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INDEPENDENT RISK EVALUATION FOR THE LIBERTY PIPELINE

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The Geological Survey of Canada (GSC) provided very valuable assistance to the project. Dr. I. Konuk is thanked for his wide-ranging technical guidance that was provided during many discussions.

As well, the GSC had the foresight to undertake a detailed structural analysis of the behaviour of a single steel pipe when subjected to the combination of soil displacements induced by ice gouging, pipeline temperature increases, and the effects of pipeline internal pressure. Detailed analyses were carried out by Dr. Abdellfettah Fredj under the direction of Dr. I. Konuk. They investigated different structural modelling approaches, and they identified key trends and parameters.

This basic work was very helpful for this project, and the GSC used their model to analyse several cases of direct interest to this project. Their results were used directly as an input to this risk evaluation.

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EXECUTIVE SUMMARY

Conclusions

Basis for Conclusions - A detailed analysis has been carried out to determine the risk for each of the concept pipeline designs produced by Intec, 1999; 2000. Risk (which is the product of the event probabilities and event consequences) was defined in terms of the volume of oil expected to be released over the 20-year life of the Liberty Pipeline.

The study investigated and quantified the following:

(a) the hazards for the pipeline. The hazards investigated included ice gouging, strudel scour, permafrost thaw subsidence, thermal loads leading to upheaval buckling, corrosion, operational failures, and third party activities;
(b) the response of the pipeline to these hazards; and
(c) the consequences of pipeline failure for each hazard, taking into account the monitoring systems that will be used. Consequences were evaluated for three types of pipeline failure: (i) rupture, (ii) flow through the maximum stable crack, and (iii) flow through pinholes (termed seepage).

Review Process - A draft final report was submitted by FTL in July, 2000, which was extensively reviewed. The comments received, and FTL's direct reply to them, are provided in Appendices F and G, respectively. The main text of the report was revised as well in response to the comments received.

Approach – Risks due to ice gouging and strudel scour were determined by establishing and quantifying event trees. Risks due to permafrost thaw subsidence, thermal loads leading to upheaval buckling, corrosion, operational failures, and third party activities were evaluated by analyzing failure statistics for pipelines in other regions.

Summary Results - The risk was evaluated first for a base case that represented FTL's best estimate for all input parameters. The risk for the base case for each pipeline design is summarized in Table 1.

Table 1: Total Risk[1] for the Base Case for Each Pipeline Design

Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe-in-HDPE[2]	Flexible Pipe[2]
28 ; 28	8 ; 13	24 ; 24	29 ; 28

Notes:
1. All risk values are in bbls.

2. The risk values are for the pipe designs produced by Intec, 1999; 2000, respectively.

Most Significant Hazards - Oil releases resulting from operational failures were found to pose the vast majority (about 95%) of the total risk for the single steel pipe, the pipe-in-HDPE, and the flexible pipe designs.

The most significant risks for the steel pipe-in-pipe design were oil spilled as a result of operational failures that breach both the inner and outer pipes, and oil spilled during repair operations.

Comparison of Pipe Designs – For the base case, the steel pipe-in-pipe design was found to have about 30 to 50 % less risk than the single steel pipe, the pipe-in-HDPE, and the flexible pipe designs. This was primarily due to the secondary containment provided by the steel pipe-in-pipe design.

The single steel pipe, the pipe-in-HDPE, and the flexible pipe designs all had comparable risk within the accuracy of the analyses conducted.

Sensitivity Analyses - An extensive sensitivity analysis was conducted. The following factors had the greatest effect on the total risk for the Liberty Pipeline:

(a) the water depth at which the hazard occurs;
(b) the performance of the monitoring systems;
(c) the assumptions made regarding secondary containment;
(d) the occurrence frequency, and hence, risk, for oil releases due to operational failures and third party activities; and
(e) the assumptions made regarding the pipeline failure mode.

Maximum Expected Risk for Each Pipeline Design – This was evaluated using a simplified approach that accounted for the risk augmentation factors listed above. The maximum expected risk was about 60% more than the base case values for the single steel pipe, the pipe-in-HDPE, and the flexible pipe designs (Table 2). The maximum risk for the steel pipe-in-pipe design was about 2 to 3 times more than the base case value (i.e., 24 bbls vs 8-13 bbls, respectively).

Thus, the differences between the four designs reduced somewhat as a result of the sensitivity analyses. Nevertheless, the relative rankings of the four pipe designs was unchanged compared to the base case (Table 1) as follows:

(a) the steel pipe-in-pipe design had the least risk, and;
(b) the single steel pipe, the pipe-in-HDPE, and the flexible pipe all had more risk than the steel pipe-in-pipe. Furthermore, these three designs had equal risk within the accuracy of the analyses.

Table 2: Total Expected Maximum Risk[1] for Each Pipeline Design

Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe-in-HDPE[2]	Flexible Pipe[2]
45	24	44	45

Notes:

1. All risk values are in bbls.
2. The risk values are the maximums for the pipe designs produced by Intec, 1999 ; 2000, respectively.

Probability of a Spill Larger Than 1000 Barrels – The steel pipe-in-pipe design was found to have the lowest probability of a large spill (Table 3). The single steel pipe, the pipe-in-HDPE, and the flexible pipe designs were found to be equivalent within the accuracy of the analyses conducted.

Table 3: Total Probability of a Spill Exceeding 1000 Barrels[1]

Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe-in-HDPE[2]	Flexible Pipe[2]
0.0138 ; 0.0138	0.00158 ; 0.00234	0.0138 ; 0.0138	0.0138 ; 0.0138

Notes:

1. All values are for the base case.
2. The listed probabilities are for the pipe designs produced by Intec, 1999 ; 2000, respectively.

Uncertainties - The most important uncertainties are considered to be:

(a) the significance of the risk variations determined for the four pipeline designs. This issue was not investigated as it was beyond the Terms of Reference or scope of work. However, because this is considered to be the most significant uncertainty affecting the interpretation of the results, this would be a useful follow-on investigation.

(b) the information available to assess oil releases arising from operational failures is very limited as pipelines have not yet been operated offshore in the Arctic. As a result, the study was forced to rely on failure statistics from other regions to evaluate the risk due to this hazard.

The determination of the risk due to operational failures was also hindered by the fact that the Liberty Pipeline has only been developed to the concept design stage. This risk will be affected and controlled by issues such as operator training schedules, maintenance plans, surveillance, and monitoring which have not yet been finalized.

(c) the assumptions necessary to evaluate the secondary containment provided by the steel pipe-in-pipe and the pipe-in-HDPE designs.

(d) the information available to define the material properties and behaviour for the pipe-in-HDPE and flexible pipe designs.

Recommendations - The study results as well as the key uncertainties identified suggest logical areas for further study, or for the future application of resources as follows:

(a) the significance of the risk variations determined for the four pipeline designs should be investigated.

(b) operational failures were found to be the most significant hazard. Two actions are recommended:

    (i) this finding should be investigated further. In particular, this finding should be re-examined after key issues such as operator training, surveillance, and monitoring plans have been developed further for the Liberty Pipeline.

    (ii) future efforts aimed at ensuring the safety of the Liberty Pipeline should be focussed on minimizing the risk posed by operational failures and third party activities. This suggests that efforts should be focused on such activities as operator training, surveillance, and monitoring.

(c) the behaviour of a steel pipe-in-pipe that is exposed to operational failures should be investigated further. The work should be aimed at obtaining better definition of the scenarios that will occur, and the pipe response to these events.

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1.0 INTRODUCTION

1.1 Background

British Petroleum Exploration Alaska (BPXA) wishes to build a pipeline to bring oil onshore from its Liberty site in the Alaskan Beaufort Sea. Intec, 1999 developed four conceptual designs for the Liberty Pipeline, as summarised below (see also Figure 1.1 and Table 1.1). Intec, 1999's work included a risk analysis for each of the four concepts, with risk being defined as the oil quantity likely to be released over the 20-year life of the pipeline.

(a) a single carrier pipe (termed "single wall steel pipe");
(b) a cased pipe, in which the carrier pipe is placed inside a steel outer pipe (termed "steel pipe-in-pipe");
(c) a cased pipe, in which the carrier pipe is placed inside a High Density PolyEthylene outer pipe (termed "pipe-in-HDPE");
(d) a single layered composite flexible carrier pipe (termed "flexible pipe").

Table 1.1: Key Parameters for the Initial Liberty Pipeline Concept Designs (Information taken from Intec, 1999)

	single wall steel pipe	steel pipe-in-pipe	pipe-in-HDPE	flexible pipe
depth to top of pipe (ft)	7	5	6	5
Risk over 20 years (bbls of oil)	$1.6 * 10^{-3}$	$2.8 * 10^{-2}$	$1.4 * 10^{-2}$	$1.4 * 10^{-1}$

Intec, 1999's conceptual designs and analyses were reviewed by Stress Engineering, 2000, as well as others. In response to comments received Intec, 2000 re-analyzed the pipeline alternatives with some design changes (Table 1.2), as follows:

(a) cover depth – this was standardized at 7 feet for each pipe design;
(b) geometry and size – the wall thicknesses were changed for the steel pipe-in-pipe (Table 1.2). The other pipe designs were unchanged.

Table 1.2: Key Parameters for Subsequent Liberty Pipeline Concept Designs (Information taken from Intec, 2000)

	single wall steel pipe	steel pipe-in-pipe	pipe-in-HDPE	flexible pipe
depth to top of pipe (ft)	7	7	7	7
Pipe design parameters:	Unchanged from the initial design	<u>Changed</u>: Outer pipe wall thickness : to 0.500 in. from 0.844 in. Inner pipe wall thickness : to	Unchanged from the initial design (Figure 1.1)	Unchanged from the initial design

	(Figure 1.1)	0.688 in. from 0.500 in.		(Figure 1.1)
risk over 20 years (bbls of oil)	$2.1 * 10^{-3}$	$3.4 * 10^{-4}$	$1.7 * 10^{-3}$	$1.4 * 10^{-2}$

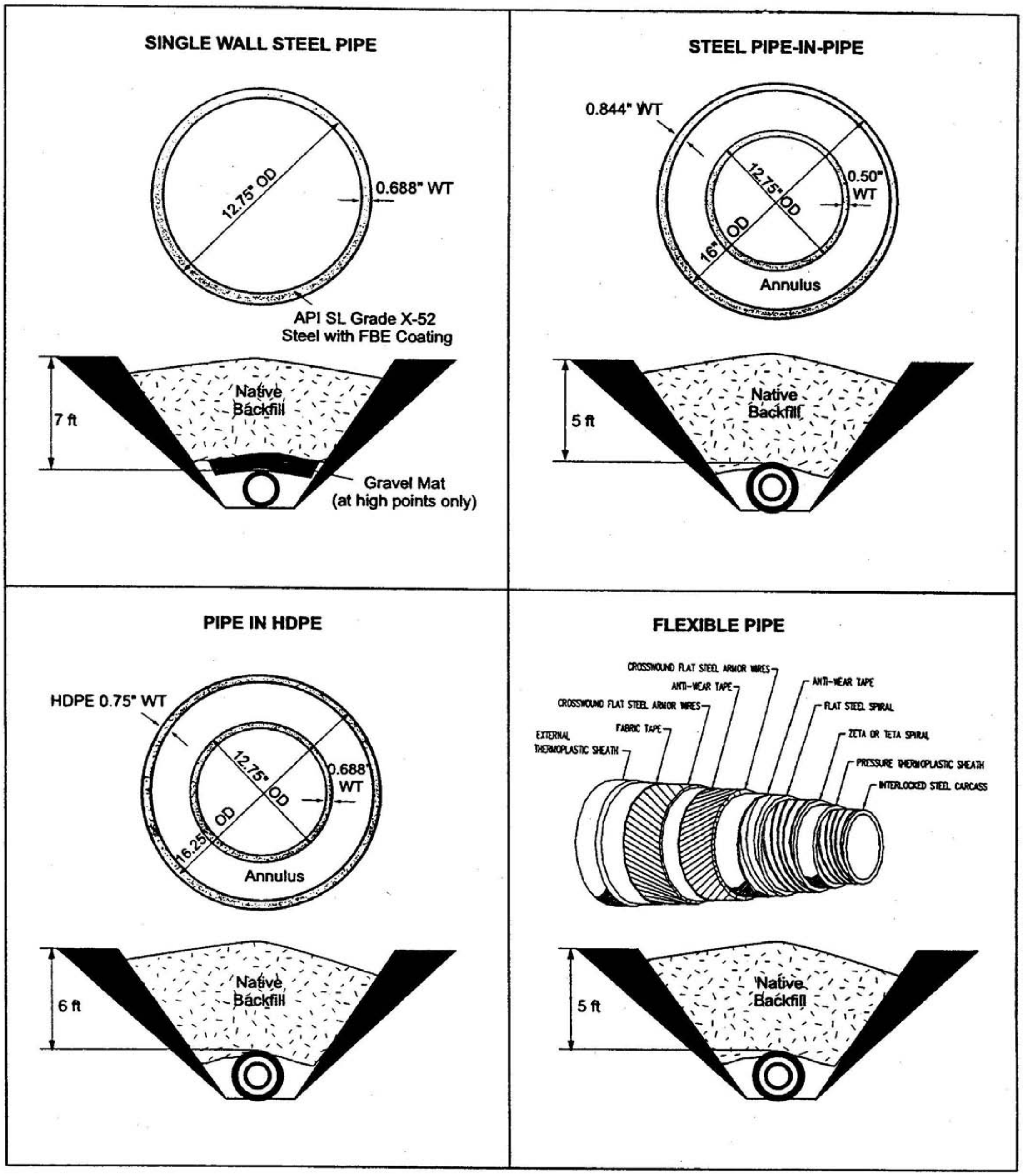

Figure 1.1: Initial Pipeline Configurations (after Intec, 1999)

1.2 Project Scope and Objectives

The objective of this project was to conduct an independent evaluation of the risk associated with each of the Liberty Pipeline alternatives.

It was recognized at the outset that the following parameters would be fixed for the purposes of this study:

(a) definition of risk – this was defined in terms of the amount of oil likely to be spilled over the life of the Liberty Pipeline, as a result of the various risk sources.

As a result, only operational risks were considered in this project. The construction, decommissioning or abandonment phases of the Liberty Project were not considered because this was beyond the scope or terms of reference for the project.

(b) pipeline life – this was set at 20 years.

(c) oil flow rate – this was set at 65,000 barrels per day, over the life of the pipeline.

(d) pipeline designs – the risk analysis was constrained to the four concept designs produced by Intec, 1999; 2000. A total of eight cases were analyzed, as follows:

(i) the four designs initially developed by Intec, 1999 (Table 1.1); and
(ii) the four revised designs produced by Intec, 2000 (Table 1.2).

(e) pipeline monitoring and leak detection – it was assumed that the Liberty Pipeline would be fitted with both a PPA/MPLBC and a LEOS system (acronyms defined subsequently). Furthermore, it was assumed that both systems would be maintained and kept operational throughout the life of the pipeline. It was presumed that the monitoring systems would be operational at the time when hazards of concern occurred.

It is recognized that some system downtime may occur. However, it was considered quite unlikely that a combination of events would take place in which the monitoring system failed at the same time as the hazards occurred.

1.3 Historical Perspective

It is important to recognize that very few pipelines have been designed, built, or operated in offshore waters that are exposed to ice or Arctic conditions. To our knowledge, the only ones that were buried were:

(a) the Drake F-76 flowline that was installed as a demonstration project offshore of Melville Island in the Canadian Arctic (Palmer et al, 1979).

Unfortunately, the experience gained from this pipeline is of little benefit to this project as the pipeline was only operated for a very short time in 1978 and has not been monitored since then. Consequently, there is no information available (at least in the public domain) regarding its fate.

(b) the pipeline crossing Nevelskoi Strait, between Sakhalin Island and mainland Russia. Although this pipeline has operated without damage (to our knowledge) since 1958 (Surkov et al, 2000), this experience is also of little benefit to this project because very little quantitative information is available regarding this pipeline.

Other experience has been gained from ice-induced damage to a water intake line at Hay River NWT (Noble and Comfort, 1980), and from ice scour investigations in Lake Erie (e.g., Grass, 1984).

Furthermore, it is recognized that experience is being gained with the current Northstar Pipeline project. However, again, this experience is of relatively little benefit to this risk analysis project because the Northstar pipeline has not yet been operated. Nevertheless, some of the research done in support of the Northstar Project is useful for this risk evaluation.

Furthermore, it is also important to recognize that the vast majority of the pipelines currently in service are "single wall steel pipe". Although a few pipe-in-pipe designs have been built (CCORE, 2000), they were designed with the objective of providing insulation to the carrier pipe, to provide improved operating efficiency. They were not built with the objectives of providing improved structural reliability or secondary containment. Hence, this experience base is not very applicable to the case of interest here.

For this project, the most important implication of this limited experience is that there is very little historical design or practical field experience that can be referred to provide reliable "judgments" with respect to:

(a) either pipelines for use in offshore, Arctic conditions; or
(b) pipe-in-pipe configurations designed to provide improved structural reliability or secondary containment.

1.4 Report Structure

The report is divided into 9 sections, as follows:

(a) Section 2 : Analysis Framework – This section provides an overview of the risk analysis methodologies used.

(b) Section 3: Hazards – This section discusses Liberty Pipeline hazards. For some hazards, only summary information is presented in Section 3, while detailed information is provided in the respective appendices.

(c) Section 4: Pipeline Response and Failure Criteria - This section relates the response of the pipeline to the hazards described in the previous section and introduces failure criteria. Summaries of probable pipeline response and probabilities of failure are provided in this section while more complete descriptions of the numeric and analytic models used to evaluate pipeline response are described in Appendices C and D.

(d) Section 5: Pipeline Corrosion - This section describes the potential for corrosion in the Liberty Pipeline and its probable effect.

(e) Section 6: Monitoring Systems - This section describes various technologies available to monitor the pipeline in an effort to detect leakage and thus reduce the consequence of failure.

(f) Section 7: Consequence Modelling - This section describes the oil spill model and the consequence of each mode of failure.

(g) Section 8: Risk Analysis - This section presents the results of estimates of pipeline oil spill risk for each of the four pipeline configurations. Sensitivity analyses are also presented in this section to obtain bounds on the oil spill risk for the Liberty Pipeline.

(h) Section 9: Conclusions and Recommendations - This section presents the conclusions of the risk analysis by comparing the four design alternatives and highlighting significant project findings. Recommendations for further investigation and analysis are provided in this section as an indication of the way forward in developing a more complete understanding of the risks associated with offshore arctic pipelines.

2.0 ANALYSIS FRAMEWORK

In general terms, the risk evaluation was carried out as depicted in Figure 2.1. More detailed information is given in the flowchart shown in Figure 2.2, and in the steps listed below:

(a) Step 1 - Verify the analysis objectives and the analysis scope;
(b) Step 2 – Identify the risk sources (termed hazards);
(c) Step 3 – Estimate event probabilities for the hazards;
(d) Step 4 – Estimate the system degradation that will occur;
(e) Step 5 – Determine the pipe response and establish failure criteria and probabilities;
(f) Step 6 - Estimate the event consequences;
(g) Step 7 – Calculate operational risk, and compare alternatives.

The general approach used for each step is described in the following sections.

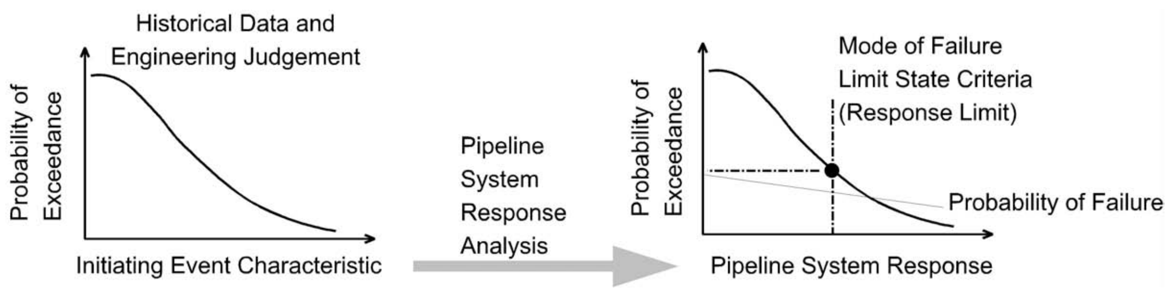

Figure 2.1: Failure Probability Estimation

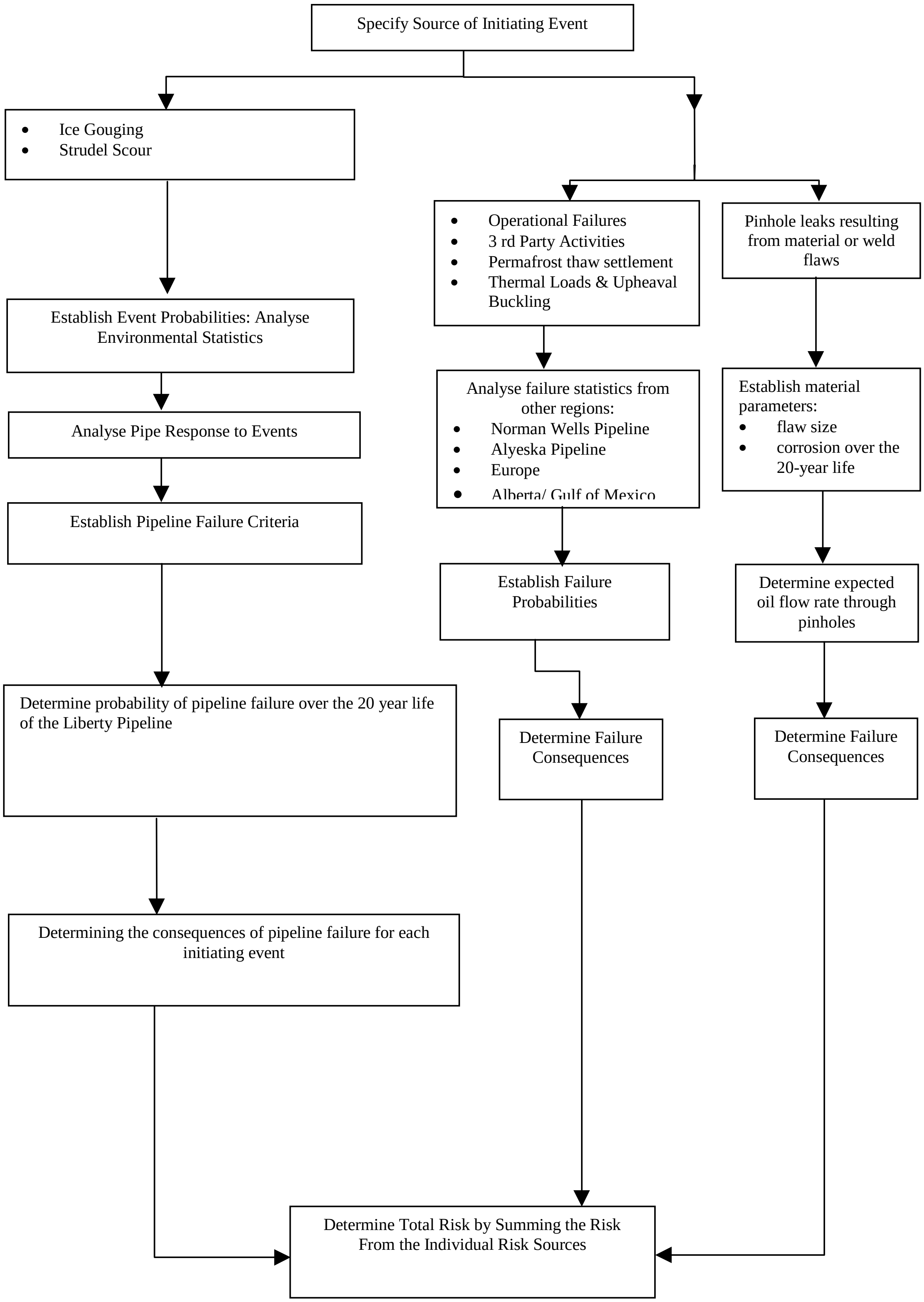

Figure 2.2: Overview of Risk Analysis Approach

2.1 Step 1 - Identify the Analysis Objectives and the Analysis Scope

The general objective of this project was to conduct a third party independent assessment of the risk of failure for the Liberty Pipeline during its 20-year design life, with risk being defined as the quantity of oil likely to be spilled over this period.

The specific objectives were to:

(a) conduct a risk analysis by:
   (i) defining the individual risk sources, and establishing their event probabilities;
   (ii) establishing the system degradation likely to occur over the pipeline life;
   (iii) establishing the pipeline response to the risk sources, and the probability of failure;
   (iv) determining the consequences of each potential type of pipeline failure, taking into account the pipeline monitoring systems likely to be used and their reliability; and,
   (v) establish the most likely and the maximum pipeline leak sizes for each mode of failure.

(b) calculate the probability of a large spill associated with each pipeline design alternative developed by Intec, 1999, 2000, with a large spill being defined as one greater than 1000 barrels of oil.

(c) compare the pipeline design alternatives developed by Intec, 1999, 2000 in relation to:
   (i) their risk; and,
   (ii) the uncertainty associated with the calculated risk values.

(d) conduct appropriate sensitivity analyses.

(e) make recommendations as appropriate.

2.2 Step 2 – Identify Risk Sources

2.2.1 Introduction

Because the objective of the design process is to manage or mitigate risk exposures, the recognition of risk sources is arguably the most important step. Generally, risk sources may be identified based on:

(a) a review of previous performance;
(b) the collection of expert opinion; and,
(c) the development of failure event trees.

Because design and field operational experience with Arctic offshore pipelines is very limited (Section 1), risk sources were mainly identified in the current project based on the latter two approaches. Expert opinion was collected primarily through information gathering done by reviewing research reports, offshore pipeline design documentation, risk sources identified in Intec, 1999; 2000, as well as in the Request For Quotation, and other literature.

First, a comprehensive listing of risk sources was assembled, and was reviewed to ensure that no significant ones were missed. They were also assessed qualitatively prior to formal risk assessment.

2.2.2 General Approach

The potential risk sources and the methods used to evaluate their occurrence probabilities are summarised in Table 2.1.

Table 2.1: Hazards Considered and Method of Evaluation

Hazard	Method Used to Evaluate Occurrence Probability
Ice Gouging	Establish event trees and analyse environmental data
Strudel Scour	Establish event trees and analyse environmental data
Permafrost thaw settlement	Based on analyses of failure statistics
Thermal loads leading to upheaval buckling	Based on analyses of failure statistics
Third party activities (e.g., construction activities, anchor dragging, sabotage, etc.)	Based on analyses of failure statistics. See below for operational failures.
Operational failures (e.g., operator error, pumping against a closed valve, SCADA system failure, etc.)	Based on analyses of failure statistics. It was initially intended to investigate third party activities and operational failures separately. However, upon analysis of the failure statistics, it was found necessary to group these two hazards together as it was not possible to evaluate them separately.
Material defects or weld flaws, and the development of pinhole leaks over time (e.g., due to the combined effects of corrosion and operating pressure histories)	Based on analyses of failure statistics.

2.2.3 Coupled Cases

In developing the list of risk sources, it became apparent that a number of coupled cases were of concern. The following ones were included in the analyses:

(a) Partial trench cover loss due to strudel scour, which in turn leads to increasing the risk associated with upheaval buckling

(b) multiple ice gouging by ice keels travelling in opposite directions (termed multiple gouging) – this case was included because it would lead to a load reversal for the buried pipeline. In contrast, a single crossing by an ice keel would only load the pipeline in one direction.

It was considered useful to investigate the multiple gouging case because full scale bending tests have shown that a pipeline can withstand quite high strains in one direction without developing a leak. The pipe is expected, however, to have less resistance to failure from a stress reversal, although it was recognised that only limited quantitative information is available to define this type of pipeline response.

2.3 Step 3 – Estimate Occurrence Probabilities for the Hazards

2.3.1 Ice Gouging and Strudel Scour

Historical data are not available for evaluating these hazards because pipelines have not been operated in Arctic conditions up to now (section 1). Consequently, occurrence probabilities were established for these hazards by defining event trees and analysing environmental data.

2.3.2 All Other Hazards (In Table 2.1)

Failure rates were inferred by analysing statistics from a number of sources as follows:

(a) the Trans Alaska Pipeline System (TAPS);
(b) the Norman Wells Pipeline (which is an oil pipeline in northern Canada);
(c) failure statistics compiled for land-based pipelines by the United States Department of Transportation (DOT);
(d) failure statistics compiled by the Minerals Management Service (MMS), for the Gulf of Mexico;
(e) failure statistics compiled for land-based pipelines by the CONCAWE, (Conservation of Clean Air and Water in Europe);
(f) failure statistics compiled for land-based pipelines by the Alberta Energy and Utilities Board (AEUB).

The failure statistics for the TAPS and the Norman Wells pipelines were used as the primary sources of information because:

(a) they are both single-product lines which is the case for the Liberty Pipeline as well.

(b) they are both located in remote regions where the population density is low, which is similar to the Liberty Pipeline.

(c) they are both modern pipelines, which have been operated in a manner that is expected to be similar to the case for the Liberty Pipeline. The TAPS and the Norman Wells pipelines began operation in 1977 and 1985, respectively.

The above data were used to establish historical industry average failure rates. It was recognised that these comparisons could not be definitive for a number of reasons, and as a result, engineering judgement was applied as well.

2.4 Step 4 – Establish Expected System Degradation (Corrosion)

2.4.1 Overview

Corrosion is recognised as one of the primary degradation mechanisms of buried pipelines on the basis of the numbers of failures that have been experienced over the years. The failure statistics include large numbers of corrosion related failures, and in some instances they amount to approximately half of the failures for the database. Information such as this must be viewed cautiously, as discussed above, because the pipelines in some of the data include small diameter gathering lines and lines that are not routinely inspected. Pipelines in these cases exhibit worse failure statistics than large diameter pipelines, i.e., NPS12 and larger.

The approach taken to determine system degradation was to rely on the historical failure incidences and apply engineering judgement as to the applicability of the data to the present analysis.

2.4.2 Internal Corrosion

Failures caused by internal corrosion are to be expected in any pipelines that could collect water or solids along the bottom of the pipe. This could occur at low points in a pipeline, such as in valleys or river crossings, or in any sections of a line that exhibit laminar flow. In the latter case, the solids drop out of the oil and collect along bottom, leading to conditions that are prone to internal corrosion failures. Crude streams with high water and solid contents present the greatest concerns for pipeline operators in terms of internal corrosion. Pipeline operators can combat internal corrosion through the regular use of corrosion inhibitors added to the crude stream and by running cleaning pigs through the line to remove water and sludge.

Information on corrosion failures is readily available from the various historical sources. The problem, however, is that the data does not always report whether the initiation site was related to internal or external corrosion. This often requires engineering judgement to establish whether initiation occurred on the inside or outside of the pipe.

2.4.3 External Corrosion

From our experience with large diameter pipelines, we would expect to see more general degradation of the pipe from external corrosion than internal corrosion in the failure data. The main reason for this statement is that there was a period of time where all new pipelines were being coated with thin film polyethylene to provide corrosion protection. It is well known that these films have not performed as expected. In fact, since they shield the pipe from cathodic protection currents, they allow corrosion to progress essentially on its own. For this reason, we might expect to see a large number of failures in the historical information, and assigning a value to the expected performance of the Liberty Pipeline might not be directly related to past results.

Another important fact from the historical data is that the type of coating is essentially never listed. This makes it impossible to draw any correlations with expected behaviour, and again, it was necessary to apply engineering judgement to assign expected failure probabilities.

2.5 Step 5 – Determine Pipe Response and Establish Failure Probabilities

2.5.1 Overview

This involved the following general steps. See also Figure 2.2.

(a) establish the expected pipeline modes of failure (with failure being defined as loss of product containment).

(b) establish and quantify the expected pipeline structural response to various hazards - For the single steel pipe design, this was done using structural analyses of the pipeline's global response.

For the steel pipe-in-pipe design, the global and the local response of the pipeline were both evaluated.

(c) establish pipeline failure criteria

2.5.2 Global Response

Four potential failure modes were analysed as follows:

(a) lateral deformation – this was quantified using large-displacement ANSYS finite element analyses for a buried pipeline that is exposed to large soil displacements, thermal expansion and internal pressure.

(b) instability / buckling - this was quantified in a two-step process. First, closed-form analyses (using the approach in Palmer et al, 1990) were used to establish whether or not upheaval buckling would occur for various cases. Then, large-displacement finite element analyses were carried out to quantify the strains and pipe displacements associated with the upheaval buckling that occurred.

(c) unsupported spans – this was analysed using simple calculations to determine the bending moments and strains associated with various unsupported spans.

(d) pipe wall overload (corrosion damage) – this was assessed by analysing the growth of corrosion pits to the point where leakage occurs.

2.5.3 Local Response

The local response of the steel pipe-in-pipe design was analysed using ANSYS finite element analyses with results from the global analyses (described in section 2.5.2) being used as inputs).

2.5.4 Establish Failure Criteria

Two types of failure criteria were established for this risk analysis, as follows:

(a) the conditions necessary to either cause stable cracks that will leak; or cracks that will be unstable and lead to rupture - Failure criteria for this case were established by first reviewing test data and design codes. It was noted that design codes and design practices are not formulated directly with respect to product loss. Instead, they are specified in relation to either a safe strain or stress, or to limit states that do not include product spillage. This would lead to an overly conservative result in this project (for evaluating oil spill volumes).

    Failure criteria for pipeline rupture were established by reviewing large-scale test data obtained with: (i) samples of the pipe that was used for the Northstar Pipeline; (ii) bend tests done in Japan; and (iii) wrinkling tests done at the University of Alberta.

    These same criteria were used for the growth of stable cracks although it was noted that this probably errs conservatively. The pipe’s resistance to leakage is related primarily to its toughness, with respect to the size of a stable flaw that can remain under operating conditions without rupturing.

The X52 pipe specified for the Liberty Pipeline has high toughness that will prevent failures in a brittle manner. Rather, the pipe will develop a relatively small opening and will leak product at a rate that is related to the supply of oil to the leak site.

(b) the growth of corrosion pits to the point where leakage occurs. This was done using an approach developed for assessing corrosion pits, B31G (Battelle 1989), by relating the remaining area below the pit to its maximum pressure carrying capacity.

2.6 Step 6 – Estimate Failure Consequences

A consequence model was set up to quantify failure consequences for each risk source.

2.6.1 Types of Pipeline Failure

Three types of pipeline failure were considered as follows:

(a) rupture;

(b) flow through the maximum stable crack – this was quantified by determining:
   - (i) the maximum stable axial and circumferential crack sizes, and how its size would vary with pressure, and;
   - (ii) the expected oil flow out of these orifices using published guidelines for pipelines (BS PD6493) and AS (Australian Standard) 1978, 1987

(c) seepage through corrosion pits, weld defects, and material defects (also termed pinhole leaks in this report).

Pipeline failure by rupture or flow through a large stable crack would be detectable by the PPA/MBLPC monitoring system that will be used. The oil volume spilled for these failure modes was determined based on the response time, and the oil drainage that would occur after line shut-in.

Seepage would not be detectable by a PPA/MBLPC monitoring system. This oil volume was determined based on the leak detection capabilities of the PPA/MBLPC and the LEOS monitoring systems that will be used.

2.6.2 Evaluation of the Performance of the Monitoring Systems Used

It was presumed that the Liberty Pipeline would be fitted with a PPA/MBLPC and a LEOS monitoring system, based on Intec, 1999; 2000. The capabilities of these two systems were established by reviewing past performance and by engineering judgement where necessary. The parameters assessed included the leak detection thresholds, the alarm time, and the number of false calls.

2.6.3 Establish and Quantify the Failure Sequence

Times, and oil spill volumes, were established for each of the following steps in the failure sequence that was presumed to occur:

(a) the time required for the monitoring system(s) to respond;
(b) the time elapsed between first notice of an alarm and the decision by the operator to take action;
(c) the time required for valve closure to shut-in the line.

It was further presumed that an additional oil loss would occur as a result of line depressurisation, as was done by Intec, 1999; 2000.

2.6.4 Oil Released After the Line is Shut In

It was presumed that oil would drain from the line after shut-in and depressurisation. Oil drainage volumes were calculated for each point along the route. The water depth where the pipeline failure occurs was found to be significant because the Liberty Pipeline has a number of “high points’ that would act to trap oil.

Oil drainage was calculated for the water depth ranges represented by each hazard, because they occur at different water depths along the pipeline route.

2.7 Step 7 – Calculate Risk and Compare Pipeline Design Alternatives

2.7.1 Risk Calculation

In general, the risk associated with any risk source is governed by the product of its consequences and its event probability (Equation 2.1). This general approach was used to calculate the risk for each hazard.

$$R_{total} = \sum (C_i * P_i) \qquad [2.1]$$

where: R_{total} = the total volume of oil expected to be spilled in the 20-year life of the Liberty Pipeline for the pipeline design under consideration

$\sum (C_i * P_i)$ = the sum of the product of the event consequences, C, and the event probability, P, for each individual risk source, i, over the 20-year life of the Liberty Pipeline

The total risk was determined for each of the eight pipe designs established by Intec, 1999; 2000 (Tables 1.1 and 1.2, respectively).

2.7.2 Comparison of Design Alternatives and Sensitivity Analyses

This work involved two general tasks as follows:

(a) comparisons to establish the relative performance of the four design alternatives, and their sub-alternatives (Section 1) based on their predicted risk levels.

(b) sensitivity and uncertainty analyses – an extensive sensitivity analysis was conducted. The parameters investigated included:
   (i) the failure mode(s);
   (ii) the pipeline failure criteria;
   (iii) the expected and the worst-case performances of the monitoring systems used;
   (iv) the expected and the worst-case failure rates for the most significant hazards;
   (v) the uncertainties associated with the various inputs.

(c) oil spill volumes – the most likely and expected maximum spill sizes were estimated for each concept design.

3.0 HAZARDS

3.1 Overview

The hazards of interest to this project are the ones with potential to lead to oil release. The risk analysis approach used varied depending on the type of hazard, as summarised below:

(a) Environmental hazard: The following types of environmental hazards were evaluated:
   (i) ice gouging;
   (ii) strudel scour;
   (iii) permafrost thaw subsidence; and
   (iv) thermal loads, loading to upheaval buckling.

   These events are described in Sections 3.2 to 3.5, respectively. Risks for ice gouging and strudel scour were determined by establishing event trees. Risks for permafrost thaw subsidence and thermal loads were established by analysing failure statistics.

(b) operational failures, 3rd party damage, and pinhole leaks – an implicit approach was used to evaluate risk for these events, as failure statistics for other regions were analysed.

   These events are described in Sections 3.6 to 3.8, respectively. The analyses undertaken to establish failure occurrences resulting from pipeline operations are discussed in Section 3.9.

3.2 Ice Gouging

3.2.1 Introduction

The ice gouging hazard is difficult to analyse because a wide range of scenarios may occur, and very little information is available to evaluate the ice keel-soil-pipe interaction. It is generally recognised that three types of interactions are possible depending on the proximity of the pipe to the bottom of the ice keel (Palmer et al, 1990), as shown in Figure 3.1 and summarised below:

(a) Zone 1 – in this case, the pipeline is located above the keel bottom, and thus, the moving ice keel contacts it.

(b) Zone 2 – a pipeline in Zone 2 is below the keel bottom, and thus not contacted by it. However, large soil displacements may occur in Zone 2 (e.g., Woodworth-Lynas et al, 1996), which have the potential to cause large pipeline strains in response to the gouging event.

(c) Zone 3 – Zone 3 is located beneath Zone 2. It is recognised that soil displacements will reduce steadily with depth below the moving ice keel. Soil displacements in Zone 3 are small enough that a pipeline in Zone 3 would only experience elastic strains. A pipeline in Zone 3 would be safe.

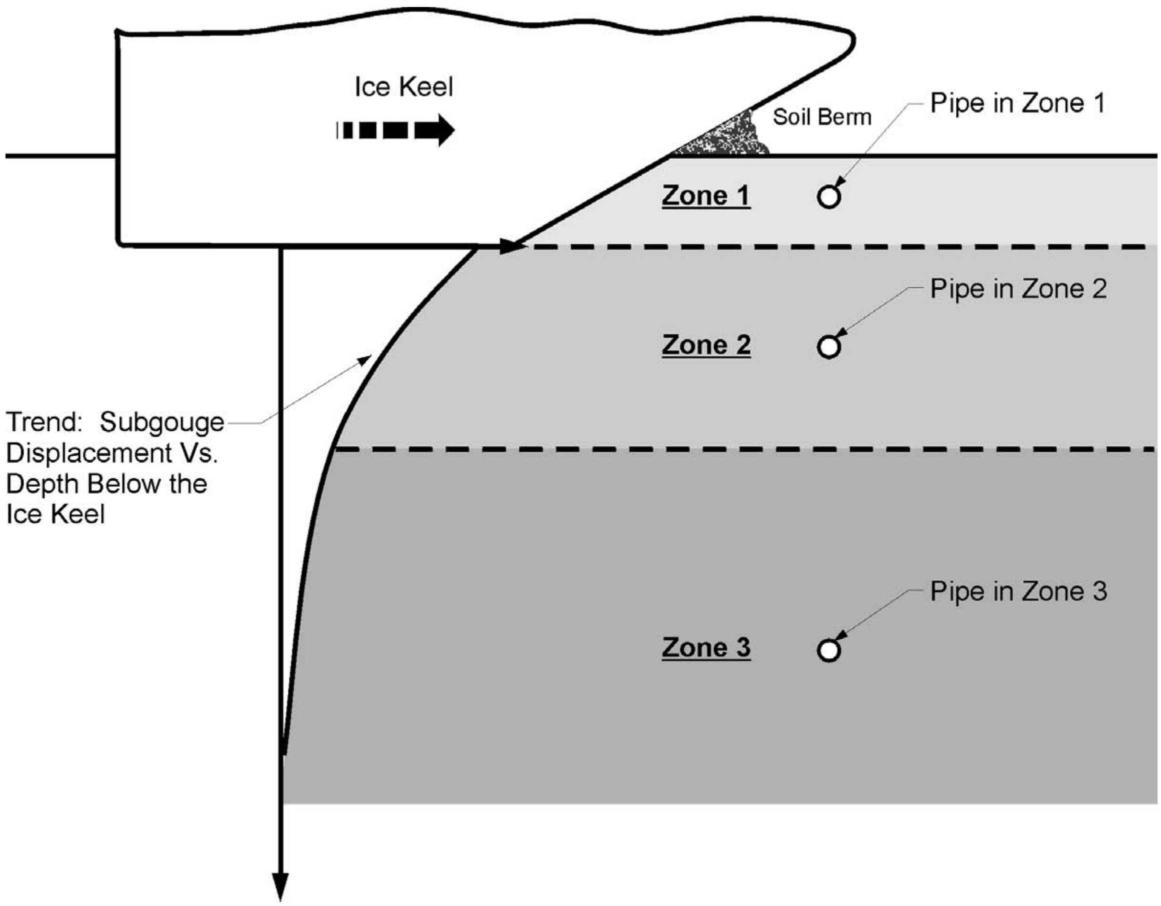

Figure 3.1: Ice Keel-Pipe Interaction Zones

The risk analysis approach used for the ice gouging hazard is shown in Figure 3.2. Risks were evaluated independently for the three cases outlined as follows.

3.2.2 Pipe in Zone 1

It was assumed that any ice-pipe contact would lead to pipeline rupture, and as a result, no structural analyses were performed. The risk was evaluated based solely on probabilistic analyses and consequence modelling.

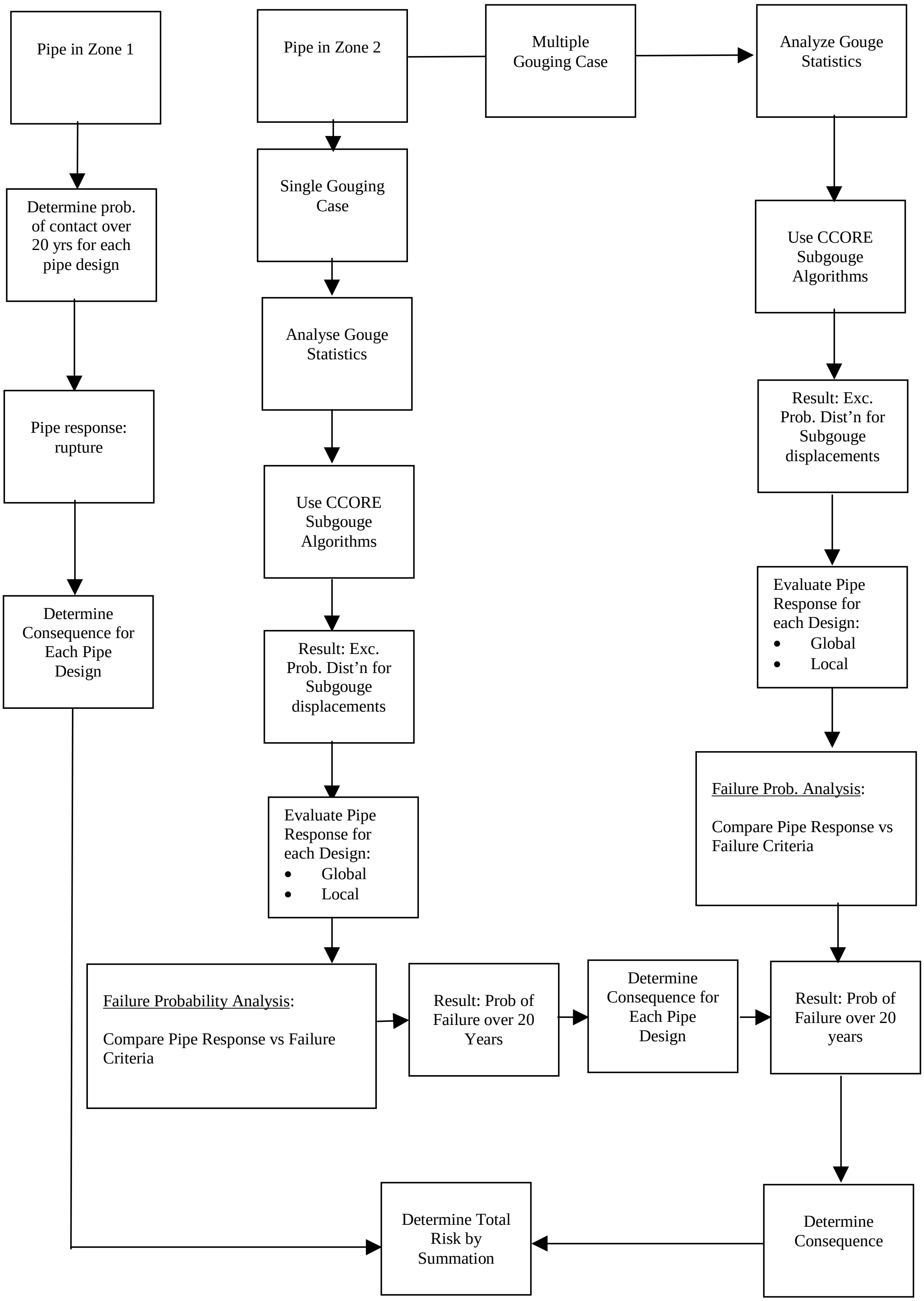

Figure 3.2: Ice Gouging Risk Analysis Flowchart

It is recognised that this approach probably errs conservatively as simple calculations have indicated that some ice-pipe contact may be tolerable (e.g., Croasdale et al, 2000). However, the available information is inadequate to use this potential risk limit in the analyses being done here.

3.2.3 Pipe in Zone 2 – Single Gouging Case

In this scenario, the pipeline route is crossed once by an ice keel. Soil displacements occur which load the pipeline.

The available ice gouge data were first reviewed. The data set is quite small which introduces uncertainties as ice conditions are known to vary from year to year (Appendix A). The greatest uncertainty is associated with defining the gouge impact rate (i.e., the number of new gouges expected to cross each mile of the pipeline route per year). FTL's analysis suggested that the gouge impact rate may vary from about 0.049 to 0.41 gouges per mile per year (Appendix A).

As a result, event probabilities were evaluated for three gouge impact rates which span the expected range (Figure 3.3 and Appendix A).

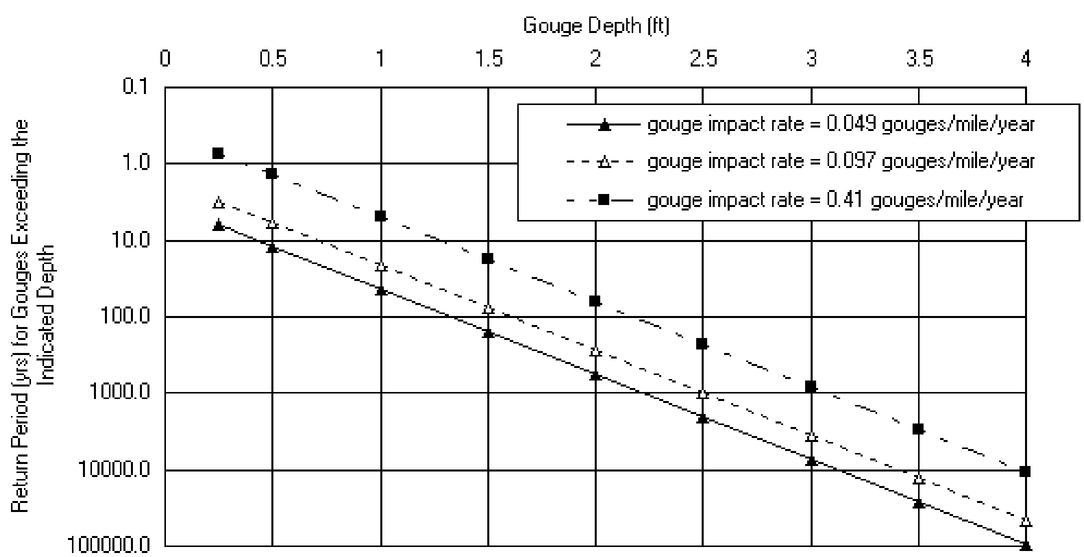

Figure 3.3: Sample Result - Gouge Depth Return Periods: Gouges Only Occur At Water Depths Greater Than 10 Ft

The strains exerted on the pipeline are governed by the soil displacements that occur, and probably ice-related parameters as well, such as the ice keel strength and the ice keel vertical uplift that occurs. However, it is not possible to account for these ice-related parameters reliably with the current state-of-the-art.

As a result, Intec, 1999; 2000, analysed this soil-pipe interaction as a displacement-controlled problem. Of necessity, this same approach was used in this project. Comments are made in subsequent sections regarding the possible errors introduced by this approach.

For a displacement-controlled analysis of this soil-pipe interaction, the key environmental inputs are: (i) the soil displacement field (ii) the temperature differential and (iii) the pipeline's operating pressure.

Of necessity, subgouge displacements were defined using algorithms developed based on small-scale centrifuge tests (Woodworth-Lynas et al, 1996; Nixon, 1997) as these are the only ones that are publicly available. These are the same ones used by Intec, 1999; 2000. Subgouge displacement exceedence probabilities were calculated for gouge widths of 18 feet and 30 feet as pipeline failure criteria were developed for these two gouge widths (described in section 4). Sample results are shown in Figure 3.4, and Table 3.1, while complete results are provided in Appendix A.

