the equations.

Table D-2 was obtained by sorting the 1998 strudel scour data set (Coastal Frontiers Co. 1999) by strudel scour diameter. The average strudel scour diameter is 59.5 ft, and the median diameter is 45 ft.

TABLE D-2: FREQUENCY DISTRIBUTION FOR MAXIMUM HORIZONTAL DIMENSION (DIAMETER) OF STRUDEL SCOURS OBSERVED IN 1998

Class Limits (ft)	Class Center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of Exceedence
2.5						1.0000
	7.5	2	0.071	2	0.071	
12.5						0.9286
	17.5	1	0.036	3	0.107	
22.5						0.8929
	27.5	3	0.107	6	0.214	
32.5						0.7857
	37.5	6	0.214	12	0.429	
42.5						0.5714
	47.5	8	0.286	20	0.714	
52.5						0.2857
	57.5	2	0.071	22	0.786	
62.5						0.2143
	67.5	0	0.000	22	0.786	
72.5						0.2143
	77.5	2	0.071	24	0.857	
82.5						0.1429
	87.5	2	0.071	26	0.929	
92.5						0.0714
	97.5	2	0.071	28	1.000	
102.5						0.0000
	107.5	0	0.000	28	1.000	
112.5						0.0000
	117.5	0	0.000	28	1.000	
122.5						0.0000
	127.5	0	0.000	28	1.000	
132.5						0.0000
Number of observations = 29						
Average of maximum horizontal dimension (diameter) = 59.5 ft						
Median of maximum horizontal dimension (diameter) = 45 ft						

The exceedence probability function that best fit the Table D-2 data is given by:

$$EP_H = e^{-0.031(H-13.5)} \quad \text{(D-2)}$$

The probability of exceedence vs. horizontal dimension class limits (first and last columns of Table D-2) are plotted in Figure D-2.

Analysis of scour diameter and depth data indicates only a weak correlation between the two variables. A weak correlation may exist between limiting maximum scour depth and diameter based on stable scour wall slope limits, but the observed diameters and depths are essentially independent variables, as can be seen in Figure D-5.

Probability of a Strudel Scour Forming On Top of the Pipeline

The 30 strudel scours identified in 1998, lie between Foggy Island and the far side of the Kadlerosholik River, a distance of approximately 9.3 miles of shoreline. Assuming that all these strudel scour were formed in 1998, on average there are of 3.4 strudel scours per mile of shoreline per year. This number can be used to characterize the risk of a strudel scour event forming on top of the pipeline as follows.

The average strudel scour diameter (1998 data set) is H_a = 59.5 ft. Considering a two-mile band centered along the pipeline alignment, a total of $2\times3.4 \cong 7$ strudel scours can form in the general vicinity of the pipeline alignment. Thus, the probability of one strudel scour being formed on top of the pipeline is P_T= 59.5/10,560 = 0.00563 (where 2 miles = 10,560 ft). With 7 strudel scours predicted to be within a 2-mile shoreline section centered on the pipeline, the probability that one or more strudel scours are formed on top of the pipeline per year is

$$P_{YT} = 1-(1-0.00563)^7 = 0.039 = 3.9\% \text{ ....} \quad \text{(D-3)}$$

Note that if the full 9-mile length parallel to the shoreline is considered, then $P_{YT} = 1-(1-59.5/(9\times5280))^{31.5} = 3.9\%$; and the same area ratio is obtained.

Risk and the Design Strudel Scour for 1998

From the analysis above, it can be seen (Fig. 2-9) that for a strudel scour event to affect the pipeline, it must form on top of it and its depth must be greater than the distance from seabed to bottom of pipe. These two conditions independently affect the pipeline, therefore the combined probability is found by multiplying each individual exceedence probability function. Due to the independence between the strudel scour depth and the strudel scour diameters, the joint probability which includes strudel scour diameter can also be found be multiplying each of the individual exceedence probability functions.

Therefore, based on the 1998 data set, the probability that a strudel scour is **1)** formed right on top of the pipeline, **2)** has its depth greater than a given depth *D*, and **3)** has the horizontal diameter (at seafloor level) greater than *H*, is given by:

$$EP_{T\&D\&H} = 0.039\times e^{-1.156(D-0.3)}\times e^{-0.031(H-13.5)} \text{ ....} \quad \text{(D-4)}$$

The subscript on the left-hand side of Eq. D-4 above, *T&D&H*, is meant to convey a strudel scour on ***T***op of the pipeline, with a certain ***D***epth, and a certain ***H***orizontal diameter. For example, the likelihood of a strudel scour having a diameter (at the seabed) greater than 15 ft and being deeper than 8 ft is,

$$EP_{T\&D\&H} = 0.039 \times e^{-1.156(8-0.3)} \times e^{-0.031(15-13.5)} = 5.07 \times 10^{-6} = 0.0005\%$$

Note that such an event has a return period of T = 1/0.0005% $\cong$ 200,000 years.

Analysis of the 1997 Data Set

Strudel Scour Depth

Table D-3 was obtained by sorting the 1997 strudel scour data set (Coastal Frontiers Co., 1998) by scour depth and excluding the strudel observations for which depth was not recorded. The minimum strudel scour depth reported is 0.4-ft deep; the maximum is 8.1-ft deep, and the average depth is 2.75-ft. The median depth is 2.1 ft.

TABLE D-3: FREQUENCY DISTRIBUTION FOR DEPTH OF STRUDEL SCOURS OBSERVED IN 1997

Class Limits (ft)	Class center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of Exceedence
0.25						1.0000
	0.875	14	0.3333	14	0.3333	
1.50						0.6667
	2.125	13	0.3095	27	0.6429	
2.75						0.3571
	3.375	7	0.1667	34	0.8095	
4.00						0.1905
	4.625	2	0.0476	36	0.8571	
5.25						0.1429
	5.875	3	0.0714	39	0.9286	
6.50						0.0714
	7.125	1	0.0238	40	0.9524	
7.75						0.0476
	8.375	2	0.0476	42	1.0000	
9.00						0.000
Number of observations = 42						
Average depth = 2.75 ft						
Median depth = 2.1 ft						

The exceedence probability function (EPF) that best fit the Table D-3 data is given by:

$$EP_D = e^{-0.4148(D-0.307)} \quad \text{.......................................} \quad \text{(D-5)}$$

The probability of exceedence vs. class limits are plotted in Figure D-3. In this case, a strudel scour with a depth greater than or equal to 8 ft has an exceedence probability of 4.1 %.