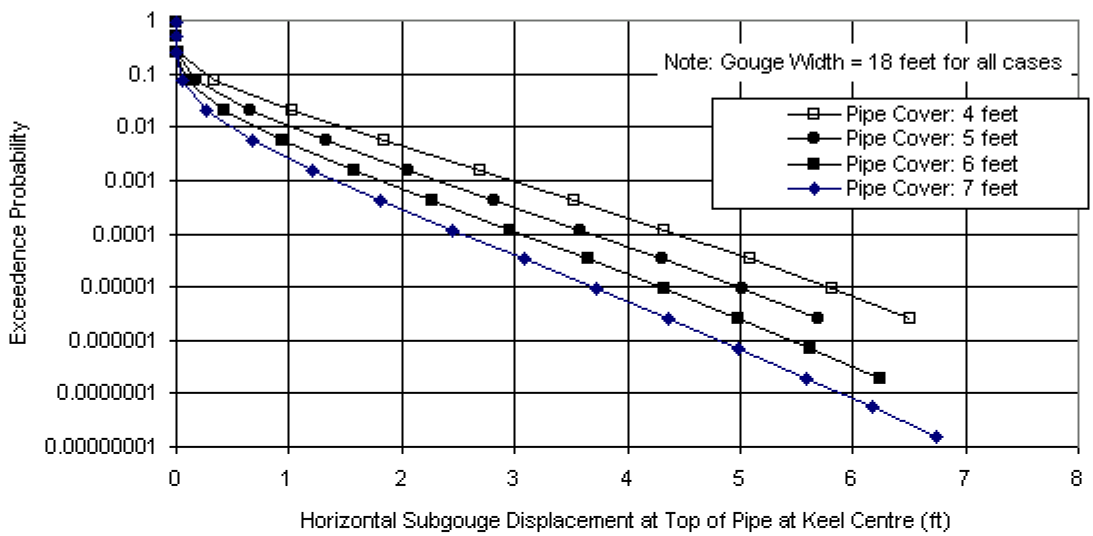

Figure 3.4: Sample Result: Subgouge Soil Horizontal Displacements: Gouge Width = 18 Feet

Table 3.1: Subgouge Soil Displacement Exceedence Probabilities

Exceedence Probability	Soil Displacement (ft)		Soil Displacement (ft)		Soil Displacement (ft)	
	Cover=7 ft	Cover=7 ft	Cover=6 ft	Cover=6 ft	Cover=5 ft	Cover=5 ft
	Width=18 ft	Width=30 ft	Width=18 ft	Width=30 ft	Width=18 ft	Width=30 ft
10^{-3}	1.4	1.8	1.8	2.3	2.3	3.0
10^{-4}	2.5	3.2	3.0	3.9	3.7	4.7
10^{-5}	3.7	4.7	4.3	5.5	4.9	6.4

Efforts were made to assess the reliability of the calculated subgouge displacement fields. The available information is derived from small-scale centrifuge tests and from general observations at land-based ice gouges. This is difficult to assess, partly because the main results are proprietary and only summary results have been published. However, the published information indicates that the results are subject to significant uncertainty. It was conservatively estimated that the published algorithms (to define the subgouge displacement field) might underestimate the actual values by up to a factor of about 10 (Appendix A).

The risk analyses for this case was evaluated by using the results of the probabilistic analyses in combination with structural analyses, and consequence modelling.

3.2.4 Pipe in Zone 2 – Multiple Gouging Case

In this scenario, the pipeline route is crossed twice by ice keels moving in different directions. This case was analysed because it may lead to a stress reversal in the pipeline (in contrast to the single gouging case which will load the pipeline in one direction only). Although pipeline failure criteria are not available for this type of loading, a pipeline is expected to have less resistance to failure in this mode (Section 4).

Event probabilities for the multiple gouging scenario were evaluated by conducting probabilistic analyses (Figure 3.5, Table 3.2, and Appendix A). They showed that:

(a) there is a relatively high probability that the Liberty Pipeline will be re-gouged at some location along its length over its 20-year lifetime;
(b) the gouge depths for most of the re-gouging cases will be shallow;
(c) the probability that the pipeline will be re-gouged by two deep gouges is quite low. For example, the probability that the pipeline will be crossed by one 2.5-3 ft deep gouge, and a second one more than 3 ft deep is 10^{-6} for the highest impact rate to be expected (i.e., 0.41 gouges/mile/yr).

The risk for this case was evaluated using the results of the probabilistic analyses, in combination with simplified structural analyses and consequence modelling.

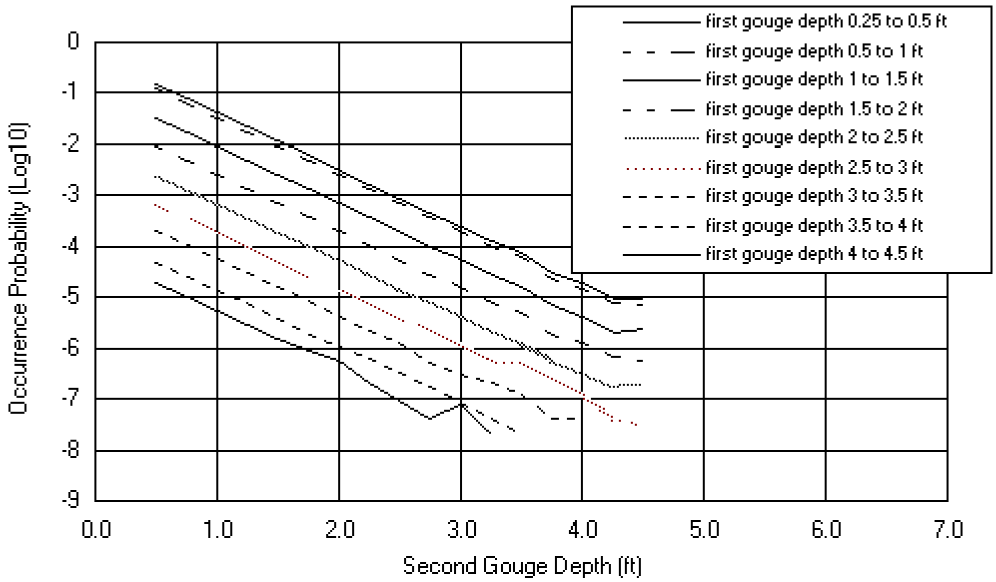

Figure 3.5: Multiple Gouging Occurrence Frequency for the Liberty Pipeline 6.12 Mile Length; a Gouge Impact Rate of 0.41 gouges/mile/yr.; and a Time Period of 20 years

<u>Note to Figure 3.5:</u>
The multiple gouging analyses were based on the total pipeline length (of 6.12 miles) rather than the 3.3 mile long pipeline section between the 10 and 22 foot water depths (which is the range where ice gouges have been observed to date). This selection was made to err conservatively (Appendix A).

Table 3.2: Summary Results: Gouge Combination Frequencies over the 20-Year Life of the Liberty Pipeline

Depth Range of First Gouge (ft)	Depth of Second Gouge (ft)	Gouge Impact Rate (gouges/mile/year)	Occurrence Probability
2.5 to 3	3	0.049	$2.5 * 10^{-8}$
2.5 to 3	3	0.097	10^{-7}
2.5 to 3	3	0.41	10^{-6}
2.5 to 3	4	0.049	$2 * 10^{-9}$
2.5 to 3	4	0.097	10^{-8}
2.5 to 3	4	0.41	$1.3 * 10^{-7}$
2.5 to 3	5	0.049	$2 * 10^{-10}$
2.5 to 3	5	0.097	10^{-9}
2.5 to 3	5	0.41	10^{-8}

3.2.5 Calculating the Total Risk Due to Ice Gouging

As stated previously, for the purposes of this investigation, risk was defined as the oil volume expected to be spilled over the 20-year of the Liberty Pipeline. Several hazards contribute to the total risk of which ice gouging is one of them.

As described in the preceding sections, a number of scenarios contribute to the total risk due to ice gouging. The total ice gouging risk, $R_{\text{tot-ice gouging}}$, was determined as follows:

$$R_{\text{tot-ice gouging}} = R_{\text{Zone 1}} + R_{\text{Zone 2-single gouging}} + R_{\text{Zone 2-multiple gouging}} \qquad [3.1]$$

where: $R_{\text{zone 1}}$ = the risk for a pipe being located in Zone 1
$R_{\text{zone 2-single gouging}}$ = the risk for a pipe in Zone 2 for the single gouging case
$R_{\text{zone 2-multiple gouging}}$ = the risk for a pipe in Zone 2 for the multiple gouging case

It should be noted that the risks for a pipe in Zone 1 were calculated independently of those for a pipe in Zone 2. No allowance was made for the inter-relation between these two cases (e.g., by truncating the input distributions appropriately - Appendix A). This approach was selected for simplicity and because it errs conservatively. As will be shown subsequently, the results are not significantly affected by this simplification as the individual risks due to ice gouging are a small proportion of the overall total.

The risks for a pipe in Zone 2 were calculated as follows:

(a) Single gouging – this was calculated directly based on the gouge data and the failure criterion established (section 8).

(b) Multiple gouging – this was analysed in a two-step process. The failure probability was evaluated first based on whether or not failure would have occurred during the pass of the first gouge, and if this did not occur, then based on the pass of the second gouge.

3.3 Strudel Scour

The strudel scour process has been described by a number of investigators (e.g., Reimnitz et al, 1974; Palmer et al, 2000; Blanchet et al, 2000). Strudel scours are produced during spring runoff by the drainage of water pooled on the ice surface through the ice sheet. This process has been found to produce pits or short linear troughs in the seabed, generally in water depths from 4 to 20 feet, which represents the majority of the Liberty Pipeline route.

3.3.1 Mechanisms by Which Strudel Scour May Lead to Pipeline Failure

Strudel scour may potentially lead to pipeline failure through a number of mechanisms. The following ones were analysed because they are believed to be of most concern.

(a) Unsupported pipe. The pipe may become unsupported if the soil under it is removed by a strudel scour. In this case, the forces acting to cause pipeline failure would be the weight and buoyancy of the pipeline and its product, as well as any residual thermal stresses. This case was analysed by Blanchet et al, 2000, and by Intec, 1999; 2000.

(b) Partial removal of trench backfill, in turn leading to pipeline failure by upheaval buckling. Although the strudel scour may not be large enough to uncover the pipe, it may remove enough cover material that failure by upheaval buckling occurs. This case was not analysed by Blanchet et al, 2000, or Intec, 1999; 2000.

Two other scenarios that were considered were hydrodynamic drag forces and fatigue resulting from oscillations produced by vortex shedding, both due to the strudel scour jet impinging on the pipeline after having been exposed by strudel scour. These have not been investigated in this project because simple calculations have shown that they are quite unlikely to lead to pipeline failure (Palmer, 2000).

3.3.2 Overview of the Risk Analysis Approach

The risks associated with strudel scour producing an unsupported pipe or causing a partial soil cover loss were evaluated (Figure 3.6), as follows:

$$R_{\text{tot-strudel scour}} = R_{\text{Unsupported pipe}} + R_{\text{partial cover loss}} \quad [3.2]$$

where: $R_{\text{tot-strudel scour}}$ = the total risk associated with strudel scour hazards
$R_{\text{Unsupported pipe}}$ = the risk for strudel scour to produce an unsupported pipe
$R_{\text{partial cover loss}}$ = the risk for strudel scour to cause partial loss of the trench cover, which in turn leads to pipeline failure by upheaval buckling

The risks for these two cases were calculated independently. No allowance was made for the inter-relation between these two cases (e.g., by truncating the input distributions appropriately - Appendix B). This approach was selected for simplicity and because it errs conservatively. As will be shown subsequently, the results are not significantly affected by this simplification as the individual risks are relatively small and the overall analyses are subject to large uncertainty.

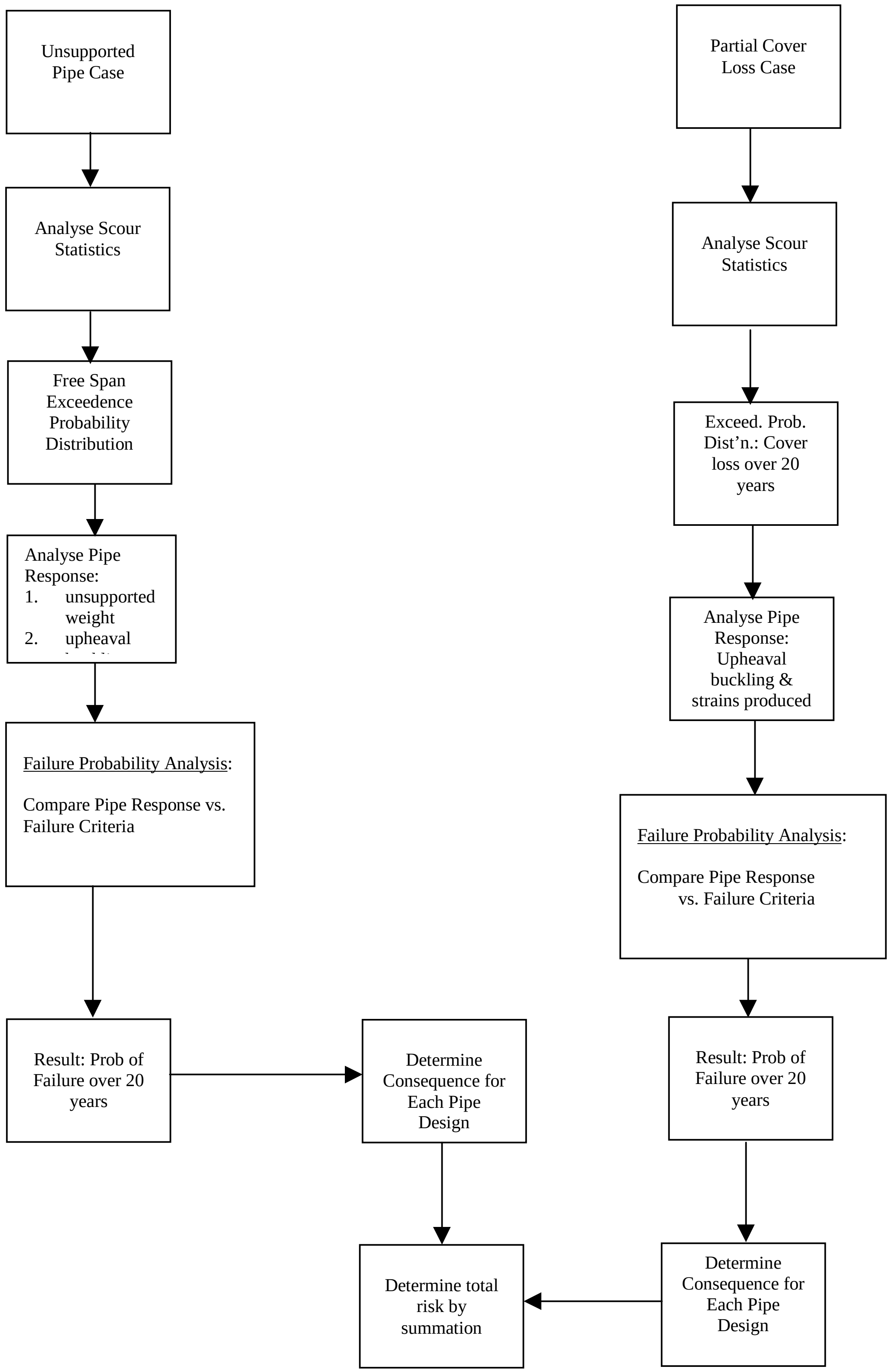

Figure 3.6: Strudel Scour Risk Analysis Flowchart

3.3.3 Strudel Scour Leading to an Unsupported Pipe

The case has been analysed in detail by Blanchet et al, 2000. Their work was taken at face value because they have made significant efforts to analyse the available data in a logical manner, and to account for the factors affecting the data. FTL is in agreement with their approach.

FTL's work was focussed on evaluating the uncertainty associated with their results (Appendix B). The following factors limit the confidence that can be placed in their results:

(a) The data set is small, as strudel scours have only been surveyed in the vicinity of the Liberty Pipeline route in 1997 and 1998 (Coastal Frontiers Corp., 1998; 1999).

(b) Blanchet et al, 2000, classified 1997 and 1998 as "mild to average" years. Hence, the data set does not encompass the range likely to be produced should a "severe" year occur. The uncertainty introduced by this is difficult to evaluate because the factors and processes controlling strudel scour parameters are not well understood (as demonstrated by Blanchet et al, 2000).

Figure 3.7 shows the exceedence probability distribution calculated by Blanchet et al, 2000. FTL used this directly as one input to the risk analyses in this project because they used a logical approach to develop them (Appendix B).

Blanchet et al, 2000 also considered the uncertainty in their results. They determined confidence limits by conducting weighted sensitivity analyses (Appendix B). Their calculations indicate that the confidence limits are relatively large. For the base case they used, the 90 % confidence limit encompasses a range of exceedence probabilities of about 12 times. This range (of 12 times) was used as another input for subsequent risk analyses conducted in this project.

Blanchet et al, 2000 did not consider the potential effect of a "severe" year as their analyses were based on the data available. The principal effect of a "severe" year would be to increase their calculated exceedence probabilities due to increases in the scour width distribution and the strudel scour generation rate (Appendix B). The combined effect of these two factors could potentially increase the freespan exceedence probabilities by a factor of about 3.5 (Figure 3.7), compared to the base case, and this was another input for subsequent risk analyses conducted in this project.

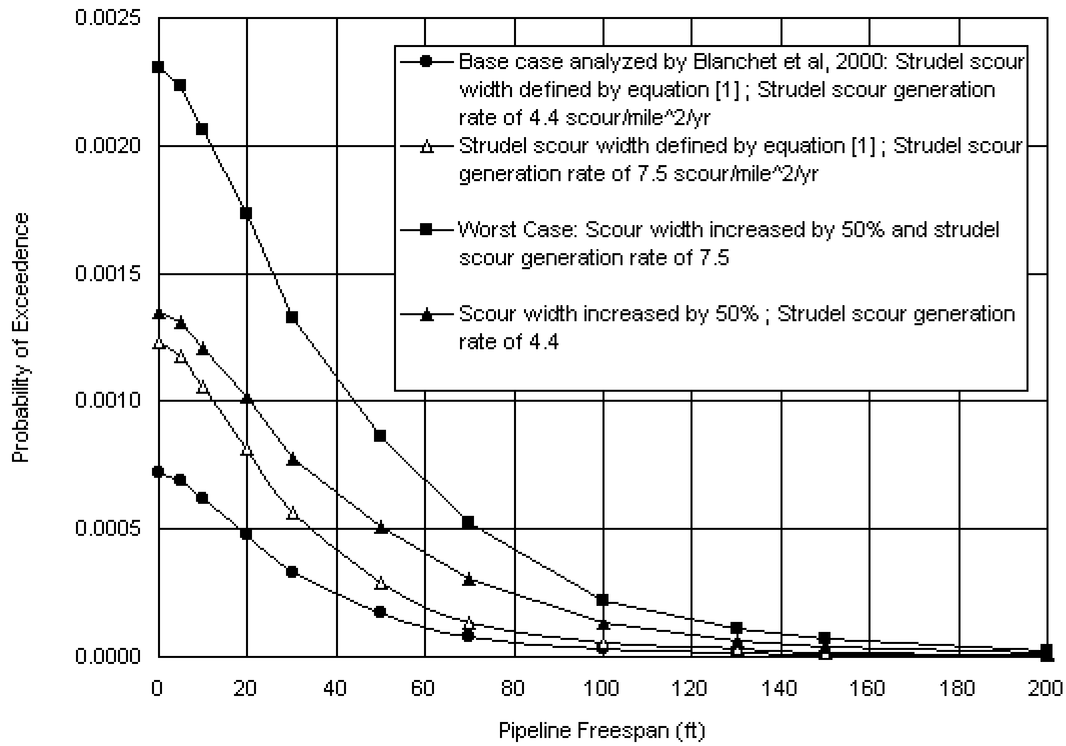

Figure 3.7: Probability of Strudel Scour Producing an Unsupported Pipe

Notes to Figure 3.7:

1. The original figure was taken from Blanchet et al, 2000. Lines for all cases other than the base case were added to the figure by FTL.
2. All calculations and plotted lines are with respect to a strudel scour depth of 8 ft.

3.3.4 Partial Soil Cover Removal by Strudel Scour

It was recognised that although the strudel scour may not be large enough to uncover the pipe, it may remove enough backfill material that failure by upheaval buckling occurs. This case was analysed in two general steps as follows:

(a) Step 1 – Evaluate Event Probabilities for Partial Cover Removal by Strudel Scour (Section 3, Appendix B).

(b) Step 2 – Evaluate Pipeline Response (Section 4).

Event probabilities were evaluated for various soil cover removal cases over the 20-year life of the Liberty Pipeline (Figure 3.8, Table 3.3, Appendix B).

As expected, the exceedence probability is increased for smaller soil cover losses, and it is increased when the strudel scour generation rate is increased.

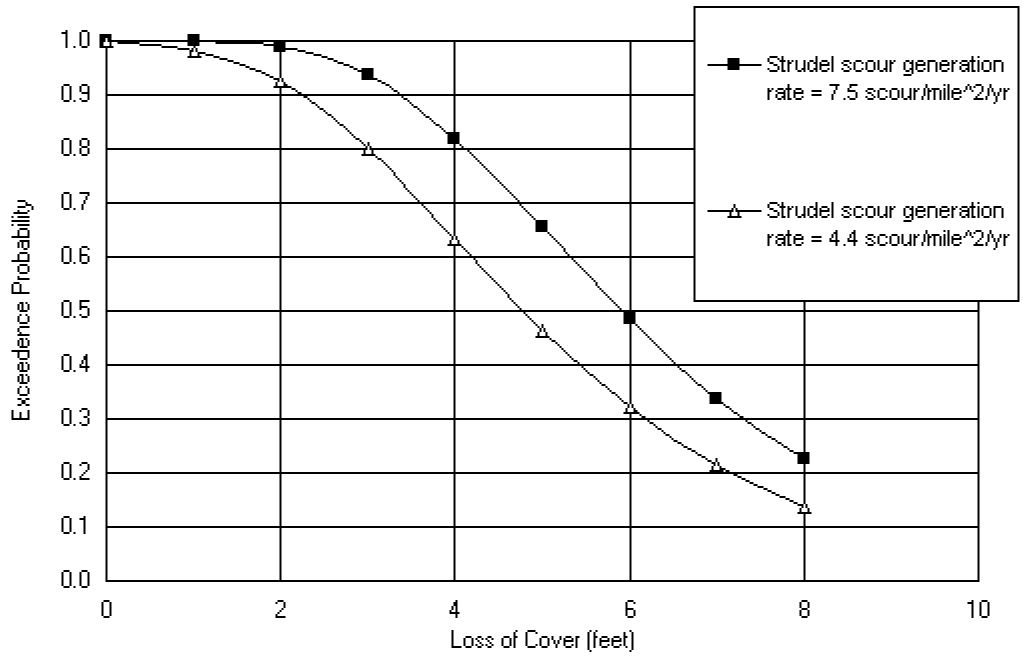

Figure 3.8: Exceedence Probability Distribution For Soil Cover Loss Produced by Strudel Scour Over the 20 Year Life of the Pipeline, and Over the 5.25 Mile Length Where Strudel Scours May Occur

Table 3.3: Cover Losses Produced by Strudel Scour

Cover Loss (ft)	Number of Occurrences in 20 Years and Occurrence Probability (brackets) for: Strudel Scour Generation Rate (scours/mile^2/year) = 4.4	Strudel Scour Generation Rate (scours/mile^2/year) = 7.5
2	0 (0.073)	0 (0.012)
	1 (0.195)	1 (0.052)
	2 (0.255)	2 (0.118)
	3 (0.220)	3 (0.175)
	4 (0.141)	4 (0.194)
4	0 (0.367)	0 (0.181)
	1 (0.370)	1 (0.311)
	2 (0.184)	2 (0.266)
	3 (0.061)	3 (0.150)
	4 (0.015)	4 (0.063)
6	0 (0.679)	0 (0.517)
	1 (0.263)	1 (0.341)
	2 (0.051)	2 (0.113)
	3 (0.0065)	3 (0.025)
	4 (0.00059)	4 (0.004)

3.4 Permafrost Thaw Subsidence

3.4.1 Introduction

Permafrost is defined in the Alyeska web site as “any rock or soil material that has remained below 32° F continuously for two or more years. The two-year requirement excludes from the definition the overlying ground surface layer, which freezes every winter and thaws every summer (called either the "active layer" or "seasonal frost")”. Permafrost can be further classified into the following five types:

- *“Cold permafrost* — Remains below 30°F, and which may be as low as 10° F as on the North Slope; tolerates introduction of considerable heat without thawing.
- *Ice-rich* — 20% to 50% visible ice.
- *Thaw-stable* — Permafrost in bedrock, in well drained, coarse-grained sediments such as glacial outwash gravel, and in many sand and gravel mixtures. Subsidence or settlement when thawed is minor, foundation remains essentially sound.
- *Thaw-unstable* — Poorly drained, fine grained soils, especially silts and clays. Such soils generally contain large amounts of ice. The result of thawing can be loss of strength, excessive settlement and soil containing so much moisture that it flows.
- *Warm permafrost* — Remains just below 32° F. The addition of very little additional heat may induce thawing.”

The North Slope and much of the western area of Alaska are in an area of continuous permafrost (Figure 3.9), the depth of which can extend to 2,230 ft. The left side of Figure 3.9 shows a profile through the continuous permafrost area during the summer months, indicating that there is an active layer that seasonally thaws and freezes. This action can lead to one of the following problems:

- *"Frost-heaving* — When the active layer freezes, ice forms, pushing the ground surface upward.
- *Frost-jacking* — When heaving occurs as described above, if a structure imbedded in the ground is not properly anchored to resist such movement, the structure will be forced upward along with the ground surface. In most cases, the structure does not return to its original position when the active layer thaws during the following summer. The net upward movement is called "jacking." This phenomenon can occur whenever there is seasonal freezing and thawing of the active layer, and is not limited to permafrost areas.
- *Thaw settlement* — Structures founded on "thaw-unstable" permafrost may settle if the large amounts of ice in the thaw-unstable permafrost are melted. Melting is typically caused by heat from the structure or changes to the natural thermal conditions."

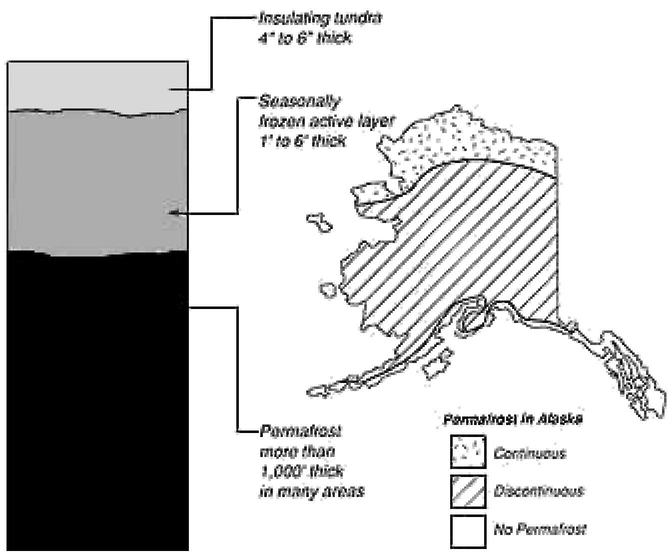

Figure 3.9: Locations of Permafrost Areas Within Alaska (from Alyeska web site)

3.4.2 Frost Heave Problems for Pipelines

Problems associated with frost heave or frost-jacking require seasonal freezing of the soil beneath the pipeline. As the Liberty Pipeline will be operating at maximum and average inlet temperatures of 150° and 135°F, respectively, frost is not expected to form beneath the line after it becomes operational unless shut down for an extended period of time. In the first season following construction, it is likely that there will be some frost heave in the near-shore and overland sections of the line. The magnitude of the frost-jacking phenomenon is illustrated by frost heave predictions completed for the Norman Wells line (Nixon et al, 1984) (that was also 12.75 inches in diameter) which were as great as 3.8 in., after the second or third year of operation. The Norman Wells line experiences an active permafrost layer in close proximity to the pipe. Therefore, it sees annual freeze and thaw cycles that promote frost heave. Frost heave displacements of the Liberty Pipeline are expected to be less than 3.8 in. before it goes into operation as the elevated pipeline temperature (compared to the Norman Wells line) will prevent ground freezing in the vicinity of the pipe.

The predictions of thaw bulb depth are based on concepts developed during the design of the Norman Wells pipeline and have been confirmed through regular monitoring programs. The Norman Wells line provided additional challenges because: (a) the oil was chilled to just below 32°F at the inlet to prevent thaw bulb formation and (b) the Norman Wells line passes through regions of discontinuous permafrost. At the design stage, Nixon, 1984 predicted thaw bulb depths along the Norman Wells line of 0.7 to 0.8 m in mineral soils and 1.2 m in organic soils. These predictions were confirmed by the field monitoring done as the maximum settlements observed after 12 years of operation did not exceed 1 m (AGRA, 1999). This shows that the Nixon, 1999 analysis is a reliable method for determining thaw settlement. Therefore FTL believes that the Nixon, 1999 analysis will accurately represent the conditions that would develop along the Liberty Pipeline.

Intec, 1999 reviewed the soil investigations along the proposed Liberty right of way, and how the depth of the permafrost varies with water depth. They report that permafrost or ice-bounded soil is present close to the seabed for water depths of less than 5.5 feet; then the permafrost drops away quickly as the water depth increases. This reflects the presence of the bottomfast ice in the nearshore area, which is responsible for maintaining the permafrost in the winter months by removing heat from the sea bottom. The 5.5 ft. water depth is the approximate limit of the bottomfast ice. The significance of this process is that at water depths exceeding approximately 5.5 ft, the seawater is above freezing, which maintains the saline subsoils above their melting temperature.

Thaw settlement analyses were undertaken for the Liberty Pipeline by Nixon Geotech Ltd, 1997 based on an average pipeline temperature of 137°F, and soil temperatures ranging from 20°F at the 1-foot water depth to 25.7°F at the 4-foot depth. The predicted thaw bulb depths after 20 years of operation were 36 and 67 feet at the 1-foot and 4-foot depths, respectively.

Nixon, 1997's analysis for the Liberty Pipeline design predicts pipeline settlements of 0.1 ft at the 1-foot water depth and 0.9 ft. at the 4-foot water depth.

3.4.3 Event Probabilities

The number of failures attributable to thaw settlement obviously depends on the number of pipelines that go through areas of permafrost. As there are relatively few pipelines that are installed in such areas, the failure data is limited. The DOT database was the one source of information (Appendix E) that contained a listing for thaw settlement, and was listed at 0.5 % of the total number of failures. This number was determined on the basis of 2 failures from a total of 361 over a 5-year period.

Based on FTL's first-hand experience with the monitoring programs on the Norman Wells Pipeline (a line which runs through discontinuous permafrost in Northern Canada), there have not been any failures although there has been some pipe movement due to thaw settlement. This is due primarily to the use of internal inspection tools that are able to monitor curvature changes, i.e., thaw settlement, from which the operator can plan remedial action to remedy the situation before failure occurs. FTL expects that comparable technology would be utilised for the Liberty Pipeline to prevent failures due to thaw settlement.

It is also believed that the fact that there have been no failures on the Norman Wells line can be attributed to the pipeline designers having accounted for thaw settlement at the design stage. The Liberty design has followed the same design philosophy as the Norman Wells pipeline, and therefore a low damage rate from thaw settlement is expected.

3.4.4 Conclusions

Permafrost thaw settlement, and the development of thaw bulb, is a well known phenomenon. It has been studied sufficiently that methods are available to predict it reliably. The analysis method used by Nixon (see Intec 1999) for the Liberty Pipeline has been shown to compare well with field observations made at the Norman Wells Pipeline, and it is considered to be a reliable method for the Liberty Project.

Field surveys have been carried out along the Liberty Pipeline right-of-way with the result that soil and permafrost conditions along it are well known.

Consequently, because both the settlement process and the site-specific input data required to analyse it are well known, permafrost thaw settlement poses very little risk to the Liberty Pipeline, provided that soil displacements are taken into account at the design stage.

For this risk analysis, FTL opted to use the number quoted by Hovey and Farmer, 1993, which is 0.5 % of the total number of failures, or 0.0003 occurrences over the 20-year life of the Liberty Pipeline.

3.5 Thermal Loads

3.5.1 Controlling Factors

Thermal loads are produced because the pipeline's temperature will increase when it is in service, as a result of the warm oil being pumped through it. This will cause thermal strains in the pipeline, and has the potential to lead to an upheaval buckling failure of the pipeline. (Pipeline response and failure modes are discussed in Section 4).

Intec (1999; 2000) considered upheaval buckling resulting from thermal strains as one potential hazard, and used the following environmental inputs for their analyses:

(a) pipeline installation temperature (subsea): 30°F;
(b) pipeline operational temperature: 150°F – this errs conservatively as the average inlet operating temperature is expected to be 135°F (Intec, 1999);
(c) temperature differential: 120°F;
(d) maximum height of an imperfection in the pipeline trench: 1.5 feet.

While it is noted that the required backfill requirements (to prevent upheaval buckling) will be sensitive to the above inputs, they were taken as given for the analyses done here because they are considered to be reasonable, and FTL is not able to suggest improved or alternative values.

3.5.2 Failure Event Probabilities

The failures from thermal loads on the pipeline represent a low number of occurrences as was the case for thaw settlement (section 3.4). Hovey and Farmer, 1993, list them as 0.5 % of the total number of failures, and the Concawe 1998 results attribute 2.57 % of the failures to "landslide/subsidence". Since the Concawe data does not separate the incidents further, it is not possible to comment on the breakdown between the two causes. As with thaw subsidence, FTL has had direct experience with the Norman Wells monitoring program, and is aware that there have not been any failures from thermal loading on the pipe. There have, however, been several sites that have been moving due to upheaval buckling, but regular monitoring and remedial action have prevented any failures over its 16-year operating life. FTL expects that the regular monitoring programs for the Liberty Pipeline will likewise prevent failures due to thermal loading.

For this analysis, a failure probability of 0.0003 occurrences over the 20-year life of the Liberty Pipeline has been selected.

3.6 Operational Failures

There are many possible causes of failures that can be attributed to operator error. The two that are considered in this section, pumping against a closed valve and SCADA system failure, were chosen based on our experience where these errors have caused major pipeline leaks.

3.6.1 Pumping Against a Closed Valve

Maintenance activities on the line often require closing valves to isolate a section. The valves are either manually or remotely operated, and once the maintenance has been completed it is necessary to return the valves to their original positions before the line is restarted. Communication problems between the field crews and the control center concerning the valve status can lead to the line being restarted against a closed valve.

Remotely operated valves are sometimes configured to drive to the closed position in the event of an upset condition, such as a power failure or a loss of communication. This presents another instance where the line might unknowingly be operated against a closed valve. In fact, Alyeska reported an uncommanded closing of a mainline valve and subsequent overpressuring of their line (Alyeska web site).

Pipelines that have a marked change in elevation must be controlled so as to avoid developing a vapor column. If the line were to be restarted upstream of a vapor column while a downstream valve was closed, the operator could continue pumping without acknowledging an increase in pressure at the next downstream pressure transmitter. The operator would believe that there was a long column to squeeze before the line was fully packed. The length of time of continued pumping would be based on the experience of the operator in being able to determine the nature of the problem.

If the closed valve was just downstream of a station one would expect that the pump would be shut down on high pump case pressure or overheating of its bearings. This assumes that there has not been a loss of communication between the operator and the instrumentation along the line. One would not normally attempt to start a pump at a station that has lost communication with the control center.

These are just a few possible scenarios that could lead to the line being operated against a closed valve. They are more related to operator error either in terms of a failure to communicate field information to the line operator, or the operator not knowing the status of all of the valves in the section before starting the line.

3.6.2 SCADA System Failure

Pipelines are operated from a control center through the implementation of a Supervisory Control And Data Acquisition (SCADA) system. Line characteristics such as pressure, temperature, flow rate, and density are monitored at remote locations and this information is relayed through a Remote Terminal Unit (RTU) back to the control center.

The pipeline operator monitors the information and uses it to make changes, such as operating pumps and valves, to control the flow through the line. The same information that is utilized by the operator can be used as inputs to a Leak Detection System (LDS) which functions separately to determine if there has been a change in the parameters, indicating the possibility of a leak. The LDS alarms the operator of the condition and continues to monitor the line. If the leak indication continues, subsequent alarms are sent to aid the operator in deciding on corrective actions. The operator can then decide whether Emergency Flow Restricting Devices (EFRD) are needed to isolate the line.

The SCADA information is transmitted using one of the following: company-owned lines, commercial telephone service, radio, microwave, or satellite communication. A failure in any of the systems between the RTU and the control center will obviously affect the information that is displayed by the SCADA system. Power outages at remote stations are a frequent cause of lost communications, as are severe electrical storms. Data might not be available if the power has been disconnected at a station for maintenance purposes. The operator must have the training and experience to be able to work the line with the missing information, while still evaluating the possibility that there could be a leak or rupture. In a report on SCADA, LDS, and EFRD, Borener and Patterson, 1995 interviewed several pipeline companies regarding these systems. They found that there is a balance between the number of 'false calls' generated by the monitoring systems and the sensitivity of the alarms to (the lack of) SCADA information, as excessive alarms might cause the operator to ignore true leak warnings. Borener and Patterson observed that there was no real substitute for a well-trained operator, as they are the ones who can override the warning systems in the event of a SCADA failure, or they can shut down the line in the event of unusual SCADA information.

3.6.3 Occurrences of Human Error

All of the databases reviewed in Appendix E list a category of failures that fall under human error or operational error. They range from 2.31 % of all failures in the Concawe results to 10 % of failures in the Gulf of Mexico, with the DOT results at 6 % of the total number of incidents. This range reflects the complexities of the operations and with each database, as the greatest numbers of failures are associated with the offshore pipeline systems. The Concawe results list human error and operational errors separately, at 2.31 % and 0.72 %.

The failure occurrences attributable to operator error or equipment error will be discussed further in section 3.9.

3.7 Third Party Damage

In general, this category refers to the actions of third parties. For the Liberty Pipeline, some potential examples of third party actions include strikes by ship anchors, ship groundings, and sabotage.

3.7.1 Background

The review of pipeline failure statistics (Appendix E) has shown that third party damage and corrosion are the most frequently listed causes of pipeline failures. The data is sometimes particular to the range of products carried by the lines and their diameters and must be scrutinised to extend the results to the Liberty Pipeline. For example, statistics that show a predominance of corrosion failures might be representative of small diameter pipe such as gathering lines that are not readily piggable to determine their condition. However, the fact that third party damage is either first or second in all failure statistics shows that it remains one of the major concerns for a pipeline operator.

Third party damage is usually the result of construction activity in the vicinity of a buried line and, according to DOT statistics, ‘damage by others’ occurs over six times more often than ‘damage by operator’. It has been our experience that excavating equipment and farming activities are probably linked most often with this type of damage. In many cases of contact the equipment operator was unaware that there was a buried pipeline in the vicinity. There have also been instances of contact resulting in fatalities where the wrong line was marked in a right-of-way containing several parallel lines. Another recent instance of contact that we are aware of resulted from contact with an appurtenance welded to the top of the line. The pipe was exposed so the operator knew the depth of the line, and there was even a company employee watching the work in progress. However, the short piece of capped pipe that was struck did not appear on any company drawings. Some other cases of pipe contact occurred during drainage tile installations.

In many cases, third party damage can be avoided by notification programs such as ‘1st Call’ or ‘Call Before You Dig’, but they cannot avoid all contact. The fact that contractors working under the direction of operating companies, or even company employees themselves, have struck the pipe, shows that accidents can happen to anyone. The subcategories within the ‘outside force’ category in DOT statistics includes the following as a percentage of 10-year failures (Table 3.4):

Table 3.4: Subcategories Within the "Outside Force" Category

Subcategory	% of the 10-Year Failures
Damage by others	73
Damage by operator or its contractor	12
Natural forces	6
Other outside force	5
Ship anchor	1
Washout	1
Landslide	0.5
Subsidence	0.5
Frost heave	0.5
Fishing operations	0.5
Earthquake	0
Mudslide	0

The first two categories account for 85 % of the total failures from outside force in a 10-year period, showing the significance of third party damage.

In addition to being the most frequent type of failure, outside force also accounts for the largest spill volumes, as noted under spill statistics (Appendix E). This is attributable to the fact that outside force often results in rupture of the pipeline and product release at full line rate until the situation is under control.

3.7.2 Occurrences of Third Party Damage

This category represents the greatest single damage cause in most databases (Appendix E). The exceptions are the failure statistics that are populated primarily by small diameter gathering lines, which exhibit more corrosion failures. The failures are typically in the 30 to 40 % range of the total.

It is questionable how applicable the failure statistics would be for the Liberty Pipeline because there will be fewer chances for third party damage along its route due to the facts that: (a) the population density is low, and: (b) the line is offshore an area where the vessel traffic and tonnage is much lower than any cases represented in the databases.

In an effort to obtain the best estimates possible, failure statistics for the Norman Wells and Alyeska pipelines were reviewed in detail. Because these statistics did not allow a reliable assessment of third party activities in isolation from operational failures, these two hazards were evaluated together. This allowed the objectives of the project to be met, which is an evaluation of the total risk.

The combination of operational failures and third party activities is discussed in section 3.9.

3.8 Pinhole Leaks

3.8.1 Background

A concern with any buried structure is that at some point it could develop a small leak that could go undetected for an indefinite period of time. Leaks in this category would include those that cannot be detected by Mass Balance (MB) or Pressure Point Analysis (PPA), as they are below the detection thresholds during pipeline operation.

Onshore pipelines utilize aerial patrols and landowner visits as part of their leak detection process to identify pinhole leaks. The surveillance by air can spot pools of oil that collect on the surface, and can also identify areas of discolored vegetation that are indicative of leaking hydrocarbons. Company employees can then be dispatched to investigate discoloration of the vegetation and determine if there is a leak. Aerial patrols are typically undertaken on a weekly basis, but bad weather can ground the flights as they are undertaken at low elevations. Calls from landowners have proven to be an effective means of leak detection as hydrocarbon vapors are readily distinguishable, and the landowners along the right of way have company contact information to respond promptly to any concerns.

Another instance of expressed concern from pinhole leaks is that the leak might never reach the surface, and that it could release hydrocarbons indefinitely into the environment. If the leak were to enter into a drinking water supply it would eventually be noticeable, but the issue would remain to find the source of contamination and clean up the spill.

The most common causes of pinhole leaks include corrosion, stress corrosion cracking, and weld defects. Corrosion pits are the most frequent type of corrosion that eventually leak. Internal corrosion pits are usually found on the bottom of the pipe and are in low points on the line where water collects. The pitting on the outside of the pipe is frequently beneath polyethylene tape, as the tape shields the pipe surface from cathodic protection (CP) currents that are intended to protect the pipe. Pits can also be found on lines coated with other types of coatings but in areas that have insufficient CP. The end result in either case is a small diameter pit that eventually penetrates the pipe wall and leaks product. The hole could be enlarged by erosion due to the accelerated flow through the orifice, or by continued corrosion.

Stress corrosion cracking is a form of corrosion that develops fine cracks at the steel surface, and the cracks advance through the thickness by a combination of anodic dissolution and hydrogen embrittlement. Adjacent cracks link up to form a longer crack that continues to grow and eventually it becomes large enough to either leak or rupture.

The longitudinal welds from pipe fabrication in the mill and field girth welds are frequently associated with leaks. Defects from the pipe mill include lack of fusion on electric resistance welded pipe, centerline cracks and porosity in submerged arc welds, or weld toe cracks.

With girth welds the leaks are almost always connected to cracking that has initiated from the weld root as a result of hydrogen cracking, or has initiated from a root defect such as lack of penetration, incomplete penetration, lack of fusion, or burnthrough.

The leaks attributed to the above causes can be quite small, and in the case of a tight crack, would not leak unless the line was operating near the maximum operating pressure. At lower pressures the crack would close and the leak would stop. This often presents a problem when the line has been excavated and crews are trying to locate the source of a leak that has stopped because the pressure is not sufficient to open the crack.

For example, the leak is often observed to have come from a fine crack, which is barely noticeable, even when one knows where they are looking. The leak is a very fine spray, and does not leak unless the line is returned to near its maximum operating pressure.

Leaks of this magnitude are essentially only found by aerial or foot patrols by company employees, or notification from the public after investigating a smell of hydrocarbons.

3.8.2 Occurrences of Pinhole Leaks

The leaks that fall into this category are those that develop leaks as a result of corrosion, or those that develop leaks at tight cracks such as weld defects. The Concawe results list a total of 40% of failures to these causes, with 12% from external corrosion, 6% from internal corrosion, and 22% from material faults. The DOT statistics show a shift in the causes, with 27% from corrosion and 8% from material and weld defects, but the total of 35% is comparable to Concawe data.

The number of occurrences of pinhole leaks was determined separately for corrosion (section 5) because current pipeline coating materials and in-line inspection technology will essentially eliminate corrosion failures on the Liberty Pipeline, compared to historical results. The occurrences of pinhole leaks from material and weld defects are included under operational failures in the following section.

3.9 Combination of Third Party Activities and Operational Failures

3.9.1 Introduction

It was recognized at the outset that the failure statistics would be of limited applicability to the Liberty Pipeline for a number of reasons as discussed in Appendix E, and outlined below:

(a) the MMS database represents pipelines in the Gulf of Mexico and nearshore Pacific Ocean where vessel traffic, tonnage, complexity of operations, and the range of products transported are considerably different from the conditions expected for the Liberty Pipeline.

(b) the DOT and Concawe statistics include onshore pipelines that run through areas of much higher population densities than the planned Liberty offshore route.

(c) most of the pipelines in the onshore data have a requirement that only 10 % of the girth welds must be nondestructively examined following welding. Offshore lines require 100 % of all welds to be nondestructively examined.

(d) all databases include pipelines that are not routinely inspected with in-line tools that can detect and size anomalies such as corrosion or other pipe defects.

Nevertheless, the database review done in this project provided useful information regarding the types of failures that might be expected, and their relative frequencies of occurrence (Appendix E). This information is valuable in view of the current limited operational experience with Arctic pipelines (section 1).

3.9.2 Failure Histories for the Norman Wells and Alyeska Pipelines

Because it was apparent that the failure statistics in the various databases could not be used directly to establish failure occurrences for Liberty, failure histories were examined in detail for the Alyeska and the Norman Wells Pipelines. These two pipelines are considered to be most applicable to the Liberty Pipeline because:

(a) they are located in remote northern regions where the population density is low.

(b) they are both single-product lines, which is similar to the Liberty Pipeline.

(c) they are both modern pipelines, and have been operated in the manner that is expected for Liberty.

(d) failures and repair incidents have been reported.

(e) 100 % of the welds were inspected during construction.

Of course, there are some differences between the Liberty Pipeline, and the TAPS and Norman Wells pipelines. The differences include:

(a) the Liberty Pipeline is offshore whereas the TAPS and Norman Wells ones are land-based;

(b) the Norman Wells and TAPS pipelines have higher D/t (Pipe diameter/wall thickness) ratios than the single steel pipe design for the Liberty Pipeline, which is the only one of the four Intec designs for which this comparison can be made.

The TAPS and Norman Wells failure statistics were examined to establish failure rates for the combination of third party activities and operational failures.

Upon detailed investigation of the failure statistics (described subsequently), it was found that all of the reported failures were operational ones. For the operational failure hazard, the first difference outlined above (i.e., that the Liberty Pipeline is offshore) will not cause significant inaccuracies in applying the TAPS and Norman Wells data to Liberty.

The fact that the Liberty Pipeline has a low D/t ratio is expected to cause the TAPS and Norman Wells failure statistics to overestimate the failure rate for Liberty. This error was considered to be acceptable as:

(a) it is conservative:
(b) the other similarities described above will lead to reasonable results for Liberty, and;

(c) all of the other failure statistics (described in Appendix E) are considered to be much more inapplicable to Liberty.

3.9.2(a) Alyeska Pipeline

The Alyeska Pipeline is an NPS 48, 800-mile long line that runs through from the Alaska North Slope to the port of Valdez on the south coast of Alaska. It started operations in 1977 and transports approximately 500,000,000 bbl/year of crude oil. The incident history for the Alyeska Pipeline was obtained from their website under “Pipeline Operations”. The information includes summaries of major repairs, major crude oil leaks (i.e. > 100 bbl), and the total leak amounts, with values of 1 teaspoon or more included in the totals. This site, however, includes information only from 1977 to 1993, representing 17 years of experience. To determine if there were more recent failures, the Alaska Department of Environmental Conservation website was searched. This site includes summaries for only the last two years, but did include one leak of 1.3 bbl in 1999, bringing the total number of years of statistics to 19 for this line.

It should be noted that the following incidents were excluded from the listed failures because they are not considered applicable to the offshore portion of the Liberty Pipeline:

(a) an oil spill resulting from the grounding of the Exxon Valdez;
(b) an oil spill of 16013 bbls that occurred in 1978 due to sabotage (“bullet holes”).
(c) leaking valves in a tank farm that were responsible for releasing 3200 and 238 bbls in 1980 in two different incidents and a drain connection failure in 1981 that released 1700 bbls.
(d) Two spills due to “pipe settlement” of 1500 bbls and 4000 bbls, in 1979. These failures are related to slope movements, based on the information contained in the Alyeska website concerning the two failures in question:
    (i) June 1979 - MP 166.43 - north side Atigun Pass; hairline crack caused by buckle. Covered with 56-in. dia., 6-ft. welded split sleeve; 19 steel supports installed. Pipe reburied.

(ii) June 1979 - MP 734.16 - 1 mi. north of PS 12; hairline crack caused by buckle in pipe. Covered with 56-in. dia., 6.1-ft. welded split sleeve; 7 steel supports installed. Pipe reburied.

These two pipe settlement incidents were considered to be caused by pipe movement down a steep slope, and not thaw settlement. This conclusion is based on both occurrences being located in mountain pass regions (see the elevation drawing at the bottom of this web page http://www.alyeska-pipe.com/factbook/fact_2e.html).

3.9.2(b) Norman Wells Pipeline

This is an NPS 12, 540-mile long pipeline that runs through discontinuous permafrost between Norman Wells, NWT to Zama, AB. It began operation in April 1985 and continues to deliver an average of 11,000,000 bbl/year; apart from the production facilities at Norman Wells, there are injection points in the southern NWT. There was only one incident history for the Norman Wells Pipeline that was reported to the National Energy Board over its 15 years of operation. Note that the reporting limit to the National Energy Board is 10 bbl.

3.9.2(c) Failure Summaries

The failures are summarized in Table 3.5. It can be seen that, for both pipelines, most incidents involved relatively small spill volumes, but the majority of the released oil resulted from a few large failures. As a measure of the number of occurrences related to spill size, Alyeska uses a cut-off of 100 bbl. This same criterion was used here as it was not possible to determine how many occurrences were included in the volumes less than 100 bbl. One incident was assigned per year to the category of spills less than 100 bbls, realizing that this might not be totally accurate. This is not an exact approach, but the results will not be sensitive to this assignment because the total amount released by all of the spills less than 100 bbl was only 2.7% of the total oil spilled.

The 100 bbl limit gives an indication of the numbers of failures that can be classified as either a rupture or as a leak (seepage). This limit was also used to provide background information regarding the consequences for each type of failure; the average spill volumes for spills greater than and less than 100 bbls were 1860 and 24.6 bbls, respectively (Table 3.6). It should be noted that these consequence values were not used for the risk calculations ; failure consequences specific to the Liberty Pipeline were calculated separately (section 7).

3.9.3 Results

The information from the combination of these two pipelines was used to estimate the expected numbers of occurrences for the Liberty Pipeline. The results from the Norman Wells and Alyeska pipelines were scaled to Liberty based on the numbers of line-miles and the years of operations, as this exposure index has been used by others (e.g., Hovey and Farmer, 1992). The total pipeline mile-years are:

(a) Alyeska – 19 years x 800 miles, giving a total of 15,200
(b) Norman Wells – 15 years x 540 miles, giving a total of 12,600.

The combination of the Alyeska and Norman Wells Pipelines gives a total of 27,800 pipeline mile-years of operation.

The total mile-years for the Liberty Pipeline is 122 (i.e., 6.12 miles by 20 years).