Strudel Scour Diameter

Table D-4 was obtained by sorting the 1997 strudel scour data set (Coastal Frontiers Co. 1998) by strudel scour diameter. The average strudel scour diameter is 26.74-ft and the median diameter is 24 ft.

TABLE D-4: FREQUENCY DISTRIBUTION FOR MAXIMUM HORIZONTAL DIMENSION (DIAMETER) OF STRUDEL SCOURS OBSERVED IN 1997

Class Limits (ft)	Class Center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of Exceedence
2.5						1.0000
	7.5	54	0.215	54	0.215	
12.5						0.7849
	17.5	80	0.319	134	0.534	
22.5						0.4661
	27.5	59	0.235	193	0.769	
32.5						0.2311
	37.5	16	0.064	209	0.833	
42.5						0.1673
	47.5	14	0.056	223	0.888	
52.5						0.1116
	57.5	15	0.060	238	0.948	
62.5						0.0518
	67.5	4	0.016	242	0.964	
72.5						0.0359
	77.5	1	0.004	243	0.968	
82.5						0.0319
	87.5	1	0.004	244	0.972	
92.5						0.0279
	97.5	5	0.020	249	0.992	
102.5						0.0080
	107.5	0	0.000	249	0.992	
112.5						0.0080
	117.5	1	0.004	250	0.996	
122.5						0.0040
	127.5	1	0.004	251	1.000	
132.5						0.000
Number of observations = 251						
Average of maximum horizontal dimension (diameter) = 26.74 ft						
Median of maximum horizontal dimension (diameter) = 24 ft						

The exceedence probability function that best fit the Table D-4 data is given by:

$$EP_H = e^{-0.0456(H-3.66)} \qquad \text{(D-6)}$$

The probability of exceedence vs. horizontal dimension class limits (first and last columns of Table D-4) are plotted in Figure D-4.

Again, analysis of scour diameter and depth indicates only a very weak correlation between the two variables. As indicated previously, a weak correlation may exist between limiting maximum scour depth and diameter based on stable scour wall slope limits, but the observed diameters and depths are essentially independent variables, as can be seen in Figure D-6.

Probability of a Strudel Scour Forming On Top of the Pipeline

Coastal Frontiers Corporation (1998) observed 251 strudel scours on the seafloor between Endicott Satellite Drilling Island (SDI) and west of Goose Island. Drawing No. CFC-385-00-003 in Coastal Frontiers Co. (1998) indicates that the strudel scours are generally distributed in a band along the shoreline following about the 8-ft water depth contour. This survey encompassed approximately 14.4 miles of shoreline. Thus, in this area an average of 17.4 strudel scours per mile per year can be estimated. This average conservatively assumes that all observed strudel scours were formed in the 1997 breakup.

It can be noticed in Drawing No. CFC-385-00-003 that the pipeline is crossing an area in which the actual population of strudel scours is much below the average of 17.4 strudel scours per mile. However, in order to be conservative, the average value is used. It is also assumed that the strudel scours in any area are randomly distributed. Taking an arbitrary 2-mile wide shoreline section centered on the proposed route, there will be $2 \times 17.4 \cong 35$ strudel scours in the pipeline area.

The average strudel scour diameter is H_a = 26.7 ft, thus the probability of one strudel scour being formed on top of the pipeline is P_T= 26.7/10,560 = 0.00253. With, 35 strudel scours predicted to be within a 2-mile shoreline section centered on the pipeline, the probability that one or more strudel scours are formed on top of the pipeline per year is

$$P_{YT} = 1 - (1 - 0.00253)^{35} = 0.085 = 8.5\% \qquad \text{(D-7)}$$

Risk and the Design Strudel Scour for 1997

Based on the 1997 data set, Equations D-5, D-6, and D-7 are used to determine the probability of a strudel scour **1)** formed right on top of the pipeline, **2)** with depth greater than a given depth *D*, and **3)** with a horizontal diameter (at seafloor level) greater than *H*:

$$EP_{T\&D\&H} = 0.085 \times e^{-0.4148(D-0.307)} \times e^{-0.0456(H-3.66)} \quad \text{(D-8)}$$

Analysis of the 1982 Data Set

In 1982, McClelland Engineers conducted a bottom survey of an area between the Sag River Delta and West Dock development for Exxon Corporation in order to identify strudel scours and ice keel gouges. This was essentially a repeat of the 1981 survey conducted by Harding Lawson Associates which is discussed below. The survey area was divided into seven subdivisions but for the purpose of data analysis and comparison to the Liberty Island pipeline route, data from two areas were not included in this analysis. One of these areas was located directly outside the main outlet of the Sag River, which will naturally have more flood water than the other areas. The other area was a unique area being close to the West Dock area and the authors of the report (McClelland Engineers 1982) acknowledged that strudels could form preferentially in that area due to conditions there.

McClelland Engineers (1982) report 324 individual strudel scours; 68 of these were beneath the trackline of the vessel. The average diameter of the scours was 54 feet and most of the scours were found to be less than 4 feet deep. A maximum scour diameter of approximately 131 feet was observed. A maximum scour depth of 22 feet was observed but this was located in the area directly outside the main outlet of the Sag River and may not be relevant to the proposed pipeline route. The survey report does not give a good indication about the width of the individual strudel scours. Individual strudel scours are reported to have slopes greater than 30%. The ship's trackline did not always cross the scour at its deepest point therefore a depth correction was applied to depth data based on an evaluation of where the trackline crossed the individual strudel scour and an assumed shape for strudel scours.

No information is provided in the report to break down the 324 individual scours into the different survey areas. However, the 68 scours directly beneath the trackline were grouped according to area; this grouping indicated that approximately 54% of the scours could be considered pertinent to the pipeline route. Therefore, it is assumed that 175 of the individual scours (54% of the 324) might be applicable to the planned pipeline route. The survey encompassed approximately 6.4 miles of shoreline. This results in an average of 27.3 strudel scours per mile per year again conservatively assuming that all recorded strudel scours were formed in the spring of 1982. Alternatively, the report suggests a scour density up to 0.7 scours/km^2/year for areas considered relevant to the proposed pipeline route. Given that the pipeline route is 6.1 miles in length, one can arrive at a value of 11.1 strudel scours per mile of shoreline per year. The values from these two calculation methods bracket the value obtained from the 1997 survey data.

The 1982 data presented on the corrected depths for individual strudel scours has been analyzed and is presented in Table D-5. Results indicate an exponential exceedence probability function of:

$$EP_D = e^{-0.4319(x-0.408)} \quad \text{(D-9)}$$

which has an R^2 value of 0.97. This function can be compared to that from the 1997 survey. For the likelihood of a scour depth being greater than 8 feet, the function derived from the 1997 data yields a probability of 4.1%; the function derived from the 1982 survey gives a probability of 3.8%.

TABLE D-5: FREQUENCY DISTRIBUTION FOR STRUDEL SCOUR DEPTHS FROM 1982 MCCLELLAND SURVEY DATA

Class Limits (ft)	Class center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of exceedence
0.00						1.0000
	1	13	0.3514	13	0.3514	
2.00						0.6486
	3	16	0.4324	29	0.7838	
4.00						0.2162
	5	5	0.1351	34	0.9189	
6.00						0.0811
	9	3	0.0811	37	1.0000	
12.00						0.0000
Number of observations = 37						
Average depth = NA						
Median depth = NA						
Notes: NA - Data not available						
Report data presented with uneven class widths.						

Analysis of the 1981 Data Set

Harding Lawson Associates conducted a survey of the Duck Island/Sag Delta Development Project in 1981 for Exxon. The survey was conducted in approximately 2 to 23 feet of water and encompassed approximately 265 miles of survey trackline. The purpose of the survey was to quantify strudel scour and ice gouge characteristics for use in pipeline design and routing and for pipeline risk analyses.

Maximum strudel scour depth was determined from 65 strudel scours which lay directly below the trackline. The deepest strudel scour encountered was 11 feet below the mudline and 120 feet in diameter. Diving on this strudel scour indicated that the strudel scour contained 2-3 feet of fill giving it an original depth of 13-14 feet. The majority of observed strudel scours were less than 4 feet deep; only 2% were deeper than 10 feet.

To analyze the data, the procedure presented above is repeated. It is estimated that the survey encompassed 6.4 miles of shoreline. A total of 105 strudel scours were observed. This yields an average of 16.4 strudel scours per mile per year by conservatively assuming that all recorded strudel scours were formed in the spring of 1981. This value is similar to the one reported above.

The report provides a relative cumulative frequency plot for strudel scour depths based on the 65 scours which were immediately below the trackline. These data have been analyzed and results are presented in Table D-6. Results indicate an exponential exceedence probability function of:

$$EP_D = e^{-0.4766(D-1.022)} \qquad \text{(D-10)}$$

which has an R^2 value of 0.97 as indicated on the plot of Figure 8. This function can be compared to the function from the 1997 survey. For the likelihood of a scour depth being greater than 8 feet, Equation 11 gives an exceedence probability of 3.6%. This correlates well with the above depth exceedence probability given above.

TABLE D-6: FREQUENCY DISTRIBUTION FOR STRUDEL SCOUR DEPTHS FROM 1981 HLA SURVEY DATA

Class Limits (ft)	Class center (ft)	Frequency	Relative Frequency	Cumulative Frequency	Relative Cumulative Frequency	Probability of exceedence
0.50						1.0000
	1	NA	0.1529	NA	0.1529	
1.50						0.8471
	2	NA	0.3569	NA	0.5098	
2.50						0.4902
	3	NA	0.2431	NA	0.7529	
3.50						0.2471
	4	NA	0.0785	NA	0.8314	
4.50						0.1686
	5	NA	0.0392	NA	0.8706	
5.50						0.1294
	6	NA	0.0353	NA	0.9059	
6.50						0.0941
	7	NA	0.0274	NA	0.9333	
7.50						0.0667
	8	NA	0.0236	NA	0.9569	
8.50						0.0431
	9	NA	0.0196	NA	0.9765	
9.50						0.0235
	10	NA	0.0157	NA	0.9922	
10.50						0.0078
	11	NA	0.0039	NA	0.9961	
11.50						0.0039
	12	NA	0.0039	NA	1.0000	
12.50						
Number of observations = 65						
Average depth = NA						
Median depth = NA						
Note: NA - Data not available.						