Simple scaling to the Liberty Pipeline indicates that the number of failures expected due to the combination of operational failures and third party activities over the 20-year life of the Liberty Pipeline will be as follows:

(a) No. of spills greater than 100 bbls (termed major incidents) : 0.01316
(b) No. of spills less than 100 bbls (termed minor incidents) : 0.05705

Table 3.5: Failure History Summary for the Alyeska Pipeline and the Norman Wells Pipeline

Year	Operator	Volume, bbl	Cause
1977	Alyeska	300	Explosion
1977	Alyeska	1800	Construction Damage
1982	Alyeska	39	unspecified cause
1983	Alyeska	4	unspecified cause
1984	Alyeska	81	unspecified cause
1985	Alyeska	27	unspecified cause
1986	Alyeska	40	damaged tee
1987	Alyeska	4	unspecified cause
1988	Alyeska	16	unspecified cause
1989	Alyeska	1700	hull crack
1990	Alyeska	6	unspecified cause
1991	Alyeska	11	unspecified cause
1992	Alyeska	19	unspecified cause
1992	Norman Wells	62.9	Girth Weld Crack
1993	Alyeska	98	unspecified cause
1999	Alyeska	1.3	unspecified cause

Table 3.6: Risk Determination Summary

Spill Volume Category	No. of Failure Occurrences for Alyeska & Norman Wells	Alyeska & Norman Wells Event Failure Rate (no./ mile/ year)	Projected No. of Operational & 3rd Party Failures for the Liberty Pipeline over its 6.12 mile length and 20 life	Average Consequence of Spills (bbl)
> 100 bbl	3	0.0001079	0.01316	1860
< 100 bbl	13	0.0004676	0.05705	24.6

The risks that are included in Table 3.6 are those that would be attributable to the expected combination of pipe and weld defects, third party actions, and operational failures. It was not possible to assign a consequence to each of the possible accident causes because of insufficient details in the statistics themselves.

The worst case situation for the number of failures from weld defects, third party actions, and operational failures would be to include the failures that were excluded from the summaries excluding the Exxon Valdez spill, which is clearly not related to the operation of the Alyeska pipeline. This would add 6 failures in the >100 bbl category, increasing the number of occurrences from 0.01316 to 0.03948, as the worst case failure occurrence.

4.0 PIPELINE RESPONSE AND FAILURE CRITERIA

4.1 Overview

This section outlines the techniques used to estimate the structural response and ultimate failure of pipelines subjected to the hazards described in previous sections. The effects of the initiating events were analysed by prescribing their loads or displacements on the pipeline to determine the resulting strains. The global behaviour of the pipeline to these load effects was first evaluated. Later, local extreme responses were analysed for some cases.

The relationships between the initiating events (hazards), pipeline responses and failure criteria are illustrated in Figure 4.1. As shown in Figure 4.1 different initiating events (hazards) can result in similar forms of pipeline response. The limit on pipeline response or maximum allowable value before failure is related to the pipeline material properties. Only ultimate strength, or loss of containment, failure modes are of interest in this oil spill risk investigation. Other serviceability modes of failure, including excessive ovality or deformation, either restrict oil flow or impede in-line inspection. While serviceability modes of failure reduce the utility of the line and could ultimately reduce its structural integrity (e.g., ovalised pipe more easily deforms and buckles) or increase the probability of failure for subsequent load realisations, these issues are not part of the scope of this project.

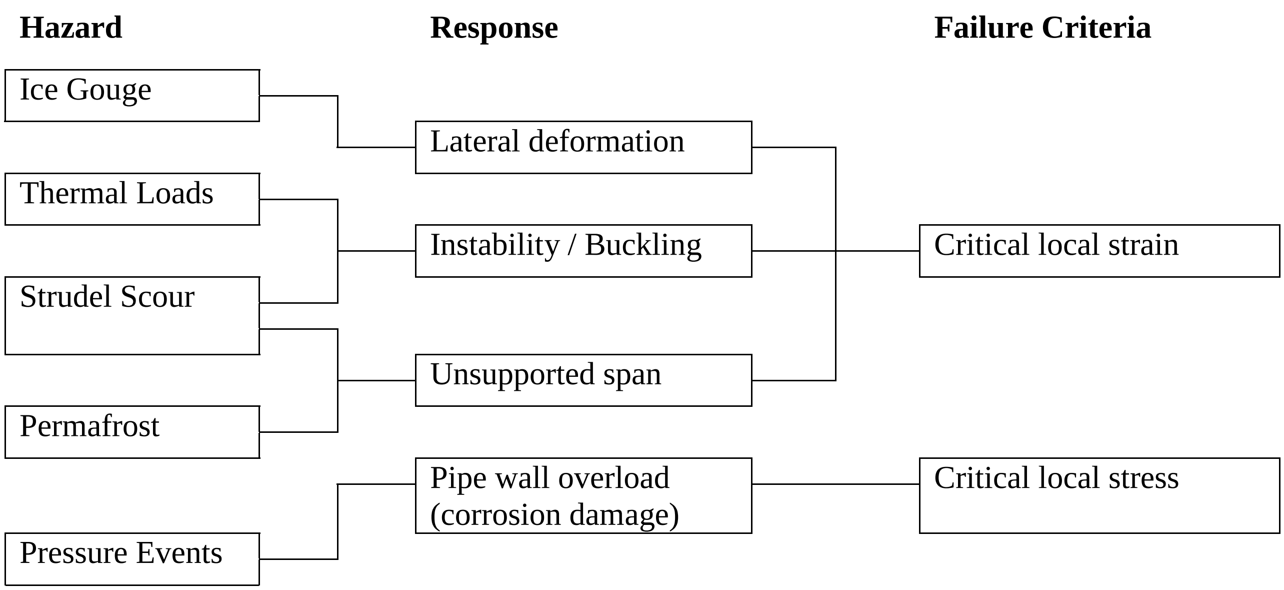

Figure 4.1: Pipeline Responses to Various Hazards

The failure criteria introduced in this section are based on the ultimate material behaviour and are in reference to failure being defined as loss of containment.

The sections which follow provide information on the structural analysis work completed to estimate the response of the pipeline designs to various hazards. The responses analysed included:

- pipe lateral deformation (see section 4.2 for single wall pipe and section 4.3 for pipe in pipe)
- upheaval buckling (see section 4.4)
- unsupported spans (see section 4.5)
- corrosion reduced pipe wall overload (see section 4.7)

These sections provide summaries of the response of the pipeline to the initiating events along with some behaviour trends which may be used to develop a better understanding of offshore arctic pipeline design issues. Additional details on the pipe response models are given in Appendices C and D.

The ability of the linepipe materials to support the resulting deformations is discussed in section 4.6 to identify a failure criteria, strain. Section 4.7 summarises the results developed in this section by relating specific structural responses and failure criteria to each initiating event (hazard).

4.2 Single Wall Pipeline Response: Lateral Deformation

In this structural analysis work, the response of a single walled pipeline segment to lateral deformations was estimated. This work included finite element analyses of a pipe element model subjected to lateral deformations resulting from ice gouge induced soil movements. This analysis work is similar to that performed by Intec (Intec 2000) with the exception that the problem was treated as a large deformation problem to account for second order load effects. The analytical results are based on a review and validation of the results obtained for this deformation scenario by Drs I. Konuk and A. Fredj of the Geological Survey of Canada (GSC). The finite element models and the analyses are described in more detail in Appendix C.

4.2.1 Analysis Approach

This project made use of a detailed investigation by Drs I. Konuk and A. Fredj of the Geological Survey of Canada (GSC) into the global behaviour of a buried pipeline that is exposed to large soil displacements, thermal expansion and internal pressure. They developed ANSYS finite element models to analyse the global response of some of the Liberty Pipeline designs to ice gouging events.

Their model is termed the GSC Model in this report. A report is not yet available that describes the GSC Model in detail although Drs I. Konuk and A. Fredj have verified that the descriptions presented here regarding the model set up, inputs, and results are accurate (Appendix G, section G6). Furthermore, during the course of this project, FTL received a copy of the GSC Model and ran it for a number of cases. These runs produced the same results as those obtained by the GSC, and consequently, FTL has confidence in the results provided by the GSC.

It should be noted that the GSC Model was developed totally independently from the models produced by Intec, 1999; 2000, and the structure and components of the two models have not been compared in detail. Consequently, although the two models are generally similar in appearance (Appendix C), they may differ with respect to some details.

The GSC Model was used in this project for a number of reasons. It provided an independent check on the results obtained by Intec, 1999; 2000. Furthermore, the GSC Model was a large displacement analysis in contrast to Intec's analyses that were all small displacement ones (in their report). This provided information to evaluate the error introduced by treating the problem as a small displacement one. This source of error was noted in the design review (Stress Engineering Services, 2000). As well, the GSC's global analyses were carried out for a wider range of input parameters than those in the Intec, 1999; 2000 reports.

4.2.2 Analysis Simplifications and Scope

It was recognised at the outset that the analyses included a number of simplifications as follows:

(a) displacement-controlled problem – both Intec, 1999; 2000 and Drs I. Konuk and Fredj analysed the interaction as a displacement-controlled problem by applying soil displacements to the springs supporting the pipe. In practice, the forces represented by these spring displacements may not be realised due to limits such as the strength of the ice keel, or the force required to uplift the ice feature. It is recognised that a displacement-controlled analysis is the only reasonable way to analyse the problem now as the current state-of-knowledge is inadequate to incorporate these effects reliably.

Furthermore, this simplification probably errs conservatively.

(b) Three-dimensional vs two-dimensional analyses - both Intec, 1999; 2000 and the GSC analysed the interaction as a 2-D one by only considering horizontal soil subgouge displacements. It is recognised that vertical soil subgouge displacements occur as well (Intec, 1999; Nixon, 1999; Appendix A).

Recently, the GSC Model has been extended to three dimensions and preliminary results show some increase in both the maximum strains and the location where it occurs (I. Kouk, personal communication). This would be a worthwhile follow-on investigation.

(c) Aftermath of an ice gouging event – the analyses done by both Intec, 1999; 2000 and the GSC consider the interaction up to the point of the peak load level. They do not consider the rebound and aftermath of the event, which would include strain relaxation and possibly reversal after the ice passes over the pipeline and/or if the pipeline is shut down.

The models used in this study could be extended to consider this. This would be another worthwhile follow-on investigation.

(d) Minimum applicable radius of curvature and gouge width – it is possible that during a gouging event considering pipes buried relatively close to the sea bed surface, the minimum radius of curvature would be small enough to cause a buckle or wrinkle, especially for a narrow gouge. For some of the high strain cases, the curvature at the tip of the gouge is about 10°/m, which is sufficient to cause a wrinkle.

The development of a wrinkle would have a very significant effect because this would produce an order-of-magnitude drop in stiffness, which would lead to larger strains at the buckle and larger pipe displacements (I. Konuk, personal communication).

This would be another worthwhile follow-on investigation.

Despite these limitations, useful information was obtained from the GSC investigation. Since the response of the heated oil pipeline is highly non-linear, a variety of sensitivity studies were completed to investigate the following issues:

(a) to compare the results obtained using small deformation theory with large displacement theory. This was considered to be important because the ice gouging process can generate large soil, and possibly pipe, displacements [section 4.2.3 (a) and (b)];

(b) the effect of temperature change magnitude (which was defined as: operating - installation temperature in the preliminary design study (Intec 2000)) [section 4.2.3(c)];

(c) the relationship between soil displacement and pipe behaviour for various gouge widths [section 4.2.3(d)]; and

(d) the relationship between pipe geometry and lateral displacement for a given subgouge soil displacement [section 4.2.3(e)].

Three base cases were used (Table 4.1). These base cases represent single wall pipe representations of each pipeline configuration. A listing of all of the analysis cases considered is presented in Table C.2 of Appendix C.

Table 4.1: Single Wall Pipeline Analysis Base Cases

Pipe Size (in) (OD x Wall Thickness) & Label	Δ Temp (°F)	Internal Pressure (psi)	Gouge Width (ft)	Gouge Depth (ft)	Depth Below Keel Bottom (ft)	Peak[1] Soil Displ. (ft)
12.75 x 0.688 (SP[3])	120	1415	18	3	1	3.53
16 x 0.844 (P-P1[3])	120	1415	18	3	1	3.53
16 x 0.5 (P-P2[3])	120	1415	18	3	1	3.53

Notes:
1. The peak soil displacement is the horizontal soil displacement below the centre of the keel at the indicated depth below the keel bottom (of 1 foot). This was calculated as described in Appendix A using the subgouge displacement algorithms developed for clay.
2. Eighteen (18) feet is the average gouge width (Section 3 and Appendix A).
3. The pipe cases correspond to the Intec, 1999 ; 2000 concept designs as follows:
   (a) SP - Single P – this is the single steel pipe design (Section 1)
   (b) P-P1 -Steel P-P 1 – this is the outer pipe of the steel pipe-in-pipe design produced by Intec, 1999 (Section 1 and Figure 1.1).
   (c) P-P2 - Steel P-P 2 – this is the outer pipe of the steel pipe-in-pipe design produced by Intec, 2000 (Section 1 and Table 1.2).

4.2.3 Results

The results obtained from the GSC investigation, summarised in the sections which follow, illustrate the trends described in the previous section.

4.2.3(a) Pipe Lateral Displacements for Large Vs Small Displacement Analyses

Table 4.2 compares small and large displacement analysis results for the “Single Pipe” case (which has a 12.75 in outside diameter, and a 0.668 inch wall thickness) and is exposed to: 1415 psi internal pressure; a 120°F temperature increase; and soil displacements resulting from different gouge depths and widths.

The shape of the displaced pipeline will be controlled by the combined effects of the pipeline’s characteristic length, and the soil displacement field. For small gouge widths, the pipeline’s characteristics will govern as the pipeline will be unable to “respond” and follow the subgouge displacement field.

This offers a means for potentially limiting the strains exerted on a pipeline during an ice gouging event. A design with a long characteristic length (i.e., large rigidity) would be attenuated and not follow the subgouge displacement field to the same extent as one with a short characteristic length. As will be shown subsequently, the results indicate that the characteristic lengths of the current designs are relatively close to the gouge widths that will occur. Consequently, further optimisation might be possible although, of course, this would have to be carried out in the context of all the other factors that must be considered in developing an optimum solution. This has not been considered further because this is beyond the scope of this project.

For wide gouges, the soil displacements are large enough that they control the shape of the pipe.

In these cases, the peak lateral pipe displacements for the small and large displacement cases are similar (see rows 1,2 and 5 of Table 4.2). For narrow gouges, (rows 3 and 4 of Table 4.2), the peak lateral pipe displacement was much more for the large displacement analysis case.

4.2.3(b) Axial Displacements and Strains for Large Vs Small Displacements

The trends identified above (with respect to the results from large vs small displacement analyses) are not observed for the pipe axial displacements or strains. For all gouge widths analysed, significantly larger axial displacements and maximum strains (tensile) were given by the large displacement analyses (Table 4.2). The peak compressive strains (considered to be negative) predicted by the large displacement analyses were less than those from the small displacement analyses.

Furthermore, a close review of the data indicated a number of inconsistencies in the small displacement analysis results. Consequently, it is believed that large deformation analyses are necessary to investigate the ice gouging lateral displacement problem.

Table 4.2: Comparison of Single Wall Pipeline Large and Small Displacement Finite Element Results (results taken from GSC)

Pipe[2] Config'n	Gouge		Pipe Cover [ft]	Small Displacement Analyses					Large Displacement Analyses				
	Wid [ft]	Depth [ft]		Pipe Displ. [m]		Strain [%]			Pipe Displ. [m]		Strain [%]		
						Axial		Equiv[1]			Axial		Equiv[1]
				Lateral	Axial	Max	Min		Lateral	Axial	Max	Min	
SP	30	6	7	2.13	0.03	1.81	-4.32	6.68	2.07	0.23	2.51	-2.72	4.25
SP	30	3	4	1.36	0.023	0.70	-2.54	3.97	1.59	0.17	2.81	-3.73	5.78
SP	18	3	4	0.29	0.003	0.24	-0.64	1.07	1.13	0.12	3.61	-5.44	8.386
SP	25	3	4	0.92	0.015	0.56	-1.97	3.11	1.45	0.16	3.56	-4.82	7.44
SP	50	3	4	1.82	0.024	0.46	-1.37	2.30	1.84	0.21	1.69	-2.04	3.32

Notes:

1. The equivalent strain is the accumulated equivalent plastic strain or the total accumulated Von Mises plastic strain. It does not include the small contribution of elastic effects but provides a measure of the total plastic deformation.
2. The pipe configurations are defined in the notes to Table 4.1
3. The internal pressure was 1415 psi for all runs.
4. The temperature increase was 120°F for all runs.

4.2.3(c) Effect of Temperature Increase Magnitude

The effect of the difference between pipeline construction and operating temperature was investigated by the GSC by conducting runs for three different temperature change magnitudes for the base case single wall pipe. Figure 4.2 indicates that while the ice gouge soil displacement at the pipe remains constant, the pipe displacement and maximum equivalent strains increase with the temperature change.

It is seen that:

(a) as the pipe temperature increases, the pipe deformations more closely follow the soil displacements. This extra deformation is due to the increased axial load developed by the thermal load. The deformation mechanism can be related to the buckling of a structure with a lateral load.

(b) the pipeline design could be optimised to reduce the effect of temperature and thus reduce the effects of both ice gouge-related lateral displacements, and upheaval buckling.

(c) in a pipe-in-pipe design, due to the insulating effect of the annulus, the outer pipe will be cooler than the inner pipe. This advantage of a pipe-in-pipe system can only be quantified through a thermal analysis of the pipe configuration. This is an important effect that must be considered to make a definitive comparison between a single pipe and a steel pipe-in-pipe design. An allowance was made for this variation in temperature in the analyses (described subsequently).

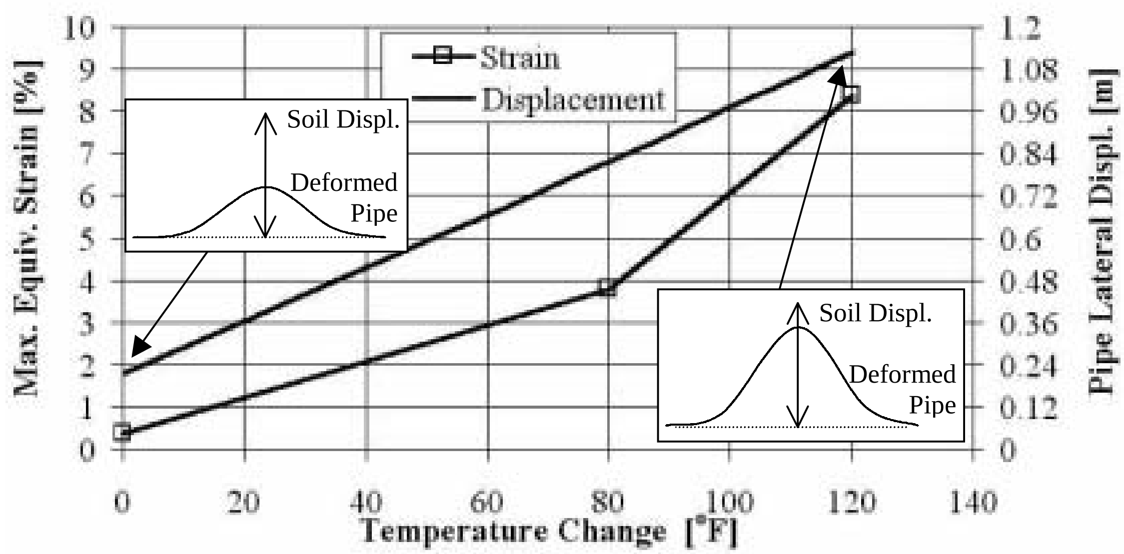

Figure 4.2: Effect of Temperature on Ice Gouge Induced Single Wall Pipeline Deformations

<u>Notes to Figure 4.2</u>:
1. Pipe configuration – SP – single steel pipe – see Table 4.1
2. The internal pressure was 1415 psi for all runs.
3. The soil displacements in Table 4.1 were applied for each run.

4.2.3(d) Effect of Soil Displacement Magnitudes

This was analysed by Konuk and Fredj of the GSC by applying subgouge displacement fields corresponding to various gouge depths and widths to the model.

The results of these analyses are summarised in Figure 4.3 for 18 and 30 ft wide gouges. It is noted that while the pipe lateral displacements continue to increase, the equivalent strains do not.

This suggests that there is a critical soil displacement (that is dependent on gouge width), for each pipe/load combination, which will result in the maximum equivalent plastic strain. This corresponds to a reduction in peak curvature, (i.e., a broader deformed pipe shape).

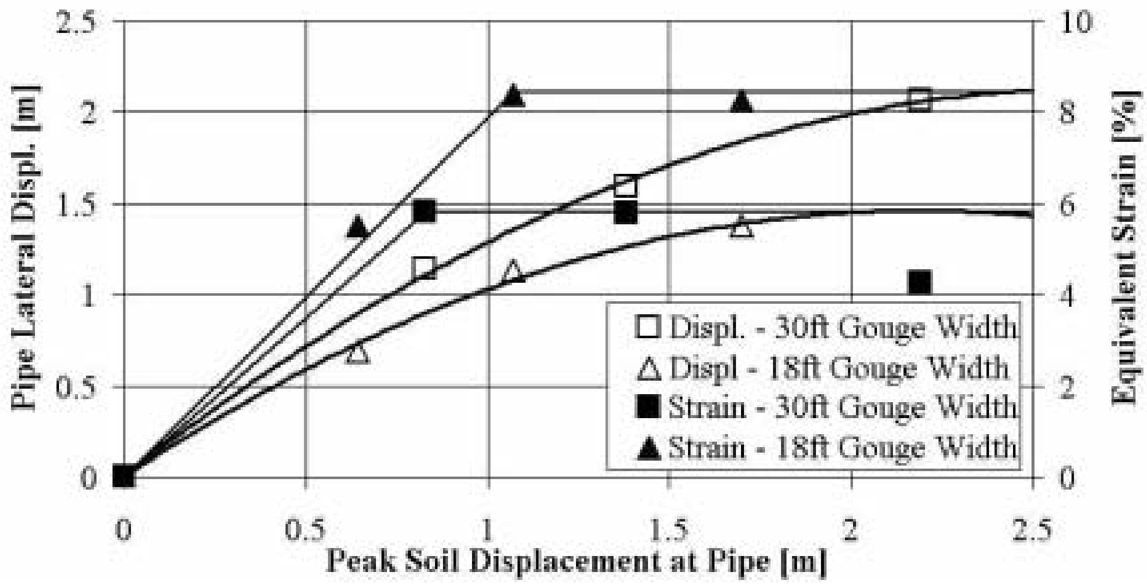

Figure 4.3: Effect of Ice Gouge Induced Soil Displacements on Single Wall Pipelines

<u>Notes to Figure 4.3</u>:
1. Pipe configuration – SP – single steel pipe – see Table 4.1
2. The internal pressure was 1415 psi for all runs.
3. The temperature increase was 120°F for all runs.

The information in Figure 4.3 was used in the risk analysis to relate ice gouge characteristics to single wall pipe equivalent strains. The lines shown in the figure represent lateral displacement bi-linear strain relationships that were fitted to the results. With a greater scope of pipe deformation analysis these bi-linear trends would likely be smooth functions. The resulting equivalent plastic strain regression equations and coefficients are listed in equation 4.1 and Table 4.3 below.

$$\text{Equivalent Plastic Strain (\%)} = \begin{cases} A \cdot D & [\text{when } D \le C] \\ B & [\text{when } D > C] \end{cases} \quad [4.1]$$

where: D = the horizontal soil displacement at the keel centre at the pipe, in meters

Table 4.3: Regressed Soil Displacement and Equivalent Strain Relationship for Single Wall Pipelines

Gouge Width (ft)	Constants for equation 4.1		
	A	B	C
18	7.879	8.446	1.072
30	6.98879	5.8	0.8299

Note:
1. Pipe configuration: SP (single steel pipe case – section 1 ; Table 4.1)

4.2.3(e) Effect of Pipe Diameter and Wall Thickness

The effect of pipe geometry on outer pipe behaviour was explored by modelling the three different outer pipe base case sizes (Table 4.1). The results of this analysis are shown in Table 4.4. The axial pipe displacement is inversely related to the pipe area as one would expect for an axially loaded structure. It is also noted that the lateral displacement is not directly related to the bending stiffness, using the moment of inertia of the pipe section as an index, but rather the lateral displacements are inversely proportional to the pipe's radius of gyration as would be expected in a buckling problem.

These results indicate that the section properties that control the pipe behaviour are the cross-sectional area for axial pipe displacements, and the radius of gyration for lateral displacements. This may be used to help develop structurally optimal pipeline configurations to resist lateral deformations, although this is beyond the scope of the current project.

Table 4.4: Effect of Single Wall Pipeline Geometry on Deformation

Pipe Size (in) & Label (OD x Wall Thickness)	Area [in^2]	Moment of Inertia [in^4]	Radius of Gyration [in]	Pipe Displacement [m]		Equivalent Strain [%]
				Lateral	Axial	
12.75 x 0.688 ; SP	26.1	475.7	4.3	1.128	0.115	8.386
16 x 0.844 ; P-P1	40.2	1157.4	5.4	1.083	0.095	8.290
16 x 0.500 ; P-P2	24.3	731.9	5.5	1.073	0.104	10.000

Notes:
1. Soil displacements were applied in each case as defined in Table 4.1.
2. The internal pressure was 1415 psi for each run.
3. The temperature increase was 120°F for each run.

4.3 Structural Behaviour of a Pipe-in-Pipe Pipeline Configuration

4.3.1 Background: Analysis Objective and Approach

Intec, 1999; 2000 used a simplified approach in their concept design process to account for the presence of the inner pipe by analysing the steel pipe-in-pipe case as a single pipe with additional cross-sectional area. In the design review that was carried out, Stress Engineering, 2000 was in general agreement with this simplified approach as they felt that a large displacement event that caused failure to the outer pipe would fail the inner pipe as well.

However, it is important to recognise that the inner pipe will most likely not be fixed to the outer pipe (based on current practices for pipe-in-pipe designs) but rather it will be supported on internal spacers. This has three significant implications as follows:

(a) the inner pipe will sag to some extent between the spacers (due to the combined effects of the self-weight of the pipe and its contents, thermal strains, and longitudinal strains resulting from the internal pressure in the pipe). This provides a built-in "relief" system as some extension of the outer pipe will be required before the inner pipe starts to "feel" significant axial strains. Preliminary investigations showed that this "displacement delay" could have a significant effect in reducing the strains exerted on the inner pipe (Appendix C) although more detailed analyses are required. This effect was conservatively neglected in the analyses used as the basis for this risk assessment.

(b) the displaced shape of the inner pipe will be affected by the ability of the inner and outer pipes to move in the axial direction relative to one another and by the characteristics (spacer separation and diameter) of the pipe spacer system. The inner pipe will tend to adopt a shape of minimum curvature. This may cause lower bending and axial strains to be exerted on the inner pipe (compared to the outer one) during large displacements (e.g., caused by ice gouging). This was investigated using finite element analyses, which are described in this section and in Appendix C.

(c) the annulus between the inner and outer pipes provides a thermal break which allows the outer pipe to remain at a lower temperature in service. This insulating effect has been used to reduce operating costs but it also has the potential to reduce the thermally induced axial loads generated by the expansion of the outer pipe thus reducing pipeline lateral deformation.

All of the above considerations offer means by which a pipe-in-pipe design may potentially provide additional structural integrity compared to a single wall pipe design. The overall purpose of these pipe-in-pipe finite element analyses was to investigate the potential significance of these considerations as they have important implications for evaluating the relative merits of single wall vs steel pipe-in-pipe designs.

The specific objectives were to investigate:

(a) the effect of pipe geometry on the behaviour of the inner pipe [Section 4.3.3],

(b) the local behaviour of the pipe-in-pipe structural system which was not considered fully in the concept design process used by Intec, 1999; 2000 [Section 4.3.2], and;

(c) the effect of outer pipe temperature on pipeline deformations [Section 4.3.2].

4.3.2 Lateral Deformation Induced Pipe-in-Pipe Inner Pipe Strains

A range of finite element analyses were completed to develop an appreciation for the effects of interest. Additional details regarding the pipe-in-pipe finite element analyses are presented in Section C3.4 of Appendix C. These analysis results were developed by modelling the pipe lateral deformation process a large deformation finite element problem.

Table 4.5 presents some of the results generated for the pipe-in-pipe analysis. In general, the displacement and strains are lower than those observed in the single pipe analysis results, shown in the large deformation results of Table 4.2, primarily due to the reduction in cross-sectional area which is subjected to the thermal load. In the pipe in pipe analyses the ratio of pipe stiffness to axial load is significantly increase due to the differential thermal load applied to the inner and outer pipes (e.g., 50^{o}F outer pipe vs. 120^{o}F inner pipe). If it is assumed that the inner and outer pipe experience the same thermal load, the pipe deformations are increased significantly. Since the temperature differentials for the inner and outer pipes have a significant effect on integrity of the pipeline this area should be investigated in more detail using a heat flow analysis. The heat flow analysis was not completed in this project.

Table 4.5: Local Detailed Finite Element Pipe-in-Pipe Analysis Results

Pipe Con Fig[2]	Case [4]	Gouge		Cover Depth (ft)	Temp. Change (°F)	Max. Equiv. Plastic Strain (%)		Max. Bending Strain (%)		Spacer Separ'n (ft)	Center[1] Relative To Spacers
		Wid (ft)	Depth (ft)			Outer Pipe	Inner Pipe	Outer Pipe	Inner Pipe		
P-P1	2	18	3	4	120	0.1	0.1	0.2	0.12	20	Between
P-P2	3	18	3	4	120	0.55	0.32	0.65	0.29	20	Between
P-P1	9	18	6	7	120	0.24	0.23	0.32	0.22	20	Between
P-P1	11	18	1.6	7	120	0.05	0.06	0.15	0.09	20	Between
P-P1	13	30	3	4	120	24.5	22.0	4.2	3.5	20	Between
P-P1	2-10	18	3	4	120	0.09	0.14	0.19	0.15	10	Between
P-P1	2-11	18	3	4	120	0.1	0.1	0.2	0.12	40	Between
P-P1	2-12	18	3	4	120	0.09	0.16	0.19	0.16	20	At Spacer

Notes:

1. "Between" indicates that the center of the gouge track, and the point of maximum deflection (for narrow gouges) was located at mid-span between two spacers. "At spacer" signifies that the center of the gouge track was located at the spacer.
2. The pipe configurations were defined as follows. P-P1 and P-P2 correspond to the pipe-in-pipe designs produced by Intec,1999 and Intec, 2000, respectively (section 1).

Pipe Configuration	Outer Pipe		Inner Pipe	
	Outside Diameter (in)	Wall Thickness (in)	Outside Diameter (in)	Wall Thickness (in)
P-P1	16.0	0.844	12.75	0.50
P-P2	16.0	0.50	12.75	0.688

3. The internal pressure was 1415 psi for all runs.
4. The following conditions were applied in the analyses

Case No	Δ Temp [°F]	Depth Below keel (ft)	Peak Soil Displ[2]. [ft]	Comment
2, 2-10, 2-11, 2-12	120 inner / 50 outer	1	3.53	Base Case
3	120 inner / 50 outer	1	3.53	Base Case
9	120 inner / 50 outer	1	5.58	Larger gouge depth; same width
11	120 inner / 50 outer	1	2.12	smaller gouge depth; same width
13	120 inner / 50 outer	1	4.56	same gouge depth; larger width

4.3.3 Effect of Spacer Separation and Loading Location

Intec, 1999; 2000's pipe-in-pipe designs were only developed to the concept stage, and thus they do not specify the spacer separation.

The effect of spacer separation was investigated in a preliminary manner by considering spacer separations from 10 to 40 feet. It is recognised that these spacings are more than current practices for pipe-in-pipe design, which are typically less than 3 feet. However, a wider range was investigated because most existing pipe-in-pipe designs have been developed with the primary purpose of providing increased efficiency (by insulating the carrier pipe) rather than considering carrier pipe integrity or secondary containment. If secondary containment were the primary objective, a designer would seek to optimise the design for this objective in the context significantly different design constraints.

As shown in Figure 4.4, the inner pipe strain is quite dependent on the spacer separation. The bending strain and the total equivalent plastic strain both decrease greatly as the spacer separation is increased from 10 to 20 feet, however, further increases in the spacer separation (to 40 feet) produced relatively little change in strain (Figure 4.4). This suggests that there may be an optimum spacing (which of course would be specific to each design) although further analyses are required to define this.

The location of the gouge track center had relatively little effect on the strains (compare cases 212 and 2 in Table 4.5), probably because the spacer separation is about the same size as the width of the gouge being considered and because of the small inter pipe annulus size which does not allow the inner pipe to freely deflect in the lateral direction.

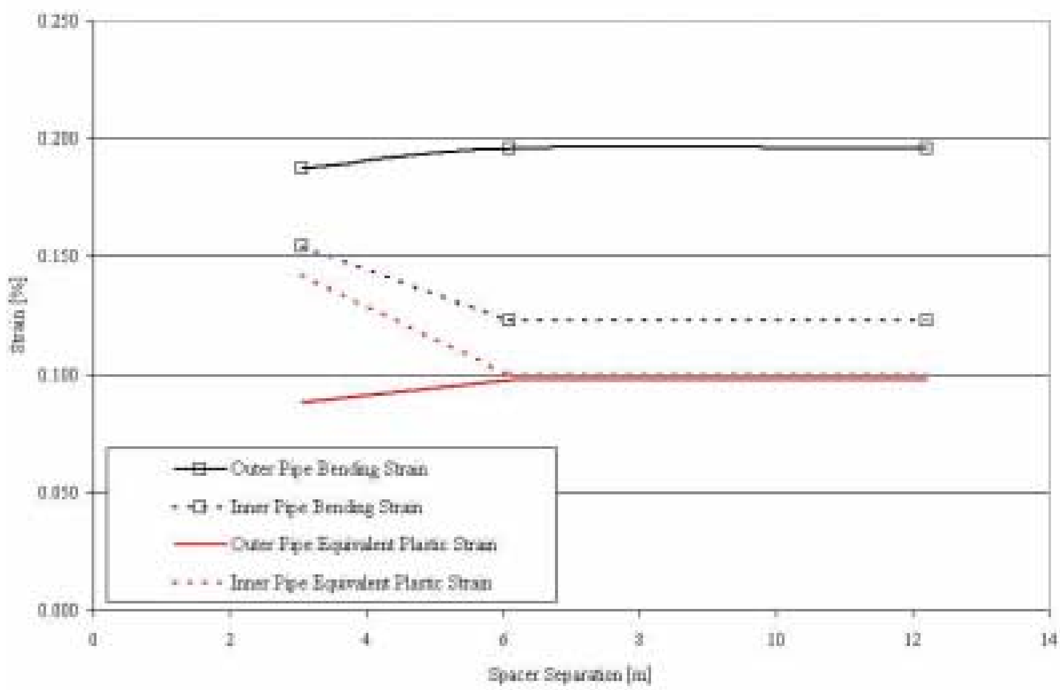

Figure 4.4: Effect of Spacer Separation on Strain Distribution

Notes:
1. Soil displacements were applied in each case as defined in Table 4.1.
2. The internal pressure was 1415 psi for each run.
3. The temperature increase was 50°F for each run.
4. Pipe-in-Pipe Configuration: P-P1
5. Location of center of gouge track: at mid-span between two spacers.

4.3.4 Concluding Remarks

In general, the analyses indicate that the inner pipe bending and Von Mises strains will be 45-84% and 58-100% of those on the outer pipe respectively, using the current configurations. It is noted that the gap between the inner and outer pipes (i.e., a total of 0.8 or 1.125 inches for the Intec, 1999 and Intec, 2000 designs respectively) is relatively small, which limits the potential for inner pipe strain reduction. This gap is less than most existing pipe-in-pipe configurations (Table C.1 in Appendix C). It is noted that the smaller the gap between the inner and outer pipes, the more the pipe-in-pipe system acts as if the inner pipe is continuously restrained from deflection by the outer pipe as would be the case with a rigid insulation filling the inter pipe annulus.

The results obtained in the sensitivity study indicate that:

(a) the configuration of the pipe-in-pipe system can greatly affect the resulting behaviour of the inner and outer pipes. It is possible to develop designs (e.g., based on the spacer spacing and the gap as well, although this was not varied greatly here) in which the inner pipe will experience significantly less strain than the outer one. While beyond the scope of this project, the pipe-in-pipe configuration could be optimised to improve its performance relative to that of the single pipe configuration.

(b) it is not necessarily true that an ice gouging event that would fail the outer pipe would also fail the inner one. Evaluations must be done on a case-by-case basis.

(c) For the pipe-in-pipe configurations and ice gouge lateral displacements investigated, the strains developed in the carrier pipes in the single and pipe-in-pipe configurations differ by more than a factor of 0.7 (compare large deformation results in Tables 4.2 and 4.5). The differenCe in carrier pipe strains is a result of the assumed pipe-in-pipe configuration and thermal loading which cause different pipeline axial loads. A conservative bound on the difference between the pipe-in-pipe behaviour and the single pipe behaviour has been chosen since:

- the actual temperature differential (120°, 80° or 50°F) for the outer pipe is not known and should be determined by a heat flow analysis once the final pipe configuration and insulation characteristics are known; and
- the geometric configuration of the pipe-in-pipe configuration was assumed in this analysis.

- the effect of the relative position of the peak pipe curvature the pipe-in-pipe spacer has not been fully explored.

For this reason, the carrier pipe strains in a pipe-in-pipe system will be taken as 70% of the peak strains estimated using equation 4.1.

4.4 Upheaval Buckling

4.4.1 Analysis Approach

Closed-form analyses (using the approach in Palmer et al, 1990) and finite element analyses were both carried out to investigate upheaval buckling. Details regarding these analyses are given in Appendix D while summary information and trends are provided in this section.

4.4.2 Analysis Scope and Results

4.4.2(a) Evaluation of Whether Upheaval Buckling Will Occur

Palmer et al, 1990's analytical upheaval buckling model was used to evaluate the depth of cover required to prevent upheaval buckling. The soil cover was presumed to consist of the following, based on Intec, 1999:

(a) 1 foot of gravel with the properties given in Intec, 1999, overlying the pipe; and
(b) native soil with the properties given in Intec, 1999, on top of the gravel.

As expected, the required cover depth increases with the imperfection height (Figure 4.5), and the results obtained are in general agreement with those determined by Intec, 1999.

The length of the imperfection implicit in the analyses was also calculated as this was an input to the finite element analyses that were performed. The imperfection length ranges from about 50 to 260 feet for the ranges of imperfection heights considered (Figure 4.5). These results indicate that for an imperfection height of 18 inches, upheaval buckling will occur when the depth of cover is less than 5 ½ feet. This corresponds to a scour depth of 1 ½ feet.

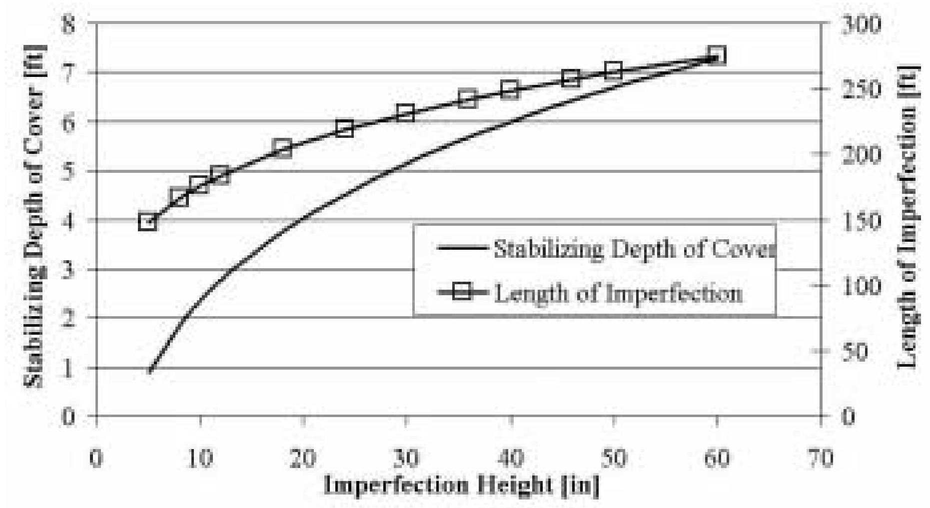

Figure 4.5: Soil Cover Required to Prevent Upheaval Buckling

Palmer et al, 1990's approach was developed to be a design tool. In this project, it was extended by conducting finite element analyses to investigate the post-buckling pipe behaviour.

4.4.2(b) Evaluation of Pipeline Strains Resulting From Upheaval Buckling

A large displacement finite element model of the pipeline was developed to consider various cover depths. However, only a single imperfection height (of 1.5 ft) was considered. This imperfection height was used because it is the one selected by Intec, 1999 as a design basis, and it is considered to be a reasonable estimate of the variability in the trench bottom. It was also noted that the initial imperfection height will not affect the buckled shape of the pipe; however, a smaller imperfection height will lower the susceptibility of the pipeline to upheaval buckling.

The results of the upheaval buckling finite element modelling are shown in Figure 4.6. These results describe the vertical displacement of the buckled pipes and the resulting equivalent plastic strain.

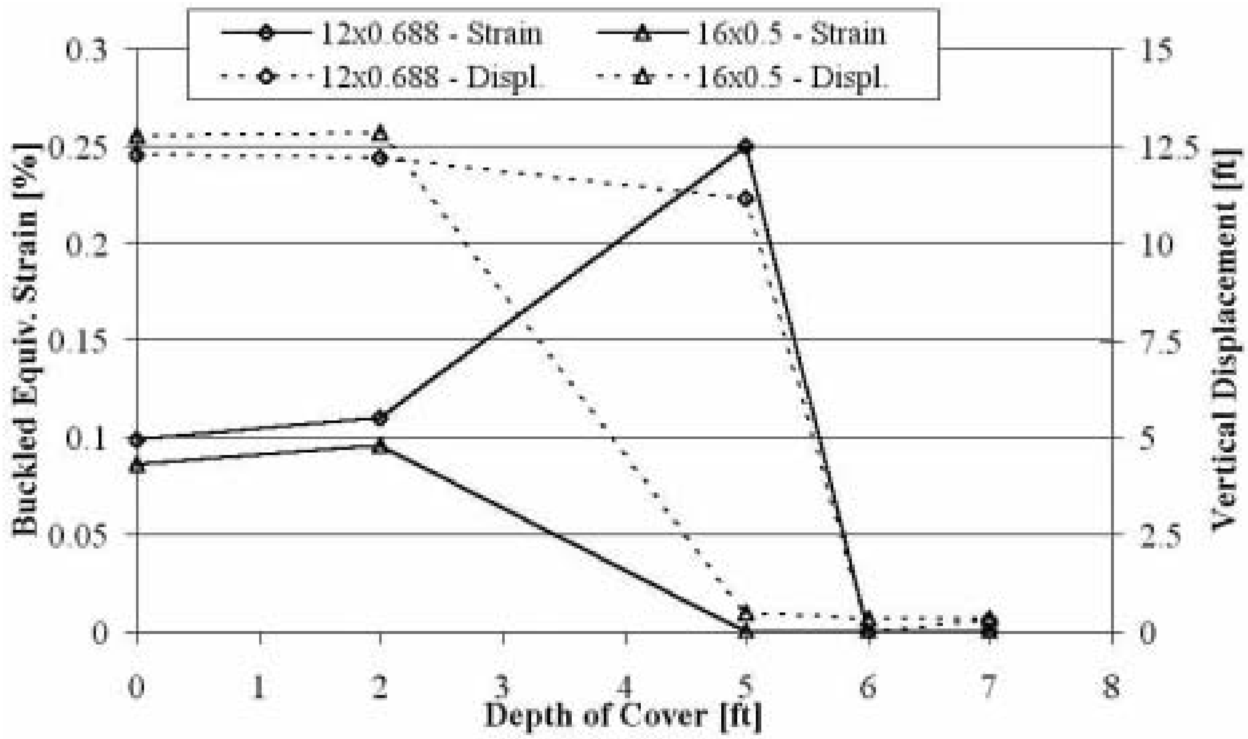

Figure 4.6: Buckled Pipe Displacements and Equivalent Strains

In the above modelling results, the pipeline loss of cover was assumed to occur uniformly over the entire length of the buckle. This assumption is conservative in terms of the onset of buckling, however, the post buckling shape of the pipeline could be affected by this assumption. A narrower area of cover loss in which bucking occurs could promote greater curvature and thus higher strains.

4.4.3 Concluding Remarks

It is noted that while large displacements are predicted, the strains are relatively low because the buckled shape has low curvature. In general, the width of the buckle is ten times as wide as it is high which produces a small pipe curvature. These results indicate that even in the most severe buckling event, the equivalent strain is less than 1%, which should not be a concern for the integrity of the pipe. Based on this finding it was decided that upheaval buckling need not be considered in additional detail since it will not result in sudden pipeline rupture.

If left unattended, through multiple pipeline shutdowns, heating and cooling events, a buckle could progress and thus reach a more significant strain level. This was not investigated or considered in this project because it is a coupled case that is likely to be rare, and also likely to be discovered with the pipeline monitoring that is intended.

Conservatively, upheaval buckling will be assumed to occur when more than 1 foot of cover is lost. The resulting strains in all cases will be assumed to be 1%.

These simplifying assumptions are made with a knowledge that upheaval buckling will not affect oil spill risk.

4.5 Unsupported Span

An unsupported span may be produced by a strudel scour that removes the soil supporting the pipe.

Based on simple calculations, the bending moments and strains associated with an unsupported span, were estimated. Details of this calculation are given in Appendix D while a summary is given in Figure 4.7. The results of this approximate analysis indicate that even under relatively severe settlements, the resulting bending strains are not high, as a bending strain in excess of 1.2% was not exceeded in the outer pipe**.** This level of strain is consistent with the strain levels observed in unsupported span events.

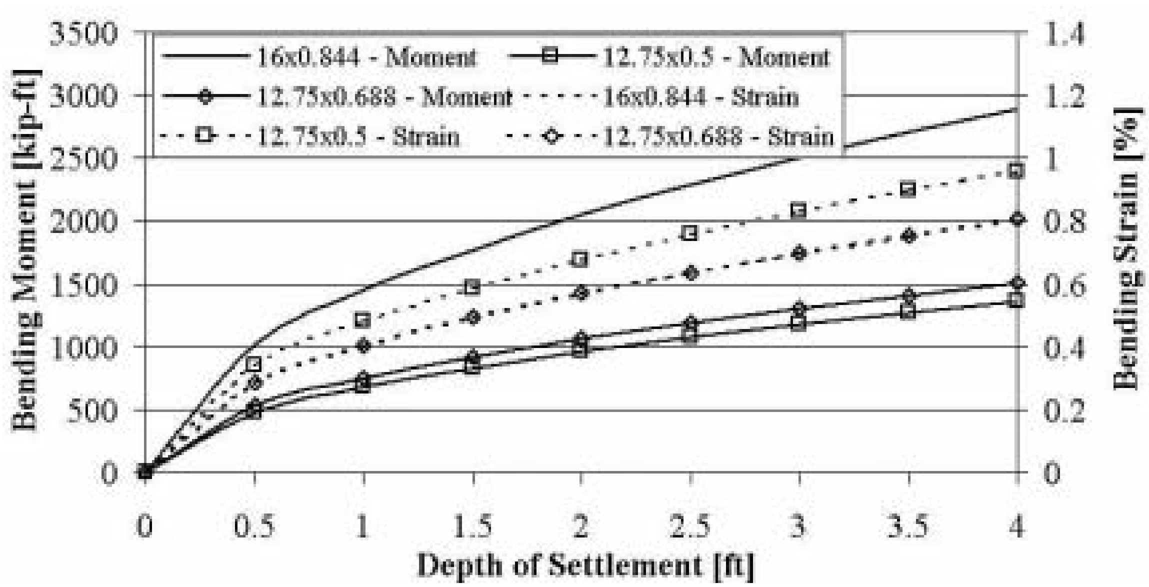

Figure 4.7: Maximum Moment and Bending Strain Due to Settlement

It is also expected that the inner pipe strains of a pipe-in-pipe system would be lower than those calculated here. The curvature reduction afforded by the spacer arrangement discussed in the lateral displacement scenario would be applicable to this situation as well.

These results indicate that unsupported spans will not lead to significant risk for the pipeline. A similar conclusion was reached in a study by BPXA (BPXA 2000). Closed-form calculations were used to estimate the maximum permissible unsupported span lengths, assuming an infinitely deep subsidence, for each pipe configuration:

- single wall steel pipeline, 165 feet
- pipe in pipe, 175 feet, and
- pipe in HDPE, 195 feet.

These calculations were completed with simple beam theory by assuming that failure occurs when the carrier pipe reaches its yield stress. These results are conservative, since reaching 72% of the yield strain (0.72 * 0.5% = 0.36% strain) represents only a small fraction of the deformation capacity of the material.

An additional analysis was performed by BPXA (BPXA 2000) to investigate in detail the effects of pressure, temperature, dead load (pipe weight), sustained load (content), and hydrodynamic loads (due to strudel scour jets). The results indicated that the single wall steel pipeline could safely span a length of 56 feet according to the maximum allowable stresses prescribed by ASME B31.4. Again, it is noted that the codified strain limit is only a fraction of the yield strain which in turn is a small fraction of the fracture strain.

No detailed calculations were carried out for the pipe-in-pipe or the pipe-in-HDPE options. However, due to increased stiffness of the pipe-in-pipe configuration, it is expected that this option could span a length greater than 56 feet (depending on the type and separation of the pipe spacers). It is also expected that the pipe-in-HDPE would be able to accommodate a span greater than 56 feet as its stiffness is at least that of the single wall steel pipeline while its submerged weight is lower.

By comparing the allowable span lengths developed by BPXA in its detailed and beam theory span lengths, assuming that most of the strains are developed by axial extension and that the failure criteria were similar, it was estimated that the strain ratios in these calculations is 2.7:1. By applying this ratio to the results shown in Figure 4.7, the strains developed by subsidence events for each carrier pipe geometry may be conservatively estimated by the linear equations related to the carrier pipe dimensions as shown below.

[for 12.75 x 0.5 pipe]	Bending Strain = 2.7*(0.158 Depth + 0.346)	[4.2]
[for 12.75 x 0.688 pipe]	Bending Strain = 2.7*(0.132 Depth + 0.289)	

4.5.1 Concluding Remarks

Based on the results of the analyses completed and the information collected, it has been concluded that the magnitudes of the strudel scour events required to promote pipeline failure are consistent with very rare events. Therefore detailed investigations of these pipeline behaviours were not pursued and a conservative failure criteria was formulated.

The pipeline deformation resulting from a strudel scour is a function of both the depth and length over which the pipe displaces. In the risk analysis, the criteria for the formation of a stable crack will require that the unsupported span be in excess of 150ft. The strain developed for spans in excess of 56 feet will be estimated according to equation 4.2

4.6 Failure Criteria: Leakage Through Stable Cracks or Rupture

Two types of failure criteria need to be established for this risk analysis, as follows:

(a) the conditions necessary to either cause stable cracks that will leak; or cracks that will be unstable and lead to rupture. This is considered in section 4.6.

(b) the growth of corrosion pits to the point where leakage occurs. This is considered in section 4.7.

4.6.1 Materials Used and Their Properties

4.6.1(a) Materials Specified for the Liberty Pipeline

Ultimate strength limits in this risk assessment must be defined with respect to loss of fluid containment integrity. Intec, 1999; 2000’s concept designs were based on the use of the following materials (Table 4.6).

Table 4.6: Material Descriptions

Configuration	Outer Pipe	Inner Pipe
single steel pipe	Grade X52 Steel	None
steel pipe-in-pipe	Grade X52 Steel	Grade X52 Steel
pipe in HDPE	High Density Polyethylene (HDPE)	Grade X52 Steel
flexible pipe	Composite Flexible Pipe	None

4.6.1(b) Material Properties

Test data and product literature were reviewed to obtain information regarding the measured and minimum specified material properties (Table 4.7).

Table 4.7: Linepipe Material Properties

Material	Data Source	Yield Stress [MPa]	UTS* [MPa]	Uniform Strain [%]	Tensile Modulus* [MPa]	Thermal Expansion [10^{-6} in/in/^oF]
X52 Pipe	API Spec.	Min. 359	Min. 455	Min. 25		6.5
	Test Results[1]	470 404	590 556	39 27.6	210000 210000	
HDPE	Plexco Test Data[2] Piping Handbook[3] IPEX - PipeLine[4]		22 22	Strain Rate Dependant[5]	7585 827 3408	90 3.2

Notes:
1. Bjornoy et. al. 2000
2. Chevron 1999
3. Nayyar 1992
4. IPEX 1999
5. Temperature & strain rate dependent

Figure 4.8 presents a stress-strain plot derived from a tensile test on a X52 linepipe steel specimen. The yield point (which occurs at 0.5% total strain) is 428.8 MPa which is well below the uniform limit (the maximum load carrying capacity or strain at which necking occurs) and the ultimate tensile strength of 542 MPa. The material flow stress, is another commonly used material failure limit and it is defined as the yield stress plus 69 MPa.

High Density PolyEthylene (HDPE) is a manufactured material whose composition can be modified to alter its mechanical properties. The type of HDPE pipe used as the basis for the concept designs produced by Intec 1999; 2000 is not specified in their report. This makes it difficult to evaluate the integrity of the design. The mechanical properties of HDPE are time, temperature and load dependent. As the temperature increases and the pressure remains constant, the creep rupture strength decreases. Conversely, as the temperature decreases the strength increases. Due to the complex non-linear behaviour of the HDPE material and its relative stiffness compared to the steel pipe, its structural contribution to a pipe in pipe system was neglected in this project. However, the potential effect of the HDPE for secondary containment for small leaks was considered in the consequence model (described in section 7).

Properties for the flexible pipe used in Intec, 1999; 2000's concept designs were also not specified in their reports. This makes it difficult to evaluate the flexible pipe design definitively. For this project, it was presumed that the flexible pipe had similar strength and integrity as the single steel pipe. While this assumption allowed this project to proceed, it should be recognized that verification is necessary before the study results for the flexible pipe can be used definitively.

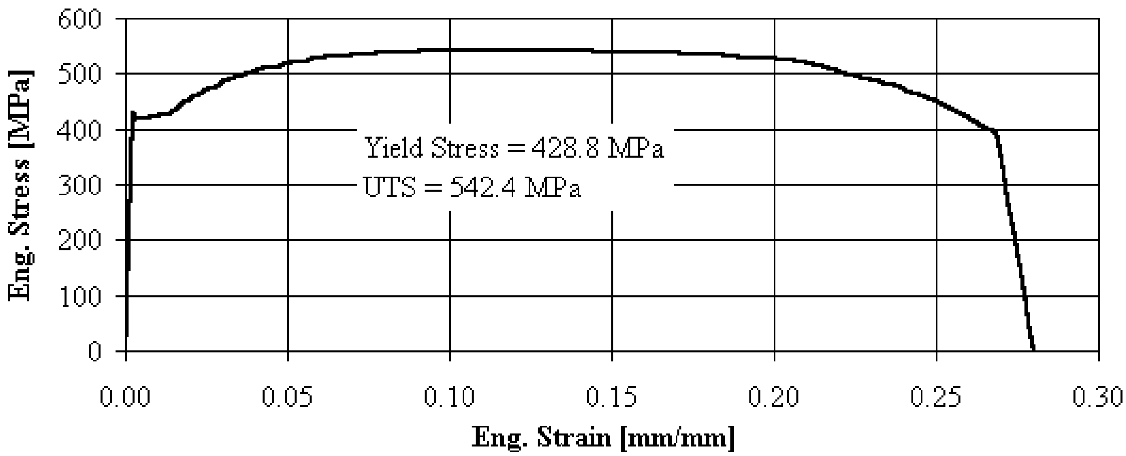

Figure 4.8: X52 Stress-Strain Behaviour

4.6.2 Traditional Design Methods

Traditional structural or pipeline design has been based on keeping stresses below the elastic limit; this uses yield as the failure criterion. Failure was precluded by applying a factor of safety (Working Stress Design, WSD) or partial safety factors (Load and Resistance Factor Design, LRFD).

While these are safe design criteria, they are very conservative ones for predicting the ultimate strength or loss of product containment for a pipeline, as these limit-states occur well above yield (Figure 4.8). However, while the ultimate tensile strength and uniform limit indicate the maximum load carrying capacity and strain at the onset of necking respectively, for a tensile specimen, they are non-conservative design limits for structural components. The stress state in a pipeline is three-dimensional which develops constraint, reducing the strain to failure. Fabrication or material inhomogeneities can also reduce the load or deformation carrying capacity of a structural system.

For example, the equivalent strains to failure in end-capped and uncapped pressurised pipes are 0.5 and 0.58 times that in a tensile specimen, respectively, where the factors “0.5” and “0.58” are the material work hardening exponents (Backofen 1972). In these cases, the material stress-strain (σ , ε , respectively) behaviour is idealised by a power function as follows:

$$\sigma = K\,\varepsilon^n \qquad [4.2]$$

where n is the material work hardening exponent.

To reduce the level of conservatism and to increase design efficiency, design codes and standards have started to adopt strain-based design criteria which more easily allow the consideration of post yield design criteria. Table 4.8 (Dinovitzer and Smith, 1998) presents a recent summary of the design strain limits used in the pipeline industry. It is noted, however, that these strain limits are for design and thus, they are implicitly conservative, especially for pipeline failure by loss of containment.

Table 4.8: Design Strain Limits

Source	**Strain Limit**
CSA Z662	No Explicit Limit (Elastic Analysis)
CSA Z662 - Sec 11[1]	2.5% Principal Strain
CSA Z662 - App. C[2]	0.53% (2.5%)
DNV [3]	0.2% (2.0%) Plastic Longitudinal Strains
BSI [4]	0.1% Plastic Equivalent Strain
GL [5]	D/t Dependent Longitudinal Strains < 1.0% or < 1.5% for controlled deformation or < 2.0% for local discontinuities
SAA	No Explicit Limit (Elastic Analysis)
API	No Explicit Limit (Elastic Analysis)

Notes:
1. Applies to installation and or infrequent loads
2. Value in brackets is a suggested maximum based on observed pipe behaviour, which may be used if it is shown that it will not promote failure or interfere with pipeline operation.
3. 0.2% residual longitudinal strains but allows 2.0% local longitudinal strains.
4. Reference zero strain level does not include any residual strains from construction, installation or pressure testing. This strain limit is strictly for operating pressures and thermal strains.
5. Allows higher longitudinal strain levels for displacement-controlled deformations and local strain concentrations.

In order to accurately determine the probability of loss of containment, failure criteria most closely predicting that limit state must be used.

It is becoming recognised that the strain to failure in a pipeline with tough base materials and weldments can be higher than the design strain limits. It has been noted that strain limits as high as 5 to 10% plastic strain could be acceptable (CSA Z662-App. C; Bai 1999). Three mechanical testing programs are described in the next section which support this statement.

4.6.3 Full-Scale Bend Test Programs

4.6.3(a) Full Scale Bend Tests on the Northstar Pipe

A recent mechanical testing program performed in support of the Northstar project (Stress Engineering 1998a; 1998b) included full-scale bend tests. The test specimens were grade X52 linepipe with a 10.75” diameter and 0.594 wall thickness. The test specimen configurations and results are summarised in Table 4.9.

The results of the Northstar full scale testing indicate that the X52 linepipe, including welds with flaws, is capable of supporting bending strains of up to 10% without leakage. Of course, these results are specific to the conditions tested and one must be careful not to generalise them. However, they are considered to be quite applicable to the Liberty Pipeline because the tests were done with pipe of the same grade and general size as will be used at Liberty; and they were pressurised to about the same level as for Liberty (for test 4). These results demonstrate the ductility of carefully designed and constructed pipelines.

Table 4.9: Northstar Full Scale Bend Tests

Test	**Specimen / Test Description**	**Synopsis of Test Results**
1	- Pipe with no weld - pipe pressurised to 500 psi	1) Deformed to 2.4% bending strain - no leakage 2) Deformed to avg. strain of 5% - no leakage
2	- Pipe with girth weld containing a 3/16 inch deep, 2 inch long embedded flaw - pipe pressurised to 500 psi with water at 30°F	1) Deformed to 1.8% strain and inspected - no flaw growth observed ; then put back into the test machine and deformed further. 2) Deformed to 3.6% strain and inspected - no flaw growth observed
3	- Pipe with girth weld with a 1 inch long, 1/8 inch deep root flaw - pipe pressurised to 500 psi with water at 30°F	1) Deformed to 3.6% strain and inspected - no flaw growth observed ; then put back into the test machine and deformed further 2) Deformed to average measured strain of 4% - no leakage
4	- Pipe with girth weld with a 1.2 inch long, 1/8 inch deep root flaw - pipe pressurised to 500 psi with water at 30°F	1) Deformed to an average measured strain of 10.6% - the test was stopped due to excessive ovality due to buckle at misaligned weld joint 2) The specimen was then pressurised to 1568 psi with water - no leakage occurred

4.6.3(b) Flexural Testing of Pipe Bends in Japan

Yoshizaki et. al., 1998 conducted flexural testing of pipe bends that were fabricated from 100, 200 and 300 mm diameter 215 MPa yield strength pipes with 5.4, 6.8 and 7.4 mm wall thicknesses, respectively. The pipes were pressurised to 14.5 psi with nitrogen. The tests were done by increasing the curvature of the pipe bends.

The tests demonstrated that the pipe bends were capable of sustaining strains in the range of 25% (measured with respect to the initial bent shape of the specimen) without leakage. A test which involved reducing the curvature (i.e., "straightening the bent pipe out") found that leakage was only observed at a strain of about 40%. It is recognised that these test results are not directly applicable to the Liberty Pipeline; the most important differences between these tests and the Liberty Pipeline include:

(a) the variation in ductility of the steel - in old steels, a lower strength steel would generally exhibit greater ductility. In steels from modern production processes (especially TMCP steels), the tensile and toughness properties are customised based on chemistry and rolling practice. Therefore, the relative ductility of the pipe elbows and the Liberty X52 pipe is uncertain.

(b) the formed pipe elbows would have reduced ductility due to the plastic deformation involved in their formation.

(c) the pipe section used for the elbows are made from thinner-walled pipe would tend to buckle more readily than the thicker-walled Liberty pipe configurations thus resulting in greater strain concentrations at the wrinkle.

Nevertheless, although these tests are for thinner wall, lower strength pipes (than will be used for the Liberty Pipeline), they demonstrate the ductility of steel linepipe.

4.6.3(c) University of Alberta

A testing program at the University of Alberta (Dorey et. al. 1999) involved eccentric compression of pressurised X52 grade pipes to develop wrinkles or buckles. Local wrinkles were formed during these tests, and the pipe experienced local strains in excess of 9% without leakage. These tests were followed up with additional testing (Das 2000) on 12.75 inch diameter (NPS12) pipes to study the behaviour of wrinkles. In these tests, local longitudinal compression and tensile strains of 15.4% and 8.1% were measured upon wrinkle formation. After wrinkle formation, the axial load was removed while keeping the pipe's internal pressure at 80% of the yield point of the material. The internal pressure created a tensile force in the pipe wall, by acting on the end plates, that was equivalent to roughly half the compressive load applied to the pipe to create the wrinkle. The tensile load created plastic strains in the wrinkle bends that were in the opposite direction to the strains that formed the wrinkles. This strain reversal, low cycle fatigue, testing was repeated until a crack formed and leakage occurred. Three or four post yield level strain reversal cycles were possible before failure occurred in these tests.

4.6.4 Rupture or Crack Formation Failure Criteria Used for This Project

The following criteria were adopted as the base case for the risk analyses done:

(a) first loading cycle of the pipeline - 10% Von Mises strain limit. This is a conservative limit as the Von Mises strain is significantly larger than the axial strain (by about 2 for the cases considered in this project).

(b) multiple load events (e.g., multiple ice gouging – section 3.2) - it is suggested that a pipe would fail in multiple load events in which a cumulative Von Mises strain of 15% is achieved. This approach recognises the finite ductility of the steel.

It should be recognised that the above values are subject to considerable uncertainty as little information is available, especially for multiple loading cycles. However, the selected criteria is conservative with respect to the collected test data since:

- often the strains reported refer to the strains at which testing was halted rather than the failure strains,
- the reported strains are uni-axial, whereas, the strain limit used in this investigation is an equivalent strain (that is practically equivalent to a Von Mises strain) which considers all of the strain components in the multi-axial stress states, and
- the sense of the calculated strains are not considered, in that compressive strains are assumed to be as damaging as tensile strains. This is done in acknowledgement of the fact that the pipe element finite element models do not consider wrinkling or buckling which can result in secondary tensile strains.

The significance of these uncertainties for this project was investigated using sensitivity analyses (section 8).

4.7 Failure Criteria: Corrosion Pit Plastic Collapse

4.7.1 Overview of the Mechanism

Blunt defects in ductile pipeline steels have been shown to fail through a mechanism of plastic flow. This phenomena occurs at maximum load in a pressurised pipe, which is a load controlled condition (i.e., the pipe begins to increase in strain while its load is held constant or diminishes). The best known example of unstable plastic flow is the formation of a neck in a typical tensile test. Beyond the point of necking, the specimen cannot carry any additional load, although it can continue to strain. In the case of blunt corrosion defects, unstable plastic flow occurs when the defect forms a large enough bulge that it begins to increase in strain and grow while the pressure is held constant. As it does so, the wall of the bulge becomes increasingly thinner until it cannot support a load and finally fails.

4.7.2 Analysis

As pressure in a thin wall tube increases beyond yielding, two opposing tendencies become significant:

(a) strain hardening - this is a material characteristic that tends to increase its load carrying capacity beyond yield.

(b) a reduction in wall thickness - this is a volumetric effect resulting from increasing strains in the circumferential and longitudinal directions. It tends to decrease the load carrying capacity of the defect.

Failure occurs when the decrease in load carrying capacity in the defect overcomes the increase in load carrying capacity due to strain hardening.

A currently accepted approach for the assessing corrosion pits, Modified B31G (Battelle 1989), is to relate the remaining area below the pit to its maximum pressure carrying capacity. It is assumed that the remaining pipe wall below the corrosion feature fails when its area projected onto a longitudinal plane is reduced to a point where the load carrying capacity reaches a "flow stress". In simplified form, the internal pressure at failure in the defect is given by the following modified B31G surface flaw failure formula:

$$P_f = \frac{2t}{D}\left(\sigma_y + 10{,}000\right)\left(\frac{1 - 0.85\frac{d}{t}}{1 - 0.85\frac{d}{t}\frac{1}{M}}\right) \qquad [4.3]$$

where:

$$M = \sqrt{1 + \frac{1.255}{2}\frac{L^2}{Dt} - \frac{0.0135}{4}\frac{L^4}{D^2t^2}} \qquad \text{for} \qquad L \le \sqrt{50Dt}$$

$$M = 0.032\frac{L^2}{Dt} + 3.3 \qquad \text{for} \qquad L > \sqrt{50Dt}$$

and:

D	= the pipe diameter	d	= the corrosion pit depth
t	= the pipe wall thickness	M	= the Folias bulging factor
L	= the length of the defect	σ_y	= the yield stress
P_f	= the internal pressure at failure.		

In this simplified form, the cross-sectional area of the corrosion pit is approximated by the product of 0.85 times the pit maximum depth and its length.

4.7.3 Failure Criteria

Based on the above failure criterion, the failure conditions were evaluated for various corrosion pit geometries for a 12.75 in. diameter pipe with a 0.5 in. wall thickness. The results shown in Figure 4.9 relate the corrosion feature depth to pipe wall thickness to the failure pressure ratio (failure pressure/Maximum Operating Pressure [MOP]) for a range of corrosion feature lengths.

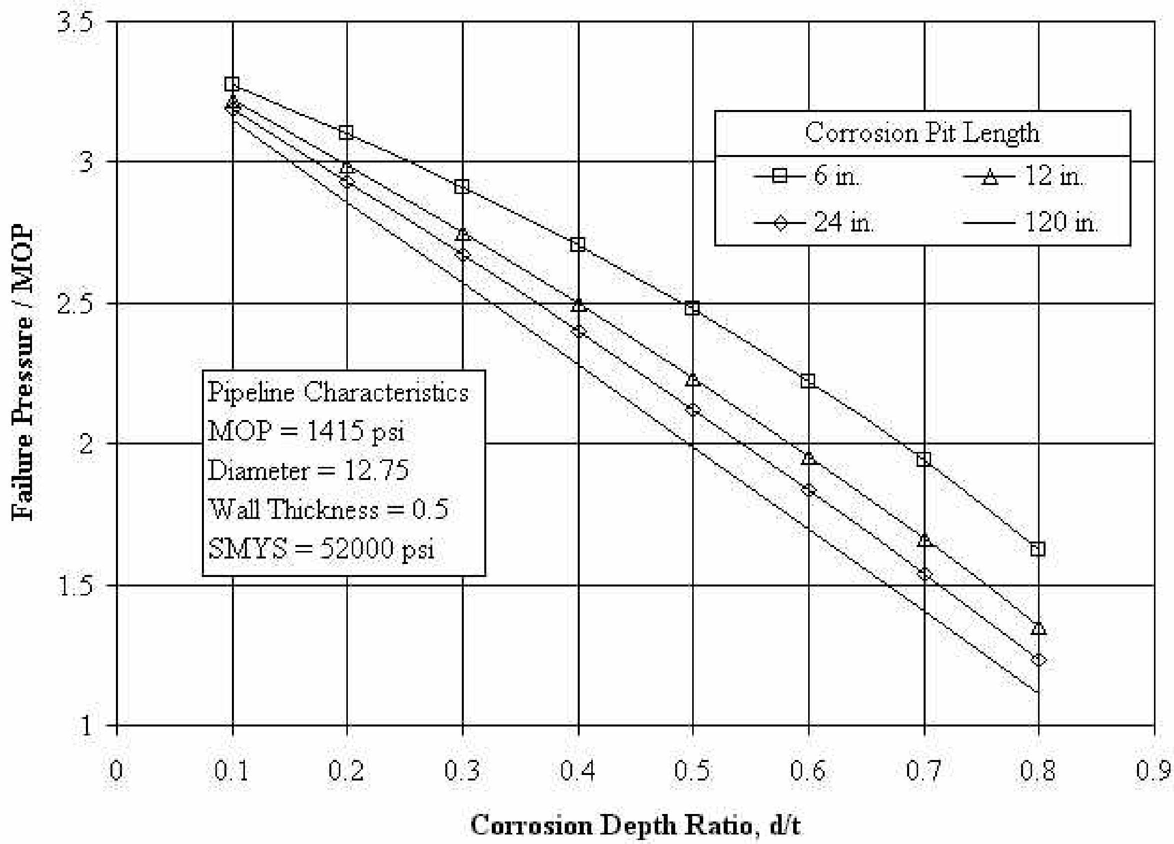

Figure 4.9: Failure Pressures for Corrosion Pit Depths and Lengths

The results in Figure 4.9 show that a corrosion pit would have to be at least 80% through-wall and have an infinite length to fail at 1.1 times the maximum operating pressure. This pressure corresponds to the maximum surge pressure under upset conditions. The failure pressure for an infinitely long corrosion feature with a depth of 50% of the pipe wall thickness would be twice the maximum operating pressure; this is a condition that clearly would never happen. Since Liberty will be regularly inspected for corrosion, it is extremely unlikely that failures will result from corrosion alone.

It is also noted that while the Modified B31G failure criteria are formulated in terms of hoop stress at failure, axial (longitudinal) loads can influence the failure pressure. High longitudinal loads due to bending of the pipe will further constrain deformation in the hoop direction and thus reduce the hoop stress at failure. This effect is likely to be more significant if the axial stresses are load-controlled. For example, an area of metal loss might be expected to fail at a lower pressure level if it is located on the compressive side of a large bend at which curvature increases with increasing axial load. While the constraint effect is significant for offshore Arctic pipelines in ice gouge events, internal corrosion features are most likely to be located at the 6 o’clock position (as this is where contaminants will accumulate) while the maximum bending stress will be located at the 3 and 9 o’clock positions.

While a revised corrosion failure criteria considering the effects of a multi-axial stress state has been developed (Battelle 1995), it has not been applied in this report.

4.7.4 Concluding Remarks

Based on the results demonstrated above, it is most likely that in a well maintained pipeline in which corrosion pits are not allowed to grow beyond 50% of the pipe wall thickness, failure would only occur due to other load events. Leakage due to corrosion in the presence of normal operating pressures should not be an issue. Even accidental over pressure situations such as pumping against a closed valve or pressure waves set-up by rapid valve closure are unlikely to promote failure. It is expected that the rate of corrosion failure would be linked to operational errors or other initiating events but would not be independent events, as long as the pipeline is designed, coated, cathodically protected, inspected and maintained appropriately.

In considering the potential for pipeline failure the effect of pipe wall thickness needs to be considered.

4.8 Summary and Conclusions

4.8.1 Pipeline Failure Modes

Oil may be released as a result of pipeline failure due to the following behaviours:

(a) lateral deformation;
(b) instability / buckling ;
(c) unsupported spans, and ;
(d) pipe wall (corrosion feature) overload.

These behaviours are limited by the strength or ductility of the pipe material. The sections which follow, summarise the behaviour to failure criteria discussions in the previous sections and describe how this information will be used in the risk assessment.

4.8.2 Lateral Deformation Failure Mode and Failure Criteria

The lateral pipe deformation behaviour discussed in this section will be associated with ice gouge events. The behaviour of a single pipe pipeline (peak strain) will be related to the ice gouge event in terms of its maximum lateral soil displacement and the gouge width according to equation 4.1.

The limit of safe lateral deformation will be assessed according to an allowable strain criteria. In a single loading event, a strain limit of 10% Von Mises will be used. When considering multiple ice gouge events (see section 3.2), the criteria for failure is the accumulation of a cumulative Von Mises strain of 15%.

4.8.3 Local Behaviour of a Pipe-in-Pipe Configuration

The lateral deformation of a pipe-in-pipe design will be estimated by considering the single and pipe-in-pipe lateral deformation behaviours. The strain on the inner carrier pipe was conservatively taken to be 70% of that for a single pipe of the same size and wall thickness.

The limit of safe lateral deformation will be assessed according to an allowable strain criteria. In a single loading event, a strain limit of 10% Von Mises will be used. When considering multiple ice gouge events (see section 3.2), the criteria for failure is the accumulation of a cumulative Von Mises strain of 15%.

4.8.4 Upheaval Buckling Failure Mode and Failure Criteria

Conservatively, upheaval buckling will be assumed to occur when more than 1 foot of cover is lost, resulting in a 1% strain in all cases.

The limit of safe upheaval buckling deformation will be assessed according to an allowable strain criteria. In a single loading event, a Von Mises strain limit of 10% will be used.

4.8.5 Unsupported Span Failure Mode and Failure Criteria

In the analysis of unsupported spans it will be assumed that pipeline failure, stable crack formation, occurs only when the unsupported span length exceeds 56ft and the bending strain exceeds 5%. The bending strain developed in a strudel scour event is estimated based on equation 4.2.

4.8.6 Corrosion Pit Plastic Collapse Failure Mode and Failure Criteria

Allowing for operational over pressure events, exceeding 110% of the Maximum Operating Pressure (MOP), it can be assumed that corrosion damage will result in a failure when the depth of corrosion exceeds 80% of the wall thickness. This result can only be applied with knowledge of the operating pressure history and thus the probability of exceeding the MOP. In the absence of this information, the failure rates observed historically on similar pipelines will be used.

5.0 PIPELINE CORROSION

Corrosion is one of the major failure causes on oil and gas pipelines, as shown by reviewing the oil spill statistics available from the MMS, DOT, and other sources. The damage attributed to corrosion can be internal, beneath water or other deposits in low-lying areas, or on the external surface as a result of coating damage or deterioration and insufficient cathodic protection. Both instances of corrosion must be considered for the long-term integrity management of the pipeline.

5.1 Internal Corrosion

Internal corrosion is a particular concern for gathering lines, and the pipelines between the gathering lines and cleaning facilities, because of impurities that are present in the oil and gas, such as carbon monoxide, carbon dioxide, hydrogen sulphide, oxygen, brine, and other compounds. The methods available to prevent internal corrosion on these lines include the use of internal coatings, selecting pipe material that is resistant to the compounds in the oil, removing the water, sludge, and corrosion products from the line by running cleaning pigs, or injecting chemical inhibitors. The Liberty Pipeline will have pig launching and receiving traps that can be used to regularly clean the line and guard against a build-up of contaminants, which could promote internal corrosion.

The problems related to internal corrosion reported for the Trans-Alaska Pipeline System (TAPS) were reviewed to make judgement on the corrosion that might be observed on the Liberty Pipeline, as the crude would have similar characteristics. Corrosion is found primarily in dead legs in the pipeline system (Ricca, 1991). It can be described as one of the following two types: isolated, discrete pits with diameters from 0.5-1.0 in. that are covered with iron sulphide; and broad troughs of slime-covered connected pits, 1 to 2 in. wide and up to 3 ft. long. The corrosion is always at the 6:00 o'clock position in a 15-degree band. The average pitting corrosion rate is 30 to 40 mils/yr., and the maximum corrosion rate is 75 mils/year. In the main pipeline system, there are low general corrosion rates and the pipe is essentially the nominal wall thickness. Ricca, 1991 notes that there is no corrosion where the oil velocity exceeds 3.5 to 4 ft/sec. (1.07 to 1.22 m/sec.)

The Liberty Pipeline will have a flow velocity of 6 ft/s at a design flow rate of 65,000 bbl/day. The flow rate corresponding to a fluid velocity of 3.5 ft/s is approximately 40,000 bbl/day, and therefore one would not initially expect internal corrosion on this line on the basis of the TAPS results unless the rate dropped below this value.

As the field matures, the flow rate would decrease and internal corrosion would then become a concern. However, the regular in-line inspection schedule would detect any corrosion along the line and mitigative measures, such as corrosion inhibitor injections could be initiated to maintain line integrity. There are not expected to be any dead legs on Liberty Island, but if there were, it is expected that the pipe wall thickness in such piping would likely be regularly monitored to ensure that internal corrosion is not becoming a problem.

5.2 External Corrosion

External corrosion occurs where the coating has been damaged or where there been a general deterioration of thin film polyethylene coatings, exposing the pipe surface to the groundwater environment. Cathodic protection (CP) currents applied to the pipeline or sacrificial anodes can normally protect the pipe surface for localized coating damage. However, for the case of polyethylene tape coatings, the tape shields the pipe surface from the applied currents, and corrosion proceeds as if the pipe was unprotected by CP.

A summary of external corrosion for the Alyeska Pipeline is provided by Vieth et al, 1997, and is based on the results of second generation inspection tools. The oil reached Valdez on 1 August 1977, the first IPEL corrosion pig (first generation low resolution) was run in the line in April 1987, and the first high-resolution tool, NKK corrosion pig, was run in June 1989. Therefore the results are indicative of corrosion rates over a 12-year or longer period. They note that even with the latest tool technology there are significant differences in the number of pig calls amongst the in-line inspection (ILI) tools.

A pig call is an indication above a size threshold that has been agreed upon to be included in the inspection report. It will include all indications that are above code limits and smaller indications that the operator would want to monitor, or possibly repair, depending on their locations.

The most recent ILI results show a marked increase in external corrosion. For example, comparing the results from 1991 to 1994, there is almost a tenfold increase in the number of pig calls, due mainly to the tools ability to identify relatively shallow corrosion; they show the following:

Table 5.1: Summary of Pig Calls for External Corrosion < 75 mils

Year	Number of Pig Calls	Joints With Corrosion < 75 mils
1991	7,000	935
1994	67,000	10,000

The authors (Veith et al, 1997) compare the results from 5 pig runs in the period from 1991 to 1994 to show that one of the inspections gives the best correlation between reported and actual results. The distribution of external corrosion pits from one of the high-resolution second generation tools is given in Table 5.2. These results demonstrate that the majority of corrosion is relatively shallow, but there are examples of the pits exceeding 200 mils in depth.

Using the worst case, assuming that this inspection run was in 1991, one could conservatively predict corrosion pit depths as deep as 0.200 in. within 12 years of operation. One would expect much lower corrosion rates with the advances in coating technology that have occurred in the last decade.

Table 5.2:Summary of High Resolution Pig Calls

Range of pig call depths, mils	Number
0-50	4845
50-75	3497
75-100	2264
100-125	591
125-150	155
150-175	47
175-200	21
>200	9
Total	11,427

Vieth et al, 1997 use the information from the inspection tool runs to calculate the probabilities that a reported call will exceed the critical depth of corrosion on the line. The critical Corrosion Depth (CD) is calculated by assuming a single pit with a length of 6 in. that can be tolerated and still maintain a 1.39 factor of safety between the maximum operating pressure and the predicted failure pressure (Vieth et al, 1997). The probability of exceeding the CD on each pipe joint is calculated to identify which joints should be excavated, and higher priority can be assigned on the ones with the highest probabilities of exceedance.

The calculations for CD employ a slight modification of the equations contained in ASME B31G; results for the three alternatives for the Liberty Pipeline are provided in Table 5.3. The critical corrosion depths for an assumed 6-inch long corrosion pit are 0.236-in. for the steel pipe and steel pipe in HDPE case, and 0.157-in. for the steel pipe in pipe. If one were to use the depths observed from the Alyeska inspections, the critical depths would be reached approximately 12 years after installation of the Liberty Pipeline.

Table 5.3: Liberty Pipeline – Critical Depth of 6 in. Corrosion Pit[(a)]

	Steel Pipe	Steel Pipe in Pipe	Steel Pipe in HDPE
Pipe wall thickness, in.	0.688	0.500	0.688
Critical depth, in.	0.236	0.157	0.236
Critical depth, % WT	34	32	34

(a) Calculated using a modification of the B31G equations for allowable corrosion pit depths

The Liberty Pipeline will use a 40 mils thick fusion bond epoxy (FBE) coating, which represents the best available coating, and will use anodes and CP for corrosion protection. It is our opinion that these measures will ensure that external corrosion will be mitigated to the best standards currently in use. Annual potential measurements at the shore crossing and at Liberty Island will be made (Intec, 1999) which will provide an indication that the anodes are adequately protecting the offshore pipeline segment.

These measures will undoubtedly result in significantly lower corrosion rates for the Liberty Pipeline, and we would expect a corrosion pit of 0.200 in. depth would most likely not be observed until after 20 years.

5.3 In-Line Inspection

The Liberty Pipeline will be designed with launching and receiving traps for using in-line inspection (ILI) tools. They are launched to clean the line and to run tools capable of detecting corrosion and other anomalies long before they become a concern to the safe operation of the line. The conditions and parameters monitored by ILI tools include wall thickness, pipe body ovalization, and pipe bending (Intec, 1999).

The typical pipeline inspection schedule for the Liberty Pipeline given in Table 5.4 shows that there will be regular inspections for wall thickness, mechanical damage, and geometry surveys.

Table 5.4: Typical Pipeline Inspection Schedule (Intec, 1999)

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 initial wall thickness or geometry pig survey.

ILI tools provide an indication of the actual condition of the pipeline, and allow the operator to plan repairs and other mitigative actions. Another potential benefit is the possibility to actually monitor changes on the pipeline. By comparing results from subsequent inspection runs, for example, one can determine corrosion growth rates.

The pipeline curvature can be determined using tools such as the Geopig (trade name for the BJ Pipeline Services geometry tool), which is a tool that can provide operators with three dimensional geographic information via inertial navigation and sonar caliper measurements. This tool allows operators to assess conditions such as slope movement, subsidence, and frost heave, and provides detailed information on dents, buckles, wrinkles and bending strain. In our opinion, the Geopig represents the best available technology for monitoring these conditions, and would most likely be selected for inspection of the Liberty Pipeline.

5.4 Failure Frequencies

The failures attributable to corrosion from Intec, 1999 have been assigned the damage frequencies listed in Table 5.5. It is noted that these damage frequencies apply only to small/medium leaks; frequencies for all other damage categories are taken as 10^{-8}.

Table 5.5: Estimated Damage Frequencies for Liberty Alternatives (Intec, 1999)

Initiating Event	Estimated Damage Frequency (Occurrences per project lifetime)			
	Single Pipe	Pipe in Pipe	Pipe in HDPE	Flexible Pipe
Internal Corrosion	10^{-8}			10^{-8}
External Corrosion of Inner Pipe		10^{-4}	10^{-3}	
Internal Corrosion of Outer Pipe		10^{-4}		
External Corrosion	10^{-6}	10^{-4}	-	10^{-6}

The reliabilities of these expected damage frequencies are considered in the following sections and compared to the ones determined by FTL in this project.

5.4.1 Single Steel Pipe

Internal corrosion for the single pipe case was given a frequency of 10^{-8} by Intec, 1999 because the oil is a non-sour processed crude and it is considered extremely unlikely that this type of oil would cause internal corrosion. In the discussion to Section 5.1, the likelihood of internal corrosion was considered to be remote because of the high flow rates and the ability to pig the line to remove any water and sludge, and ILI would detect any corrosion before it could lead to failure. This is substantiated from experience with crude oil transmission pipelines in that internal corrosion is found only in areas where water or wax has accumulated, such as at low points in the line and dead legs within stations. The TAPS experience (Ricca, 1991) is in agreement with this statement.

In estimating the damage frequency of 10^{-6} for external corrosion, Intec, 1999 stated that:

(a) the pipe wall thickness is more than 3 times that necessary for pressure containment,
(b) there is a 40 mils thick epoxy coating;

(c) the CP system should adequately protect the pipe, and
(d) ILI tools will be used for wall thickness measurements.

They recognize that some coating degradation will occur, and have given a higher damage frequency than the internal corrosion case.

The failure statistics review (Appendix E) has shown that corrosion is one of the most frequent causes of pipeline failure. In some databases (i.e., the MMS and EUB ones), it is listed as the predominant incident. However, these statistics include many small diameter lines that are not piggable for corrosion monitoring. Other statistics (i.e., DOT, Concawe) list corrosion just behind third party damage as the most likely cause of failure. In FTL's review, it was noted that: (a) external corrosion occurred more than 5 times more often than internal corrosion in terms of number of incidents (Concawe, 1998), and (b) external corrosion failures released more than 4 times the spill volumes than internal corrosion (Bynum, 1983). This information suggests that any statistics related to failure frequencies can be considered to be representative of external corrosion, and that failures due to internal corrosion represent a small fraction of the total failure number.

The approach taken in this study to estimate damage frequencies was to start from the failure statistics. In Appendix E, it was noted that the failure data would not always represent the same situations one would expect for the Liberty Pipeline. In the case of corrosion, failure rates of 2.62, 0.244, and 0.016 spills/1000 miles/yr., were observed for the MMS, DOT, and Concawe data, respectively. In our opinion, we believe that the Concawe results most closely match the Liberty Pipeline case. The Concawe data is considered to match the Liberty case on the basis of the corrosion failure rates. The MMS and DOT statistics included many small diameter lines that were not regularly inspected, or were subject to high failure rates as they had high water contents or low flow rates. The Concawe pipelines included more large diameter lines which were regularly inspected, and thus were considered to be the most representative of the Liberty Pipeline. For the 7.5 miles (6.12 miles offshore) of the Liberty route, the Concawe failure rate, gives an estimated 0.00012 spills/7.5 miles/yr.

It is also recognized that the additional wall thickness of the Liberty Pipeline (compared to the minimum WT needed for pressure containment) reduces the chance of a corrosion failure. In Appendix E, it was noted that the probability coefficient was decreased by 4.7/in.; since the additional thickness for Liberty amounts to 0.461 in., we can use a reduction factor of 2.17, resulting in a damage frequency for corrosion for the entire line of 5.52×10^{-5}/yr, or 1.1×10^{-3} over the 20-year life of the line. Furthermore, it is expected that the improved coating would improve the corrosion resistance tenfold, and another 100 times improvement can be assigned on the basis of the comprehensive ILI schedule. The enhanced performance that has been assigned to improved coatings and inspection is consistent with the risk assessment techniques that have been implemented over the past decade. The increasing failure rate due to external corrosion that has been observed and is reflected in the databases is considered to have resulted from the use of thin film polyethylene tape in the 1970s. The current epoxy coatings are expected to perform at least 10 times better than the polyethylene tape.

Similarly, many failures within the data are on lines that do not have traps for launching and receiving internal inspection tools. If traps are available and have been used in the past, one would expect a tenfold improvement in failure rates with the inspected line. With the current improvements in high-resolution inspection tools, it is expected that pipeline operators can expect an additional tenfold improvement in failure rates, particularly with the inspection schedule that will be implemented for Liberty.The net result is a damage frequency of 1.1×10^{-6}, which is similar to the one listed by Intec (1999).

The analysis in Appendix E showed that internal corrosion is 5 times less likely to occur than external corrosion. Starting from the external damage frequency in the paragraph above, an estimated frequency of 2.2×10^{-7} for internal corrosion was obtained. This is slightly higher than the 10^{-8} value used by Intec. We believe that if the line is down for any extended period of time (e.g., due to a leak), and repairs cannot be made immediately due to environmental conditions, this would increase the chance of internal corrosion developing in the line.

5.4.2 Steel Pipe in Pipe

The Intec, 1999 damage frequency occurrence of 10^{-4} for the inner pipe represents external corrosion, as they suggest that internal corrosion with sweet oil is unlikely. The higher frequency compared to the single wall pipe has been assigned by Intec, 1999 because the exterior of the inner pipe cannot be cathodically protected, and one cannot monitor the condition of the outer pipe.

A damage frequency for the external pipe of 10^{-4} was given by Intec, 1999 to the outer pipe because there is the possibility of corrosion from damage to the external coating or corrosive material in the annulus. ILI tools cannot directly monitor the external pipe condition, and therefore repairs could not be planned to mitigate corrosion before it could lead to a failure.

FTL's estimate of damage frequency was based on the same logic used for the single steel wall pipe (Section 5.4.1). A major difference between the two alternatives is that ILI tools cannot be used to monitor the condition of the outer pipe. We start with the corrosion failure statistics from Appendix E, which gives 0.000016 spills/mi/yr, or 0.0024 spills over the life of the pipeline. The interior pipe in this alternative is 0.5-in. Wall Thickness (WT), compared to the 0.688-in. WT of the single pipe. Thus, the thickness reduction factor is approximately half of the single pipe, giving a factor of 1.09, which gives a failure rate of 0.0024/1.09 = 0.0022. An improvement in performance of 10 times would be assigned due to the improved coating on the pipe, and a reduction in damage frequency of 100 times was added because of the ability to monitor the condition of the inner pipe. This is offset, however, by uncertainties with the condition of the annulus; an increase in risk of 10 times has been assumed with this uncertainty. The resultant damage frequency over the life of the pipeline is therefore calculated as $0.0022 \times 10 / (10 \times 100) = 2.2 \times 10^{-5}$

It is recognized that the exterior surface of the inner pipe can be coated and cathodically protected. Fleet believes that the protective coating has a high likelihood of being damaged during installation or operation due to relative pipe movement. Also, there is no guarantee that the internal CP system will deliver protective current to the damaged area.

The lower corrosion potential for the C-Core analysis (C-Core 2000) assumed that the annulus would be packed with nitrogen. This is a possible design, but it has not been finalized. As the designs of the pipe-in-pipe alternative had not been finalized, it was decided to err conservatively in agreement with the Intec approach for external corrosion of the inner pipe.

5.4.3 Pipe in HDPE

As with the above alternatives, internal corrosion of the inner steel pipe is unlikely. The damage frequency of 10^{-3} (assigned by Intec, 1999) is higher than that for the steel pipe-in-pipe system because the outer high density polyethylene (HDPE) pipe is more likely to develop a leak in the annulus, leading to external corrosion of the inner steel pipe.

FTL is in agreement with the approach taken by Intec, 1999, and correspondingly have chosen a damage frequency 10 times greater than that for the steel pipe in pipe system, or 5×10^{-4}.

External corrosion of the HDPE is not expected to occur.

5.4.4 Flexible Pipe

Internal corrosion is considered extremely unlikely owing to the properties of the oil that will be transported.

The damage frequency due to external corrosion assigned by Intec, 1999 was the same value as that for the single wall steel pipe, (i.e., 10^{-6}) as the outer sheath would have to be compromised before the inner steel sheath would corrode.

FTL concurs with this approach and likewise assigned the same value as for external and internal corrosion of the single wall pipe, or 1.1×10^{-6} and 2.2×10^{-7}, respectively.

5.5 Summary

The Liberty Pipeline is considered to have a very low probability of failure from corrosion for the following reasons:

(a) Internal corrosion is unlikely as the crude being transported is a non-sour oil, and the velocity in the mainline will be sufficient to keep water and solids from accumulating on the inside of the pipe and eventually promoting internal corrosion.

(b) The Liberty Pipeline has been designed to have a 40 mil thick fusion bond epoxy coating, a cathodic protection system, and the pipe wall is more than twice the thickness necessary for pressure containment; these measures will help to ensure that external corrosion will not be a problem for the Liberty Pipeline.

(c) The line will have the capability to launch and receive pipeline cleaning tools and, more importantly, in-line inspection tools that are capable of detecting corrosion and other anomalies before they are large enough to cause operational problems. The proposed monitoring plan will make use of these capabilities, which will mitigate corrosion-induced problems.

(d) FTL recognizes that the exterior surface of the inner pipe can be coated and cathodically protected, but FTL believes that the coating can become damaged and the internal pipe CP system might not be effective. It is also noted in C-Core 2000 that the annulus could possibly be packed with nitrogen. However, as the design has not been finalized, it was decided to err conservatively and use the Intec approach for external corrosion of the inner pipe.

The damage frequencies developed by FTL are as follows:

Table 5.6: Estimated Damage Frequencies for Liberty Alternatives

Initiating Event	Estimated Damage Frequency (Occurrences per project lifetime[1])			
	Single Pipe	Pipe in Pipe	Pipe in HDPE	Flexible Pipe
Internal Corrosion of Carrier Pipe	2.2×10^{-7}	2.2×10^{-7}	2.2×10^{-7}	2.2×10^{-7}
External Corrosion of Carrier Pipe		2.2×10^{-5}	5×10^{-4}	
External Corrosion of Outer Pipe	1.1×10^{-6}	1.1×10^{-4}	-	1.1×10^{-6}

Notes:
1. The project lifetime is defined as the 20-year life of the Liberty Pipeline

6.0 MONITORING SYSTEMS

6.1 Leak Detection Systems for Spill Monitoring

The leak detection systems planned for the Liberty Pipeline include two independent state of the art systems, Mass Balance Line Pack Compensation (MBLPC) and Pressure Point Analysis (PPA), working in parallel. They are expected (Intec 1999) to be able to detect large leaks within 30 seconds, and small to medium leaks of 0.15% of the volumetric flow of the line, or 97.5 bbl/day, within 24 hours. Leaks smaller than this amount would be detectable using one or both of the following supplemental leak detection systems:

(a) LEOS leak detection and location system (German acronym for leak detection and location). The LEOS system is comprised of a hollow cable that is laid alongside the pipeline, which in turn is connected to a measuring station. It can be used on any of the pipeline alternatives.

(b) annulus monitoring. The second supplemental system is an annulus monitoring system; it can be used for the pipe-in-pipe, pipe in HDPE, and flexible pipe alternatives. The annulus monitoring systems could either monitor the gas directly within the space between the pipes, or employ a vacuum measurement to determine if there has been a leak.

Intec, 1999b investigated the use of other technologies or techniques for leak detection, such as through-ice sampling, remote sensing, and periodic pressure testing. However, the focus of this study was to compare the four design alternatives, which were developed on the basis that the installed monitoring methods for the Liberty Pipeline would be PPA, MBLPC, and LEOS (Intec, 1999; 2000). The issues to be evaluated include the following:

(a) capabilities - leak detection threshold capability, reliability, and polling rate.
(b) alarm response - time to initiate a leak alarm.

It is recognized that through-the-ice monitoring, aerial surveillance, and other methods are proposed as methods of low level leak detection for Northstar (US Army Corps of Engineers, 1999). This might become important if all of the above monitoring systems failed to perform as expected. It is expected that, if these alternative methods became necessary, this would increase the potential size of spills. For example, with through-the-ice sampling, one cannot be assured that the sampling will coincide with the pool of oil, and there are uncertainties related to ice access and weather conditions. Furthermore, through-the-ice monitoring is not applicable for the whole year.

In view of the fact that the proposed systems provide redundancy, this was considered to be unduly conservative. However, allowances were made for the expected worst-case performances of the three monitoring systems.

6.2 MBLPC and PPA

Both of these systems would rely on the pipeline information being continuously transmitted back to the control center on the Supervisory Control And Data Acquisition (SCADA) system. The measured parameters include pump discharge pressures, flow rates, oil temperatures, and the pressures at various points along the line, such as the shore crossing and the Badami Pipeline tie-in. Both systems compare the most recent readings to historical data from the previous few minutes to several hours, and send an alarm if a leak is suspected. Intec, 1999 states that under optimal conditions these systems would be able to alarm at 0.15 % of the volumetric flow rate. They also note that the communications link to SCADA updates the complete MBLPC information every 30 seconds, while the PPA updates its complete data set in 0.25 seconds.

Mass Balance (MB) systems measure the oil flow rates entering and leaving the pipeline, and identify leaks based on differences between the flow rates. For a system of this type, if the leakage rate is above the system's detection threshold, the time to detection is estimated as the time between volume balance calculations. Intec, 1999 have assumed that the mass balance system would require a discrepancy of 100 to 200 bbl over a one to two day period to indicate a leak. The shortest period over which MB could detect a leak would be expected to follow the guidelines provided in Appendix E of CSA Standard Z662-99 (CSA, 1999). This standard gives a 5 minute interval between volume balance reconciliations as the most stringent requirement, and the system is expected to be able to detect discrepancies exceeding 5 % of the flow over this period. If we use this as the shortest time period for Liberty mass balance calculations, the first alarm indication would be given by the MPLPC at a discrepancy of 5 % of 225 bbl over 5 minutes, which is a rate of 3240 bbl/day. As the time interval between calculations increases, MB is able to identify discrepancies at lower flow rates, i.e. the 100 to 200 bbl/day rate given by Intec. The operator would have to investigate any discrepancy, possibly by meter proving or comparison with PPA, and establish if the line should be shut down

Recently, Borener and Patterson, 1995 (also known as the Volpe report) conducted a study to:

(a) "to investigate current SCADA, LDS (Leak Detection Systems), and EFRD (Emergency Flow Restricting Devices) systems, and to identify their performance measures ;
(b) to investigate the effect of SCADA, LDS, and EFRD performance measures on their potential for reducing the hazard to the public and environment posed by oil spills ; and
(c) to investigate the feasibility and cost to liquid pipeline operators of SCADA, LDS, and EFRDs, and to report on the progress of liquid pipeline operators in adopting and implementing these systems."

In the course of their study, Borener and Patterson, 1995 collected information from the vendors of the various systems, interviewed several pipeline company representatives, and even completed an on-site investigation. They point out that the reliability and accuracy of SCADA based leak detection systems are dependent upon the following:

(a) False alarms;
(b) Accuracy problems from poor input information;
(c) Difficulties associated with line start-up and shutdown;
(d) Program bugs and other complications.

Time and a commitment to training operators is required to work out all of these problems and to be able to correctly identify situations on the line that are, or are not, indicative of a leak.

Table 6.1 summarizes some of the information that Borener and Patterson, 1995, obtained from contacting the vendors and interviewing the pipeline companies.

In order to confirm the performance given by Borener and Patterson, 1995, the literature describing the PPA and LEOS systems were reviewed, as these will comprise the main part of the Liberty Pipeline leak detection system.

Table 6.1: Leak Detection System Performance Information (Volpe)

	Gas Diffusion Technology	Pressure Signal Analysis	Volume Balance	RTTM
Response Time (< 5% of flow)	14 days[1] 1 hour[2]	32 sec.[3] (1/8 in. leak; 0.625 % of flow)	5-27 min.[4]	46 min.[5] (for 1.6 % of flow)
Response Time (> 5% of flow)	14 days[1]	8 sec.[3]	3 min.[5]	1-13 min.[4]
False Alarms	2.9 %[1]	Not reported	1 / month	Not reported
Demonstrated Sensitivity	0.005 gal/hr[1]	0.125 % of flow[3]	0.1 % of flow[4]	0.2 % of flow[6]

<u>Legend</u>:
1. Tracer Research Corporation
2. Teledyne – LASP System
3. PPA: Dupont Burnside Plant, On-line field test data 1992.
4. Scientific Software Intercomp
5. Controlotron, Inc.
6. Stoner Associates, DREM

6.2.1 Pressure Point Analysis

Pressure Point Analysis (PPA) is a leak detection technique patented by Ed Farmer & Associates (EFA) which determines leaks by looking "at the behavior of the pressure or velocity of the fluid in a line at a monitored point as it transitions from one steady state to another". The first installation of this technology was in 1988 on a sour gas pipeline (Farmer, 1989). The technique involves the following:

(a) Establish the normal operating conditions at a point;
(b) Determine if the next reading is significantly different from the preceding reading;
(c) Determine if the change is due to pipeline operating practices or a leak;
(d) Notify the operator.

6.2.1(a) Leak Occurrence

The following explanation, from Farmer, 1989, describes the leak events as having unique characteristics that can be detected by PPA. The pressure histories in a pipeline following various leak events are shown in Figure 6.1. Curve 1 is indicative of a very small leak, usually on gas lines, and is fairly difficult to detect, as the evidence exists only for a few minutes. Curve 3 is the pattern that could be expected from large holes or ruptures, and these are easy to detect.

The history shown by curve 2 is indicative of many small leaks. The pressure drops initially and then recovers to some value just below the steady state before the incident. Farmer, 1989 claims that these leaks are easy to detect as the evidence persists for many minutes.

The detection time depends on the length of time it takes for the pressure wave to reach the pressure sensors, followed by additional polling information to discern a trend in the pressures.

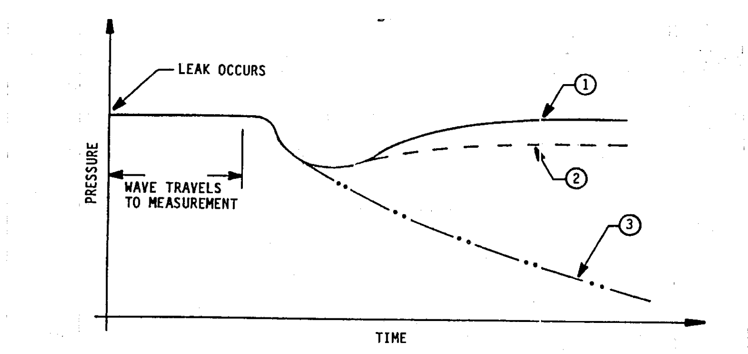

Figure 6.1: Pressure History Following a Pipeline Leak (Farmer, 1989)

6.2.1(b) Flowing Tests

The capability of the PPA system has been demonstrated on tests on numerous pipelines, including crude lines, product lines, and even lines exhibiting two-phase flow.

A test was completed on the line connecting the Dolly Varden platform off the coast of Alaska with the shore (EFA Technologies, 1994). Leaks were simulated 6 miles from the measuring point at the receiving facility. The leaks that were detected were 10.1, 6.5, 7.6, and 5.8 GPM, approximately 0.5% of the line's design flow rate; the total volume used in all four tests was less than one barrel. There were no false calls.

Another field test (Farmer et al, 1991) evaluated a 10-mile long crude oil line in the Arabian Gulf that operates at relatively low pressures (<100 psig). The pressure transmitter was at landfall, there was a high point (+150 ft) at approx. 7 miles, and it ended in tankage at 10 miles. The test results are shown in Table 6.2. As a result of the low pressures at the high point and at the refinery due to elevation and line losses, higher leak rates were needed to obtain a leak indication. Nonetheless, all of the results show that leaks were detected well within one minute, and at flow rates as low as 0.10% of the volumetric flow.

EFA Technologies, 1994 also stated that tests completed on a mainline crude oil line owned by ARCO were able to detect leaks as small as ¼ in., and even 1/8 in. under certain conditions.

One of the most challenging installations for a PPA system was on a 54-mile segment of a dual-phase ethylene line. The difficulty with this example lies with accurately measuring the flow and characterizing the density from the pressure and temperature measurements. The tests demonstrated that a 0.25-in. leak could be observed at all points along a 54-mile line segment within 12 minutes, while one could expect that the closest point for alarm notification would take 2-8 minutes. (The pressure wave from a leak propagates at a speed of 700-800 ft/sec.) Due to the nature of the line operation, EFA concluded that PPA would not be able to detect leaks from a 0.125-in. hole. This example shows that PPA is usable in situations where other technologies were not able to provide leak detection.

Table 6.2: Tests on BAPCO Pipeline

Line Flow Rate: 5250 gpm Landfall Pressure: 78 psig Refinery Pressure: 20 psig				
Leak Location	Detection Time, s	Volume Collected, gal.	Approx. Leak Rate, gpm	% of Line Rate
Landfall	22	3	8.2	0.16
Landfall	12	1	5	0.10
Landfall	7	1	6.6	0.13
High Point	35	3	5.1	0.10
High Point	19	4.5	14.2	0.27
Refinery	15	4	16	0.30
Refinery	9	3	20	0.38

Another difficult test for the PPA system was on a Phillips Petroleum offshore production pipeline system that connects two platforms with an onshore treating and production facility in La Conchita, CA. The line transports a three-phase unstabilized fluid consisting of crude, large amounts of water, gas, and solids at a rate of 6,000 bbl/day (175 gpm). Leaks were simulated at both platforms and at the production facility. The results of the tests (Table 6.3) show that leaks at rates from 3 to 9 gallons/minute were reported within 12 to 66 seconds. The concern from possible spills precluded continuing with additional tests to determine the threshold of detection, and it was concluded that leak rates of less than 1.7% of flow would be detectable.