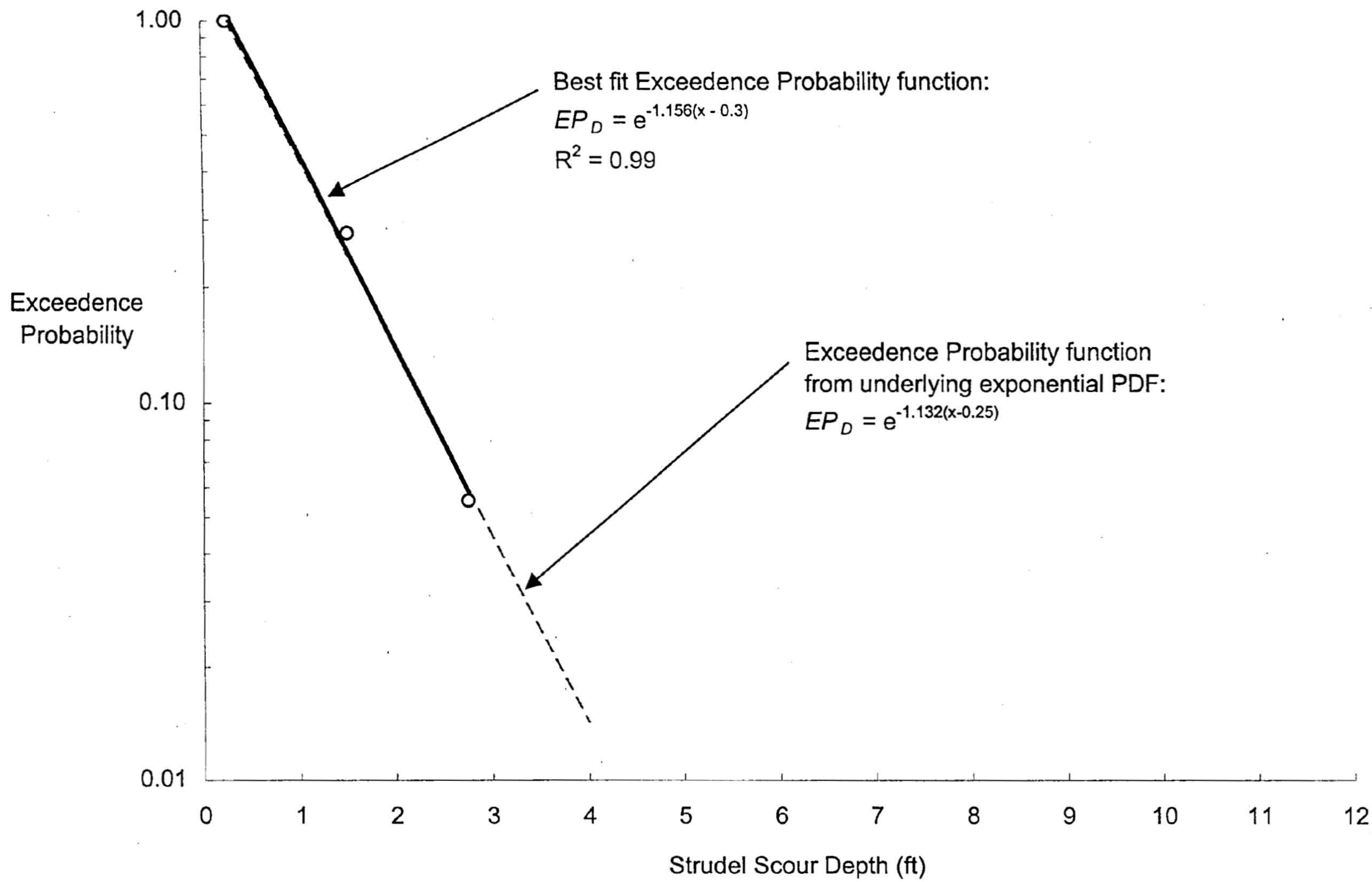


Figure D-1: Exceedence probability of strudel scour depths - 1998 data set

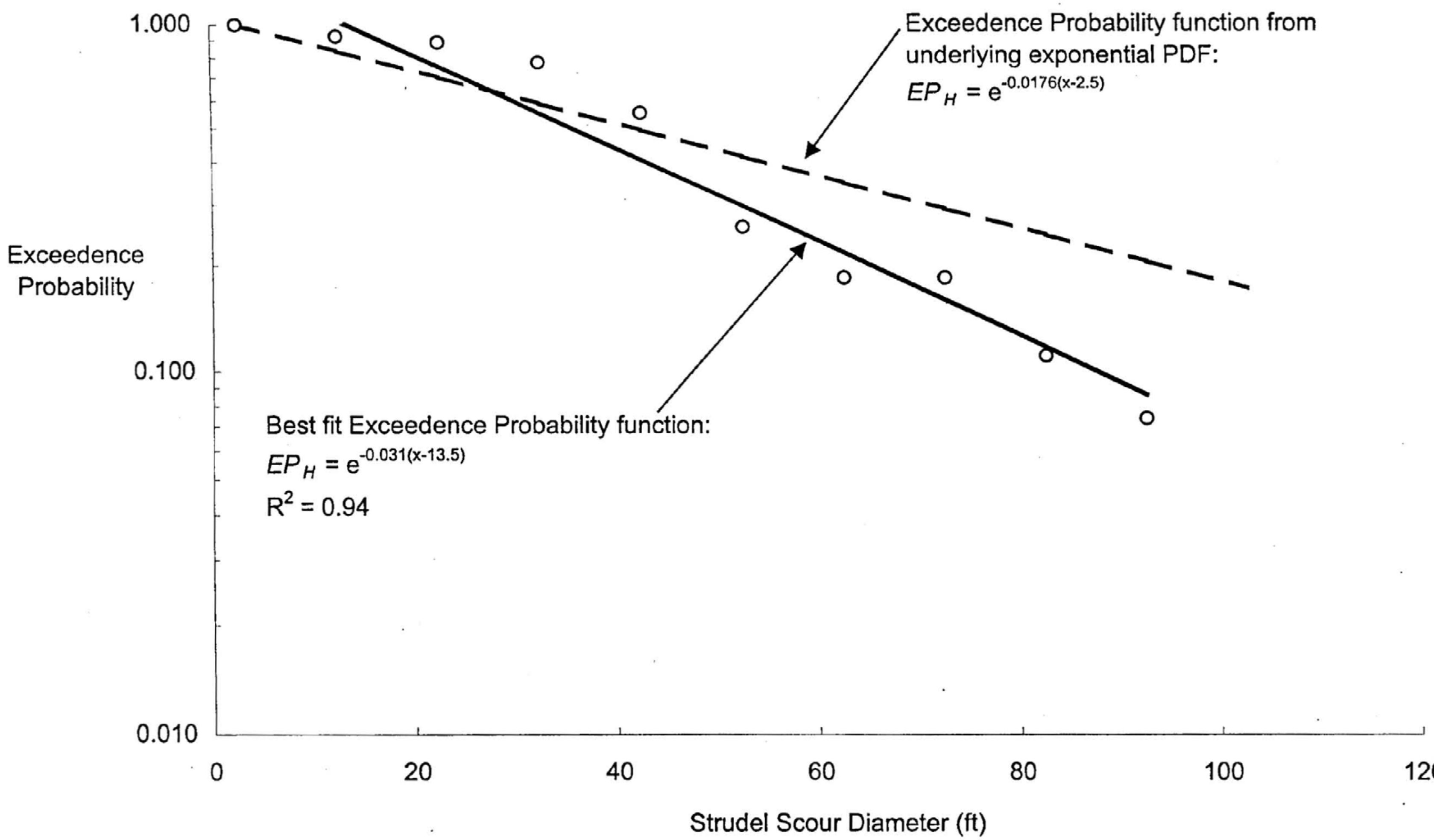


Figure D-2: Exceedence probability of strudel diameters - 1998 data set

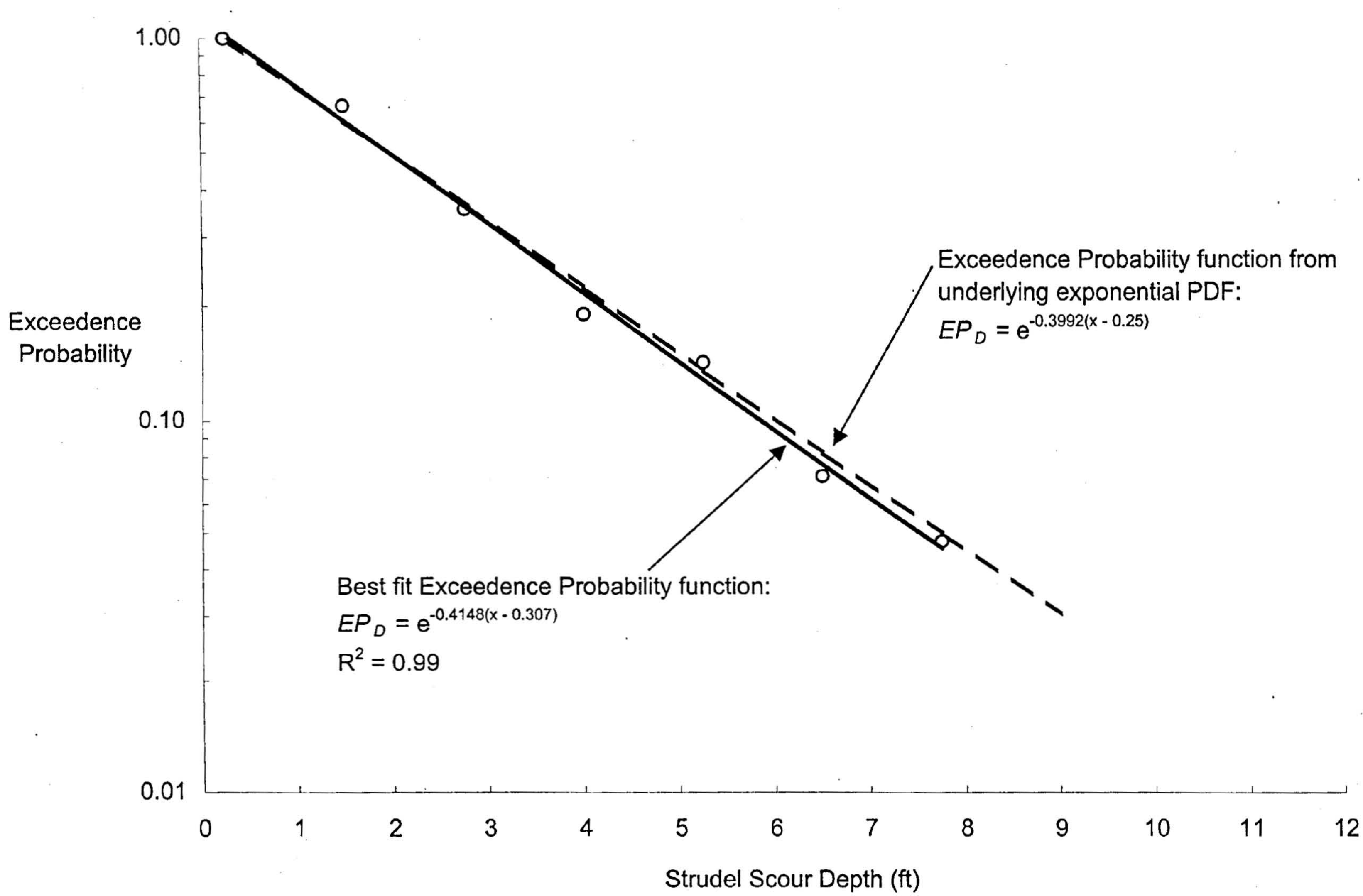


Figure D-3: Exceedence probability of strudel scour depths - 1997 data set

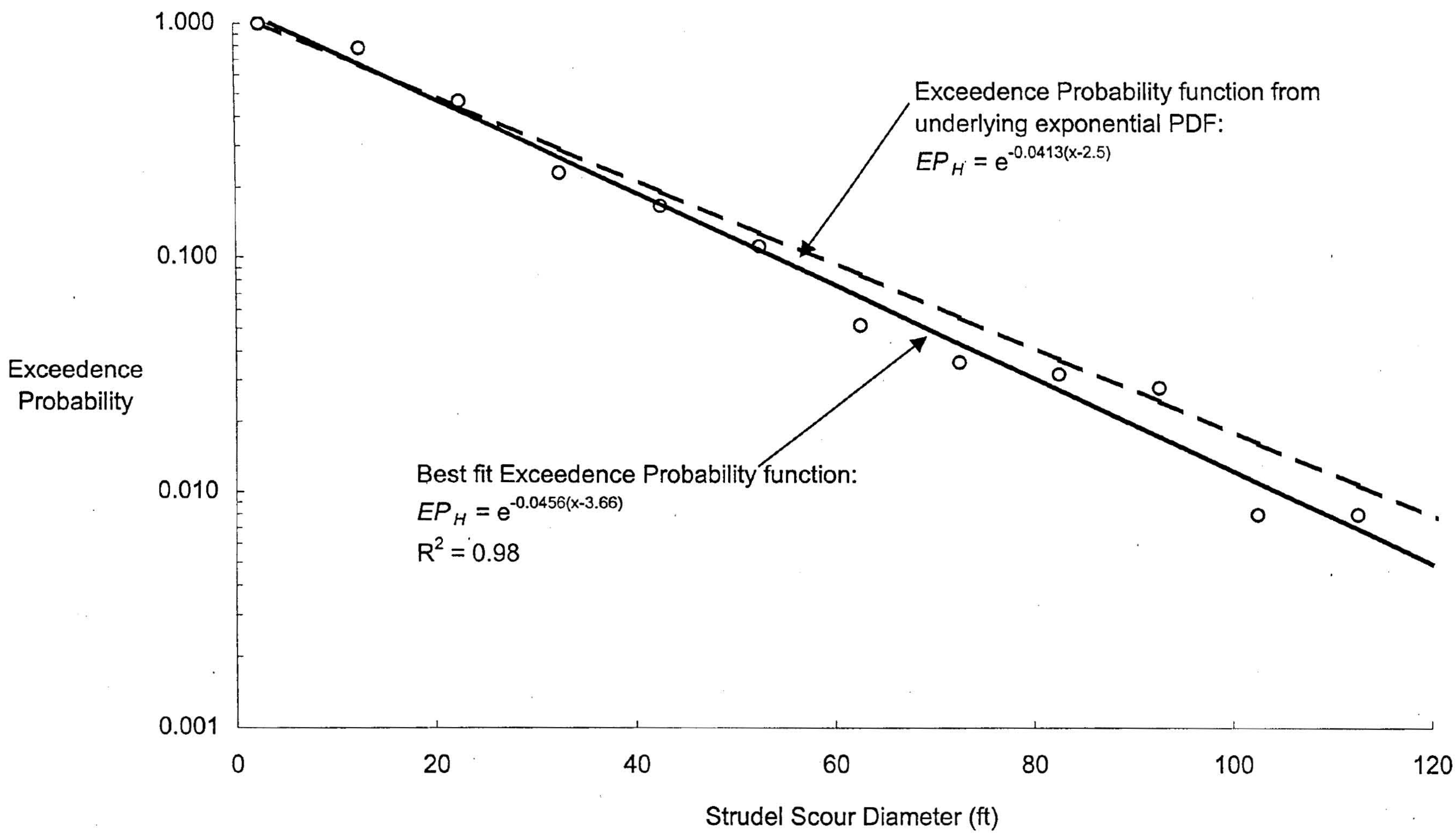


Figure D-4: Exceedence probability of strudel scour diameters - 1997 data set

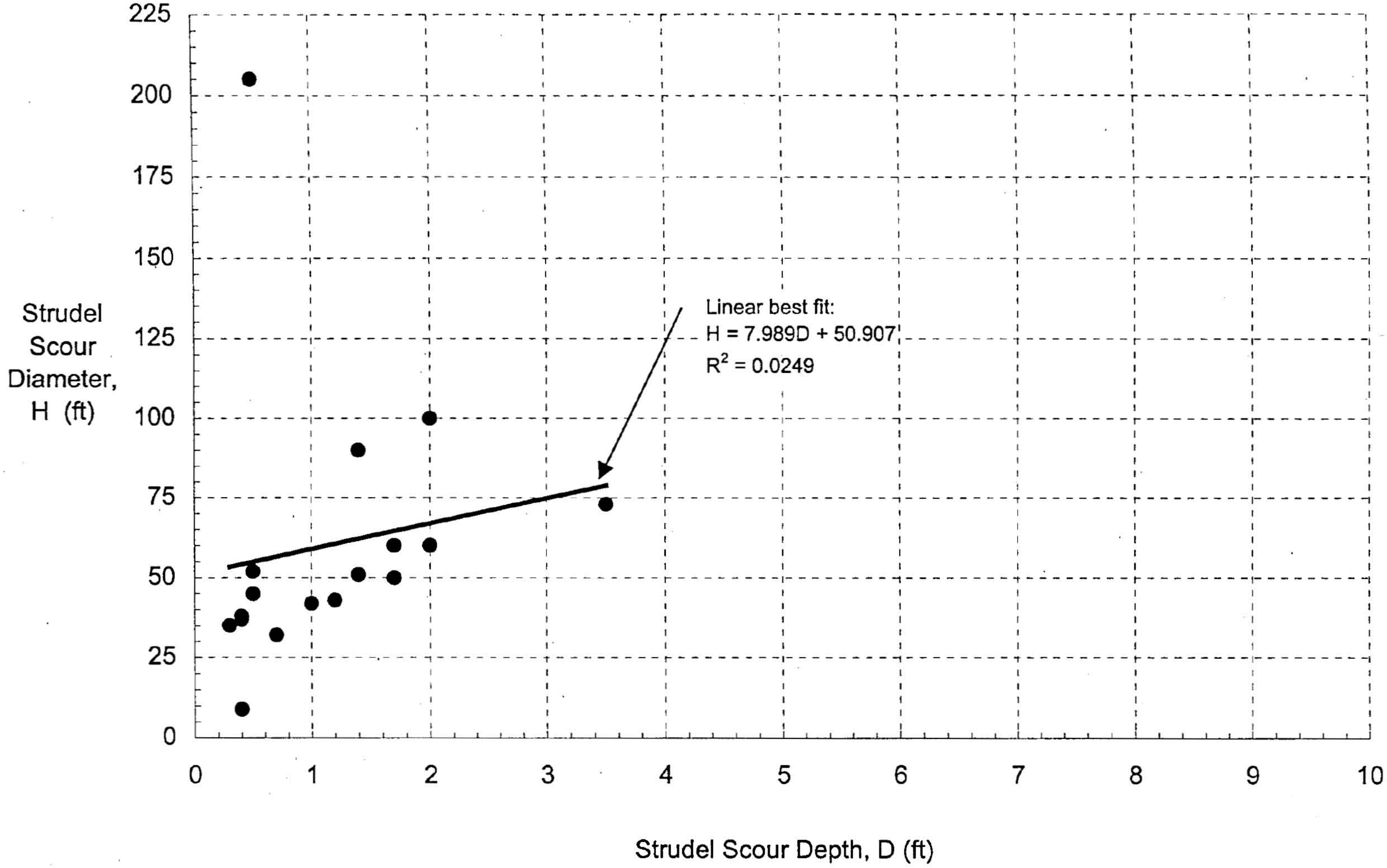


Figure D-5: Strudel scour diameter vs. depth - 1998 data set

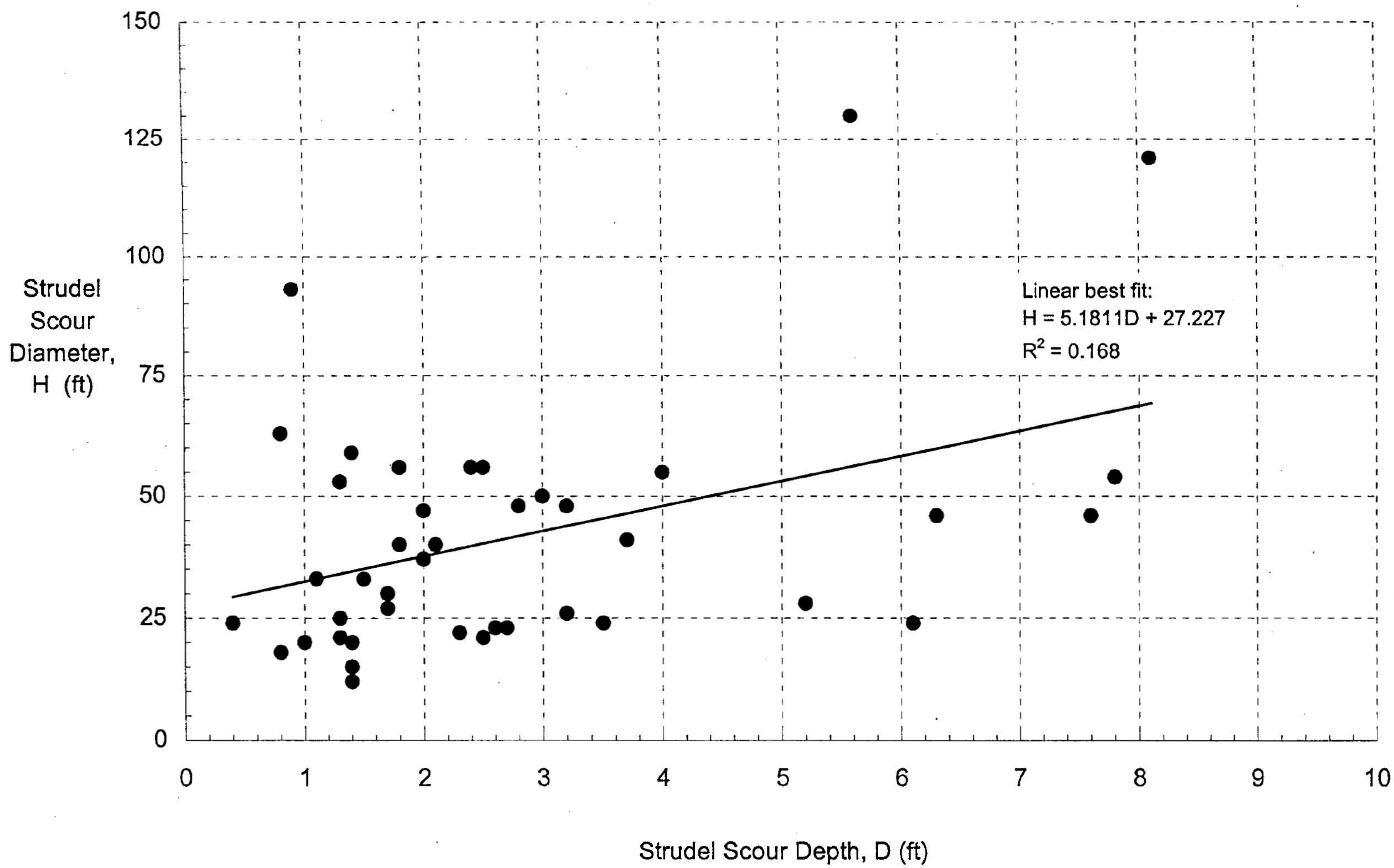


Figure D-6: Strudel scour diameter vs. depth - 1997 data set

APPENDIX E
REPAIR OPTIONS

E.1 Welded Repair with Cofferdam

This method consists of constructing a sheet pile cofferdam around the damaged segment of pipe and performing a welded repair inside the dewatered cofferdam. This method has been used extensively for shallow water construction and pipeline repairs. For a pipeline, the application would be applicable in Zone I and in Zone II during open water. However, with limited ice management, this method can be extended into freeze-up until an ice thickness of six inches is reached. This would correspond to approximately late October. The maximum