The leak-locating portion of PPA was tested on a 19.5-mile pipeline, which was either 10-inch or 14-inch diameter (Farmer, 1992). All leaks were detected within 60 seconds, and with a location error between 106 and 950 ft. (0.10 to 0.92 % of the pipeline length).

Table 6.3: Leak Detection in Phillip's Offshore Pipeline System

Location	Nominal Leak Size, in.	Leak Rate		Detection Time, seconds
		gpm	% of flow	
Hogan	¼ - ½	6	3.43	21
Hogan	1/8 – ¼	3	1.7	66
Houchin	1	7	4.0	12
Houchin	½	3	1.7	15
La Conchita	1	9	5.14	17
La Conchita	1/3 – 1/2	6	3.43	52

6.2.1(c) Leak Detection – Static Conditions

Leaknet is the commercial name for the technology marketed by EFA Technologies that is used to detect leaks from facilities such as underground storage tanks and pipelines under pressure test. It is part of the PPA software package, and the program can easily be switched between flowing and static operation. The capabilities under static conditions on pipelines are summarized in Table 6.4. If one interpolates between the two examples, one could expect that Leaknet would be able to detect leaks of 2 gal/ hour (1.14 bbl/day). The Leaknet system has been certified by the California State Water Resources Control Board for leak detection on pipelines of 2.2 gph. However, there is a limitation that the maximum capacity of the line is 116,230 gallons, and certification above this volume would require additional testing. At a line fill of approximately 3700 ft^3/mile for Liberty, the 7.6-mile length would require a volume of 207,000 gallons; additional tests would be needed, and they would likely confirm the use of this technology to detect leaks just above the 2 gph range.

Numerous tests have been completed to address the reliability of Leaknet, and all results demonstrate that 100 % reliability can be expected in this mode.

Table 6.4: Leak Detection Capabilities of Leaknet (EFA, 1995)

Line Size, in.	Leak Rate, gph	Volume Lost on Detection	Percent of Line Fill
16	2.3	10.24 ounces (92 ml)	0.00003
8	0.08	0.38 ounces (14 ml)	0.00006

6.2.2 Capabilities of PPA

The review of the sources describing the PPA system and its capabilities support the performance characteristics reported by Volpe; they are as follows:

Response Time: 32 sec. at < 5 % of flow
8 sec. at > 5 % of flow

Demonstrated Sensitivity: 0.125 % of flow

The number of false calls is very low once the system has been running for a while and the operators are familiar with its capabilities.

PPA can also be used as a means of leak detection in the event that the line is shut down for any reason. Tests would have to be undertaken to certify the detection capability, but leak rates just slightly greater than 2 gph would likely be reported.

6.3 LEOS Leak Detection System

Intec, 1999b, selected LEOS system as the best available technology for supplemental leak detection on the basis of a thorough study undertaken. As the Liberty and Northstar projects were similar, LEOS was selected by Intec, 1999 as the supplemental leak detection system for the Liberty Pipeline.

6.3.1 LEOS System Method of Operation and Previous Installations

The operating principle for the LEOS system has been described in various publications (e.g., Intec, 1999b; Owens, 2000). The system detects leaks by periodically sampling the vapour within a tube that is permeable to gases and vapours. In the event of a leak, some of the leaking substance diffuses into the tube due to the concentration gradient. The gas within the tube is regularly sampled by pushing a column of air past a gas sniffer at a constant speed. The sensor measures the vapour concentration and the relative distance along the length of the tube, allowing a determination of the size of the leak and its location. Figure 6.2 shows the general mode of operation of the LEOS system and a representation of the expected results from a large and a small leak.

The detectors in the sensor unit are chosen to match the product(s) in the pipeline system that is being monitored. Siemens (the manufacturer and vendor of the LEOS system) claims that 73 substances can be detected using the LEOS system, including crude oil.

The first LEOS applications (in 1978) were installed for monitoring ethylene pipelines, one of which was a crossing of the Rhine River, and for monitoring possible contamination in a groundwater protection area. Other LEOS installations have included municipal gas supply lines, product lines, impermeable surfaces, chemical warehouses, industrial plants, landfill sites, and crude oil pipelines.

Of the 28 total installations, there are 18 pipeline applications, with some of the systems used to monitor more than one pipeline. Figure 6.3 shows the distribution of pipeline installations by length. The majority of the systems in current use are installed on pipelines that are 6 km or shorter, although there are three installations on 20 km long pipelines, one for a 10 km line (the Northstar Pipeline), and two 8 km pipelines. With 25 of these installations having been installed in the last decade, this shows that it has become a recognized technology for leak detection.

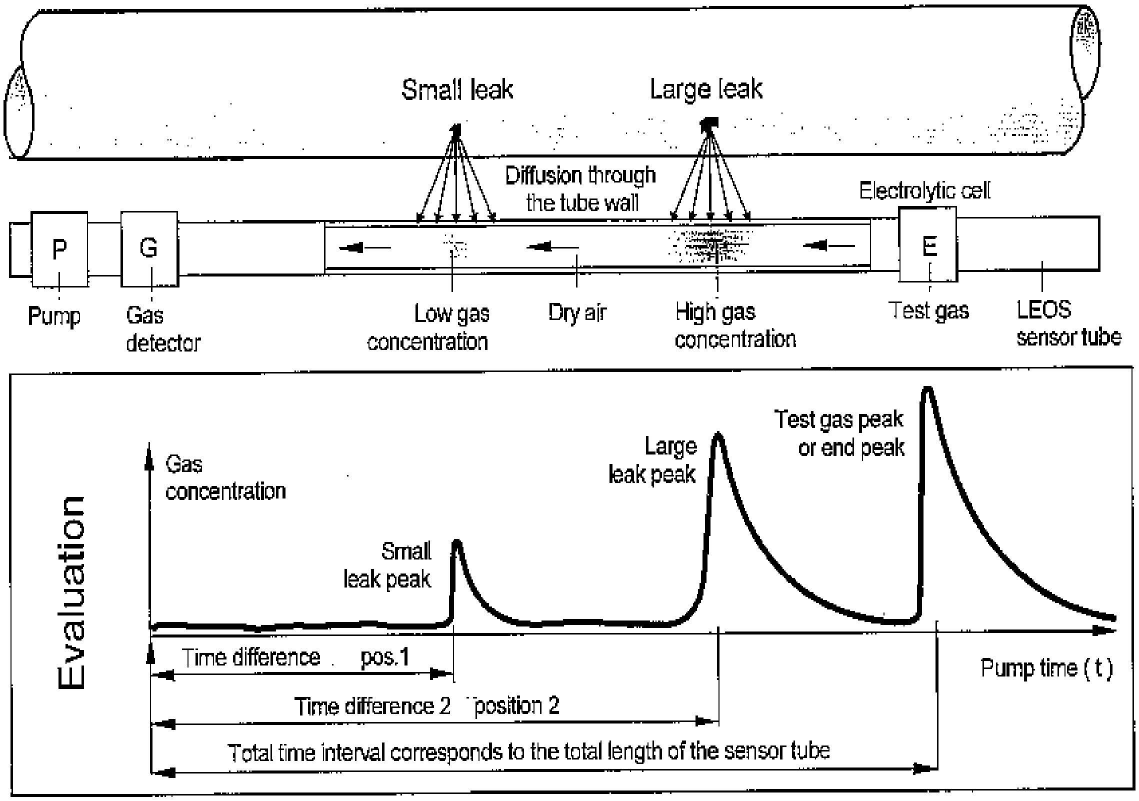

Figure 6.2: Mode of Operation of the LEOS System for a Pipeline Application.

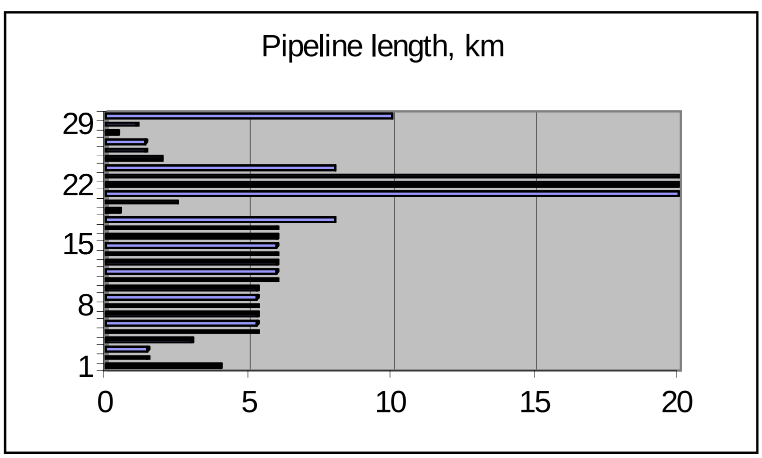

Figure 6.3: Summary of Number of LEOS Pipeline Installations of Various Lengths

6.3.2 LEOS System Performance and Field Verification Testing

It is important to recognise that the LEOS system detects leaks as a result of the build-up of gas vapours in the soil. The manufacturer claims that the LEOS system will detect gas concentrations as low as 10 ppm (Siemens, 1990). This has several important implications for the performance of the LEOS system, as follows:

(a) the leak detection time is highly dependent on the time required for gas vapours to diffuse through the soil to the LEOS sensing tube, and;

(b) small leaks that are initially below the leak detection threshold are likely to be eventually detected when a long enough time period elapses that the gas concentration increases to the detectable limit.

A summary of some of the laboratory, full-scale, and field tests undertaken by Siemens (the manufacturer and vendor of the LEOS system) shows that field tests are usually included as a part of the LEOS system commissioning for a specific project (Table 6.5).

Table 6.5: Field Tests of the LEOS System

Substance	Documentation	Environmental Condition
Petrol	Siemens	Buried pipeline in soil
Propane in water	Siemens	Buried pipeline, groundwater
Jet A1	Siemens	Low temperature test (> 0 °C)
Ethylenoxide	Commissioning Test	Insulated pipeline
Methylethylenketon	Commissioning Test	Air in concrete channels
Cable oil	CommissioninTest	Soil contamination
FCC gas (mixture of ethane, propane, propane, butane)	Commissioning Test	Buried pipeline in soil
Heavy hydro cracker petrol (≥ C5)	Commissioning Test	Buried pipeline in soil
Propane	Commissioning Test	Buried pipeline in soil
Benzol	Commissioning Test	Buried pipeline in soil
C5 - mixture	Commissioning Test	Buried pipeline in soil
Salt water	Siemens	Buried sensor tube in soil or groundwater

Many tests have been undertaken over the years to verify the performance of the LEOS system, with various combinations of wet and dry conditions and soil types. Early experience (Danish Oil & Natural Gas Inc., 1990) gave indications that LEOS might demonstrate unsatisfactory performance with high water tables and in soils with high clay content. Because the sensor tubes are permeable to water vapour, there was concern that this could affect the performance of the system. In dry clay it was believed that gas permeation to the sensor tubes would be affected, and LEOS would have trouble detecting leaks.

These questions were addressed in a series of tests that were conducted with crude oil between June 1988 and May 1990 on the Danish Crude Oil and Condensate Transportation System (Danish Oil & Natural Gas Inc, 1990), using the LASP (the predecessor system to LEOS) system. The tests also addressed issues relating to system capabilities for the leak rate and duration, and the distance between the leak and the gas detector.

The Danish tests involved two installations, a 300 m long section in clay/clay sandy soil, and a 1000 m long section in sandy soil with a high water table. The tubes were looped in each section and connected to valves which allowed recirculation of the gases during the collection period to investigate the question of detection distance. The capability of the system in various soil conditions is shown in Figure 6.4. As a response of 1.0 volts is necessary to produce an alarm, the results show that 0.4 liters/day of crude is detectable from a leak located at 420 m from the gas sensor for wet and dry sand, and for wet clay. These particular tests did not produce an alarm for dry clay conditions at injection rated of up to 1.6 liters/day. With the Liberty Pipeline being situated in wet soils, one can conclude that any leaks will readily reach the sensor tubes.

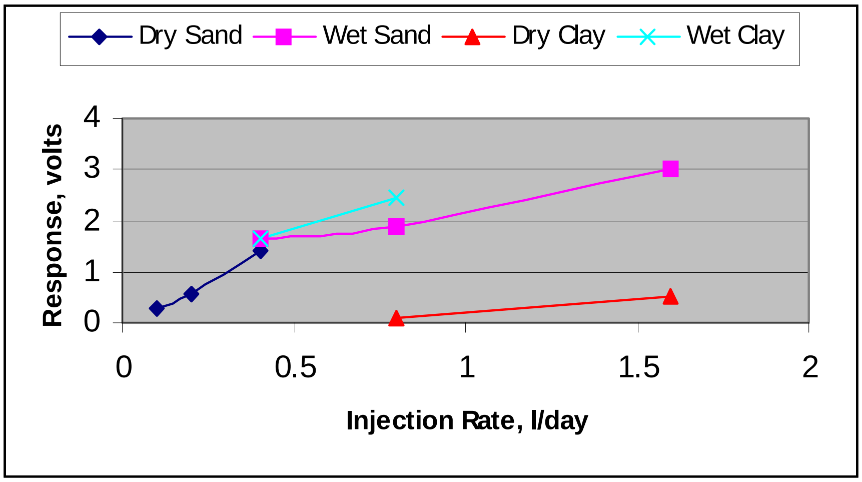

Figure 6.4: Maximum Response vs. Injection Rate at 420 m from the Sensor (Danish Oil Pipeline Inc., 1990)

The results of tests to determine the detection capabilities as a function of distance from the sensor location are shown in Figure 6.5. The figure indicates the decrease in response that would be expected with increasing distance from the gas detection unit. The detection threshold of the LASP (predecessor system to LEOS) system is reduced with distance between the leak source and the sensor due to mixing of the spilled product vapour with the air column in the remainder of the tube, which reduces its concentration peak (Figure 6.2). Furthermore, the background levels of gases, such as methane, impose a limit on the sensitivity of the LEOS system that can be achieved in practice.

Mixing of the gas vapours in the LEOS tube imposes a limit on the sensitivity of the LEOS system in combination with the background vapour levels for a positive leak indication.

One of the conclusions (from the Danish Oil Pipeline, 1990) was that the longest section that could be monitored would be 6 km; this conclusion was drawn from the performance in dry sand, which is found along their pipeline route. A similar conclusion concerning the length limitation was quoted in the Slovak specification (Siemens, 1992): "distances of up to 7.5 km can be monitored in a single measuring loop with out additional equipment." When questioned on this point, Siemens responded (Bryce, 2000**)** that they are able to design the system so that it can detect a leak up to 10 miles from the source. The design options that can be incorporated include increasing the tube diameter, thereby decreasing internal resistance during the evacuation of air from the tube. Ultimately, the length of the line is dictated by the sample air evacuation time, and the target polling rate. For the Liberty Pipeline, the results for the wet sand conditions would be more appropriate, and one could expect that the system would detect leaks up to just over 10 km (6.2 miles) from the detection unit.

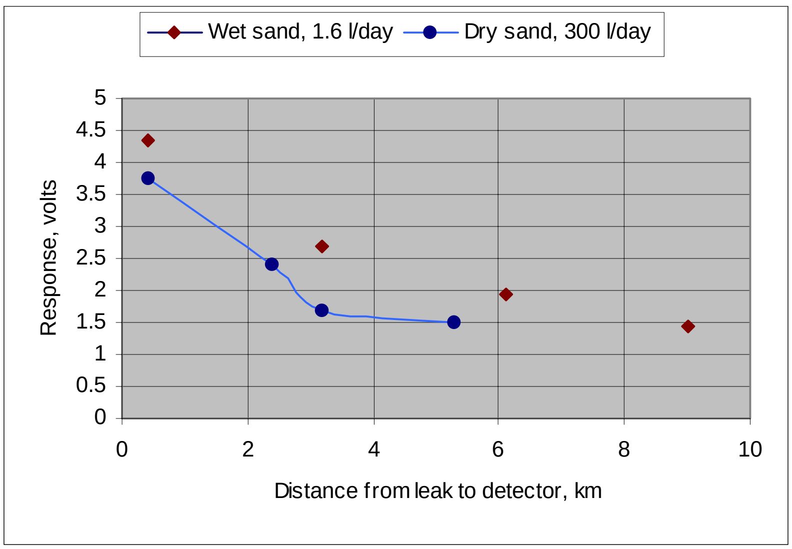

Figure 6.5: Leak Detection Capability of The LASP System as a Function of Distance from the Leak Source for Two Different Tests (Danish Oil Pipeline, 1990). (The system indicates a leak at voltages greater than 1.0)

The Danish Oil Pipeline tests (1990) included an examination of the capabilities as a function of leak rate, and are presented here in Table 6.6. In these results, one can see that injection rates over 0.4 liters/day are necessary to produce an alarm in sandy soils.

Table 6.6: Detection Capabilities of LASP system as a Function of Leak Rate at 420 m From the Detector (Danish Oil Pipeline, 1990)

Soil Material	Injection Rate, l/day	Duration Before Alarm, days	Leak Size, liters	Maximum Signal, volts
Dry Sand	0.1	>25	2.4	0.3
	0.2	>15	3.0	0.55
	0.4	7	2.8	
Wet Sand	0.4	3	1.2	
	0.8	1	0.8	
	1.6	3	4.8	

The authors of the Danish test report conclude from their results that leaks greater than 2 l/day will generate an alarm within 20 days for a distance between the leak and the gas detector of up to 6 km, provided that the leak does not occur in an area with dry clay.

Another example of the lower limit detection capability of the LEOS system was provided from testing completed in 1990 at the Zurich Midfield 200 subfloor fueling facility (Siemens, 1990) with 20 l (about 5 US gal) of jet fuel in a wet sandy soil. They demonstrated that the LEOS system was able to positively identify the leak within 24 hours.

The Danish Oil Pipeline Inc. tests (1990) also investigated the ability of the LEOS system to define the location of a leak. The positional accuracy achieved was found to be dependent on the total length of the measuring loop. It was better than 25 m for a length of 5000 m, roughly, or about 0.5 % of the length of tube.

One final point that is worthy to note from the Danish Oil Pipeline (1990) experience is that in over 1 year of operation there has not been any false calls with the system.

6.3.3 Selection and Installation of the LEOS System for the Northstar Pipeline

The LEOS system was selected (Bryce, 2000) as a supplemental monitoring system for the Northstar Pipeline based on:

(a) the test data provided by Siemens for previous projects;
(b) an endorsement for LEOS provided by the Bavarian TUV (as a certifying authority), and;
(c) the fact that it was the best available technology for supplemental monitoring.

Based on the test data presented for specific tests on methane, ethane and propane, the Northstar project team concluded that the LEOS system would be fit for its intended purpose. Nevertheless, they recognise that it is an unproven technology for Arctic pipelines (Owens, 2000).

Consequently, they made significant efforts to develop a sound, safe design that would mitigate against leaks developing, and hence the LEOS system being required (Owens, 2000).

This point was recognised by Intec, 1999, for the concept design they produced for the Liberty Pipeline as they recommended the LEOS system because it is the best technology currently available. However, they stated that this recommendation could change (e.g., should an improved technology become available in the future or based on the field experience at Northstar).

There have been no installations in this environment from which to obtain information to quantify the likelihood of failure. However, based on review of the literature describing the system and its growing use for leak detection, it is considered that this technology has matured to the point where any field problems can be remedied and the system is expected to function as intended.

In an attempt to include this uncertainty in our analysis the expected worst case performance for the LEOS system was defined (see Table 6.8) and this data was used to define one of the sensitivity studies presented in section 8.2.3.

The LEOS tube was successfully installed this past winter on the Northstar Pipeline. It was pneumatically tested to confirm the integrity of the LEOS tube (Bryce, 2000). However, performance testing has not yet been completed. Siemens intends to visit the site later this year and perform benchmark tests to confirm it is functioning properly. This will include injecting a small amount of hydrogen as a test peak for the system. Other tests may be conducted at that time (P. Bryce, personal communication).

The Northstar LEOS system will not be fully operational until after the measuring station is delivered with the warehouse module in the fall of 2001. Shortly thereafter, when the tube has been hooked up and the test peak generator has been primed and switched on, further more detailed testing and calibration will be done to determine what the background level of naturally occurring methane is along the route. This will enable Siemens to set the system alarm threshold above the background methane levels.

The evolution of hydrogen from the sacrificial anodes will need to be evaluated during field trials as LEOS is sensitive to hydrogen which could affect background readings. LEOS has never been installed in sea water, and the experience from Northstar will provide an indication regarding whether salt or marine growth would affect the performance of the LEOS system. Siemens has stated that this is not expected to be a problem (P. Bryce, personal communication).

The conclusion for this project is that experience is not yet available from the Northstar project to use for evaluating the expected performance of the LEOS system at the Liberty Pipeline.

6.3.4 LEOS System Capabilities and Comparison to Stipulation 18

To obtain a Permit, the Northstar Project was required to meet the threshold leak volume stipulated in the US Army Corps of Engineers Stipulation 18 (Intec, 1999b) of 32.5 bbls/d. The Northstar project team was confident that the LEOS system would allow them to meet this requirement (Bryce, 2000) and this was one reason for installing it.

One would reasonably expect that the Liberty Pipeline would be required to meet the same criterion. Provided that the LEOS system performs as expected at Northstar, this provides a lower bound for the expected performance of the LEOS system.

In fact, smaller leaks would likely be detectable (Siemens, personal communication), but tests on the Northstar configuration remain to be completed to confirm the lower limit (given by Siemens) of 0.3 bbl/day after a diffusion time of 24 hours.

6.3.5 Configuration of the LEOS System Proposed for the Liberty Pipeline

The LEOS sensing tube will be protected within a conduit strapped to the side of the pipe and lowered into the trench during construction (Figure 6.6). One concern with this arrangement is that there could be a leak on the opposite side of the pipe, and it would have to migrate to the vicinity of the tube before it could be detected. This issue was evaluated in the Intec, 1999, report, based on a computer analysis that was prepared for the Northstar Pipeline design. These analyses predicted that vapours from a leak on one side of the pipeline would take about 4-6 hours to diffuse to the sensor tube on the opposite side of the pipe. The field test results examined in FTL’s review support the computer diffusion model as very small leak rates were shown to be detectable within short periods of time.

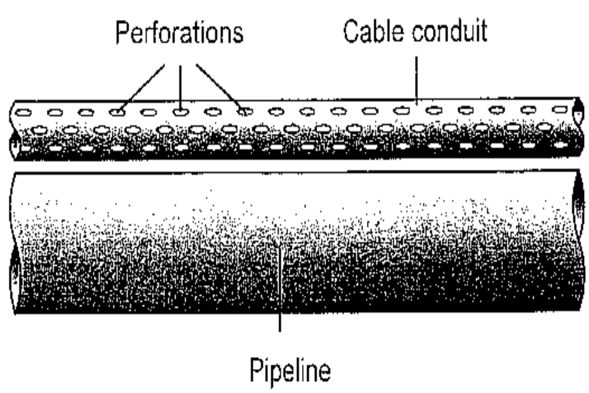

Figure 6.6: Plan View Arrangement of LEOS System for Pipeline Monitoring Where the LEOS Sensing Tube is Located Inside of the Protective Cable Conduit.

Another concern from the design review for the Liberty Pipeline (Stress Engineering Services, 2000) was that the trench backfilling process might compromise the integrity of the LEOS system. Although this is an important issue, it is beyond the scope or terms of reference for this project. The risk analyses conducted here are based on the presumption that the LEOS system can be safely installed. This appears to be the experience from the Northstar Pipeline (section 6.3.4). The conclusion that the LEOS system can be safely installed was reached following personal communication with the Peter Bryce who spearheaded the LEOS design for Northstar. The successful installation was demonstrated through pneumatic testing. (Details are given in section 6.3.3.)

6.4 Other Supplementary Leak Detection Systems

The pipe-in-pipe, pipe in HDPE, and flexible pipe configurations lend themselves to other leak detection technologies, or modifications of the ones described above. In all cases, the leak detection methods would be used to detect leaks below a threshold of 0.15 % of the volumetric flow rate. The proposed use for these alternatives and a brief description of each are included here.

6.4.1 Pipe-in-Pipe and Pipe in HDPE

The annulus between the two pipes is similar to the concept of a separate tube for LEOS detection capability. The air in the annulus is sampled instead of using a separate tube, and the system would be expected to perform as well as the original configuration.

Another idea for the annular space in this alternative is to draw a vacuum on the annulus and monitor the pressure during operation. A leak through either the inner pipe or the shell would result in a loss of vacuum, and would be investigated.

6.4.2 Flexible Pipe

The layered construction of this alternative makes it possible to include a fibre optic cable in one of the intermediate layers to signal a leak from the inner sheath.

With each of the possible systems described here, there would need to be additional development and testing to confirm the capabilities for leak detection. The analysis for risk assessment will not include detailed discussion of these other options.

6.4.3 Capabilities of Other Supplementary Systems

The in-line hydrocarbon sensors described in the Intec, 1999 report would react to the presence of oil or water and transmit this information to the monitoring station. The time to detection is related to the type of sensor system, the dispersion rate of the oil, and its concentration when it reaches the in-line sensor. If periodic monitoring similar to the LEOS arrangement, the maximum detection time would include the sampling interval (6 hrs) and the time between samples (24 hrs).

With the systems that monitor a vacuum, the readings are continuous, and an alarm would be reported as soon as the pressure dropped below the detection threshold. These supplementary systems are expected to be able to alarm at leak rates comparable to LEOS, and are not considered further in our evaluation.

6.4.4 Conclusions Regarding Supplementary Leak Detection Systems

Although a number of technologies are available that may potentially be used, further development would either be required to develop an operational system(s) or they are not expected to provide significant improvement over the leak detection methods specified in the Intec, 1999 report. Consequently, supplemental monitoring systems were not considered further in this risk analysis.

6.5 Summary of Leak Detection Systems

The leak detection capabilities included in Intec, 1999 are consistent for each of the pipeline alternatives: a large leak would be detected within 30 seconds and a small leak (less than 0.15% of flow) within 24 hours. FTL has reviewed the literature for the various technologies and analysed reports describing the capabilities of the systems. FTL's analysis was focused on the PPA system from EFA Technologies, MBLPC software, and the LEOS system from Siemens Power Generation Group, as they would be used for all pipeline alternatives.

6.5.1 PPA and MBLPC Monitoring Systems

The developers of the PPA system claim that this technology is able to detect leaks smaller than 5% of the flow rate within 32 seconds. This limit is considered to be conservative, in our opinion, for the Liberty application as there is only one input and one output point on the line, and the line length is relatively short compared to examples in the literature, making it much simpler to calculate discrepancies. Intec, 1999 suggested a slightly shorter alarm time of 30 seconds. This value (of 30 seconds) was used for subsequent risk analyses. This difference in alarm time will not have a significant effect on the total volume of spilled oil as it will change it by less than 1% (section 7). FTL is therefore in agreement with the values in Intec, 1999, of 97.5 bbl/d (which is 0.15% of the 65,000 bbl/d flow rate), and 30 seconds for the alarm time.

The MBLPC software would be expected to provide a backup to the PPA system and take a bit longer to alarm, as it was presumed that calculations are completed at 5 minute intervals. This results in a loss of 225 bbl before alarm. The effect of this backup was not considered because it has been presumed that the primary monitoring system(s) are operational when the hazards occur (Section 1). However, an assessment was made of the expected worst case performance of the PPA system, and the performance of the MBLPC was used for sensitivity analyses (Section 7).

6.5.2 LEOS System

The results that have been examined lead to the conclusion that the LEOS system will be capable of detecting leaks at very low concentrations, with the actual threshold limits being unique to each installation. Siemens has estimated (Intec, 1999) that the LEOS system should be able to detect hydrocarbon levels as low as 50 liters/day (0.3 bbl/day) for the Liberty Pipeline, and to be able to locate the leak to within +/-160 feet. FTL's analysis supports this claim, and optimistically one can presume that even smaller leaks would be detectable, depending on their distance from the measuring equipment.

Our investigation into this technology showed that LEOS technology has been around for many years and is now becoming widely accepted (and installed) as a proven leak detection technology (see section 6.3.2). There have been obstacles to overcome with design changes over the years and these have been successfully developed. The only uncertainty remaining with the Northstar installation has to do with the background hydrogen level that arises from the use of cathodic protection. These will be overcome with the Northstar trials, and the system should be better than a prototype when installed on Liberty.

6.5.3 Expected Leak Detection Capabilities Used for Subsequent Risk Analyses

This is summarized in Table 6.7. These were used for the base case risk analyses that were conducted.

6.5.4 Expected Worst Case Leak Detection Capabilities

It is recognised that the above leak detection capabilities are subject to some uncertainty. For the risk analyses conducted here, the expected worst case performance of the leak detection systems was also considered (Table 6.7).

For the PPA system, the worst case performance on a single phase line was 0.4% of design flow rate, while all tests were able to detect in less than 1 minute. This was taken as the worst case for the analyses conducted here.

For the LEOS system, the worst-case was taken to be that it does not work at all. This selection was made as the LEOS system has not yet been operated in Arctic waters.

For the MBLPC system, the worst case was taken to be that it does not provide an alarm until two days have elapsed.

The above premises were used to establish the worst-case consequences for a seepage failure event (Section 7).

Table 6.7 Expected and Worst-Case Monitoring System Performance

Monitoring System	Performance Case	Detection Rate	Time to Alarm	Spill Volume Detection Threshold
LEOS	Expected	<= 0.3 bbl/d	>= 30 hrs[1]	0.4 bbl[2]
	Worst Case	Doesn't work at all	Unlimited	Depends on other systems
PPA	Expected	Rate = >= 97.5 bbls/d (0.15 % of Liberty Pipeline flow rate of 65000 bbl/d)	30 sec	>= 0.034 bbls
		Rate = < 97.5 bbl/d (0.15 % of Liberty Pipeline flow rate of 65000 bbl/d)	Unlimited	Depends on other systems
PPA	Worst Case	Rate = >= 260 bbl/d (0.40 % of Liberty Pipeline flow rate of 65000 bbl/d)	60 sec	0.18 bbls
		Rate = < 260 bbl/d (0.4 % of Liberty Pipeline flow rate of 65000 bbl/d)	Unlimited	Depends on other systems
MBLPC	Expected	Not relevant	5 minutes	225 bbls
	Worst Case	Not relevant	2 days	depends on other systems

Notes:

1. The alarm time of 30 hours was arrived at by assuming that a leak occurred near the island just after the test gas peak passed the leak location. The next sample would be 24 hours later, and adding the 6 hours required for sampling the line, a maximum alarm time of 30 hours was determined. The leak rate only needs to be a minimum of 0.3 bbl/day for detection within 24 hours.

2. At lower rates than 0.3 bbl/d, the alarm time is expected to increase. For example, consider a leak rate of 0.1 bbl/day. Provided that that gas vapours from flow rates below 0.3 bbl/day would accumulate in the vicinity of the pipeline until they produce a gas concentration similar to the 0.3 bbl/day leak, the alarm time would be expected to be a maximum of 90 hours.

   However, if gas vapours fail to accumulate in the same manner, a larger spill volume would occur before being detected. The leak detection threshold used as the worst case is described in the next section.

7.0 CONSEQUENCE MODELLING

7.1 Introduction

A consequence model was developed to calculate the oil volume released in a failure event. Two general types of failure events were considered as follows:

(a) failures that can be detected by a PPA/MBLPC system, and that lead to shut-in of the pipeline. This type of failure could be produced by pipeline rupture or by flow through cracks and flaws.

(b) failures that are not detectable by a PPA/MBLPC system because they are below its leak detection threshold. This was termed seepage here.

The model is limited to estimating the spill volume and it does not include an evaluation of the environmental impact or the event cost. Although these are important issues as well, they are beyond the scope or terms of reference for this project.

The important parameters affecting the rate of oil spill and the total spill volume include the internal pressure in the pipeline, the oil's physical properties, the pipe dimensions, shape of the opening, leak detection thresholds, and remedial action delay times. For detectable leaks, pipeline failure consequences were estimated over the time history of the event, which is comprised of three steps (Figure 7.1):

(a) line breach;
(b) leak detection; and,
(c) line shut-in and repair.

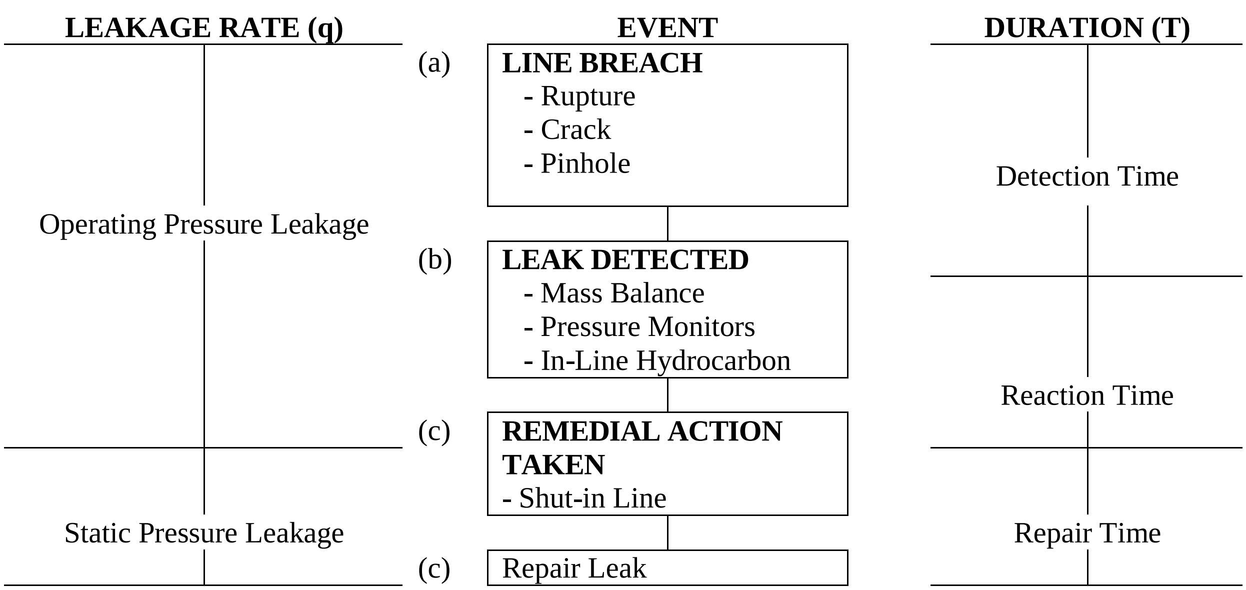

Figure 7.1: Consequence Model Event History

The total volume spilled for a detectable event will follow the time history shown in Figure 7.2. It should be noted that the shape of the time history curve will depend upon the nature of the line break. The steps are as summarised below:

(a) the line is at full operation at the instant that failure occurs.

(b) oil is pumped into the line at the production rate of 65,000 bbls/day until:
- (i) the leak is detected;
- (ii) the decision is made to initiate line shut-in; and,
- (iii) line shut-in is commenced.

(c) the flow rate is reduced as the line is shut-in and depressurised.

(d) oil is slowly released after shut-in as oil drains from the line. In practice, oil drainage will be limited by one or more of the following:

- (i) all of the oil capable of being drained from the line is released;
- (ii) the pipeline opening is repaired; or,
- (iii) the oil is evacuated from the line (i.e., the line is purged).

Because the time periods and flow rates associated with cases (i) to (iii) above are difficult to estimate, it was assumed here that all possible oil drainage would occur. This is the most conservative case.

It is noted that if the failure is a hairline crack, there would be very little oil lost beyond step 3 after the line has been depressurized, and there would likely be no oil lost as the line is purged.

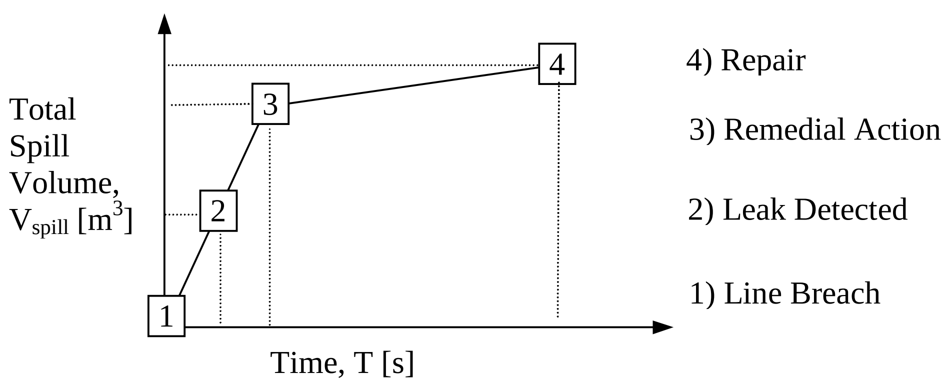

Figure 7.2: Trend: Total Volume Spilled During an Event

The consequence model and its component parts are described in the sections that follow. Three types of pipeline failure were considered:

(a) rupture;
(b) flow through flaws or cracks; and,

(c) seepage.

The total spill volume for each hazard, $V_{total\text{-}each\ hazard}$, was calculated as:

$$V_{total\text{-}each\ hazard} = V_{rupture} + V_{flaw\ or\ crack} + V_{seepage} \qquad [7.1]$$

where: $V_{rupture}$, $V_{flaw\ or\ crack}$, $V_{seepage}$ = the oil volumes spilled as a result of pipeline rupture; flow through a stable crack ; and seepage, respectively.

"$V_{rupture}$", "$V_{flaw\ or\ crack}$", and "$V_{seepage}$" were defined as follows:

$$V_{rupture} = q_{rupture} * (T_D + T_{react} + T_{valve\ closure}) + V_{depressurisation} + V_{drainage} \qquad [7.2]$$
$$V_{flaw\ or\ crack} = q_{flaw\ or\ crack} * (T_D + T_{react} + T_{valve\ closure}) + V_{drainage} \qquad [7.3]$$
$V_{seepage}$ = f ($q_{minimum}$, seepage period) – described in Section 7.3 [7.4]
$V_{drainage}$ = f (hazard type, and water depth) [7.5]

where: $q_{rupture}$ = the oil release rate for pipeline rupture while the line is under operating pressure

$q_{flaw\ or\ crack}$ = the oil release rate for pipeline failure due to flow through flaws or cracks while the line is under operating pressure

$q_{minimum}$ = the minimum detectable oil release rate(s) for the monitoring system(s) used

Seepage Period = the length of time that seepage is expected to occur. This is the time before this seepage is detected by other means, such as visual inspections, aerial reconnaissance, or third party reports.

$V_{drainage}$ = the oil volume that will drain out of the line after the valves at the shore crossing and at the island have been closed; and after it has been depressurised. This is dependent on the water depth and it varies with the hazard type, because the hazards occur at different water depth ranges.

$V_{depressurisation}$ = the oil volume increase that occurs due to expansion when the line is depressurised

T_D = the time elapsed between pipeline failure and leak detection

T_{react} = the time elapsed between leak detection and the decision to take action

$T_{valve\ closure}$ = the time required for valve closure

7.2 Leakage Rate Through a Stable Crack or Flaw

The leakage rate for this case was calculated by:

(a) establishing the expected size of a flaw or defect, and how its size would vary with pressure, and;

(b) determining the expected oil flow out of these orifices using published guidelines for pipelines (BS PD6493) and AS (Australian Standard) 1978, 1987.

7.2.1 Opening Area – Maximum Stable Crack Sizes

The opening area associated with a crack was estimated using the maximum stable through-wall crack length that may be supported in the pipe prior to fracture or plastic collapse. This crack size is estimated using the Level 2 Failure Assessment Diagram (FAD) approach outlined in BS PD6493, which considers the interaction of fracture and plastic collapse failure mechanisms. The critical crack length for the pipes considered in the Liberty Pipeline project would be dependent on material properties and pipe geometry. While the nominal (minimum specified) pipe material properties for X52 grade pipe are known, the fracture toughness (Crack Tip Opening Displacement CTOD, δ) of the base metal and weldments are not known.

Figure 7.3 describes the critical crack length for a range of CTOD values. It can be seen that the critical circumferential flaw size starts off at 220 mm at a CTOD of 0.03 mm and approaches a maximum value of 250 mm just beyond 0.10 mm CTOD.

The critical axial flaw size over the same range of CTOD starts at 150 mm and approaches a maximum of 230 mm at high toughness values.

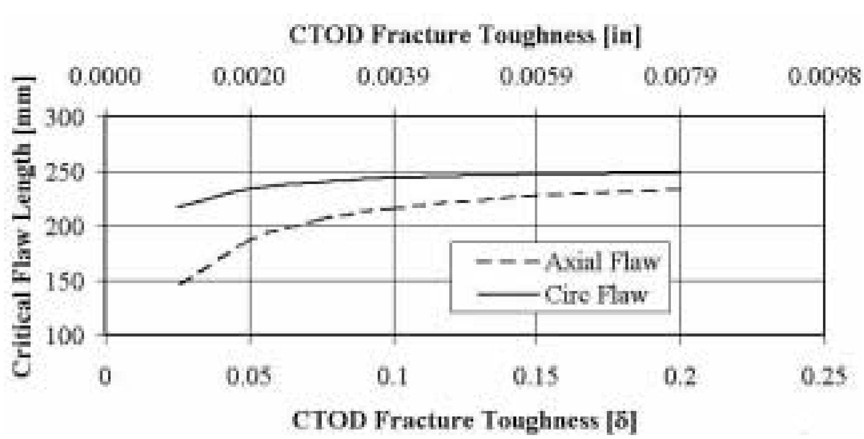

Figure 7.3: Critical Through Wall Critical Crack Length [mm] vs CTOD [mm]

As the welding procedures for Liberty have not been developed, the actual mechanical properties and CTOD values are not available. One can, however, refer to previous tests to estimate a lower bound value for the weld. The Northstar project used a custom order of Lincoln Shield Arc 80 electrodes (Harris, 2000) and completed CTOD tests to establish maximum allowable flaw sizes. The mechanical tests were not reported in the paper, but a lower bound toughness of 0.125 mm is to be expected in our opinion.

It is reasonable to assume that the Liberty Pipeline would utilise the Northstar approach and obtain a special order of electrodes. Thus the toughness would be without doubt, greater than 0.125 mm. This would ensure that the critical flaw size is not dependent on the actual toughness of the weld and the maximum flaw sizes (of 250 mm for a circumferential flaw and 230 mm for an axial flaw) from the above analysis could be used. Intec, 1999 assumed that 1 in 20 welds would have a maximum allowable weld flaw length of 25 mm. The allowable flaw length calculated here is 10 times the length that they had taken for weld defect acceptance.

To calculate the pipe opening area for the critical crack lengths, one needs to establish the Crack Mouth Opening Displacement (CMOD - Figure 7.4), and to estimate the amount of crack bulging that will occur under pressure. The CMOD can be estimated (Graville and Dinovitzer, 1996) from the following equation:

$$CMOD = \frac{2\sigma_y L}{\pi E} \ln\left(\frac{1+\sin\left(\frac{\pi\sigma}{2\sigma_y}\right)}{1-\sin\left(\frac{\pi\sigma}{2\sigma_y}\right)} \right) \qquad [7.6]$$

where L is the crack length, E is the modulus of elasticity, σ is the nominal applied stress and σ_y is the material yield stress.

This formulation estimates the elongation associated with stresses oriented transverse to the crack, but it does not consider the increased mouth opening caused by bulging.

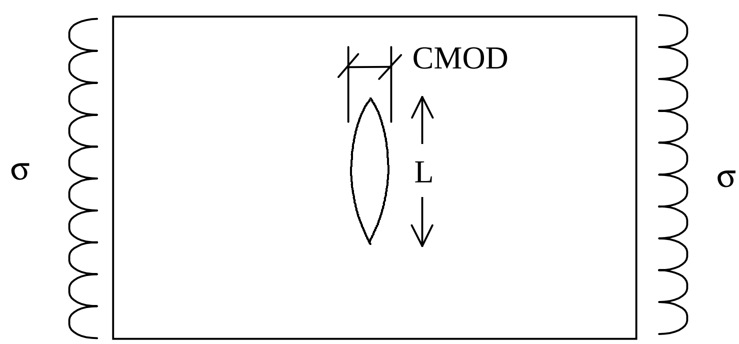

Figure 7.4: Plate Crack Mouth Opening Displacement

The load applied to the crack from the internal pressure produces the bulging deformation. In a fracture mechanics approach, the effect of bulging is accounted for using a Folias factor (Folias, 1965) and a similar formulation has been used to estimate the effect of bulging on CMOD (Graville & Dinovitzer, 1996). The plate axial extension CMOD is magnified to account for bulging by considering the pipe radius (R), wall thickness (t) and crack length in estimating a Folias-type deformation factor (F) as follows (Graville & Dinovitzer, 1996):

$$F = \left(1 + \frac{1.255L^2}{4Rt} - \frac{0.0135L^4}{(4Rt)^2}\right) \qquad [7.7]$$

By considering the above formulation, and the potential internal pipe pressures, the crack mouth opening displacements for the axial and circumferential cracks may be estimated for the internal pressure levels of interest as shown in Table 7.1. The crack mouth opening closes with reduced pressure, and at lower pressure, the bulging effect is neglected.

Table 7.1: Crack Mouth Opening Displacements (CMOD) [mm]

Internal Pressure	Axial Flaw (230 mm)	Circ. Flaw (250 mm)
Operating Pressure (taken as 1415 psi)	6.38	2.97
Shut-in pressure (taken as 1.45 psi, 10 kPa, which is representative of hydrostatic pressures after shut-in)	0.75	0.30

With the crack length and opening defined, the crack opening area is estimated by assuming that the crack edges are parabolic arcs (Figure 7.4). The crack opening area may be estimated as:

$$A_{crack} = CMOD \times L / 3 \qquad [7.8]$$

Based on this equation the crack opening areas in the operational and shut-in pressure regime may be estimated as shown in Table 7.2.

Table 7.2: Crack Opening Areas (A_{Crack}) [mm^2]

Internal Pressure	Axial Flaw (230 mm)	Circ. Flaw (250 mm)
Operating Pressure (taken as 1415 psi)	489.1	247.5
Shut-in pressure (taken as 1.45 psi, 10 kPa, which is representative of hydrostatic pressures after shut-in)	57.5	25.0

7.2.2 Opening Area - Pinholes

The smallest type of opening from which one can observe a leak is a pinhole type of defect. As the name implies, the area of the opening appears as a pinhole in the pipe, and can be either in the pipe body or in one of the welds. Pinholes in the pipe wall are often associated with corrosion pits. External corrosion can be found anywhere around the pipe circumference, and is typically found where there has been some coating damage. Internal corrosion is essentially always found between the five and seven o'clock positions, and is deepest at the six o'clock position of the pipe. Both internal and external corrosion that penetrates the pipe and causes a leak is circular in shape on the surface and through the pipe wall. For example, Alyeska (Ricca, 1991) reported pits 0.5 to 1.0 in. diameter and 125+ mils deep after approximately 12 years of service. Pits that leak only penetrate the wall at the deepest point, so one can assume that the diameter of the hole at the start of the leak would be in the neighbourhood of 1 mm. As flow passes through the orifice, the hole could enlarge by erosion, but is not expected to become any larger than 3 mm diameter, based on our experience.

The other general case of pinhole defects are those that are observed to occur at weld anomalies, such as cracks or lack of fusion defects on Electric Resistance Welded (ERW) pipe. In these cases, the cracks are very small and might only leak at or near the maximum operating pressure where the crack mouth opening is greatest. The opening areas of this class of defect would have an equivalent diameter of less than 1 mm, based on our experience.

7.2.3 Methodology for Calculating Leakage Rates for a Crack, Flaw, or Pinhole Leak

The leakage rate through a small opening, such as a crack, may be estimated as an orifice flow problem in which the leakage rate is a function of the pressure differential across the pipe wall and the estimated opening area. The leakage rate is related to the pressure difference across the pipe wall (AS 1978, 1987) as:

$$\Delta P = \left(\frac{4 \rho q^2}{\pi^2 d^4} \right) \left(3 + \frac{2 f t}{d} \right) \qquad [7.9]$$

where: ΔP = pressure difference across the pipe wall [Pa]
ρ = density of fluid (taken as 860 kg/m^3)
q = flow rate through the opening [m^3/s]
f = Darcy-Weisbach friction factor = 64 / Re [for Re < 2000]
= 0.316 / Re$^{0.25}$ [for 2000<Re<100000]
Re = Reynolds number = $4 q / (\pi d \nu)$
ν = kinematic viscosity (taken as 1×10^{-5} m^2/s)
t = pipe wall thickness [m]
d = diameter of equivalent smooth circular opening [m]

Equation 7.9 was solved for the opening areas of interest. As expected, the flow rate increases with the pressure differential and with the opening area (Figure 7.5).

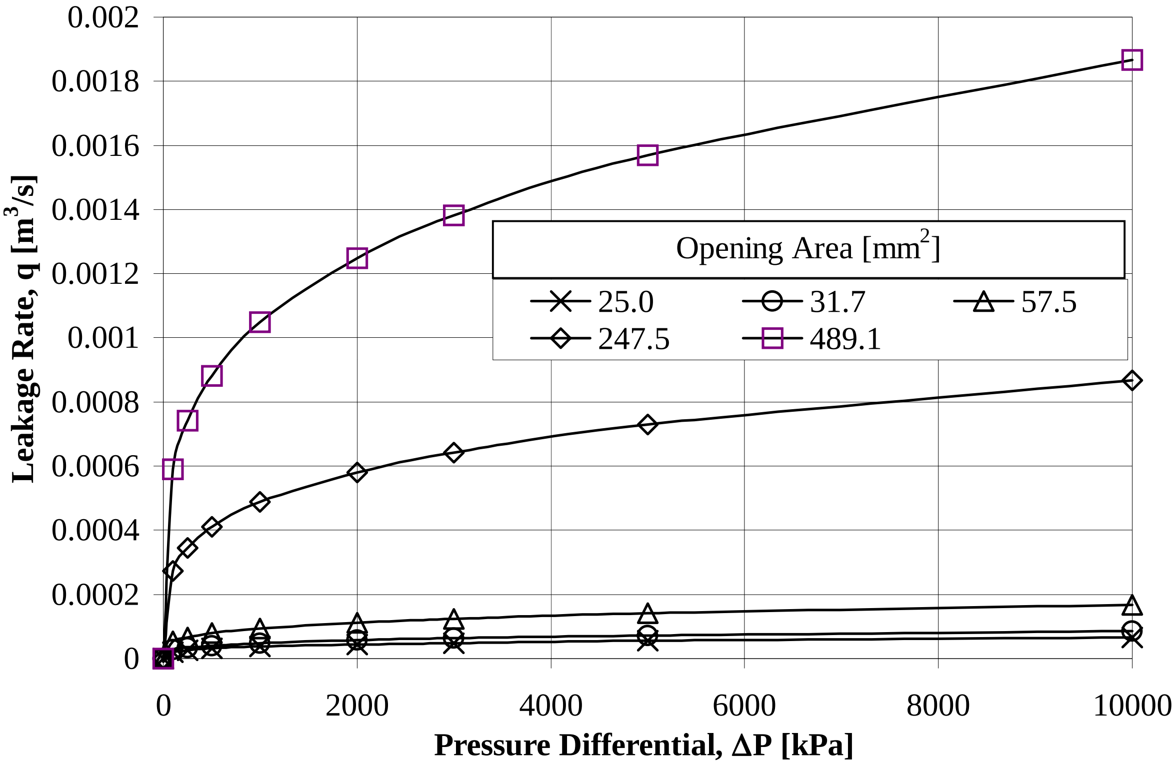

Figure 7.5: Leakage Rate and Pressure Differential Relationship for Cracks

The leak rates from tight defects or pinholes can also be obtained using equation 7.9 with appropriate values used for the opening areas. As mentioned earlier, the calculations assume that the leak discharges through a hole of equivalent diameter that is radial, has a circular cross-section, and has smooth walls. Experimental verification of the calculations has shown that the calculated leak rates slightly overestimate the actual product loss. The estimated leakage rates are shown in Figure 7.6.

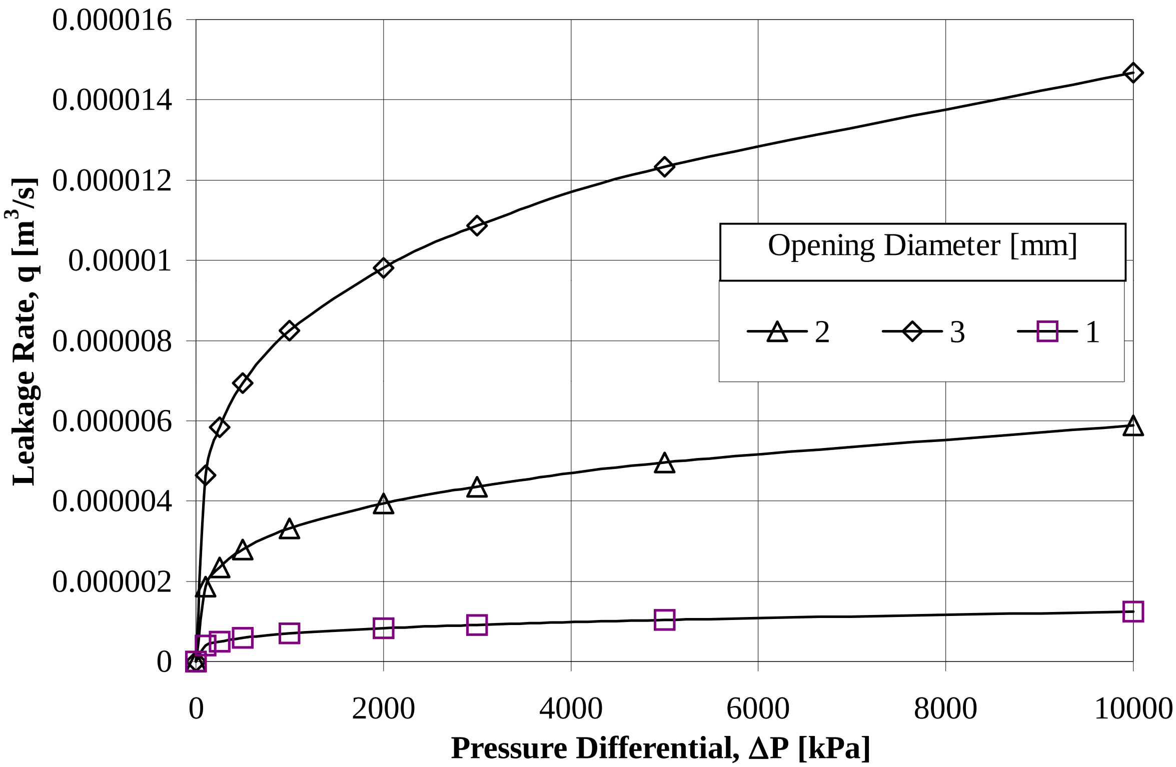

Figure 7.6: Leakage Rate and Pressure Differential Relationship for Pinhole Leaks

In Figure 7.6, the leakage rates at the maximum operating pressures are approximately 0.67, 3.4, and 8 bbl/day for the 1, 2, and 3 mm diameter holes, respectively.

7.3 Leakage Event Durations and Volumes

This section discusses leakage event durations and volumes for the case where there is no secondary containment provided by the pipeline design. The effects of secondary containment are discussed in section 8.

As stated previously (section 7.1), the oil release event was divided into the following stages (for oil releases that are detectable by PPA/MBLPC, which may be produced by pipeline rupture, flow through a stable crack, or flow through a corrosion pit):

(a) oil released between the onset of failure and the time that the leak is detected;

(b) oil released between leak detection and the time required for the operator to decide to initiate line shut-in;

(c) oil released while the line is shut-in and repaired. The total oil volume released during this stage is comprised of three parts:

(i) oil released while the valves at the island and at the shore crossing are being closed;
(ii) oil released during depressurisation of the line;
(iii) oil released by drainage after the line is shut in, and before it is repaired or purged.

In addition to the above, oil may be released by leaks that are too small to be detected by the monitoring system(s) used (termed seepage here). This is discussed in Section 7.3.5.

7.3.1 Oil Spilled Between the Onset of Pipeline Failure and Leak Detection

The detection time associated with a given failure mode was determined based on the time required for the pipeline leak detection system to recognise that leakage has occurred. The detection time is a function of the leakage rate, and the capabilities of the leak detection system(s) used (i.e., leak detection threshold, polling rate). Monitoring systems are discussed in section 6.

Leak detection systems identify that a leak is occurring, however they do not stop the leak. A well-trained operator will respond to the leakage reported by the leak detection system and shut down the pumps and isolate the line. This action does not however stop leakage, it slows it by reducing the pipe internal pressure. Leakage will continue until the pipe is emptied either through leakage or purging.

Line rupture would be readily detectable by the PPA or MB leak detection systems. Intec, 1999, stated that the PPA would likely alarm within 30 seconds. This alarm time was taken as given for the analyses presented here. Of course, the spilled oil volume is dependent on this value; however, because the oil volume spilled during the reaction and shut-in period is considerably larger as this time is much longer, the results are not very sensitive to this time period. As well, the assignment of a reaction time contains considerably more uncertainty because it involves human response.

For all of the crack opening areas defined in Section 7.2, the flow rate would be large enough that the spill would be detected by a PPA system, as shown below:

- Leak detection threshold of a PPA system: taken as 0.15% of flow rate;
- Pipeline flow rate: 65,000 bbls/day;
- Minimum detectable flow rate: 97.5 bbls/day ($1.79 * 10^{-4}$ m^3/sec).

For a pressure differential of 1415 psi (9749 kPa), flow through the maximum stable axial or longitudinal crack will produce a flow rate above 97.5 bbls/day ($1.79 * 10^{-4}$ m^3/sec). See Section 7.2 for the methodology used to establish this. Thus, the 30-second alarm time (given above for pipeline rupture) would apply as well for pipeline failure by flow through large cracks or flaws.

Smaller defects (e.g., tight cracks, pinholes) would produce flow rates below the minimum detectable flow rate for a PPA system (Section 7.2.3). This is discussed further in Section 7.3.5.

The oil spill volume was calculated by assuming that, prior to detection, the pipeline was operating at a flow rate of 65,000 bbls/day. The operational pressure differential was taken to be the internal operating pressure (i.e., 1415 psi, or 9749.2 kPa).

The leak volumes calculated for this period are summarized below:

Table 7.3: Oil Volume Spilled Between Pipeline Failure and Leak Detection, at a Pipeline Flow Rate of 65,000 bbl/day

Pipeline Failure Mode	Oil Release Rate, bbl/day	Leakage Time	Oil Volume Spilled
Rupture	65,000	30 seconds	23 bbls
Flow Through Stable Longitudinal Crack	1005	30 seconds	0.35 bbls
Flow Through Stable Circumferential Crack	489	30 seconds	0.17 bbls

7.3.2 Oil Released Between Leak Detection and the Initiation of Line Shut-In

This covers the period from detection of the leak until actions are initiated to shut in the line. The duration of this stage includes the time required to make a decision to take action and the time required to initiate the action. This includes the time period required for the operator to review the alarm and to initiate pump shutdown and line isolation. Throughout this time span, it is assumed that the pipeline remains operational at 65,000 bbls/day and at 1415 psi internal pressure.

Intec, 1999, suggested that 5 minutes would elapse during this period. Based on the high level of scrutiny that this project and the Northstar project have received, FTL expects that the Liberty pipeline would be operated to a high standard. The information presented in section 6.2.1 indicates that a 5-minute interval would be a conservative estimate of the time to detect a leak as Liberty is short line and the polling rate is less than 1 second. The PPA system would confirm the initial leak warning within a minute and it is expected that line shutdown would be initiated. This value was used directly in FTL's analyses as it is considered to be reasonable.

The calculated leak volumes for this period are summarised below:

Table 7.4: Oil Volume Spilled Between Leak Detection and the Initiation of Line Shut-In (for a Pipeline Flow Rate of 65,000 bbl/day)

Pipeline Failure Mode	Oil Release Rate, bbl/day	Leakage Time	Oil Volume Spilled, bbls
Rupture	65,000	5 minutes	226
Flow Through Stable Longitudinal Crack	1005	5 minutes	3.5
Flow Through Stable Circumferential Crack	489	5 minutes	1.7

7.3.3 Line Shut-In: Oil Released During Valve Closure and Line Depressurization

After the leak has been detected and confirmed by the operator, line shutdown would be initiated, by shutting off pumps and isolating the line. Intec, 1999 suggested a time period of 8.5 minutes for valve closure, and this time duration was taken as given for the analyses conducted here.

Leakage volumes for this period were calculated by presuming that the pipeline continues to operate at a flow rate of 65,000 bbl/day and an internal pressure of 1415 psi throughout the whole valve closure operation. This errs conservatively, as in practice, the flow rate would decrease only slightly with time after the mainline pump is shut down and up until the valves are closed completely. Note that Intec, 1999 assumed that the line would stop immediately and 170 bbl would drain from the overland section. This volume was not included in the FTL volume estimations.

In addition to the oil released during valve closure, another 27 barrels would be expected to be discharged due to expansion of the oil in the 7.5 mile long line as the pressure is reduced from 1415 to approximately 0 psi (Intec, 1999). This value was used directly for the risk analyses done here.

For pipeline failure by leakage through flaws or cracks, tight cracks would stop leaking once the pressure is reduced sufficiently to close the crack, but the worst case of reducing the pressure to zero was assumed for this project.

The calculated leak volumes for this period are summarised below:

Table 7.5: Oil Volume Spilled During Valve Closure and Line Depressurization (for a Pipeline Flow Rate of 65,000 bbl/day)

Pipeline Failure Mode	Oil Release Rate, bbl/day	Leakage Time	Oil Volume Spilled (note 1), bbls
Rupture	65,000	8.5 minutes	411
Flow Through Stable Longitudinal Crack	1005	8.5 minutes	33
Flow Through Stable Circumferential Crack	489	8.5 minutes	30

Notes:

1. The oil volume spilled is the total of the oil released during valve closure, and the amount due to oil expansion in the line during depressurisation, the latter being taken as 27 bbls (the value in Intec, 1999).

7.3.4 Line Shut-In and Repair: Oil Drainage From the Line After Depressurization

Once the pipeline flow has been stopped, and the line has been shut-in and depressurised, the leakage rate will be significantly reduced but not eliminated. Drainage will continue until one or more of the following events occur:

(i) all of the oil capable of being drained from the line is released;
(ii) the pipeline opening is repaired; or,
(iii) the oil is evacuated from the line (i.e., the line is purged).

Because the time periods required for the above actions are difficult to estimate, the volume of spilled oil was calculated here by assuming that all oil capable of draining out of the pipeline is released. This is the worst case.

The amount of oil capable of being drained is based on leak location and pipeline topography. The calculated oil volumes were limited to the offshore portion of the line, as the valves at the shore crossing and at Liberty Island would presumably be closed. Furthermore, there are a number of high spots that would act to trap oil, and the elevation of the oil-water interface was assumed to be at the elevation of the leak. In the shallower regions, the water would sink to the bottom of the pipe, thus displacing most of the oil in the line.

The offshore alignment drawings from Intec, 1999, for the Liberty Pipeline route were used to determine the elevation profile of the Liberty Pipeline Route (Figure 7.7). This was used as the basis for determining the amount of oil that could drain from the line in the event of a rupture.

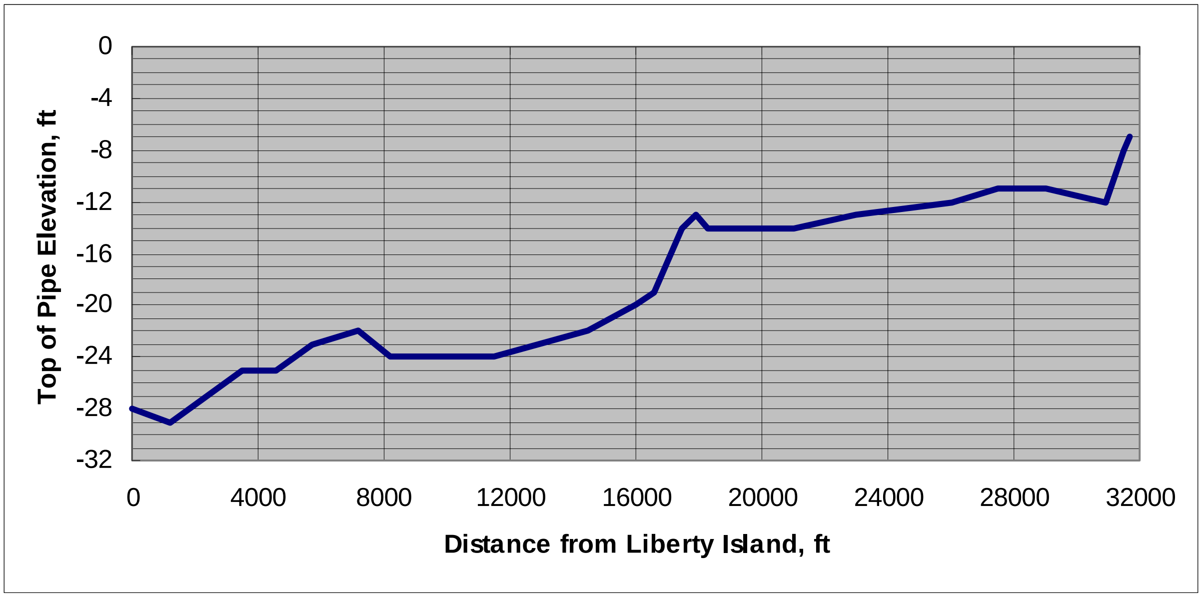

Figure 7.7: Top of Pipe Elevation vs. Distance from Liberty Island

The elevation to the top of the pipe at the edge of the berm at Liberty Island is approximately -28 ft (with respect to sea level). The line slopes down approximately 1 foot to a point 1230 ft. from the island, and then rises to the first high point of –22 ft. (relative to the pipe on either side) at 7,150 ft from Liberty Island. Going towards the shore, the pipe top elevation dips by 2 ft. and does not reach –22 ft. until 14,500 ft. from Liberty Island. There is another high point at approximately 17,920 ft. from the island, and then a final one at 27,500 ft. The pipeline crosses the shoreline at approximately 31,800 feet from the island.

The significant local high points along the line are at 7,150, 17,920, and 27,500 feet from Liberty Island. For example, a rupture 7,150 ft from Liberty Island would drain the oil between 600 ft and 14,000 ft from the island as they are at lower depths and there are no high spots to trap oil. Using a line fill of 663.5 bbl/mile (based on the steel single pipe design), a rupture at 7,150 feet would release 1,685 bbl of oil. Similar calculations at the high spots at 17,920 and 27,500 ft. from Liberty give approximate spill volumes of 2,010 and 1,590 bbl, respectively. It is seen that a rupture in line closest to Liberty Island would not result in a large spill as most of the oil would remain in the pipe. This approach was continued at other locations along the line, allowing the estimate of spill volumes shown in Figure 7.8 to be calculated.

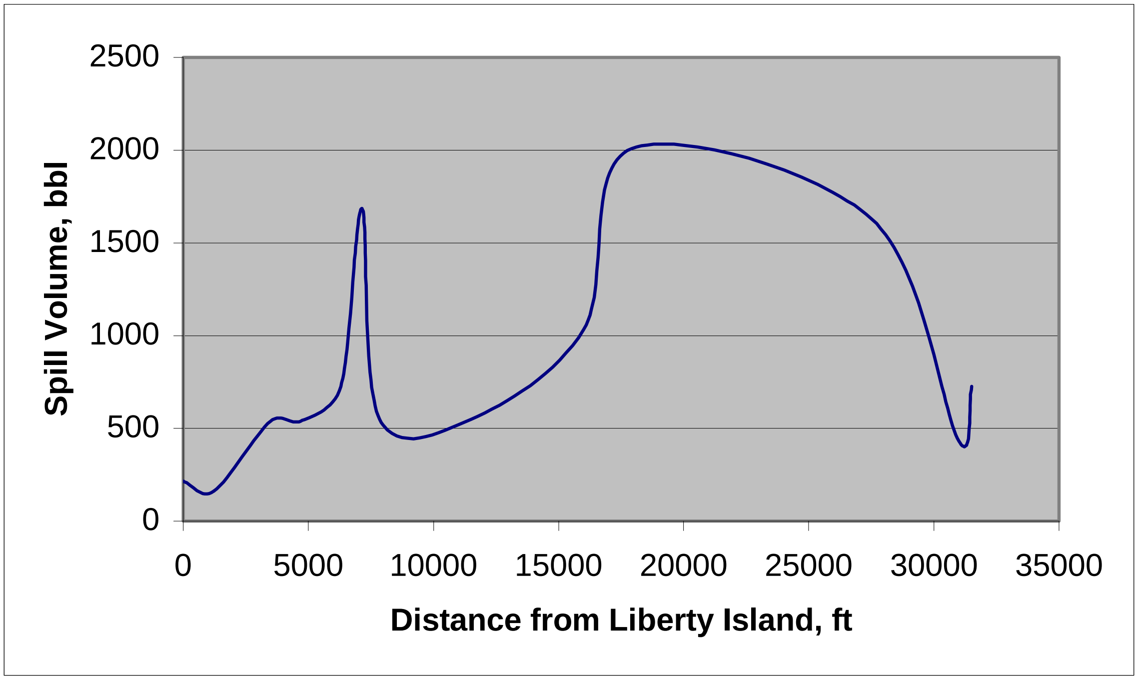

Figure 7.8: Oil Drainage Volumes in the Event of a Pipeline Rupture

The drainage volume varies with location along the pipeline. As well, because the hazards of concern occur at different water depth ranges (section 3), the type of hazard that occurs (Table 7.6) will affect the drainage volume.

Table 7.6: Oil Drainage Volumes for Each Hazard

	Oil Drainage Volumes, bbl			
	Minimum Water Depth for Hazard	Average Water Depth for Hazard	Maximum Water Depth for Hazard	Max. Drainage Volume Over Range of Applicable Water Depths
Ice gouging	10 ft ; 1880 bbl	16 ft ; 1650 bbl	22 ft ; 500 bbl	1880 bbl
Strudel scour	4 ft ; 1600 bbl	12 ft ; 1800 bbl	20 ft ; 400 bbl	2010 bbl
Permafrost thaw subsidence	0 ft ; 700 bbl	2 ft; 1850 bbl	4 ft; 1600 bbl	1900 bbl
Thermal loads causing upheaval buckling	0 ft ; 700 bbl	11 ft; 1500 bbl	22 ft; 500 bbl	2010 bbl
Operational failures	0 ft ; 700 bbl	11 ft; 1500 bbl	22 ft; 500 bbl	2010 bbl
Third party activities	0 ft ; 700 bbl	11 ft; 1500 bbl	22 ft; 500 bbl	2010 bbl

7.3.5 Seepage

The oil volume spilled as a result of seepage (e.g., through pinholes or tight cracks) will be controlled by the limits of detection of the monitoring system(s) used. Two cases were considered as follows.

7.3.5(a) Seepage Volumes for the Expected Performance of the Monitoring Systems Used

In this case, the PPA, MBLPC, and LEOS systems were all assumed to perform as expected (section 6.5). Two situations are possible within this case:

(a) a leak occurs that is below the PPA detection threshold but it is detectable with the LEOS system. The maximum possible oil spill volume would occur if the leak was at the PPA leak detection threshold and it persisted for the maximum possible sampling time for the LEOS system.

(b) a leak occurs that is below the detection threshold of both the PPA and the LEOS systems.

To analyse oil seepage volumes due to these two cases, rigorously one should: (a) evaluate the risk separately for each one by determining event probabilities and consequences for each one individually; and: (b) sum the individual risks.

A simplified approach was used here, in which the consequence was evaluated for the combination of the two cases. This errs conservatively, as it includes the risk due to case (b) twice. However, this error is slight because the oil volume released due to case (a) is about 10 times more than that for case (b). This is described subsequently.

The combined approach for consequence modelling was adopted because event probabilities cannot be defined accurately for each case separately. Failure statistics were used to establish event probabilities for seepage events (section 7.5) which are incapable of distinguishing between the two cases above. The error introduced by the combined approach used here is believed to be within the bounds of uncertainty for establishing event probabilities.

The seepage volumes for the “expected” detection limits (given in section 6) were calculated using the equations below, and are summarised in Table 7.7.

$$V_{\text{seepage (expected)}} = V_{\text{expected to be undetectable by PPA}} + V_{\text{expected to be undetectable by LEOS}} \qquad [7.10]$$

where: $V_{\text{seepage (expected)}}$ = the oil volume spilled by seepage based on the expected performances of the monitoring systems

The terms in equations 7.10 were defined as follows:

$$V_{\text{expected to be undetectable by LEOS}} = 0.4 \text{ bbls (section 6)} \qquad [7.11]$$
$$V_{\text{expected to be undetectable by PPA}} = q_{\text{expected detection threshold– PPA}} * T_{\text{Sampling LEOS}} \qquad [7.12]$$

where: $q_{\text{expected detection threshold– PPA}}$ = 97.5 bbl/d (section 6)
$T_{\text{Sampling LEOS}}$ = 30 hours (section 6), which represents the worst case sample time

Table7.7: Expected Seepage Volumes - Based on the Expected Performance of the Monitoring Systems

$V_{\text{expected to be undetectable by PPA}}$	$V_{\text{expected to be undetectable by LEOS}}$	Expected Total Seepage Volume
122 bbls	0.4 bbls	123 bbls

7.3.5(b) Seepage Volumes for the Worst-Case Performance of the Monitoring Systems Used

The following was presumed for this case (Section 6.5):

(a) the LEOS system does not work at all;
(b) the detection threshold of the PPA system is 0.4 % of the Liberty Pipeline’s flow rate of 65000 bbls/d, which gives a detection threshold of 260 bbl/d, and;
(c) the MBLPC system does not provide an alarm until two days have elapsed.

The seepage volumes for the "worst-case" detection limits (given in section 6) were calculated using the equation below:

$$V_{seepage\ (worst\ case)} = Rate_{worst\ case\ -\ undetectable\ by\ PPA} * T_{worst\ case\ -alarm\ time\ for\ MBLPC} \qquad [7.13]$$

where: $V_{seepage\ (worst\ case)}$ = the oil volume spilled by seepage based on the worst case performances of the monitoring systems

Table 7.8 summarizes the terms in equation 7.13 and the results obtained.

Table 7.8: Expected Worst Case Seepage Volumes - Based on the Expected Worst Case Performance of the Monitoring Systems

$Rate_{worst\ case\ -\ undetectable\ by\ PPA}$	$T_{worst\ case\ -alarm\ time\ for\ MBLPC}$	Expected Total Worst Case Seepage Volume
260 bbl/d	2 days	520 bbls

7.4 Spill Timing

Some of the hazards are seasonal while others may occur at any time of the year, as summarised in Table 7.9.

Table 7.9: Summary: Likely Spill Timing by Hazards

Hazard	Spill Timing
Ice Gouging	Most likely to occur at freeze-up and break-up, when the ice is mobile
Strudel scour	Limited to period when the ice is overflooded by spring runoff, typically May-June
Upheaval buckling	This depends on the mechanism leading to upheaval buckling: (a) heating of pipeline by the warm oil – will occur early on in the life of the line. (b) Partial cover loss due to strudel scour – will occur annually in spring, typically May-June (c) Permafrost thaw subsidence – risk will increase with time over the life of the pipeline as the thaw bulb grows
Operational failures	(a) Testing prior to service is expected to remove risks related to defects/problems that would cause immediate failures (e.g., equipment malfunctions, installation problems, etc.) (b) When the pipeline is in operation, the risk will increase with time over the life of the line owing to the effects of degradation such as corrosion, which increases with time.
Third party activities	Likely to occur at any time during the life of the pipeline

Because the oil drainage volume varies with the type of hazard (section 7.3), the oil drainage volume will thus vary with time of year.

The time of year will also affect the conditions under which a repair would be necessary, and the length of time that the line might need to be shut in should failure occur. However, an analysis of these issues was beyond the scope or terms of reference for this project. Oil drainage volumes will not be affected by this as the worst case has been assumed for the analyses done here (that all possible oil drainage will occur in the event of a pipeline failure).

7.5 Total Spill Volume

This section discusses leakage volumes for the case where there is no secondary containment provided by the pipeline design. The effects of secondary containment are discussed in section 8.

7.5.1 Pipeline Failure By Rupture

The total spill volumes for pipeline failure by rupture are summarised by hazard and by event step in Table 7.10.

Table 7.10: Summary: Maximum Total Oil Spill Volumes By Hazard and Event Step for a Pipeline Rupture

Hazard	Oil Released, bbls, by Event Step				Total Oil Spilled, bbls
	Pipeline Failure to Leak Detection	Detection to Initiation of Action	Valve Closure & Line Depressuriz'n	Maximum Drainage (Table 7.6)	
Ice Gouging	23	226	411	1690	2350
Strudel Scour	23	226	411	2010	2670
Thaw Subsidence	23	226	411	1900	2560
Thermal expansion leading to upheaval buckling	23	226	411	2010	2670
Oper'l Failures	23	226	411	2010	2670
Third Party Activities	23	226	411	2010	2670

The following trends are evident:

(a) Effect of Event Step - Oil drainage from the depressurised line accounts for the majority (about 70 to 75%) of the spilled oil for each hazard. See Figure 7.8 for a typical distribution.

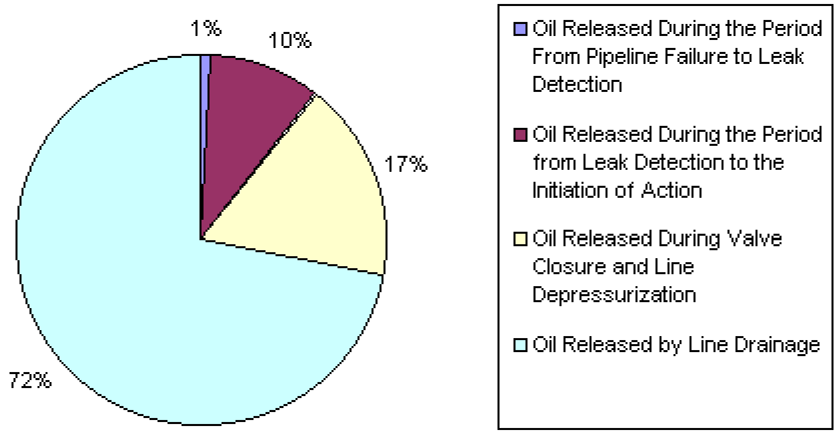

Figure 7.9: Typical Distribution of Oil Volume by Event Step (Maximum Oil Spilled During an Ice Gouging Event)

(b) Effect of Hazard Type – the oil released during rupture varies with the hazard because the hazards occur at different water depth ranges (Table 7.6). The maximum oil volume released (i.e., for the water depth causing the largest oil spill) is not highly dependent on the hazard type, as it is within 15 % for all events (Figure 7.10).

Because the hazards of concern are equally likely to occur at any water depth within the applicable range (section 3), the oil volume released at the average water depth for each hazard is more likely to reflect the actual volume spilled in the event of a pipeline rupture. As expected, these oil volumes are less than the maximums, by about 14 % on average (Figure 7.11). Permafrost thaw subsidence, strudel scour, and ice gouging are the hazards with the potential to release the most oil during pipeline rupture (Table 7.6 and Figure 7.11) because the water depth ranges at which they occur cause the most oil drainage (Table 7.6).

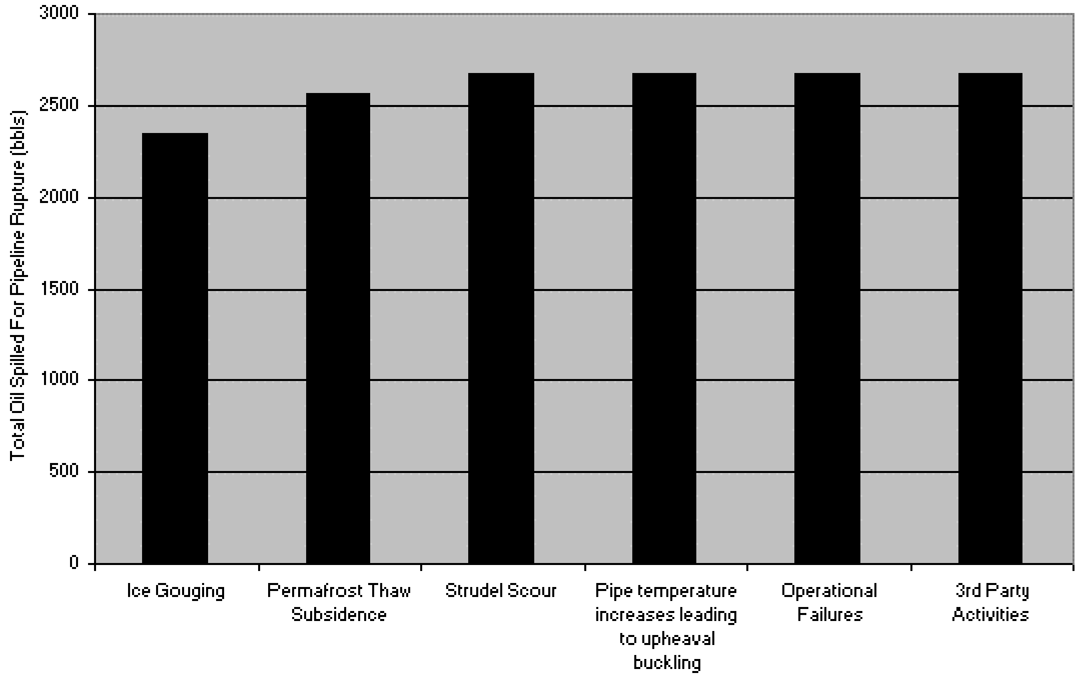

Figure 7.10: Maximum Possible Oil Spill Volumes by Hazard Type

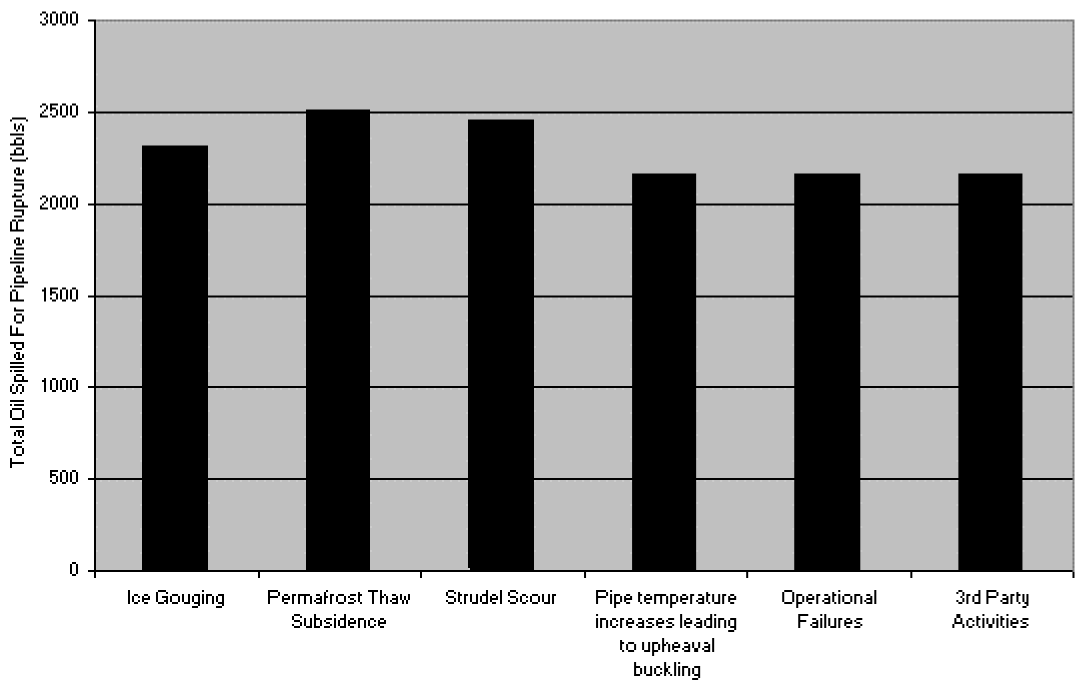

Figure 7.11: Total Oil Spill Volume by Hazard Type for the Average Water Depth Applicable to That Hazard

(c) Comparison to Oil Spill Volumes Calculated by Intec, 1999 – the total oil spill volumes are somewhat larger than that calculated by Intec, 1999 who determined an amount of 1576 bbl for pipeline rupture. This variation is due primarily to differences in the line lengths that would be drained following a rupture; Intec 1999 assumed a maximum length of 9000 ft, while FTL used a maximum of 16,000 ft. to calculate oil drainage volumes.

(d) Sensitivity Analyses: Effect of Time Durations Assigned – the following time durations were used as the base case for oil spill volume analyses (section 7.3):

(i) time required for detection: 30 seconds;
(ii) time elapsed between the presence of an alarm from the monitoring system and the decision by an operator to take action: 5 minutes;
(iii) time required for valve closure: 8.5 minutes.

It is recognised that these time assignments are subject to some uncertainty. Their potential significance was investigated by conducting sensitivity analyses as summarised in Table 7.11. The total spilled oil volume is not very sensitive to the time durations assigned to each step in the event (within bounds, of course) as the time durations would need to be increased many times to bring about a 20 % increase in total spill volume. This result reflects the fact that the majority of the spilled oil results from oil drainage from the line after valve closure and depressurisation.

Consequently, further investigation or refinement of the above time durations is not considered to be useful.

Table 7.11: Sensitivity Analysis for Event Step Durations Required to Increase the Total Spilled Oil Volume by 20%

(Base Case: Maximum Oil Released During an Ice Gouging Event)

Event Step	Event Durations Assigned for the Base Case	Event Duration Req'd to Increase the Total Spilled Spill Volume by 20 % (notes 1 and 2)	Relative Change in Time Duration
Pipeline Failure to Leak Detection	0.5 minutes	11 minutes	22 times increase
Leak Detection to Action Initiation	5 minutes	16 minutes	3.2 times increase
Valve Closure	8.5 minutes	19 minutes	2.2 times increase

Notes:
1. The maximum oil volume for the ice gouging hazard was used as the base case.
2. The total spilled oil volume for the above case is 2350 bbls (Table 7.10). The increased event durations above in Table 7.10 are those required to increase the total oil spill volume to 2820 bbls.

7.5.2 Pipeline Failure By Flow Through Cracks Or Flaws

The total spill volumes for pipeline failure by cracks or flaws are summarised by hazard and by event step in Table 7.12.

Table 7.12: Summary: Total Oil Spill Volumes By Hazard and Event Step for Flow Through Cracks or Flaws

Hazard	Oil Released (note 1), bbls, by Event Step				Total Oil Spilled, bbl (note 1)
	Pipeline Failure to Leak Detection	Detection to Initiation of Action	Valve Closure & Line Depressuriz'n	Maximum Drainage (Table 7.6)	
Ice Gouging	0.4 ; 0.2	4 ; 2	33 ; 30	1690	1730 ; 1720
Strudel Scour	0.4 ; 0.2	4 ; 2	33 ; 30	2010	2050 ; 2040
Thaw Subsidence	0.4 ; 0.2	4 ; 2	33 ; 30	1900	1940 ; 1930
Thermal expansion leading to upheaval buckling	0.4 ; 0.2	4 ; 2	33 ; 30	2010	2050 ; 2040
Oper'l Failures	0.4 ; 0.2	4 ; 2	33 ; 30	2010	2050 ; 2040
Third Party Activities	0.4 ; 0.2	4 ; 2	33 ; 30	2010	2050 ; 2040

Notes:
1. The two values are for flow through the maximum stable axial and circumferential cracks, respectively.

The following trends are evident:

(a) Effect of Event Step – the vast majority (i.e., about 97 %) of the total spilled oil results from oil drainage from the line after valve closure and line depressurisation. This is due to the assumption made here that all possible oil drainage would occur. This is the worst case as it will lead to the largest oil spill volume. It is recognised that the oil drainage may be limited by the time available for axial and longitudinal cracks to drain, in comparison to the time required for remedial actions (e.g., purging the line to clear the oil out of it). Unfortunately, this issue could not be investigated in this project due to a lack of available time within the short schedule allotted for this project.

(b) Flow Through the Maximum Stable Axial vs Longitudinal Crack – the results are not sensitive to this because the spill volume is governed by oil drainage from the line after valve closure and depressurisation.

(c) Spill Volume for Pipeline Rupture vs Pipeline Failure by Flow Through the Maximum Stable Cracks – The spill volume for the case where pipeline failure occurs by flow through the maximum stable crack is about 75 % of that for failure caused by pipeline rupture, which follows the expected trend. This is only a relatively slight reduction in oil volume, and it reflects the fact that the vast majority of the oil spilled results from oil drainage from the line after line closure and depressurisation.

(d) Effect of Times Assigned for the Durations of the Event Steps – the spilled oil volume will be very insensitive to these because the majority of the spilled oil results from line drainage.

(e) Effect of Hazard Type – the same comments as in section 7.5.1 are applicable to pipeline failure resulting from flow through the maximum stable axial or longitudinal cracks.

7.5.3 Pipeline Failure By Flow Through Small Defects or Seepage

A seepage event was defined as oil escaping the carrier pipe. These spilled oil volumes are controlled by the detection capabilities of the monitoring system(s) used, and they were evaluated for two cases (section 7.3.5) as follows:

(a) the monitoring systems perform as expected – the calculated consequence of a seepage event for this case was 123 bbls

(b) the expected worst-case perfpormance of the monitoring systems - the calculated consequence of a seepage event for this case was 520 bbls

To calculate the total oil spilled due to seepage over the 20-year life of the Liberty Pipeline, one must establish:

(a) the events that occur when the leaks are discovered – it was assumed here that the Liberty Pipeline would be shut down until the leaks are repaired. It was further assumed that no oil drainage would occur from the line, and that the line would be purged. This assumption was made because small defects would tend to close upon depressurisation and in any event the pressure head across the opening is small thus the leakage rate would be very low. Therefore, no additional oil would be released.

(b) the number of times that seepage events occur over the 20-year life of the Liberty Pipeline – The failure statistics were reviewed to investigate how many seepage events would be expected over the 20-year life of the Liberty Pipeline. Table E7, in Appendix E, lists the number of occurrences for each failure cause. FTL used the failure occurrences from Hovey and Farmer for the DOT failure statistics as they provided the most likely estimate of event occurrences that could be applied to Liberty from the failure statistics that were examined.Of these causes, the ones that are most likely to leak, rather than rupture, are corrosion, pipe defect, and weld defect. The statistics indicate a value of 0.01065 occurrences over the 20-year life of the line for pipe defects and weld defects. The damage frequencies for corrosion vary with the pipe design as summarized in Table 5.6, in section 5. By summing up their individual occurrences/20-yr life of the line, one obtains the following total number of occurrences for seepage events to the environment as follows:

(i) single steel pipe: 0.01065
(ii) steel pipe-in-pipe: 0.01565
(iii) pipe in HDPE: 0.01115
(iv) flexible pipe: 0.01065

7.5.4 Pipeline Failure Mode Versus Hazard

The previous results have shown that the oil volume released (i.e., the consequence) depends greatly on the type of pipeline failure mode that occurs. This pipeline failure mode is expected to vary with the hazard as they each bring about different pipe structural responses. Table 7.13 lists the ones used as the base case for the risk analyses.

Table 7.13: Pipeline Failure Modes Versus Hazard for the Base Case

Hazard	Pipeline Failure Mode
Ice Gouging	Rupture – selected because this can be a large displacement event involving large energies.
Strudel Scour, Permafrost Thaw Subsidence and Thermal Loads	Flow through the maximum stable crack – selected because these events typically produce pipe displacements that are controlled by the properties of the pipeline.
Corrosion	Seepage
Minor (<100 bbls) oil releases due to operational failures and third party activities	Seepage
Major (>100 bbls) oil releases due to operational failures and third party activities	Flow through the maximum stable crack.

8.0 RISK ANALYSES

8.1 Results for the Base Case

8.1.1 Base Case Definition

Risk analyses were first done for a base case, which represented FTL's best estimate for all input parameter values (Table 8.1). Sensitivity analyses were done next (Section 8.2).

8.1.2 Secondary Containment

The assumptions made regarding secondary containment are summarised in Table 8.2, and described further in the following subsections. The significance of these assumptions was investigated later with sensitivity analyses (Section 8.2).

8.1.2(a) Single Steel Pipe

This pipe design does not provide any secondary containment for any of the hazards.

8.1.2(b) Steel Pipe-in-Pipe

The secondary containment provided by the outer pipe was assumed to vary with the hazard as follows:

(a) Ice gouging, strudel scour, permafrost thaw subsidence, and thermal loads leading to upheaval buckling – these events may all cause large pipe displacements. It was presumed that an event that failed the inner carrier pipe would also fail the outer pipe as the outer pipe would experience higher flexural strains.

(b) Corrosion, minor (<100 bbls) and major (>100 bbls) incidents due to operational failures and third party activities – the analyses were conducted by allowing the outer pipe to provide some secondary containment for these hazards. This is discussed in section 8.1.3.

8.1.2(c) Pipe in HDPE

(a) This case is difficult to evaluate because the properties of HDPE are not specified in Intec, 1999; 2000 and it is known that they can vary greatly (Section 4). Furthermore, the in-service condition of the HDPE can not be monitored and can not be established with reliability. For this project, the secondary containment provided by the HDPE was assumed to vary with the hazard as follows. The significance of these assumptions was investigated later with sensitivity analyses.

(b) Ice gouging, strudel scour, permafrost thaw subsidence, and thermal loads leading to upheaval buckling – these events may all cause large pipe displacements. It was presumed that an event that failed the inner carrier pipe would also fail the outer HDPE pipe.

(c) Corrosion – Corrosion is not a concern for the HDPE although material degradation may occur over the life of the Liberty Pipeline. This cannot be evaluated definitively at present. To assign the most possible benefit to the pipe-in-HDPE design, it was presumed that seepage would be fully contained in the annulus between the two pipes. However, in this case, the calculations included an assessment of the oil that would be released during repair operations. See section 8.1.3(c).

(d) Minor incidents (i.e., < 100 bbls) as a result of operational or third party activities – as described previously, the vast majority of the failures in this category are expected to be due to operational failures rather than third party activities. Operational failures include overpressurization events, and for minor events, they would likely create pinhole leaks or seepage. In this case, the outer HDPE pipe would probably provide some protection because it is doubtful that it would be exposed to the full operating pressure of the carrier pipe. It was presumed that minor operational failures that failed the inner pipe would not fail the outer HDPE one.

(e) Major incidents (i.e., > 100 bbls) as a result of operational or third party activities – It was presumed that the HDPE pipe would provide no secondary containment in this case. This hazard would probably expose the HDPE to the full internal pressure of the carrier pipe (for operational failures which are considered to constitute the majority of the events in this category). This would probably lead to failure of the HDPE pipe.

8.1.2(d) Flexible Pipe

This design provides no secondary containment for any of the hazards.

Table 8.1: Base Case and Sensitivity Analyses

Parameter	Range of Variation	Significance
Ice Gouging Rate	• Base Case: 0.097 gouges/mi/yr • Best Case: 0.049 gouges/mi/yr • Worst Case: 0.41 gouges/mi/yr	Insignificant – affects risk by less than 10 %
Subgouge Soil Displacements	• Base Case : defined using the algorithms in Intec, 1999 & Appendix A • Worst Case : 10 times the predicted values	Insignificant – affects risk by less than 10 %
Strudel Scour	• Base Case: rate = 7.5 scours/mi^2/yr & width as per Blanchet et al, 2000 • Worst Case: rate = 7.5/mi^2/yr & width = 2 times the values in Blanchet et al, 2000; • Best Case: rate = 4.4/mi^2/yr & width as given in Blanchet et al, 2000	Insignificant – affects risk by less than 10 %
Consequence vs water depth	• Base Case: consequence defined for the average water depth in each range applicable to each hazard • Worst Case: maximum consequence within the water depth range applicable to each hazard	See Table 8.6
Pipeline Failure Mode	• Base Case: best estimate with respect to each hazard • Worst Case: all pipeline failures by rupture • Intermediate: all failures by flow through the maximum stable crack • Best Case: all failures by seepage through tight cracks or pinholes	See Table 8.6
Monitoring System	• Base Case: expected performance of monitoring systems (section 6) – consequence for a seepage event = 123 bbls (section 7) • Worst Case: expected worst performance of the monitoring systems (section 6) – consequence for a seepage event = 520 bbls (section 7)	See Table 8.6
Failure Criteria	• Base Case Values: • Single gouging in Zone 2 - 10% Von Mises strain (section 4); • Multiple gouging in Zone 2 - 15 % cumulative Von Mises strain (section 4); • Buckling due to strudel scour, thaw subsidence or thermal loads: as defined in section 4	No sensitivities done because these are lower bound values, and they are believed to be conservative.
Corrosion	• Base Case: expected values used • Worst Case: increased occurrence probability by 2	Insignificant – affects risk by less than 10 %
Third Party & Oper'l failures	• Base Case: frequencies defined by removing 4 non-applicable events that were > 100 bbls (section 3) • Worst Case – include every event except Exxon Valdez (section 3)	See Table 8.6
Permafrost thaw subsidence	• Base case – use expected values (section 3) • Worst – increase expected occurrence probability by a factor of 2	Insignificant – affects risk by less than 10 %
Thermal loads & upheaval buckling	• Base Case – use expected values (section 3) • Worst Case – increase occurrence probability by a factor of 2	Insignificant – affects risk by less than 10 %
Secondary Containment	• Base Case: Best estimate for each design (Table 8.2) • Worst case: no secondary containment	See Table 8.6

Table 8.2: Secondary Containment Assumptions

Hazard	Single Steel Pipe[1]	Steel Pipe-in-Pipe[1]	Pipe in HDPE[1]	Flexible Pipe[1]
Ice Gouging	No secondary containment	No containment – event that fails the inner pipe will fail the outer one too	No containment – event that fails the inner pipe will fail the outer one too	No secondary containment
Strudel Scour	No secondary containment	No containment – event that fails the inner pipe will fail the outer one too	No containment – event that fails the inner pipe will fail the outer one too	No secondary containment
Thaw subsidence	No secondary containment	No containment – event that fails the inner pipe will fail the outer one too	No containment – event that fails the inner pipe will fail the outer one too	No secondary containment
Thermal Loads	No secondary containment	No containment – event that fails the inner pipe will fail the outer one too	No containment – event that fails the inner pipe will fail the outer one too	No secondary containment
Corrosion	No secondary containment	See note 2.	Seepage fully contained in annulus until detection	No secondary containment
Operational & Third Party Activities - < 100 bbls	No secondary containment	See note 2.	Seepage fully contained in annulus until detection	No secondary containment
Operational & Third Party Activities - < 100 bbls	No secondary containment	See note 2.	No secondary containment	No secondary containment

Notes:
1. The information presented is for the pipe designs produced by Intec, 1999, and Intec, 2000, respectively.
2. Risks were evaluated for the combination of two cases, as described in section 8.1.3, and as summarized below:
   (a) the inner pipe fails but the outer one does not. In this case, the oil would be contained within the annulus. However, some oil would be lost during repairs.
   (b) the inner and outer pipes both fail.

8.1.3 Further Analysis of Event Consequences: Effect of Secondary Containment and Oil Lost During Repairs

8.1.3(a) Potential Scenarios

The consequences of pipeline failure were evaluated in section 7 for scenarios up to the point where the pipeline has been shut down, and all possible line drainage had occurred. They are applicable to the case where the pipeline design does not provide secondary containment, or for the case where the secondary containment has failed as well (for the steel pipe-in-pipe, and the pipe-in-HDPE designs).

For these two designs, the effect of secondary containment and oil lost during repair is dependent on the hazard under consideration. It was conservatively assumed that the outer pipe would provide no secondary containment for ice gouging, strudel scour, permafrost thaw subsidence, and thermal loads leading to upheaval buckling (Table 8.2). This was done as it is believed that an event that failed the inner pipe would fail the outer one too. Thus, oil lost during repair is only important for events resulting from corrosion, operational failures, and third party activities. The risk associated with these hazards is the sum of the risks for the following two cases:

(a) Case 1 – the inner pipe is failed but the outer one is not. This could happen if, for example: (i) a leak occurred in the carrier pipe, and oil escaped to the annulus, (ii) the leak was detected by an annulus pressure monitoring system for example, and (iii) the line was shut down. In this case, the oil would be contained in the annulus. However, some oil would be released by repair operations.

(b) Case 2 – the inner and outer pipes are both failed. This could happen for the hazards listed above if, for example: (i) a stable crack was generated in the inner pipe by an overpressurization event (which is one example of an operational failure) ; (ii) oil escaped from the carrier pipe to the annulus causing a pressure buildup in it ; (iii) the pressure buildup in the annulus was not detected, and thus that the line was not shut down ; (iv) a stable crack was generated in the outer pipe.

8.1.3(b) Oil Volume Lost During Repairs

In the case where the outer pipe has not failed (i.e., Case 1), the outer pipe will provide some secondary containment (for the steel pipe-in-pipe, and the pipe-in-HDPE designs). Thus, oil would accumulate in the annulus without being released to the environment. However, some of the oil stored in the annulus may be released during repair operations. Although a detailed analysis of repair was beyond the scope of the project (as repair techniques have not yet been specified for the Liberty Pipeline), a preliminary assessment of this issue was done in response to comments received (Appendix G, section G6).

Oil released during repair is of most concern for the steel pipe-in-pipe, and the pipe-in-HDPE designs, as the consequences for the other designs have been calculated by presuming that all possible line drainage occurs (section 7). For the Intec, 1999 and Intec, 2000 steel pipe-in-pipe designs, the line fill in the annulus is 217 and 320 bbls/mile, respectively. For the pipe-in-HDPE design, the line fill in the annulus is 282 bbls/mile.

The repair technique used will affect how much of the oil in the annulus is lost. It is unreasonable to expect that all of the oil in the annulus along the full length of the line would be lost. In the absence of information to define repair techniques, it was assumed that the oil volume lost from a 1000 ft length of line annulus would be lost. This is believed to be a conservative assumption as repairs would be expected to be localized to the damaged area, and that the remainder of the line would be isolated (preventing drainage), and cleaned. This gives the following oil spill volumes:

(a) steel pipe-in-pipe design :
    (i) Intec, 1999 design: 41 bbls
    (ii) Intec, 2000 design: 61 bbls

(b) pipe-in-HDPE design: 53 bbls

8.1.3(c) The Consequences of a Failure of Both the Inner and Outer Pipes

The consequences of pipeline failure were evaluated in section 7 for a single pipe for scenarios up to the point where the pipeline has been shut down, and all possible line drainage had occurred. These calculations gave a value of 1537 bbls for the single pipe for corrosion, minor (<100 bbls) operational failures and third party actions, and major (>100 bbls) operational failures and third party actions (section 7).

For the steel pipe-in-pipe and pipe-in-HDPE designs, the consequences of failure of both the inner and outer pipes would be higher than 1537 bbls as oil contained in the annulus would also be lost to the environment. It was conservatively assumed that all possible drainage from the annulus occurs as well as from the carrier pipe. This gives the following values for the consequence of a failure of both the inner and outer pipes for corrosion, minor (<100 bbls) operational failures and third party actions, and major (>100 bbls) operational failures and third party actions:

(a) steel pipe-in-pipe design :
    (i) Intec, 1999 design: 2141 bbls
    (ii) Intec, 2000 design: 2278 bbls

(b) pipe-in-HDPE design: 2190 bbls

8.1.4 Risk for the Base Case Pipe Designs

8.1.4(a) Calculation Procedure

As stated previously, the risk for the ice gouging and strudel scour hazards was calculated by establishing and quantifying event trees. For these hazards, the risk was calculated as follows:

$$R_{\text{Ice Gouging and Strudel Scour}} = \Sigma \text{ (\# of Failures * Failure Consequences)} \qquad [8.1]$$

where: $R_{\text{Ice Gouging and Strudel Scour}}$ = the total risk due to all scenarios associated with ice gouging and strudel scour

Σ (# of Failures * Failure Consequences) = the sum for the three ice gouging-related scenarios analyzed (section 3.2), and the two strudel scour scenarios analyzed (section 3.3) of the product of:

(a) the number of failures expected over the 20-year life of the Liberty Pipeline for the particular scenario being considered. This was determined by comparing the probability distributions and return periods for the strains induced in the pipeline with the failure criteria that established in section 4.