length of pipe which could be effectively repaired by this method is 40 feet; accordingly, this method is not considered suitable for major damage (damage that extends longer than a 40 foot pipeline section).

First the reference grid is set-up and the workboat with divers is mobilized. Next the damage survey is conducted and a repair barge with a crane suitable for driving sheet pile and clamshell excavation is mobilized. Alternatively, the repair barge may incorporate a hydraulic dredge module which has a higher excavation rate. Once on site, the barge excavates over the top of and adjacent to the damaged pipe. The pipe is then rough-cut in two places and the damaged segment removed. After the rough-cut has been made, the pipeline may shift slightly as residual stresses in the pipeline are released. The next step is to construct the cofferdam by installing interlocking sheet piling and tubular support piles. Once in place, the structure is internally braced and seated around the pipe and remaining soil is removed by airlift eduction. The cofferdam is pumped dry and two finish cuts are made. The remaining damaged section is removed and measurements for the spool is taken. The replacement spool is fabricated on the barge and lowered into place. After alignment has been achieved, conventional welds are made. The spool welds are then inspected, using NDT techniques, and field wrapped. The cofferdam is flooded and disassembled. After the structure is removed, the backfill is replaced.

Special advantages inherent in this method are that the finish cuts, alignment, welding, inspecting and testing are performed in a dry environment. Another advantage is that the amount of excavation required is small.

During the winter ice covered season, for repairs in water depths less than approximately 5 feet, a dry working environment may be achieved without using sheet pile. Repair procedures in bottomfast ice excavations would be similar to those made in a cofferdam.

E.2 Hyperbaric Weld Repair

This procedure requires the placement of a pipeline support frame and hyperbaric welding chamber over the damaged segment of the pipe. The weld repair consisting of a short pipe segment, half sole or patch, is then made in a dry environment. Conventional systems incorporate four pipeline support frames (two on either sides of the tie-in) which lift and horizontally position the pipeline in order to provide alignment during tie-in. The two inner frames (closest to the tie-in point) are also used to support the welding habitat. A system such as this weighs 124 tons which excludes auxiliary diving and welding equipment. For this reason, hyperbaric systems require a large support barge. The type of system which would be practical for arctic application would have to be transportable by locally available repair barges. Support vessels with large storage and heavy lift capacities are not expected to be available on the North Slope. For the arctic, a downscaled system would consist of a light frame which supports the habitat and possibly a short pipe segment. In this arrangement, the frame would not be intended to realign the pipeline. This system would only be suitable for minor repairs where the pipe had not been appreciably deflected from the initial alignment. Small habitats such as this have been used previously for minor damage in shallow water. They are generally fabricated from steel plate; however based on discussions with diving contractors, the use of a skin (sheet metal) and frame structure could be used to reduce weight. In this case, the pipeline would be required to anchor the habitat once dewatered. This repair method is applicable for permanent, open water repairs of minor damage in both zones. During winter, this method would be feasible in Zones I and II depending on the stability of the ice sheet.