(b) the failure consequences for that scenario (defined as the number of barrels of oil released by failure).

The event probabilities associated with all other hazards than ice gouging or strudel scour were evaluated based on failure statistics. The risk for these hazards was calculated as follows:

$$R_{\text{all hazards except ice gouging and strudel scour}} = \Sigma\ (\#\text{ of Failures} * \text{Failure Consequences}) \qquad [8.2]$$

where: $R_{\text{all hazards except ice gouging and strudel scour}}$ = the total risk for all hazards other than ice gouging and strudel scour

Σ (# of Failures * Failure Consequences) = the sum for all hazards other than ice gouging or strudel scour of the product of:

(a) the number of failures expected over the 20-year life of the Liberty Pipeline for the particular hazard being considered;
(b) the failure consequences for that hazard (defined as the number of barrels of oil released by failure).

8.1.4(b) Expected Number of Failures Over the 20-Year Life of the Liberty Pipeline

Table 8.3 lists the expected number of failures over the 20-year life of the Liberty Pipeline. The basis for most of the values in Table 8.3 are provided in the previous respective sections of the report.

Further discussion is warranted regarding the listed failure rates for the steel pipe-in-pipe for corrosion, and for the combination of operational failures and third party actions as further analyses were done to establish these values:

(a) corrosion – two cases were analysed as follows:

(i) Case 1 – the inner pipe is failed but the outer one is not – the failure rate was taken from the analyses presented in section 5.

(ii) Case 2 - the inner and outer pipes are both failed – the failure rates listed in Table 8.3 are the combined probability that the inner and outer pipes will both be failed. The individual values used to establish this combined probability are given in section 5.

(b) Major and minor failures (i.e., >100 bbls and <100 bbbls respectively) resulting from operational failures and third party actions – the same two cases above were analysed as follows:

(i) Case 1 – failure rates were established from analyses of the events that have occurred at the TAPS and Norman Wells pipelines, as described in section 3.9

(ii) Case 2 – this is a combined event in which the inner and outer pipes are both failed. The combined probability was hence evaluated. However, because the failure statistics from the TAPS and Norman Wells pipelines do not allow this combined probability to be evaluated directly, further analyses were required.

If both pipes had an equal probability of being failed, then the combined probability would be calculated by squaring the failure rates obtained for Case 1. However, this is not believed to be an accurate approach as the condition of the outer pipe can not be monitored. Consequently, the expected combined failure rate will be higher than the square of the failure rate for Case 1.

The calculated corrosion rates for Cases 1 and 2 were used as a means of scaling the failure statistics, and determining the combined probability. This was considered to be a reasonable approach as the majority of the events in this category are expected to be operational failures (discussed previously). They would be expected to include cases such as overpressurization events.

The calculation procedure is illustrated in the following example:

- Pipeline design: Intec, 1999 steel pipe-in-pipe design
- Hazard: minor operational failures
- Expected number of corrosion failures over the 20-year life of the Liberty Pipeline (Table 8.3):
  - Case 1 – 2.2×10^{-5}
  - Case 2 – 2.42×10^{-9}
- Ratio between the failure rates for Case 2 vs Case 1 squared =
  $2.42 \times 10^{-9} / (2.2 \times 10^{-5})^2 = 5$ times
- Expected number of failures over the 20-year life of Liberty Pipeline for minor (<100 bbls) operational failures for Case 1: 0.05705 (Table 8.3)
- Calculated failure rate for the combined case that the inner and outer pipes both be failed :
  $(0.05705)^2 \times 5 =$
  0.01627 failures over the 20-year life of the Liberty Pipeline

8.1.4(c) Failure Consequences

Table 8.4 lists the failure consequences for each hazard for the base case.

8.1.4(d) Risk for the Base Case for Each Pipeline Design

The total risk determined for each pipe design is summarised in Table 8.5.

Table 8.3: Expected Number of Failures For Each Hazard Over the 20-Year Life of The Liberty Pipeline for Each Design for the Base Case[2]

Hazard	Single Steel Pipe[1]	Steel Pipe-in-Pipe[1]	Pipe in HDPE[1]	Flexible Pipe[1]
Ice gouging: Single Gouging: Pipe in Zone 1	$4.08 * 10^{-7}$; $4.08 * 10^{-7}$	$6.87 * 10^{-5}$; $4.08 * 10^{-7}$	$5.30 * 10^{-6}$; $4.08 * 10^{-7}$	$6.87 * 10^{-5}$; $4.08 * 10^{-7}$
Single Gouging: Pipe in Zone 2	0 ; 0	0 ; 0	0 ; 0	0 ; 0
Multiple Gouging: Pipe in Zone 2	$7.91 * 10^{-7}$; $7.91 * 10^{-7}$	$1.40 * 10^{-6}$; $7.68 * 10^{-9}$	$5.61 * 10^{-6}$; $7.91 * 10^{-7}$	$2.53 * 10^{-5}$; $7.91 * 10^{-7}$
Strudel scour: Unsupported pipe	$6.21 * 10^{-7}$; $6.21 * 10^{-7}$	$2.57 * 10^{-5}$; $9.95 * 10^{-6}$	$1.60 * 10^{-5}$; $9.94 * 10^{-6}$	$1.65 * 10^{-5}$; $6.21 * 10^{-7}$
Partial cover loss leading to upheaval buckling	0 ; 0	0 ; 0	0 ; 0	0 ; 0
Permafrost thaw subsidence	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003
Thermal loads leading to upheaval buckling	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003
Corrosion	$1.32x10^{-6}$; $1.32x10^{-6}$	Case 1 – only the inner pipe fails: $2.2x10^{-5}$; $1.1x10^{-5}$ Case 2 – the inner & outer pipes both fail: $2.42x10^{-9}$; $1.21x10^{-9}$	Only the inner pipe fails: $5x10^{-4}$; $5x10^{-4}$	$1.32x10^{-6}$; $1.32x10^{-6}$
Operational & 3rd party activities – minor incidents with less than 100 bbls	0.05705 ; 0.05705	Case 1 – only the inner pipe fails: 0.05705 ; 0.05705 Case 2 – the inner & outer pipes both fail: 0.01627 ; 0.03255	Only the inner pipe fails: 0.05705 ; 0.05705	0.05705 ; 0.05705
Operational & 3rd party activities – major incidents with more than 100 bbls	0.01316 ; 0.01316	Case 1 – only the inner pipe fails: 0.01316 ; 0.01316 Case 2 – the inner & outer pipes both fail: 0.000866 ; 0.00173	The inner and outer pipes both fail: 0.01316 ; 0.01316	0.01316 ; 0.01316

Notes:

1. The values listed are for the pipe designs produced by Intec, 1999, and Intec, 2000, respectively.
2. See Table 8.1 for a definition of the base case.

Table 8.4: Failure Consequences For Each Hazard for Each Design for the Base Case[4]

Hazard	Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe in HDPE[2]	Flexible Pipe[2]
Ice gouging	2310 ; 2310	2310 ; 2310	2310 ; 2310	2310 ; 2310
Strudel scour	1837 ; 1837	1837 ; 1837	1837 ; 1837	1837 ; 1837
Permafrost thaw subsidence	1887 ; 1887	1887 ; 1887	1887 ; 1887	1887 ; 1887
Thermal loads leading to upheaval buckling	1537 ; 1537	1537 ; 1537	1537 ; 1537	1537 ; 1537
Corrosion	123 ; 123	Case 1 – only the inner pipe fails: 41 ; 61 Case 2 – the inner & outer pipes both fail: 123 ; 123	Only the inner pipe fails: 53 ; 53	123 ; 123
Operational & 3rd party activities – minor incidents with less than 100 bbls	123 ; 123	Case 1 – only the inner pipe fails: 41 ; 61 Case 2 – the inner & outer pipes both fail: 123 ; 123	Only the inner pipe fails: 53 ; 53	123 ; 123
Operational & 3rd party activities – major incidents with more than 100 bbls	1537 ; 1537	Case 1 – only the inner pipe fails: 41 ; 61 Case 2 – the inner & outer pipes both fail: 2141 ; 2278	The inner & outer pipes both fail: 1537 ; 1537	1537 ; 1537

Notes:
1. All consequence values are in bbls.
2. The values listed are for the pipe designs produced by Intec, 1999, and Intec, 2000, respectively.
3. See Table 8.2 for assumptions made regarding secondary containment.
4. See Table 8.1 for a definition of the base case.

Table 8.5: Risk[1] Breakdown by Hazard for Each Design for the Base Case[4]

Hazard	Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe in HDPE[2]	Flexible Pipe[2]
Ice gouging: Single Gouging: Pipe in Zone 1 Single Gouging: Pipe in Zone 2 Multiple Gouging: Pipe in Zone 2	 $9.43 * 10^{-4}$; $9.43 * 10^{-4}$ 0 ; 0 $1.83 * 10^{-3}$; $1.83 * 10^{-3}$	 0.16 ; $9.43 * 10^{-4}$ 0 ; 0 $3.23 * 10^{-3}$; $1.77 * 10^{-5}$	 0.0122; $9.43 * 10^{-4}$ 0 ; 0 0.0130; $1.83 * 10^{-3}$	 0.159; $9.43 * 10^{-4}$ 0 ; 0 0.058; $1.83 * 10^{-3}$
Strudel scour: Unsupported pipe Partial cover loss leading to upheaval buckling	 $1.14 * 10^{-3}$; $1.14 * 10^{-3}$ 0 ; 0	 0.047; 0.018 0 ; 0	 0.029; 0.018 0 ; 0	 0.030; $1.14 * 10^{-3}$ 0 ; 0
Permafrost thaw subsidence	0.57 ; 0.57	0.57 ; 0.57	0.57 ; 0.57	0.57 ; 0.57
Thermal loads leading to upheaval buckling	0.46 ; 0.46	0.46 ; 0.46	0.46 ; 0.46	0.46 ; 0.46
Corrosion	$1.6x10^{-4}$; $1.6x10^{-4}$	Case 1 – only the inner pipe fails: $9.0x10^{-4}$; $6.7x10^{-4}$ Case 2 – the inner & outer pipes both fail: $3.0x10^{-7}$; $1.5x10^{-7}$	Only the inner pipe fails: 0.0265 ; 0.0265	$1.6x10^{-4}$; $1.6x10^{-4}$
Operational & 3rd party activities – minor incidents with less than 100 bbls	7.0 ; 7.0	Case 1 – only the inner pipe fails: 2.34 ; 3.48 Case 2 – the inner & outer pipes both fail: 2.00 ; 4.00	Only the inner pipe fails: 3.02 ; 3.02	7.0 ; 7.0
Operational & 3rd party activities – major incidents with more than 100 bbls	20.2 ; 20.2	Case 1 – only the inner pipe fails: 0.54 ; 0.80 Case 2 – the inner & outer pipes both fail: 1.85 ; 3.94	The inner & outer pipes both fail: 20.2 ; 20.2	20.2 ; 20.2
Overall Total Risk	28 ; 28	8 ; 13	24 ; 24	29 ; 28

Notes to Table 8.5:
1. All risk values are in bbls.
2. The risk values listed are for the pipe designs produced by Intec, 1999, and Intec, 2000, respectively.
3. See Table 8.2 for assumptions made regarding secondary containment.
4. See Table 8.1 for a definition of the base case.

8.1.3(e) Discussion of the Base Case Results

The following observations can be made:

(a) Most Significant Hazards – The most significant hazards vary with the pipe design.

(i) single steel pipe, the flexible pipe, and the pipe-in-HDPE designs

For these designs, major operational failures and third party activities (i.e., > 100 bbls) constitute the vast majority (i.e., about 80%) of the total risk. Minor (i.e., < 100 bbls) operational failures and third party activities are the next most significant hazard. Together, major and minor incidents comprise about 95% of the total risk for these designs.

Environmentally-induced risks (i.e., ice gouging, strudel scour, permafrost thaw subsidence, and thermal loads) are a minor component of the total risk for these designs.

(ii) the steel pipe-in pipe design

Environmentally-induced risks (i.e., ice gouging, strudel scour, permafrost thaw subsidence, and thermal loads) are a minor component of the total risk for this design as well (Table 8.5).

The two most significant components to the total risk for this design are:

- oil spilled during repair operations, and;
- oil spilled as a result of operational failures that cause failures to both the inner and outer pipes.

(b) Comparison of Pipe Designs – the steel pipe-in-pipe design has a lower risk than the other designs. The significance of this variation is explored further in the next section which presents the results of sensitivity analyses.

8.2 Sensitivity Analyses and Discussion

8.2.1 Presentation of Results

Tables 8.1 and 8.6 summarise the results of the sensitivity analyses.

Table 8.6: Sensitivity Analysis Summary: Total Risk[1] for Each Design

Case	Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe in HDPE[2]	Flexible Pipe[2]
Base Case	28 ; 28	8 ; 13	24 ; 24	29 ; 28
All rupture[3]	153 ; 153	39 ; 75	154 ; 154	153 ; 153
All crack flow[4]	109 ; 109	28 ; 54	110 ; 110	109 ; 109
All seepage[5]	8.7 ; 8.7	2.2 ; 4.4	8.8 ; 8.8	8.7 ; 8.7
Worst oper'l & 3rd Party failures case	69 ; 69	18 ; 22	65 ; 65	69 ; 69
No secondary containment	28 ; 28	28 ; 28	28 ; 28	29 ; 28
Expected worst-case monitoring system performance	51 ; 51	14 ; 26	51 ; 51	51 ; 51
Worst case water depth for each hazard	35 ; 35	9 ; 15	31 ; 31	35 ; 35

Notes:
1. All risk values are in bbls.
2. The risk values listed are for the pipe designs produced by Intec, 1999, and Intec, 2000, respectively.
3. Failure by rupture - It was assumed that none of the pipe designs would provide any secondary containment.
4. Failure by flow through a stable crack – the same assumptions made regarding secondary containment for the base case were applied to this sensitivity run for each pipe design.
5. Failure by seepage – the same assumptions made regarding secondary containment for the base case were applied to this sensitivity run for each pipe design.

8.2.2 Effect of Secondary Containment

This has a major effect for the steel pipe-in-pipe design as it increases the total risk to 28 bbls from 8 to 13 bbls (depending on the steel pipe-in-pipe design being considered - Table 8.6). For the other pipe designs, the total risk is insensitive to the assumptions made regarding secondary containment.

The assumptions made regarding secondary containment affect which pipe design has the least risk as follows:

(a) Base Case – the steel pipe-in-pipe design has lower risk than the other ones (Table 8.5).

(b) No secondary containment assumed for any of the pipe designs – in this case, all four pipe designs have equivalent risk, within the overall accuracy of the analyses (Table 8.6).

8.2.3 Effect of Monitoring System Performance

The performance of the PPA/MBLPC and the LEOS monitoring systems has an important effect on the risk for each design.

For all designs (i.e., single steel pipe, steel pipe-in-pipe, pipe-in-HDPE, and the flexible pipe), the total risk is increased by about a factor of two (2) by a reduction in monitoring system performance (Table 8.6).

The risk for the steel pipe-in-pipe design is less than that for all of the other designs for a reduction in monitoring system performance.

8.2.3 Effect of Occurrence Frequencies for Operational Failures and Third Party Activities

Operational failures and third party activities are the most significant hazard for all designs (Table 8.1). As a result, the total risk is increased for each design when all events, including those that are related to shore-based facilities, are included in the statistics used to define the occurrence frequency (Section 3.9).

The risk increase is somewhat greater for the single steel pipe, the pipe-in-HDPE and flexible pipe designs (i.e., about 2.5 times greater than that for the base case) compared to about 2 times for the steel pipe-in-pipe design. This difference reflects the secondary containment provided by the steel pipe-in-pipe design.

It should be recognised that this occurrence frequency is considered to be a conservative upper bound to the true value. Nevertheless, the analyses done here are instructive because they show the significance of the occurrence frequency for operational failures and third party activities.

8.2.4 Effect of Water Depth

The water depth at which the various hazards occur affects the consequences of an event as it controls how much oil drainage takes place (Section 7). Because all of the hazards are considered equally likely to occur over their applicable water depth ranges (Section 3), the oil volume released by an event that occurs at the average water depth in the applicable range is most likely to reflect the true value over the life of the Liberty Pipeline.

The significance of the event's water depth was investigated by assuming that all hazards occur at the water depth within the applicable ranges that would release the most oil. This is the worst possible case.

The significance of this parameter is generally similar for all pipe designs. The total risk is increased by about 10 to 25 % for the worst possible water depth (Table 8.6).

8.2.5 Effect of Pipeline Failure Mode

As described in the previous text, three general modes of pipeline failure have been presumed to occur, and have been quantified as follows:

(a) complete rupture or separation of the line
(b) flow through the maximum stable crack. As described in section 7, it is recognized that many cracks will be below this size, and that the flow rates will be reduced somewhat as a result. The maximum crack size was used for calculating spill volumes to be conservative. It should be noted that this assumption has little effect on the spill volume as the majority of the spilled volume results from line drainage (section 7).
(c) seepage through tight cracks or pinholes.

As expected, rupture releases the most oil volume followed by flow through a stable crack and lastly, seepage. The type of pipeline failure is expected to vary with the hazard, and the following was presumed for the base case:

(a) pipeline rupture – an ice gouging event was presumed to cause rupture as it may result in large displacements for the pipeline.

(b) flow through the maximum stable crack – it was presumed that strudel scour, permafrost thaw subsidence, thermal loads and major (i.e., > 100 bbls) failures due to operational failures or third party activities would cause flow through a large crack.

(c) Seepage through tight cracks or pinholes – this was presumed to result from corrosion or from minor (i.e., < 100 bbls) failures due to operational failures or third party activities.

Sensitivity analyses were done to evaluate the significance of these assumptions. As expected, the total risk spans a wide range (about 30 % to 6 times the value for the base case) if the pipeline fails by rupture, or seepage, for each hazard (Table 8.6), which demonstrates the importance of the assigned failure mode.

It should be noted that the range of risk values given in Table 8.6 were done solely for the purpose of indicating the significance of the assigned failure modes. They **do not** reflect the uncertainty in the assignments made in this project, in our opinion.

8.2.6 Insignificant Parameters

The total risk was found to be insensitive to the following parameters (Table 8.1):

(a) the ice gouging frequency over a range of a factor of 10 (Section 3 and Appendix A);
(b) the potential error noted in the algorithms available to define subgouge soil displacements (Appendix A);
(c) the strudel scour generation rate and width distribution, which were both hypothesised to vary significantly for a "severe" year (Section 3 and Appendix B).
(d) corrosion.
(e) occurrence probabilities for permafrost thaw subsidence events.
(f) occurrence probabilities for thermal loading events, leading to upheaval buckling.

8.3 Expected Maximum Risk for the Pipe Designs

8.3.1 Risk Augmentation Factors and Analysis Approach

The analyses described here were conducted to estimate the most likely maximum spill volume. The sensitivity analyses have shown that the following factors have the most effect on the total risk:

(a) the water depth at which the hazard occurs;
(b) the performance of the monitoring systems;
(c) the assumptions made regarding secondary containment;
(d) the occurrence frequency, and hence, risk, for oil releases due to operational failures and third party activities, and;
(e) the assumptions made regarding the pipeline failure mode.

The sensitivity analyses demonstrated the significance of each of these risk augmentation factors by evaluating the risk for expected worst cases for each one. They also showed all of the other factors considered had an insignificant effect on the total risk, and consequently, the analyses presented here are limited to the above factors. It is important to recognise that the sensitivity analyses are done with respect to the base case, and that the worst case for each of the above factors will most likely not occur during the same event. Therefore, one should **not** combine each sensitivity result directly to determine the most likely maximum spill volume because this would greatly overestimate the actual value.

One approach would be to conduct analyses based on the expected distributions for the ranges of variation for the above risk augmentation factors. While this has the advantage that it is rigorous, it is recognised that the required inputs (e.g., occurrence probabilities for each of the above risk augmentation factors) cannot be specified accurately, which would greatly limit the reliability associated with any results obtained.

Consequently, a simplified approach was used as described below:

(a) the risk increase associated with each risk augmentation factor listed above was calculated compared to the base case.

(b) occurrence probabilities were estimated relative to the base case for each risk augmentation factor. These were established using engineering judgement.

(c) the expected risk increase associated with each risk augmentation factor was determined as the product of items (a) and (b) above.

(d) the expected total risk increase associated with all of the above risk augmentation factors was calculated by summing the individual components determined in (c) above.

This approach errs conservatively because it presumes that each of the above risk augmentation factors occurs at the same time.

8.3.2 Input Values Used and Risk Results

The assigned occurrence probabilities and the calculated maximum risks are summarised in Table 8.7.

The maximum expected risk is less for the steel pipe-in-pipe design than for the other ones which all have comparable risk, within the accuracy of the analyses (Table 8.7).

For the single pipe, the pipe-in-HDPE, and flexible pipe designs, the calculated maximum expected risks are about 1.6 times higher than the base case values. The assumptions made regarding operational failures and the perforamnce of the monitoring systems used add the greatest risk to the total (Table 8.7).

For the steel pipe-in-pipe design, the maximum expected risk is about 2-3 times larger than the base case value (depending on the design under consideration – Table 8.7). This risk increase is primarily comprised of the risk augmentation associated with the assumptions made regarding secondary containment and the performance of the monitoring systems (Table 8.7).

Table 8.7: Summary: Expected Maximum Risk[1] for Each Design

Case	Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe in HDPE[2]	Flexible Pipe[2]
Base Case	28 ; 28	8 ; 13	24 ; 24	29 ; 28
Risk Augmentation Factor: Water depth at which the hazard occurs				
Risk Increase[3]	7	2	7	6
Estimated Prob of Occurrence[4]	0.2	0.2	0.2	0.2
Factored Risk Increase[5]	1.4	0.4	1.4	1.2
Risk Augmentation Factor: Expected worst-case performance of the monitoring systems				
Risk Increase[3]	23	13	27	22
Estimated Prob of Occurrence[4]	0.2	0.2	0.2	0.2
Factored Risk Increase[5]	4.6	2.6	5.4	4.4
Risk Augmentation Factor: No secondary containment provided by any of the pipe designs				
Risk Increase[3]	0	15	4	0
Estimated Prob of Occurrence[4]	0	0.3	0.5	0
Factored Risk Increase[5]	0	4.5	2	0
Risk Augmentation Factor: Expected worst case for oil releases due to operational failures and 3rd party activities				
Risk Increase[3]	41	9	41	40
Estimated Prob of Occurrence[4]	0.2	0.2	0.2	0.2
Factored Risk Increase[5]	8.2	1.8	8.2	8.0
Risk Augmentation Factor: Worst pipeline failure mode (i.e., rupture) occurs for every hazard				
Risk Increase[3]	125	75	130	124
Estimated Prob of Occurrence[4]	0.02	0.02	0.02	0.02
Factored Risk Increase[5]	2.5	1.2	2.6	2.5
Total Risk (bbls)	45	24	44	45

Notes:

1. All risk values are in bbls.
2. The risk values listed are for the pipe designs produced by Intec, 1999, and Intec, 2000, respectively. See also Tables 1.1 and 1.2, respectively. The maximum expected risk was calculated with respect to the larger of the two base case values.
3. The risk increase was calculated by subtracting the base case risk from the respective values in Table 8.6. For example, the risk for the sensitivity analysis done with the worst water depth case was 35 bbls for the single pipe design (Table 8.6). A value of 7 bbls was determined by subtracting 28 from 35.
4. The estimated probability of occurrence relative to the base case was established using engineering judgement.
5. The factored risk increase was determined as follows:

   Factored Risk Increase = Estimated Prob of Occurrence * Risk Increase

8.4 The Probability of a Large Spill

The purpose of these analyses was to estimate the probability of a large spill, with a large spill being defined as one that would release more than 1000 bbls of oil.

This was determined using the occurrence probabilities and consequences defined for each hazard for each pipe design.

The calculated probabilities are summarised for each pipe design in Table 8.8. As expected, the following trends are evident:

(a) operational failures and third party activities comprise the greatest proportion of the total probability for the single steel pipe , the pipe-in-HDPE, and the flexible pipe designs.

The probability of a large spill due to this hazard is lower for the steel pipe-in-pipe because this design provides some secondary containment.

(b) the steel pipe-in-pipe design has the lowest probability of a large spill. This is due to the fact that this design provides some secondary containment

Table 8.8: Probability of a Spill Greater than 1000 bbls for Each Design[1]

Hazard & Failure Mode[3]	Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe in HDPE[2]	Flexible Pipe[2]
Ice Gouging/Rupture	$1.2*10^{-6}$; $1.2*10^{-6}$	$7.0*10^{-5}$; $4.2*10^{-7}$	$1.1*10^{-5}$; $1.2*10^{-6}$	$9.4*10^{-5}$; $1.2*10^{-6}$
Strudel Scour/Crack Flow	$6.2*10^{-7}$; $6.2*10^{-7}$	$2.6*10^{-5}$; $1.0*10^{-5}$	$1.6*10^{-5}$; $1.0*10^{-5}$	$1.7*10^{-5}$; $6.2*10^{-7}$
Permafrost Thaw Subsidence/Crack Flow	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003
Thermal Expansion/Crack Flow	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003	0.0003 ; 0.0003
Major (>100 bbls) operational failures or third party activities/crack flow	0.01316 ; 0.01316	0.00087 ; 0.00173	0.01316 ; 0.01316	0.01316 ; 0.01316
Total Probability	0.0138 ; 0.0138	0.00158 ; 0.00234	0.0138 ; 0.0138	0.0139 ; 0.0138

Notes:
1. All values are for the base case defined in Table 8.1.
2. The listed probabilities are for the pipe designs produced by Intec, 1999, and Intec, 2000, respectively.
3. The assumed pipeline failure modes for the base case are as follows:
   (a) ice gouging – rupture
   (b) strudel scour – flow through the maximum stable crack
   (c) permafrost thaw subsidence – flow through the maximum stable crack
   (d) thermal expansion – flow through the maximum stable crack
   (e) operational failures and 3rd party activities – flow through the maximum stable crack

9.0 CONCLUSIONS AND RECOMMENDATIONS

9.1 Conclusions

9.1.1 Basis for Conclusions

A detailed analysis has been carried out to determine the risk for each of the concept pipeline designs produced by Intec, 1999; 2000. Risk (which is the product of the event probabilities and event consequences) was defined in terms of the volume of oil expected to be released over the 20-year life of the Liberty Pipeline.

The study investigated and quantified the following:

(a) the hazards for the pipeline;
(b) the response of the pipeline to these hazards; and
(c) the consequences of pipeline failure for each hazard, taking into account the monitoring systems that will be used.

9.1.2 Summary Results

The risk was evaluated first for a base case that represents FTL's best estimate for all input parameters. The risk for the base case for each pipeline design is summarised in Table 9.1.

Table 9.1: Total Risk[1] for the Base Case for Each Pipeline Design

Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe-in-HDPE[2]	Flexible Pipe[2]
28 ; 28	8 ; 13	24 ; 24	29 ; 28

Notes:
1. All risk values are in bbls.
2. The risk values are for the pipe designs produced by Intec, 1999 ; 2000, respectively.

9.1.3 Most Significant Hazards

Oil releases resulting from operational failures were found to pose the vast majority (about 95%) of the total risk for the single steel pipe, the pipe-in-HDPE, and the flexible pipe designs.

The most significant risks for the steel pipe-in-pipe design were oil spilled as a result of operational failures that breach both the inner and outer pipes, and oil spilled during repair operations.

9.1.4 Comparison of Pipe Designs

For the base case, the steel pipe-in-pipe design was found to have about 30 to 50 % less risk than the single steel pipe, the pipe-in-HDPE, and the flexible pipe designs. This was primarily due to the secondary containment provided by the steel pipe-in-pipe design.

The single steel pipe, the pipe-in-HDPE, and the flexible pipe designs all had comparable risk within the accuracy of the analyses conducted.

9.1.5 Sensitivity Analyses

An extensive sensitivity analysis was conducted. The following factors had the greatest effect on the total risk for the Liberty Pipeline:

(a) the water depth at which the hazard occurs;
(b) the performance of the monitoring systems;
(c) the assumptions made regarding secondary containment;
(d) the occurrence frequency, and hence, risk, for oil releases due to operational failures and third party activities, and;
(e) the assumptions made regarding the pipeline failure mode.

9.1.6 Maximum Expected Risk for Each Pipeline Design

This was evaluated using a simplified approach that accounted for the risk augmentation factors listed in Section 9.1.5. The maximum expected risk was about 60% more than the base case values for the single steel pipe, the pipe-in-HDPE, and the flexible pipe designs (Table 9.2). The maximum risk for the steel pipe-in-pipe design was about 2 to 3 times more than the base case value (i.e., 24 bbls vs 8-13 bbls, respectively).

Thus, the differences between the four designs reduced somewhat as a result of the sensitivity analyses. Nevertheless, the relative rankings of the four pipe designs was unchanged compared to the base case (Section 9.1.2) as follows:

(a) the steel pipe-in-pipe design had the least risk, and;
(b) the single steel pipe, the pipe-in-HDPE, and the flexible pipe all had more risk than the steel pipe-in-pipe. Furthermore, these three designs had equal risk within the accuracy of the analyses.

Table 9.2: Total Expected Maximum Risk[1] for Each Pipeline Design

Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe-in-HDPE[2]	Flexible Pipe[2]
45	24	44	45

Notes:
1. All risk values are in bbls.
2. The risk values are the maximums for the pipe designs produced by Intec, 1999 ; 2000, respectively.

9.1.7 Probability of a Spill Larger Than 1000 Barrels

The steel pipe-in-pipe design was found to have the lowest probability of a large spill (Table 9.3).

The single steel pipe, the pipe-in-HDPE, and the flexible pipe designs were found to be equivalent within the accuracy of the analyses conducted.

Table 9.3: Total Probability of a Spill Exceeding 1000 Barrels[1]

Single Steel Pipe[2]	Steel Pipe-in-Pipe[2]	Pipe-in-HDPE[2]	Flexible Pipe[2]
0.0138 ; 0.0138	0.00158 ; 0.00234	0.0138 ; 0.0138	0.0138 ; 0.0138

Notes:
1. All values are for the base case.
2. The listed probabilities are for the pipe designs produced by Intec, 1999 ; 2000, respectively.

9.1.8 Uncertainties

The most important uncertainties are considered to be:

(a) the significance of the risk variations determined for the four pipeline designs. This issue was not investigated as it was beyond the Terms of Reference or scope of work. However, because this is considered to be the most significant uncertainty affecting the interpretation of the results, this would be a useful follow-on investigation.

(b) the information available to assess oil releases arising from operational failures is very limited as pipelines have not yet been operated offshore in the Arctic. As a result, the study was forced to rely on failure statistics from other regions to evaluate the risk due to this hazard.

The determination of the risk due to operational failures was also hindered by the fact that the Liberty Pipeline has only been developed to the concept design stage. This risk will be affected and controlled by issues such as operator training schedules, maintenance plans, surveillance, and monitoring which have not yet been finalized.

(c) the assumptions necessary to evaluate the secondary containment provided by the steel pipe-in-pipe and the pipe-in-HDPE designs.

(d) the information available to define the material properties and behaviour for the pipe-in-HDPE and flexible pipe designs.

9.2 Recommendations

The study results as well as the key uncertainties identified in Section 9.1 suggest logical areas for further study, or for the future application of resources as follows:

(a) the significance of the risk variations determined for the four pipeline designs should be investigated.

(b) operational failures were found to be the most significant hazard. Two actions are recommended:

(i) this finding should be investigated further. In particular, this finding should be re-examined after key issues such as operator training, surveillance, and monitoring plans have been developed further for the Liberty Pipeline.

(ii) future efforts aimed at ensuring the safety of the Liberty Pipeline should be focussed on minimising the risk posed by operational failures and third party activities. This suggests that efforts should be focused on such activities as operator training, surveillance, and monitoring.

(c) the behaviour of a steel pipe-in-pipe that is exposed to operational failures should be investigated further. The work should be aimed at obtaining better definition of the scenarios that will occur, and the pipe response to these events.

(d) the material properties and behaviour for the pipe-in-HDPE, and flexible pipe designs.

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APPENDIX A

INITIATING EVENTS: ICE GOUGING

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A1.0 INTRODUCTION

Because ice gouging is one event that can lead to an oil release, it merits consideration as an initiating event in this project.

A number of studies have provided insight into the general ice gouging process (e.g., Weeks et al, 1983; Palmer et al, 1990; Blanchet et al, 2000). Ice gouges are produced by the keels of moving ice features that ground on the seabed, and that are moved along it by the combination of their own inertia, and the available environmental driving forces. This process typically produces long trenches in the seabed (termed gouges).

It is generally recognised that three types of ice-soil-pipeline interaction are possible when a gouge track crosses the pipeline route, depending on the proximity of the pipeline to the ice keel bottom (Palmer et al, 1990), as follows:

(a) Zone 1 – in this case, the pipeline is located above the keel bottom, and thus, the moving ice keel contacts it.

(b) Zone 2 – a pipeline in Zone 2 is below the keel bottom, and thus not contacted by it. However, large soil displacements may occur in Zone 2, which have the potential to cause large pipeline strains in response to the gouging event.

(c) Zone 3 – Zone 3 is located beneath Zone 2. It is recognised that soil displacements will reduce steadily with depth below the moving ice keel (e.g., Woodworth-Lynas et al, 1996). Soil displacements in Zone 3 are small enough that a pipeline in Zone 3 would only experience elastic strains. A pipeline in Zone 3 would be safe.

The most significant point from the above is that the pipeline can be affected by the gouging event even if no ice-pipe contact occurs. This point was recognised by Intec, 2000, who analysed a range of cover depths for the pipeline that encompassed each of the three zones above.

A2.0 ICE GOUGING SCENARIOS THAT CAN LEAD TO AN OIL RELEASE

Two scenarios are of concern, as follows:

(a) the “single-gouge” scenario – this case was analysed by Intec, 2000, and it is briefly summarised below:
- (i) a single gouge is produced across the pipeline route.
- (ii) this produces strains in the buried pipeline, which may or may not lead to an oil release.

(b) the “multiple gouge scenario” – this case was not analysed by Intec, 2000, and it is briefly summarised below:
- (i) one gouge track crosses the pipeline route.
- (ii) the pipeline is strained but an oil leak does not develop.
- (iii) a second gouge track crosses the pipeline later at the same location as the first gouge. Furthermore, the direction of travel of the second gouging ice feature is opposite to that of the first gouging ice feature (which produced the first ice gouge).
- (iv) this causes a stress and strain reversal to the buried pipeline.

With respect to pipeline response, an important difference between the two gouging scenarios is that the multiple gouge scenario would produce a stress reversal in the pipe whereas this will not occur for the single gouge scenario.

Full-scale bending tests with a sample of the pipe intended for use on the Northstar pipeline (Stress Engineering Services, 1998a; 1998b) showed that it could withstand bending strains many times higher (i.e., more than 5) than the failure criterion for pipe rupture used by Intec, 2000 in their analyses, without developing a leak. Hence, these tests show that an oil leak is unlikely to develop from extreme bending strains produced during a single-gouge event.

However, the behaviour of a pipeline subjected to a stress reversal is expected to be more problematic. For this reason, the multiple gouging scenario was investigated although it was recognised that no information is available to define pipeline response and failure criteria for this type of event. Pipeline failure criteria are discussed in section 4 of the main text of this report.

A3.0 ICE GOUGING: THE CONTROLLING FACTORS AND THE AVAILABLE INFORMATION

A3.1 The Controlling Factors

The factors affecting the risk (defined with respect to loss of oil containment) arising from ice gouging can be broadly divided into environmental and ice-soil-pipe interaction parameters.

A3.1.1 Environmental Parameters

The usual procedure for gouging analyses is to use gouge information from seabed surveys. A number of investigators have suggested using “ice” data either as an alternative, or as a means of augmenting the “seabed” data approach.

It is important to recognise that an approach based solely on seabed gouge data relies primarily on probabilistic extrapolations for extreme events, as by definition, they are rare events.

As a result, this approach is not capable of accounting for physical limits imposed by the ice, and it may overestimate extreme events. For the Liberty Pipeline Route, the most important ice limits are considered to be:

(a) the size and type of ice feature that can enter the region – these are limited by the relatively shallow water depths along the Liberty Pipeline Route, and by the Barrier Islands which tend to prevent large ice features from reaching the area (e.g., Blanchet et al, 2000).

(b) gouge depth limitations imposed by ice strength – the strength of first year ridge keels, which are most likely responsible for creating the majority of the observed gouges in the vicinity of the Liberty Pipeline Route, may impose a significant limit on the gouge depth. This is supported by simple calculations (e.g., Croasdale et al, 2000). These calculations also suggest that some ice-pipe contact (from first-year ridge keels) may be tolerable. However, the supporting information is insufficient to use this limit definitively in the risk analyses being performed here.

Unfortunately, the “ice” approach is not considered to be feasible for the Liberty Pipeline route because not all of the required ice information is available (to our knowledge). Consequently, the “seabed” approach was used in this project for quantitative analyses. However, limitations imposed by the ice environment were used as one factor to guide the conclusions drawn from the analyses.

The following environmental parameters must be defined for the “seabed” approach:

(a) the gouge depth distribution;

(b) the gouge impact rate (defined as the number of gouges created per unit length per year) – this problem is complicated by the fact that gouges tend to be strongly oriented in the approximate east-west direction (for the Liberty Pipeline vicinity); and that gouge impact rates must be specified in relation to a gouge cut-off depth (i.e., the minimum gouge depth considered).

(c) the gouge width distribution – this affects the width of loading, and hence the stresses and strains imposed on the pipeline.

(d) the effect of water depth on the above parameters for the range of interest (i.e., those along the overall pipeline length).

A3.1.2 Ice-Soil-Pipe Interaction Parameters

The cases where a pipe lies in either Zone 1 or Zone 2 (defined in section A1) need to be considered in this project because they are the ones with the potential to release oil.

- Pipe in Zone 1 – A pipe in Zone 1 would be contacted by the ice keel. There is no consensus regarding what would happen to a pipe in Zone 1, predominantly because the information required to make definitive evaluations is not available, and detailed analyses or investigations have not been done. The problem is further complicated by the fact that many different interaction modes are possible depending on:

  (a) the type of ice feature – in general order of increasing ice gouging severity, these range from first year ridge keels to multiyear ridge keels to icebergs. However, the problem is complicated by the fact that there is considerable variation in the size and strength of each ice feature type. For the Liberty Pipeline route, it is expected that first year ridge keels will create the majority of the gouges.

  (b) the proximity of the pipe to the keel bottom – in general order of increasing ice gouging severity, the possible cases range from: (i) the pipe top being "grazed" by a first-year ridge keel, to (ii) the pipe being "hooked" by an ice keel.

  Based on comparisons with anchor-dragging loads, Palmer et al, 1990 suggested that it was unlikely that a pipeline would survive contact with an ice keel without damage. Further analyses based on more recent ice strength information (e.g., Croasdale et al, 2000) suggest that some ice-pipe contact may be tolerable although they noted that further research is required before definitive statements can be made. This is further supported by simple comparisons of the ice gouge statistics for various regions, which show considerable similarity. This may be attributable to the limiting effect of ice strength (Blasco, 2000).

  Implications and decision made for this project: This is an area where further research is required. Although it is likely (in our opinion) that some ice-pipe contact (for a first-year ridge keel) may be tolerable, as it will not cause an oil leak, the available information is inadequate to establish and quantify this with confidence.

Consequently, the risk analyses conducted in this project were based on the following premise:

> *Any ice-pipe contact will produce a rupture of any of the alternative pipeline designs.*

- Pipe in Zone 2 – this zone is located beneath the ice keel and gouge track bottom. Hence, the ice would not contact a pipe in Zone 2. However, soil displacements would occur, which would load the pipe.

  The available information is derived from:

  (a) field observations of soil strata and bedding planes at onshore locations (e.g., Woodworth-Lynas et al, 1998; Woodworth-Lynas, 2000), and;
  (b) small-scale tests conducted in a centrifuge (e.g., Woodworth-Lynas et al, 1996; Nixon et al, 1996).

  Implications and decision made for this project: The available information was utilised as much as possible in this project. However, because this is also an area where further research is required, a number of sensitivity analyses were done in an effort to represent the uncertainty in the available information.

  Subgouge displacements and their expected effect on the various pipe alternatives are discussed in sections A6 and A7, respectively.

A3.2 The Ice Gouge Information Base for the Liberty Pipeline Route Vicinity

The available information base was reviewed in detail because its reliability has a direct effect on the accuracy of any conclusions reached.

Although many seabed surveys have been conducted in the nearshore Alaskan Beaufort Sea (which are summarised in Intec, 1998a; 1998b), most of these are not applicable to the Liberty Pipeline route because they were done offshore of the Barrier Islands. The only two general sources of available information considered to be applicable to the Liberty Pipeline route are as follows:

(a) seabed surveys conducted in 1997 and 1998 in the vicinity of the Liberty Pipeline route in Stefansson Sound and Foggy Island Bay (Coastal Frontiers Corp., 1998; 1999). These data are referred to as the “1997” and “1998” surveys respectively.

(b) seabed surveys conducted over the 1972-1979 period in the lagoonal areas from longitude 145°W to 150°W (approximate values), which are summarised in Weeks et al, 1983. These data are referred to as the lagoonal data.

The 1997 and 1998 surveys are most applicable to this project. The main limitation of this dataset is that it is only covers two years, which makes it susceptible to uncertainties, as ice conditions are known to vary from year to year. Furthermore, the total number of gouges surveyed is small (i.e., 17 in 1997, and 4 in 1998).

The lagoonal data (summarised in Weeks et al, 1983) were referred to in an effort to expand the data set, and to obtain an assessment of the relative severity of the 1997 and 1998 "gouging" seasons. The following checks and adjustments were done in an effort to ensure reliable results:

(a) checks for variations in orientation – because gouges in the vicinity of the Liberty Pipeline route tend to be most commonly oriented in the east-west direction (approximately), gouging frequencies must be defined and compared with respect to a specified line orientation. The north-south direction was selected as the reference for comparisons.

    The 1998 survey was done along north-south lines. The 1997 survey was done along a combination of north-south lines, and the three pipeline routes that were under consideration. These data are discussed further in relation to gouge impact rates in section A3.3.2.

    The survey lines in the lagoonal areas were done over a range of orientations. Weeks et al, 1983, computed gouge frequencies from these data by referencing them to a line perpendicular to the main gouge orientation, which they found to be 099°. Hence, their gouging frequencies are with respect to a line that is close to north-south. These data are discussed further in section A3.3.2, which discusses gouge impact rates.

(b) adjustments for variations in gouge cut-off depth – the two data sets cannot be compared directly because Weeks et, 1983 used a gouge cut-off depth of 0.2 m (0.66 ft) for the lagoonal data whereas a cut-off of 0.25 ft was used for the 1997 and 1998 survey data.

    This variation was accounted for by extrapolating the lagoonal data to a cut-off gouge depth of 0.25 ft, using the information presented in Weeks et al, 1983, who also made similar extrapolations (to a zero cut-off depth).

A3.3 Gouge Parameter Values

A3.3.1 Gouge Depth Distribution

Intec, 2000 used the gouge depth distribution given in equation [A1] (see also Figure A1), as an input to the risk analyses they performed. This was a fit to the 1997 survey data (collected by Coastal Frontiers Corp., 1998). This was a conservative selection as this distribution produced the deepest gouges from the available datasets (Table A1).

(Please note that all figures pertaining to this Appendix are located at the end of this Appendix).

$$P(d) = e^{-2.5629\,(d+0.027)} \qquad [A1]$$

where: P(d) = the probability that a given gouge depth, d, will be exceeded

Table A1: 100-Year Gouge Depths for the Liberty Pipeline (after Intec, 2000)

Dataset	Graphical Method	Analytical Method
1997 Survey Data	1.59 ft	1.17 ft
1998 Survey Data	1.13 ft	1.04 ft
1997 & 1998 Survey Data	1.36 ft	1.12 ft

Notes:

1. Parameter values used by Intec, 2000 to calculate the above 100-year gouge depths:
(a) impact rate: 0.097 gouges (>0.25 ft deep)/mile/year.
(b) pipeline length : 6.12 miles

The lagoonal data in Weeks et al, 1983 were referred to in an effort to assess the relative severity of the 1997 and 1998 "gouging" seasons. They were one of the datasets investigated by Intec, 1998a; 1998b in support of the Northstar pipeline design.

By rearranging the equations in Weeks et al, 1983, and presuming that the gouge depth distribution is a negative exponential one, Intec, 1998a developed equation [A2] for determining the gouge depth associated with a specified return period.

$$d = c + [\ln(gtL \sin\theta) / \lambda] \qquad [A2]$$

where: d = the gouge depth for a specified return period
c = the cut-off gouge depth
θ = the gouge trend angle
λ = the exponential distribution fit parameter
g = the gouge impact rate
L = the total pipeline length

The input values below were determined separately for equation [A2] for the 0-5 m, and the 5-10 m water depth lagoonal data because they are divided in this manner in Weeks et al, 1983:

(a) c : taken as 0 ft for both water depth ranges
(b) θ : taken as 90°
(c) λ : given as 6.25 m^{-1} and 9.09 m^{-1} for a zero cutoff depth for water depth ranges of 0-5 and 5-10 m, respectively in Weeks et al, 1983

(d) g : determined to be 0.66 and 2.54 gouges/mile/yr for water depth ranges of 0-5 and 5-10 m, respectively by extrapolating the values in Weeks et al, 1983, using the same approach that they employed
(e) L : taken as 6.12 miles

The above inputs give values of 3.15 and 2.66 ft for the 100-year gouge depth for water depth ranges of 0-5 and 5-10 m, respectively.

A3.3.2 Gouge Impact Rate

As stated previously, the gouge impact rate (defined as the number of new gouges/mile/year) must be specified in relation to a given line orientation, and to a gouge cut-off depth. To be consistent, all gouge impact rates were referenced to a gouge cut-off depth of 0.25 ft, and a north-south orientation.

The 1997 and 1998 Liberty Site survey lines are shown in Figure A2 and Figure A3, respectively, along with the locations of the gouges found. The 1998 survey lines were all north-south, which is roughly perpendicular to the general gouge orientation (Figure A4).

The 1997 survey consisted of a combination of:

(a) north-south survey lines totalling about 135 statute miles in length, and;

(b) surveys along the three pipeline routes under consideration, totalling about 45 statute miles in length.

The north-south direction was selected as a reference for specifying gouge impact rates for a number of reasons:

(a) it is roughly perpendicular to the predominant gouge orientation, and hence, the maximum gouge impact rates will occur along this direction.

(b) most of the available data are in reference to this direction, as follows:

   (i) the lagoonal data in Weeks et al, 1983 – they determined gouging frequencies with respect to a line at a heading of 009° (i.e., perpendicular to the main gouge orientation), which is close to north-south;

   (ii) 1998 data – these are all with respect to north-south survey lines;

   (iii) 1997 data – most of these data are with respect to a north-south direction, or close to it (Figure A2).

> The only line with a significantly different orientation was the SDI route survey (Figure A2), which comprised about 9 statute miles of the total 180 miles surveyed. This line was oriented at about 115°, which is close to the predominant gouge direction. Consequently, fewer gouge crossings would be expected along this line than along the north-south survey lines. The magnitude of this difference can be roughly evaluated based on the size of the angle between the preferred gouge direction and the survey line direction (i.e., about 25°). This suggests that the number of gouges along this survey line length of 9 miles would be equivalent to those along a 4 mile length of north-south line. To account for this, gouge impact rates were calculated for the 1997 data using a total line length of 175 miles, instead of the 180 miles that were actually surveyed.
>
> As will be shown subsequently, the impact rate variation produced by this uncertainty in line length (i.e., 175 vs 180 miles) is insignificant compared to the differences between the lagoonal data, and the 1997 and 1998 data.

Because the Liberty Pipeline route is oriented at 030°, rather than north-south (Figures A2 and A3), efforts were made to evaluate the relationship between the gouge impact rate for the north-south direction and the one along a line with a direction of 030°. This was evaluated using an approach developed by Nessim, 1986, which is given below:

$$\frac{\lambda_{\theta pipeline}}{\lambda_{\theta surveyline}} = \frac{\rho L_{gouge(avg.)} \int_{\alpha=0}^{\alpha=\pi} \left|\sin\left(\theta pipeline-\alpha\right)\right| f(\alpha) d\alpha}{\rho L_{gouge(avg.)} \int_{\alpha=0}^{\alpha=\pi} \left|\sin\left(\theta surveyline-\alpha\right)\right| f(\alpha) d\alpha} \qquad [A3]$$

where: $\lambda_{\theta pipeline}$, $\lambda_{\theta survey\ line}$ = the gouge linear frequency along the pipeline and the survey line directions, respectively

$\theta_{pipeline}$, $\theta_{survey\ line}$ = the orientation of the pipeline and survey line, respectively

$L_{gouge\ (avg)}$ = the average gouge length

ρ = the areal gouge density

α = the gouge orientation with a probability density function of $f(\alpha)$

Equation [A3] indicates that the gouge linear frequency along the pipeline route would be 78% of that along a north-south direction. This variation was not accounted for in the analyses because:

(a) this approach errs conservatively; and,

(b) this variation is not significant compared to the impact rate variation observed between the 1997 and 1998 survey data (collected in the vicinity of the Liberty Pipeline route), and the lagoonal data presented in Weeks et al, 1983 (described subsequently).

For subsequent analyses, the north-south gouge impact rates were applied directly to the pipeline route without any corrections for their variation in orientation. The available information indicates that the gouge impact rate (defined as the number of gouges > 0.25 ft deep created each year per mile of pipeline length) may vary over a large range, as summarised below.

(a) 1997 Liberty Site survey data case - a maximum value of 0.097 gouges/mile/yr is calculated from these survey data, if it is presumed that all of the observed gouges were created in that year, which errs conservatively. However, no other assumption can be justified owing to the paucity of the available data. This approach gives an impact rate of 0.097 gouges/mile/yr (i.e., 17 gouges > 0.25 ft deep/ 175 miles of survey line). This impact rate was used by Intec, 2000 in the risk analyses that they performed.

(b) best case – a best case value of 0.049 gouges/mile/yr was determined based on the combination of the following two approaches:

(i) 1998 Liberty Site Survey data – these data indicate an impact rate of 0.056 gouges/mile/yr (i.e., 4 gouges > 0.25 ft deep/72 miles of survey line), again presuming that all of the observed gouges were created in that year.

(ii) “Corrected” 1997 Liberty Site Survey data – the 1997 and 1998 site surveys were both done by surveying several North-South lines that were 3000 ft apart. It is well known that gouges can be long features, and it is possible that the same gouge crossed more than one survey line, particularly because most of the survey lines were oriented at close to right angles to the preferred gouge orientation. This is especially likely for the 1998 survey data as three of the observed gouges are collinear, and they crossed adjacent survey lines (Figure A3). The 1997 survey results also contain a number of cases where the same gouge may have been counted more than once (Figure A2). Based on inspection of the observed gouge locations, it is possible that this may have led to an overestimation of the gouge impact rate by a factor of up to approximately two.

The “best case” impact rate was defined by dividing the 1997 survey result by two.

(c) lagoon data case – a value of 0.41 gouges (> 0.25 ft deep)/mile/yr was obtained for an orientation of 009°, which is close to north-south. It should be noted that this value was obtained by extrapolating the gouging frequencies in Weeks et al, 1983 (which refer to a cut-off depth of 0.66 ft) to a cut-off depth of 0.25 ft, as explained in section A3.2.

It should be further noted that the above impact rate calculation presumes that all of the gouges in the lagoons were new gouges. This is probably a conservative assumption. However, unfortunately, no other assumption can be justified as these data are not based on repetitive surveys that were not run along the same lines.