E.3 Surface Repair

This type of repair consists of raising the ends of the pipe to the surface, making a weld and lowering the pipeline back to the seabed. The use of a surface repair offers one significant advantage over on-bottom repairs. This is that connections can be carried out and tested in a dry, controlled environment thereby increasing the reliability of the repair. For pipelines which require a substantial trench depth (10 feet), this method is unfavorable for two reasons. First, the overburden would have to be removed prior to raising the pipe ends. For the Liberty pipeline, the corresponding trench length is approximately ten times the water depth for each pipe end (in the maximum depth, this would be 420 feet). Second, during the lowering process the pipe must be laid to the side of the original trench thereby necessitating pre-dredging of a bypass trench which is approximately 10 times the water depth in length. The repair method used in a winter operation would be very similar to a contingency mid-line tie-in installation.

The potential application of the surface repair method is feasible for all zones based on open water scenarios. The only disadvantage of this method is the large amount of excavation required.

E.4 Tow Out of Replacement String

For this operation, a replacement string of a pipeline is fabricated at a nearby shore base and pulled along the seabed to the repair site. Alternatively, a replacement string can be towed into position over the ice. The string is pulled or lowered into the original trench (damaged pipeline segment has been removed) and is welded to the existing pipeline with rigid spool pieces. This method can be applied for permanent, major repairs in all zones during the open water season or during winter using an over ice tow. The optimum application for this method is when repair segments greater than 100 feet long are required.

A general outline of the installation procedure for a bottom tow during open water is discussed in this paragraph. The first step is to excavate the entire damaged pipeline segment by clamshell dredge. The extent of damage and selection of tie-in points is also conducted during this phase. The distance between tie-in points is measured and this information relayed to the shore base which begins fabrication of the replacement string. The tie-in areas are then prepared by diver-assisted airlift eductors such that the pipeline is sufficiently exposed for rough cutting, finish cutting, and subsequent spool piece attachment. The damaged pipeline segment is rough cut at both ends and possibly at several other locations depending on the total damaged length. After rough-cuts have been made, divers attach cables to the damaged segment(s) and the tow vessel removes the segments from the trench. The tow vessel proceeds to the shore base and begins to tow the replacement string to the repair site. During this time the existing pipeline ends are prepared by finish cutting with a milling tool. The replacement string is aligned in the trench and flooded. Once flooded, the end caps are removed for the spool piece connection. The replacement string is connected to the existing pipeline either by procedures for temporary "spoolpiece with mechanical connectors" or permanent "hyperbaric weld repair".

The towing technique can also be used for on-ice repairs. In this case the replacement string is towed by either a Rolligon, Caterpillar D8 bulldozer or the like. The lowering procedure would consist of preparing an ice slot over the prepared trench and then pulling the string into the slot. To maintain pipe control, auxiliary buoys would be used during the lowering procedure. After placement within the trench is complete, the auxiliary buoys would be removed and the end caps (if installed) would be removed in preparation for the spool piece tie-in.

E.5 Rigid Spool Piece with Mechanical Connectors

This method of installation requires attaching mechanical couplings to prepared ends of the existing pipeline and making interconnection with rigid pipe fitted with angular and axial misalignment components. The configurations which are used consist of various combinations of the following components:

- forged couplings
- collet connectors
- pipeline swivels
- sleeve couplings
- ball joints
- telescopic slip joints

Worldwide suppliers of these components include:

- Big-Inch Marine Systems, Inc.
- Cameron Iron Works, Inc.
- Gripper, Inc.
- Hughes Offshore
- Murdock Machine and Engineering Company of Texas
- Nuovo Pignone

For the repair scenarios addressed in this review, rigid spool pieces with mechanical connectors are viable for both minor repairs where structural integrity is impaired and major repair with tie-ins of long replacement strings. However, this type of solution will only be used as a temporary repair and so will only be considered for minor repairs.

The first step is to excavate the repair area using a clamshell excavator for bulk spoil removal and an airlift eductor for removal of material under the pipe. After the damaged segment is exposed, the pipe is rough cut in two places and the damaged segment is towed or lifted clear of the trench. Following pipe removal, some excavation of additional spoil may be required to fully prepare the trench for the replacement spool piece. The finish cut and pipe end preparation is performed and couplings are attached to the pipe ends. These would be forged couplings with a pre-welded male half of a ball joint. If the radial forging process is used, a special adapter flange may be required to allow clearance and prevent rotation of the forging tool. After the couplings are forged, measurements for the replacement spool are taken and the spool is fabricated using straight pipe, two female ball joints, and a telescopic slip joint. The spool piece is then lowered into position. Depending on the length of the spool, a supporting spar and alignment cradles may be required to facilitate the connection phase. When alignment is achieved, the first connection is made. The second connection is made by hydraulically actuating the slip joint such that the spool piece extends longitudinally allowing the connection to be made at the second end. After all connections have been completed and the seals tested, the pipeline is then restarted.

E.6 Split Sleeve Repair Method

A split sleeve consisting of two thick-walled outer half shells with bolt hole patterns on each side can be used to make temporary repairs in cases where the mechanical integrity of the pipeline remains intact. To facilitate subsea use, these half shells are connected by a hinge and lowered in an open configuration. Once the sleeve assembly makes contact with the pipeline, the two half shells pivot about the hinge and close around the pipeline in preparation for final bolting. The insides of the split sleeves have BUNA-N or silicone packing to protect the sleeve from exposure to the product in the pipeline. Sealing rings on the sleeve ends and sides hold the packing in place and also prevent displacement of the packing material caused by leaking fluids during installation. The seals are activated by tightening the side bolts to recommended torques. Once sealed, any fluid in the annular space between the sleeve and pipe is purged by injecting nitrogen. The annular space is then completely filled by injecting epoxy.

Split sleeves have been used extensively for making temporary and permanent repairs of land pipelines. They have also been used for many subsea repair applications. In this document these components are considered to be only temporary repair methods. Worldwide suppliers of split sleeves include:

- Gripper, Inc.
- Hughes Offshore
- Plidco International, Inc.

Split sleeves can be applied for repairing minor damage such as pinholes and small dents. In general they are not applicable for repairing severed pipes or pipelines which do not have a high degree of structural integrity remaining. However, sleeves have been designed to couple pipe and can withstand high axial loading.

The major advantage of this method is that the sleeve is a relatively light, easy to handle repair component. This allows transportation by helicopters or over ice. Because of the lack of metal to metal seals, however, this method is considered only as a temporary repair. A further disadvantage is that the length of the damaged segment must be less than 20 feet, and the pipe must be structurally intact.