A3.3.3 Gouge Width Distribution

This was defined based on the 1997 and 1998 survey data for the Liberty site (Coastal Frontiers Corp., 1998; 1999), and a distribution fitted to those data by FTL, which is given below and in Figure A5:

$$P(w) = e^{(-.00254\ w^{\wedge}2)} \qquad [A4]$$

where: P(w) = the probability that a given gouge width, w, will be exceeded

A3.3.4 Comparison: 1997 and 1998 Survey Data vs the Lagoonal Data

The following conclusions are evident from the comparisons made:

(a) gouge orientation – the 1997 and 1998 survey data are in good agreement with the lagoonal data in Weeks et al, 1983.

(b) gouge depths – the lagoonal data indicate a 100-year gouge depth that is more than about 65 % deeper than the most conservative interpretation of the 1997 and 1998 survey data.

(c) gouge impact rates – the lagoonal data indicate higher impact rates than the most conservative interpretation of the 1997 and 1998 survey data by a factor of about 4.

This above variations may reflect one, or both, of the trends/questions below:

(a) it may indicate that the 1997 and 1998 “gouging” seasons were relatively light ones.

(b) it may indicate that gouging conditions in the vicinity of the Liberty Pipeline Route are less severe than those over the full extent of the lagoons.

Unfortunately, the available data is insufficient to resolve these questions. To cover the range of possibilities, subsequent risk analyses were done using a range of values for the above parameters, which is believed to span the uncertainty that is inherent in the available information.

A4.0 THE SINGLE GOUGE SCENARIO

A4.1 Gouge Data Input Requirements

The ice gouge parameters that must be defined for a risk evaluation of the single gouge scenario are as follows:

(a) the ice gouge depth and width distribution;
(b) the gouge impact rate, and;
(c) the dependence of the gouge population on the water depth range for the pipeline.

A4.2 Input Data Used

A4.2.1 Gouge Depth

The analyses conducted here were based on the depth distribution developed by Intec, 2000 (given in section A3.3.1, Figure A1, and equation [A1]). Although comparisons with the lagoonal data in Weeks et al, 1983 showed that equation [A1] produced shallower gouges (section A3.3.4), this distribution was used because:

(a) the variation in depth distribution between the two data sources was small compared to the difference in gouge impact rates. Consequently, the results will be relatively insensitive to which depth distribution is selected, as they will be overshadowed by the uncertainty produced by the observed variation in impact rate.

(b) equation [A1] is based on gouges measured in the vicinity of the Liberty Pipeline route.

For the analyses conducted here, equation [A1] was modified to reflect a gouge cutoff depth of 0.25 ft because the gouge impact rates used in this project were specified with respect to that cutoff depth (section A3.3.2).

A4.2.2 Gouge Impact Rate

As given in section A3.3.2, the available information suggests that the gouge impact rate (defined as the number of gouges > 0.25 ft deep that are produced each year per mile of pipeline length) may vary over a wide range as follows:

(a) the 1997 Liberty survey data – value indicated: 0.097 gouges/mile/year
(b) the "best case" – value indicated: 0.049 gouges/mile/year
(c) the lagoonal data in Weeks et al, 1983 – value indicated: 0.41 gouges/mile/year

These three values were used in subsequent risk analyses.

A4.2.3 The Effect of Water Depth

It is well known that, for locations offshore of the Barrier Islands, the ice gouge depth tends to increase with increasing water depth (e.g., Weeks et al, 1983). The gouge impact rate offshore of the Barrier Islands has also been found to be related to the water depth.

However, inshore of the Barrier Islands, the available data (i.e., Coastal Frontiers Corp., 1998; 1999, and Weeks et al, 1983) indicate that gouge depths, widths, and impact rates are all not strongly dependent on water depth except as follows:

(a) no gouges were measured during the 1997 and 1998 surveys at water depths less than 10 ft. The shallowest water depths at which gouges were measured during these surveys were 10.6 ft and 11.2 ft, respectively. This probably reflects the fact that large draft ice keels (which are believed to produce the majority of the gouges) ground out before reaching the shallow water areas.

Consequently, two cases were considered for the risk analyses conducted here, as follows:

(a) gouges are equally likely to occur at any point along the length of the Liberty Pipeline. This case was evaluated to provide an upper bound result.

(b) gouges can only occur at water depths greater than 10 ft. This limits the pipeline length over which gouges can occur to about 3.3 miles.

    Because no trends were evident in the gouge data (with respect to either gouge depth or frequency vs water depth), gouges were considered equally likely to occur at any water depth deeper than 10 ft.

A4.3 Gouge Depth Return Periods

Figures A6 and A7 show gouge depth return periods for the case where gouges may be produced at any water depth along the pipeline length, and where gouges are only assumed to occur at water depths greater than 10 ft, respectively.

As expected, the following trends are evident:

(a) gouge depth return periods are strongly dependent on the gouge impact rate. The range of impact rates considered in this project cause the predicted return period for a given gouge depth to vary by a factor of about 10.

(b) return periods for a given gouge depth are increased by a factor of about 2 when gouges are only allowed to occur in water depths deeper than 10 ft. This is due to the fact that this limits the “gougable” pipeline length to about 50 % of the total offshore length.

A5.0 THE MULTIPLE GOUGE SCENARIO

A5.1 Scope of Analyses

Two types of analyses were done to investigate occurrence frequencies for the multiple gouging scenario, as follows:

(a) the probability that two gouges would cross the same section of the Liberty Pipeline (termed "re-gouging") was analysed. This analysis is described in section A5.2.

(b) occurrence frequencies were calculated for various gouge depth combinations. See section A5.3.

A5.2 The Probability of a Re-Gouging Event

A5.2.1 Analysis Approach

This was calculated using Monte-Carlo analyses set up to simulate ice gouging over the life of the pipeline, which was taken as 20 years. Each simulation had the following steps:

(a) the first year of the pipeline's life was simulated by:
- (i) selecting a gouge width from the specified distribution.
- (ii) selecting a gouge crossing location along the pipeline length. The gouge crossing location was considered to be equally likely to occur at any point along the pipeline's length.

  It was recognised that this is a conservative assumption as gouges are unlikely to occur in the nearshore shallow waters (section A4). However, this was not accounted for in the analyses because they showed that multiple gouging is a rare event for deep gouges (described subsequently).

- (iii) determining the probability of contact based on the value used for the gouge impact rate.

(b) the second year of the pipeline's life was next simulated by selecting another gouge width, and crossing location, and; determining the contact probability based on the gouge impact rate.

(c) the simulation was continued up to 20 years, which is the expected life of the pipeline. The simulation was stopped in the event that any two gouges overlapped each other by any amount.

To ensure reliability, each 20-year simulation was repeated 10 million times. The whole analysis (i.e., each 10 million-time sequence) was repeated 5 or more times.

A5.2.2 Inputs Used

The gouge width distribution and the gouge impact rate must be defined in order to carry out the analyses. They were defined as follows:

(a) gouge width distribution – this was defined using equation [A4];

(b) gouge impact rate - a number of gouge impact rates were analysed to span the range of possible values, as summarised below:

(i) 1997 survey data case - value used: 0.097 gouges >0.25 ft deep/mile/yr
(ii) best case - value used: 0.049 gouges>0.25 ft deep /mile/yr
(iii) lagoon data case - value used: 0.41 gouges>0.25 ft deep /mile/yr

A5.2.3 Results: Re-Gouging Frequency

As expected, the re-gouging frequency increases with the time period considered and the gouge impact rate (Figure A8). For the highest gouge impact rate considered (i.e., 0.41 gouges/mile/yr), there is a 74% probability that the Liberty pipeline will be re-gouged at some point along its length over its 20-year life, by gouges that are at least 0.25 ft deep.

A5.3 The Frequency of Occurrence of Various Multiple Gouging Sequences

A5.3.1 Purpose of Analyses

The re-gouging frequency analyses (presented in section A5.2) show that there is a relatively high probability that the Liberty Pipeline route will be crossed twice at the same location by ice gouges over its 20-year life. To investigate the consequence of this, it is necessary to determine the frequency at which the pipeline would be crossed in opposite directions by two gouges of various depths over its 20-year lifetime. This information is required to assess the significance of re-gouging, and the risk that this process represents.

A5.3.2 Analysis Approach and Inputs Used

The occurrence frequency of various gouging sequences was evaluated by conducting Monte-Carlo analyses. Each run was set up to simulate a 20-year period, as follows:

(a) the total number of expected gouge crossings (for gouges > 0.25 ft deep) was determined for the 20 year period as the product of the gouge impact rate, the pipeline length (taken as 6.12 miles), and the period of interest (taken as 20 years). Separate analyses were performed for gouge impact rates of 0.049, 0.097 and 0.41 gouges (>.25 ft deep)/mile/year.

(b) the location, depth and width of the first gouge in the 20-year sequence was established, as follows:
   (i) gouge location – this was considered to be equally likely to occur at any point along the 6.12 mile length of the pipeline. As described in section A5.2.1, the analyses were done for the whole pipeline length, rather than for the 3.3 mile length over which gouges can occur, to err conservatively.
   (ii) gouge width – this was selected randomly from the distribution shown in Figure A5.
   (iii) gouge depth – the analyses were based on the distribution developed by Intec, 2000 (Figure A1 and equation [A1]). Because gouge impact rates were specified with respect to a cut-off depth of 0.25 ft, this depth distribution was modified to reflect that cut-off depth. The gouge depth used in the simulations was selected randomly from this modified distribution.

(c) the location, depth and width of the next gouge was established in a similar manner. The simulation then checked whether or not the second gouge overlapped the first one to any extent. If any overlap occurred, this was recorded as a re-gouging event, and the corresponding two gouge depths were binned.

(d) the location, depth and width of the next gouge was established in a similar manner. The simulation then checked whether or not any overlap of the gouges along the route occurred, and if so, recorded this as a re-gouging event.

(e) this process was repeated until all of the expected gouges during the 20-year life of the line were modelled.

Steps (a) to (e) represent one 20-year case for the Liberty Pipeline.

The most conservative interpretation of the results from this simulation is that all of the gouge overlaps that occurred were caused by gouges travelling in opposite directions (which would lead to a stress reversal for the pipe). This is believed to be overly conservative. It is more likely (in our opinion) that the number of stress reversals will be some proportion of the total number of re-gouging events. In this project, it has been assumed only half of the re-gouging events will lead to stress reversals, although it is recognised that the information required to establish this definitively is not available.

Steps (a) to (e) were repeated 50 million times to establish the occurrence frequency of re-gouging by various gouge depth combinations.

A5.3.3 Results

Figures A9, A10, and A11 show the results for the simulations done with gouge impact rates of 0.049, 0.097, and 0.41 and gouges/mile/year, respectively. As expected, the occurrence probability is affected greatly by the gouge impact rate, and the gouge depths.

Summary results are presented in Table A2.

Table A2: Summary Results: Gouge Combination Frequencies over the 20-Year Life of the Liberty Pipeline

Depth Range of First Gouge (ft)	Depth of Second Gouge (ft)	Gouge Impact Rate (gouges/mile/year)	Occurrence Probability
2.5 to 3	3	0.049	$2.5 * 10^{-8}$
2.5 to 3	3	0.097	10^{-7}
2.5 to 3	3	0.41	10^{-6}
2.5 to 3	4	0.049	$2 * 10^{-9}$
2.5 to 3	4	0.097	10^{-8}
2.5 to 3	4	0.41	$1.3 * 10^{-7}$
2.5 to 3	5	0.049	$2 * 10^{-10}$
2.5 to 3	5	0.097	10^{-9}
2.5 to 3	5	0.41	10^{-8}

A5.4 Conclusions and Significance of the Multiple-Gouging Scenario

Occurrence frequencies have been evaluated for various multiple-gouging cases. The analyses show that:

(a) there is a relatively high probability that the Liberty Pipeline will be re-gouged at some location along its length over its 20-year lifetime.

(b) the gouge depths for most of the re-gouging cases will be shallow.

(c) the probability that the pipeline will be re-gouged by two deep gouges is quite low. For example, the probability that the pipeline will be crossed by one 2.5-3 ft deep gouge, and a second one more than 3 ft deep is 10^{-6} for the highest impact rate to be expected (i.e., 0.41 gouges/mile/yr).

The next step in evaluating the significance of multiple-gouging is to make comparisons against pipeline failure criteria. Pipeline failure criteria are discussed in section 4 of the main text of this report.

A6.0 SUBGOUGE SOIL DISPLACEMENTS

A6.1 Introduction

Subgouge displacements affect the stresses and strains imposed on a pipeline in Zone 2. There are two main issues that must be evaluated for this risk analysis:

(a) the magnitudes of the subgouge displacements, and the factors controlling them, and

(b) the uncertainty in the information available to define subgouge displacements.

A6.2 The Available Information

The available information is derived from two main sources as follows:

(a) field observations of land-based ice gouge features, and
(b) small-scale tests done in a centrifuge.

A6.2.1 Field Observations Of Land-Based Ice Gouge Features

These have been described and summarised in a number of publications (e.g., Woodworth-Lynas et al, 1996; Woodworth-Lynas et al, 1998). The information base includes:

(a) observations made at Lake Agassiz in Manitoba where faults and bedding plane disruptions were observed down to about 4 m below a 2 m deep, 55 m wide scour in silty clay.

(b) observations made at Cobequid Bay in the Bay of Fundy where evidence of subgouge displacements were observed down to about 1.5 times the gouge depth (with the maximum gouge depth being about 0.25 m) in clayey silt.

These observations are useful for verifying that subgouge displacements do indeed occur. However, because the information is primarily qualitative, it is difficult to use in a quantitative evaluation of pipeline response, and risk.

A6.2.2 Small-Scale Tests Done In A Centrifuge

Small-scale tests were done in a centrifuge at the Centre for Cold Oceans Resources Engineering (CCORE) as part of the Pressure Ridge Ice Scour Experiment (PRISE). Only summary results from these tests have been published to date (e.g., Nixon et al, 1996; Woodworth-Lynas et al, 1996) as most of the results are proprietary. This makes it difficult to assess the reliability of the information.

However, it is important for this project to assess their reliability as the CCORE centrifuge test results were used as the basis for defining subgouge displacements in design and risk analyses done by Intec, 2000. The subgouge soil displacements used for these analyses are defined in Nixon, 1997, and they are discussed in section A6.3.

The most significant limitations in the CCORE centrifuge test data include the following:

(a) range of applicability of results – the published information (in Woodworth-Lynas et al, 1996) indicates that the tests were done for gouge widths of 15 and 30 m; and gouge depths of 1 and 2 m. These are considerably larger than the corresponding values for the Liberty Pipeline route. The 30%, 50% and 70 % exceedence probability gouge widths and depths are 22 ft, 17.6 ft, and 12 ft ; and 0.44 ft, 0.25 ft, and 0.11 ft, respectively (section A3).

Woodworth-Lynas et al, 1996, and Nixon et al, 1996, developed empirical predictors from the CCORE centrifuge test data to define the vertical and horizontal subgouge displacement field below the ice keel. Based on considerations of geometric similarity, they suggested that the displacement field can be scaled to different gouge widths and depths based on the horizontal displacement immediately below and at the centre of the ice keel, as follows:

$$U(0,0,0) = 0.6 * \sqrt{(b * d)} \qquad [A5]$$

where: b,d = the gouge width and depth, respectively
U(0,0,0) = the horizontal displacement immediately below and at the centre of the ice keel

The "$\sqrt{(b * d)}$" values tested in the centrifuge range from 3.9 m to 7.7 m. These minima and maxima are 116 and 8.1 times more than the respective minima and maxima produced by the range of "$\sqrt{(b * d)}$" values for the 30% to 70 % exceedence level gouges in the vicinity of the Liberty Pipeline route (i.e., 1.1 ft to 3.1 ft, respectively).

Hence, it can be seen that the centrifuge results are applicable to much larger gouges than those expected in the vicinity of the Liberty Pipeline route.

The uncertainty introduced by this variation is difficult to assess, especially without access to the raw test results. Figure A12 (taken from Woodworth-Lynas et al, 1996), which shows the fit of "U(0,0,0)" to "$\sqrt{(b * d)}$", provides some indication of the uncertainty. The plotted data show considerable scatter, and vary from the line produced by equation [A5] by up to about 30 %. Furthermore, by inspection, it may be that a non-linear fit might provide better correlation, although it should be noted that this can't be assessed without all of the test information or without detailed analyses, which have not been done here.

(b) Subgouge displacement field variability – For a relatively short track length, some of the published data indicate that "typical" subgouge displacements are quite uniform along the track (Figure A13, taken from Woodworth-Lynas et al, 1996). This would suggest that, in this case, the gouging process was relatively steady-state and uniform.

However, it should be noted that considerable variation, and non-uniformity along the track, has been observed in some of the cases tested where the soil cover was non-uniform. Figure A14 shows the observed subgouge displacements for a test done with sand overlying clay, in which "shear-dragging" and "low-angle thrusts" were observed. In this case, the clay (which was originally well below the keel bottom) was found to migrate upwards into the gouge base (Figure A14), and the subgouge displacements along the track varied by a factor of about 5. This result compares well with the field observations made at Lake Agassiz in which similar processes were observed (Woodworth-Lynas et al, 1998). This is an indication that the gouging process is non-steady (Woodworth-Lynas, 2000).

Woodworth-Lynas et al, 1998, noted that "shear-dragging" and "low-angle thrusts" only occurred in one of the centrifuge tests, and suggested that it may be attributable to the stratigraphy tested (of coarser soils overlying finer soils).

The significance of this variation for the Liberty Pipeline is difficult to assess. Generally, the test data suggest that subgouge displacements along the track will be relatively uniform (implying a relatively steady gouging process) if the pipe is overlain by uniform material. However, non-uniformities in the cover material have the potential to cause relatively large variations in subgouge displacements.

(c) The effect of a pipeline – The subgouge displacement algorithms used by Intec, 2000 are based on tests where there was no pipe in the soil. Blanchet at al, 2000, stated that proprietary tests (which BP does not have access to) have indicated that subgouge displacements are reduced significantly when there is a pipe in the soil.

Although this is a reasonable expectation, this can not be used quantitatively in this project because these test results are not available. However, this would suggest that the subgouge displacement algorithms used by Intec, 2000 would overestimate the actual values, and hence be conservative. Unfortunately, no allowance for the effect of a pipe can be made in this project.

(d) The effect of soil properties - subgouge displacement algorithms have only been developed for two relatively coarse generic cases (i.e., "clay" and "sand"), which do not take account of variations in soil properties. Woodworth-Lynas et al, 1996 observed that displacements at the base of the keel were about twice as large in dense sand as in loose sand.

For the Liberty Pipeline project, Nixon, 1997 described the soil to be expected in the trench and around it as "sandy silts to silty sands". Intec, 2000, described the upper 5-6 ft as "soft, compressible, Holocene, non-plastic silt".

Recognising that subgouge displacements would be intermediate to the "clay" and "sand" cases, Nixon, 1997 suggested an average of the two cases for use in the pipe-soil analyses done by Intec, 2000. This introduces a small variation in horizontal displacement (i.e., of less than 10 % - shown subsequently in section A6.3).

In conclusion, it can be seen that the variations in displacements given by the two sets of equations (i.e., for clay and sand) are small in relation to the differences observed as a result of sand density (i.e. loose vs. dense).

(e) The effect of ice keel failure and movements – The subgouge displacement algorithms used by Intec, 2000 are based on tests where the ice keel was simulated with an effectively rigid indentor. Ice keel failures, or movements (i.e., uplifts, which are known to occur) would be expected to reduce the subgouge displacements. As a result, the test results are expected to overestimate the actual subgouge displacements. Unfortunately, the degree of conservatism introduced by this is impossible to determine with currently available information.

Although the CCORE tests are the only means currently available for defining the subgouge displacement field quantitatively, it is important to recognise that they have only been verified in a preliminary manner with field observations. Furthermore, the CCORE test results are subject to a number of uncertainties, as summarised in Table A3.

Table A3: Uncertainties and Their Expected Significance

Source of Uncertainty	Expected Uncertainty Magnitude and Trend
Range of applicability of test results (much larger gouges tested at CCORE) & scatter in test results	1. Scatter in test results - this indicates a maximum uncertainty of about 30 %. 2. Test data outside range of applicability for Liberty – can't be assessed with available data.
Variability in subgouge displacements along gouge track	Maximum variation of about 5 times
Pipe not included in tests conducted	1. Can't be assessed quantitatively 2. Will err conservatively as it will cause some overestimation of subgouge displacements.
Effect of soil type and properties	1. Difference between results for clay and sand soils is small (i.e., less than 10 %). 2. Variations in sand density produces differences of up to about 2 times.
Ice keel failure and movements not simulated in the tests	1. Can't be assessed quantitatively 2. Will err conservatively as it will cause some overestimation of subgouge displacements.

Because it is necessary for this project to make an assessment of the degree of confidence that is inherent in the centrifuge results, the following judgement has been applied by FTL in subsequent risk analyses conducted here.

- the algorithms used by Intec, 2000, to define the subgouge displacement field are subject to considerable uncertainty. Obviously, the worst case, with respect to the strains induced on a pipeline, is that the algorithms underestimate the actual one. The sensitivity analyses conducted in this project have been done by assuming that the algorithms may potentially underestimate the actual subgouge displacements by a factor of 10. This range of uncertainty, which is an opinion only, is believed to be conservative.

A6.3 Expected Subgouge Soil Displacements

A6.3.1 Algorithms Developed for Defining the Subgouge Soil Displacement Field

The following algorithms have been developed and used in the analyses done to date for the Liberty Pipeline (Intec, 2000; Nixon, 1997):

- Vertical Displacements Below the Centre of the Keel:

Clay: $V(0,0,z)/ d = e^{(-0.333\ z/d)}$ [A6]
Sand: $V(0,0,z)/ d = 0.441 * e^{(-0.687\ z/d)}$ [A7]

- Horizontal Displacements Below the Centre of the Keel:

Clay: U(0,0,z) / U(0,0,0) = e ^ (- 0.667 z/d) [A8]
Sand: U(0,0,z) / U(0,0,0) = 1.10 * e ^ (- 0.755 z/d) [A9]

- Horizontal Displacement Distribution Along the Pipeline:

$$U(0,y,z) / U(0,0,z) = \begin{cases} 1 & \text{for } y/b < 0.25 \\ 0.5*[1+\cos((2y/b-0.5)\pi)] & \text{for } 0.25 < y/b < 0.75 \\ 0 & \text{for } y/b > 0.75 \end{cases} \quad \text{[A10]}$$

- Vertical Displacement Distribution Along the Pipeline:

$$V(0,y,z) / V(0,0,z) = \begin{cases} 1 & \text{for } y/b < 0.25 \\ 0.5*[1+\cos((2y/b-0.5)\pi)] & \text{for } 0.25 < y/b < 0.75 \\ 0 & \text{for } y/b > 0.75 \end{cases} \quad \text{[A11]}$$

where: b = the gouge width
d = the gouge depth
U(0,0,0) = the horizontal displacement immediately below the ice keel at the centre of the gouge

U(0,0,z) = the horizontal soil displacement at the centre of the gouge and at a distance z below the ice keel
U(0,y,z) = the horizontal soil displacement at a distance z below the ice keel, and at a distance y from the centre of the gouge
V(0,0,z) = the vertical soil displacement at the centre of the gouge and at a distance z below the ice keel
V(0,y,z) = the vertical soil displacement at a distance z below the ice keel, and at a distance y from the centre of the gouge

As stated previously, Nixon, 1997, recommended that the average of the values obtained for clay and sand be used for the soil-pipe analyses conducted by Intec, 2000 for the Liberty Pipeline.

A6.3.2 Predicted Subgouge Soil Displacements

Figures A15 and A16 show the predicted subgouge horizontal displacements below the ice keel centre, and along the pipe, respectively, for different gouges of interest to the Liberty Pipeline. The following trends are evident:

(a) in each case, the horizontal displacement reduces rapidly with depth below the ice keel bottom, and with distance away from the edge of the keel.

(b) as expected, the subgouge displacements reduce in magnitude with the exceedence probability level of the gouge.

(c) the differences in the results for clay and sand soil are less than 10 %.

A6.3.3 Subgouge Soil Displacement Exceedence Probabilities

The exceedence probability distribution for subgouge soil displacements under the keel centre was calculated for gouge widths of 18 ft and 30 feet because failure criteria were developed for these two gouge widths (described in section 4 of the main text). The subgouge exceedence probability distribution is shown for 18 foot and 30 foot gouge widths for different pipe burial depths in Figures A17 and A18, respectively.

This was used as an input to the risk calculations as described in the main text.

A6.4 Conclusions and Implications for Risk Analyses

The available information for defining subgouge displacements comes from land-based field observations, and from small-scale centrifuge tests. The centrifuge tests have been used to establish exceedence probability distributions for subgouge horizontal soil displacements for the gouge widths and pipe cover depths of interest.

The reliability of the centrifuge test results is difficult to establish because only limited field information is available for verifications. The field observations are useful for verifying that subgouge displacements do indeed occur, and for general verification of the small-scale centrifuge test results. However, they are mainly qualitative in nature.

The review conducted in this project suggests that the centrifuge test results are subject to a number of uncertainties which have been conservatively estimated to affect the predicted subgouge displacements by up to factor of 10. This variation was used as the basis for subsequent sensitivity analyses conducted here.

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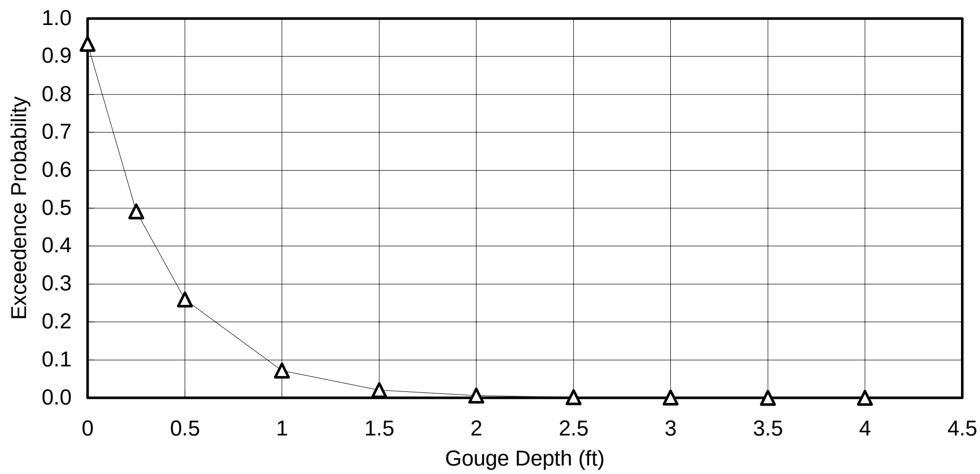

Figure A1: Gouge Depth Distribution Used by Intec, 2000

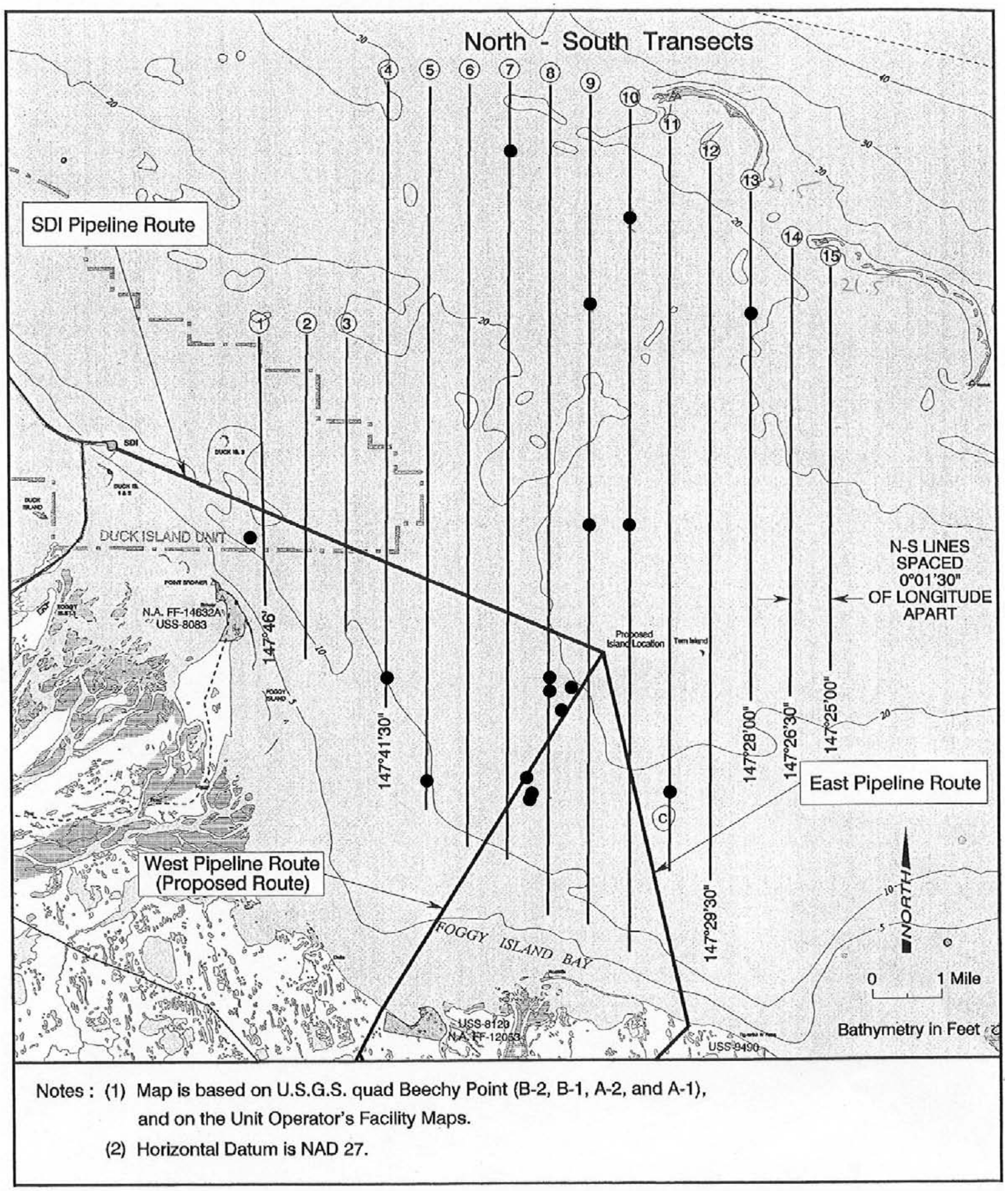

Figure A2: Gouge Locations: 1997 Liberty Site Survey

(Figure taken from Coastal Frontiers Corp., 1998;
Gouge locations – indicted by black dots - added to figure by FTL)

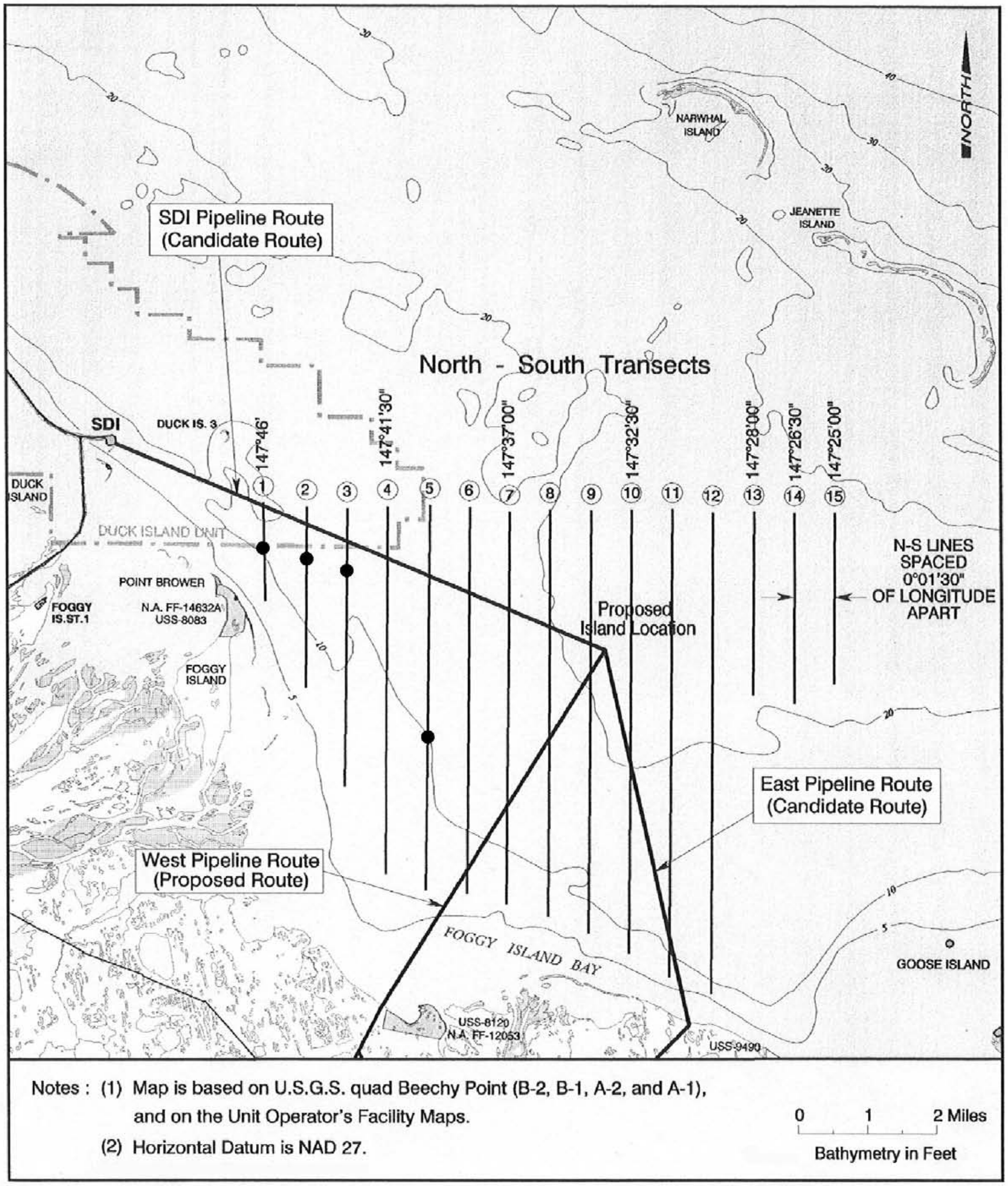

Figure A3: Gouge Locations: 1998 Liberty Site Survey

(Figure taken from Coastal Frontiers Corp., 1999;
Gouge locations – indicted by black dots - added to figure by FTL)

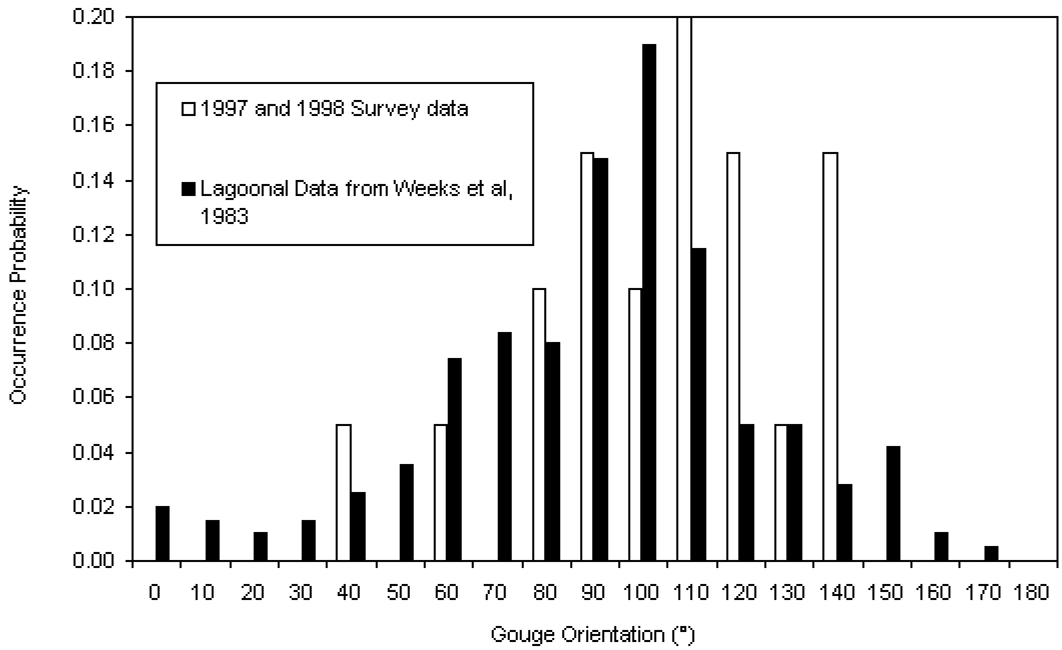

Figure A4: Gouge Orientation Distribution

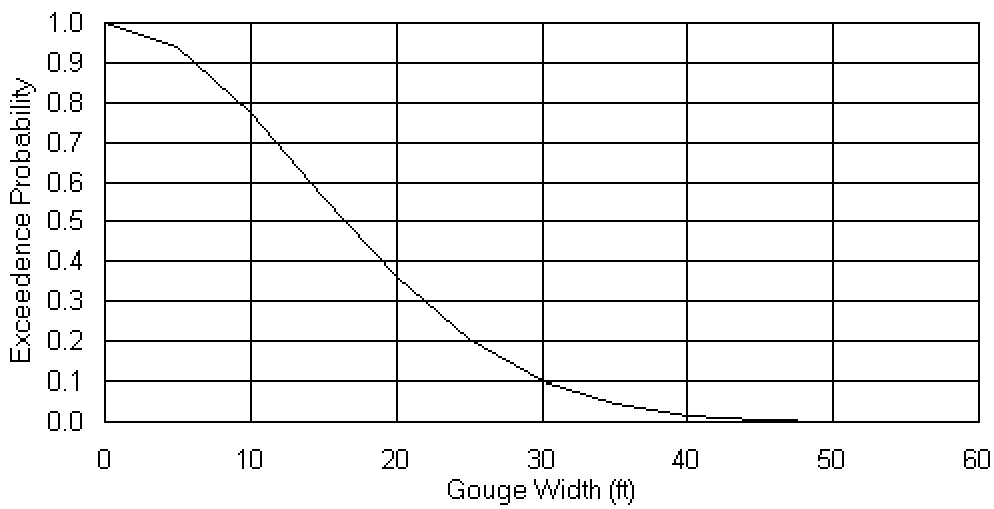

Figure A5: Gouge Width Distribution

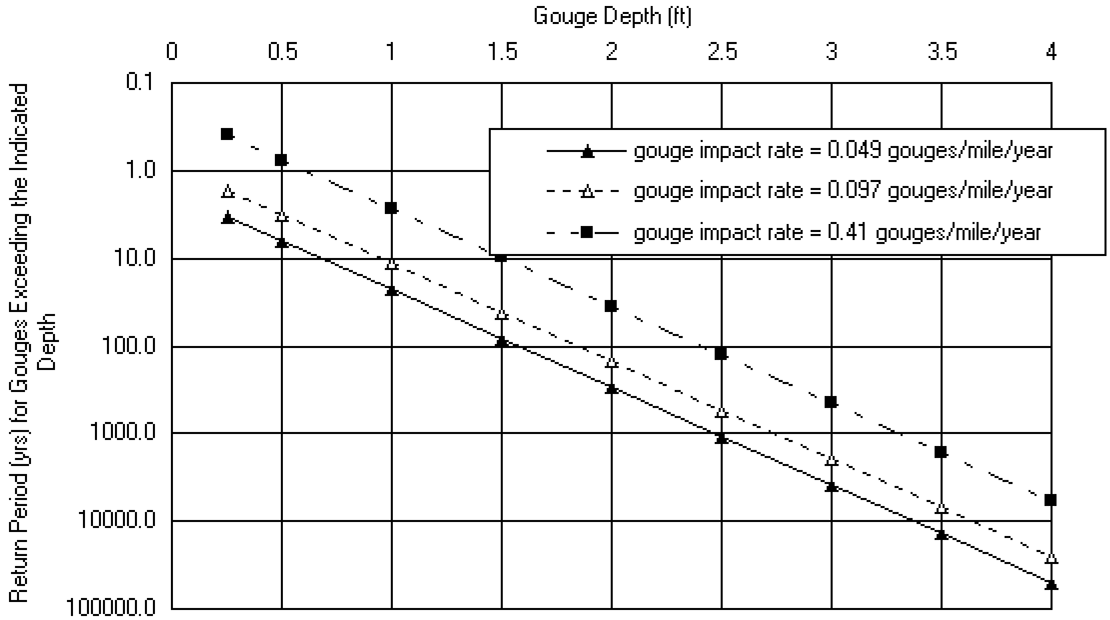

Figure A6: Gouge Depth Return Periods: Gouges Occur At All Water Depths

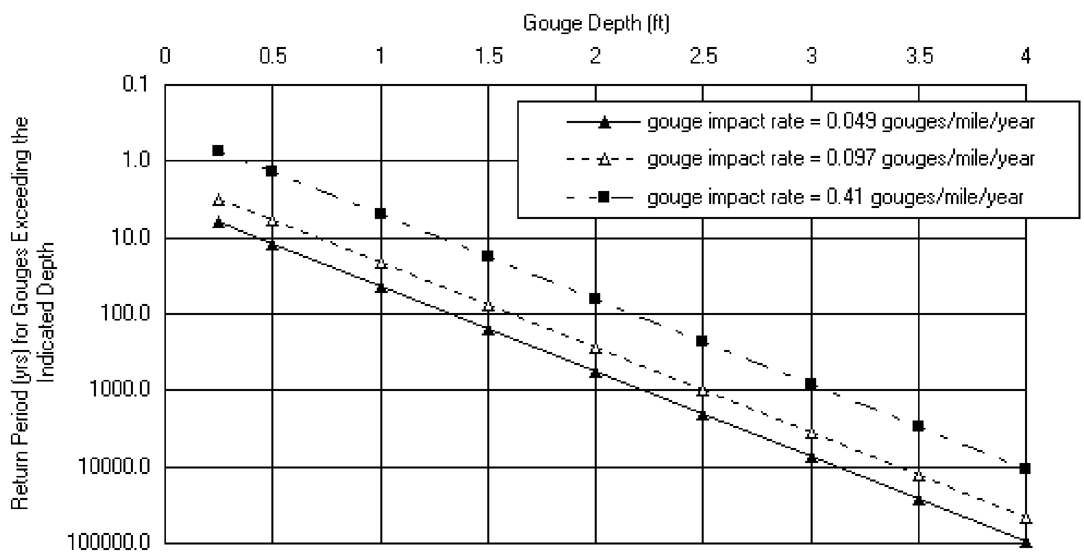

Figure A7: Gouge Depth Return Periods: Gouges Only Occur At Water Depths Greater Than 10 Ft

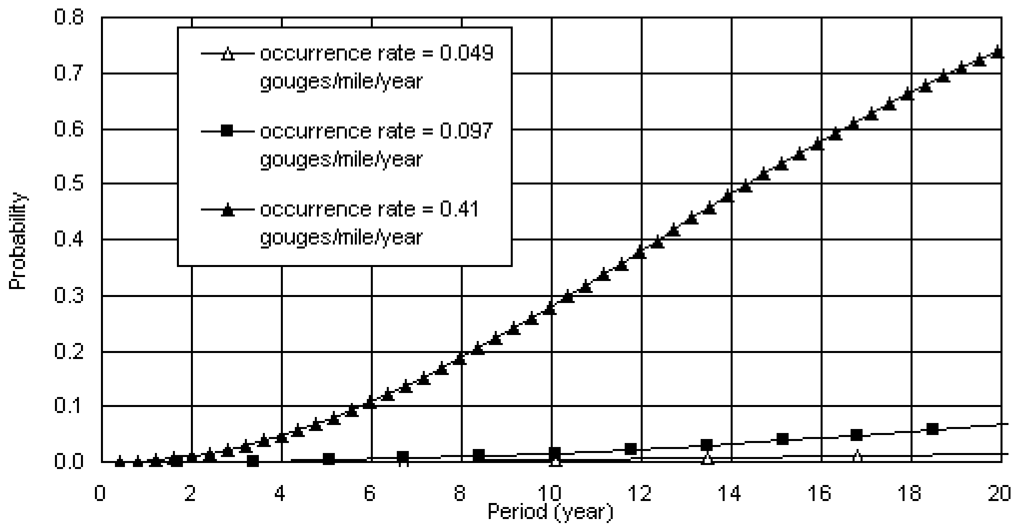

Figure A8: Re-Gouging Frequency: Probability of any Point on the Liberty Pipeline Being Crossed Twice by Ice Gouges

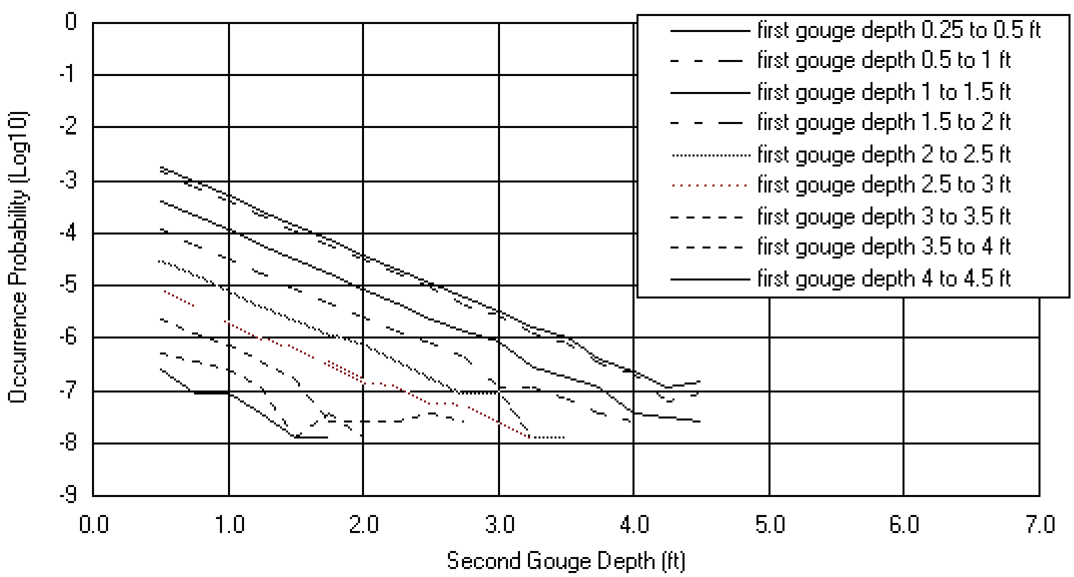

Figure A9: Multiple Gouging Occurrence Frequency for the Liberty Pipeline 6.12 Mile Length; a Gouge Impact Rate of 0.049 gouges/mile/yr.; and a Time Period of 20 years

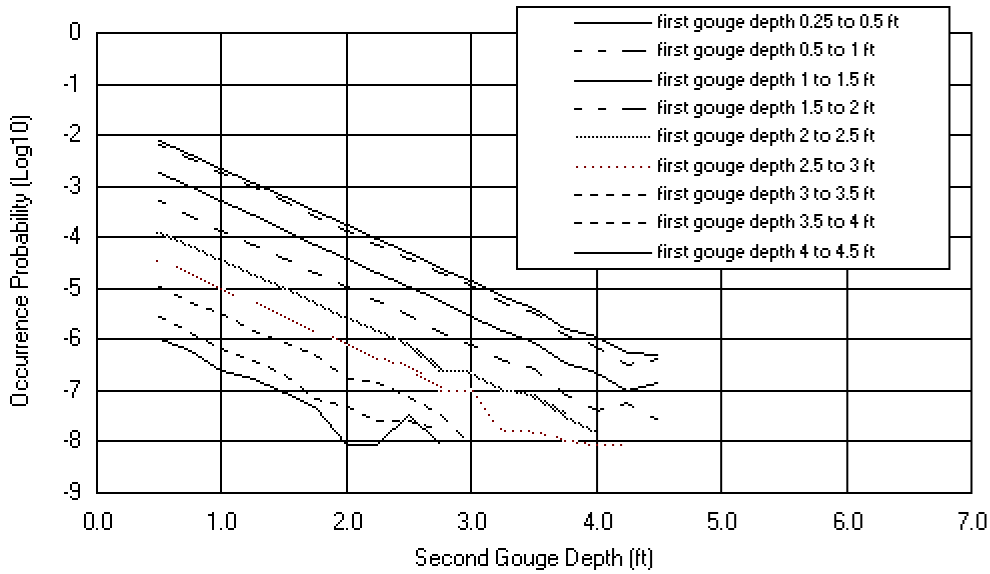

Figure A10: Multiple Gouging Occurrence Frequency for the Liberty Pipeline 6.12 Mile Length; a Gouge Impact Rate of 0.097 gouges/mile/yr.; and a Time Period of 20 years

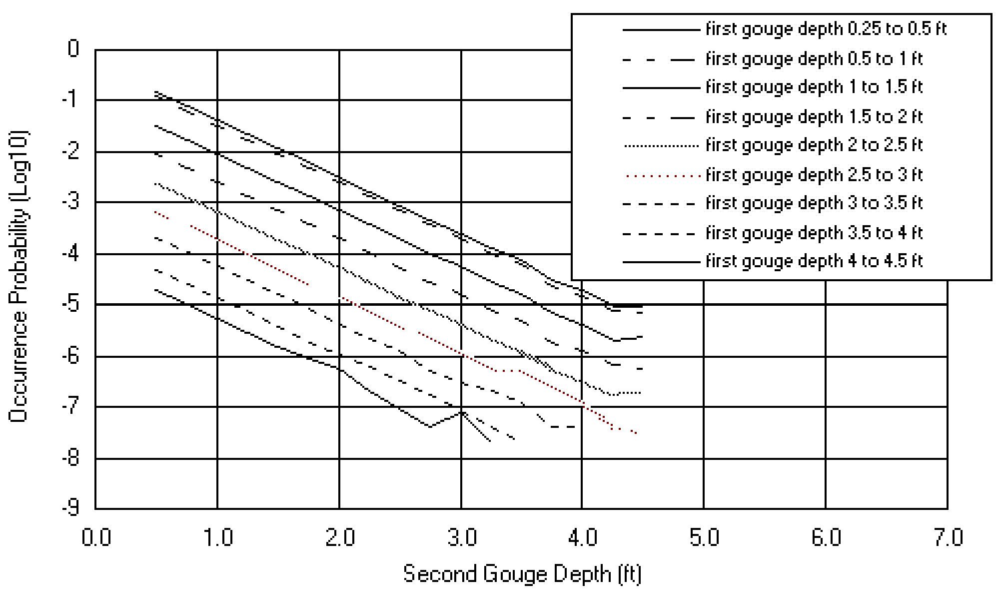

Figure A11: Multiple Gouging Occurrence Frequency for the Liberty Pipeline 6.12 Mile Length; a Gouge Impact Rate of 0.41 gouges/mile/yr.; and a Time Period of 20 years

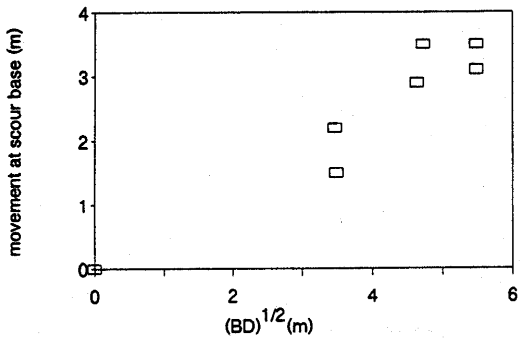

Figure 7. Relationship between displacement u(0,0,0) at gouge base and (BD)$^{1/2}$

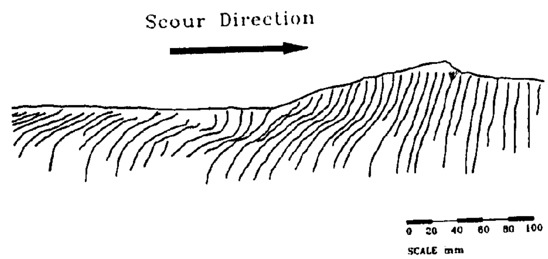

Figure 5. Longitudinal centreline profile of a typical gouge in clay after a centrifuge test, showing sub-gouge deformations displayed by originally vertical passive markers. The gouge surface is the horizontal line on the left. The soil ramp on the right represents the attack angle of the keel.

Figure A12: Subgouge Displacements Below the Keel (after Woodworth-Lynas, 1996)

Figure A13: Typical Subgouge Displacements During Centrifuge Tests (after Woodworth-Lynas, 1996)

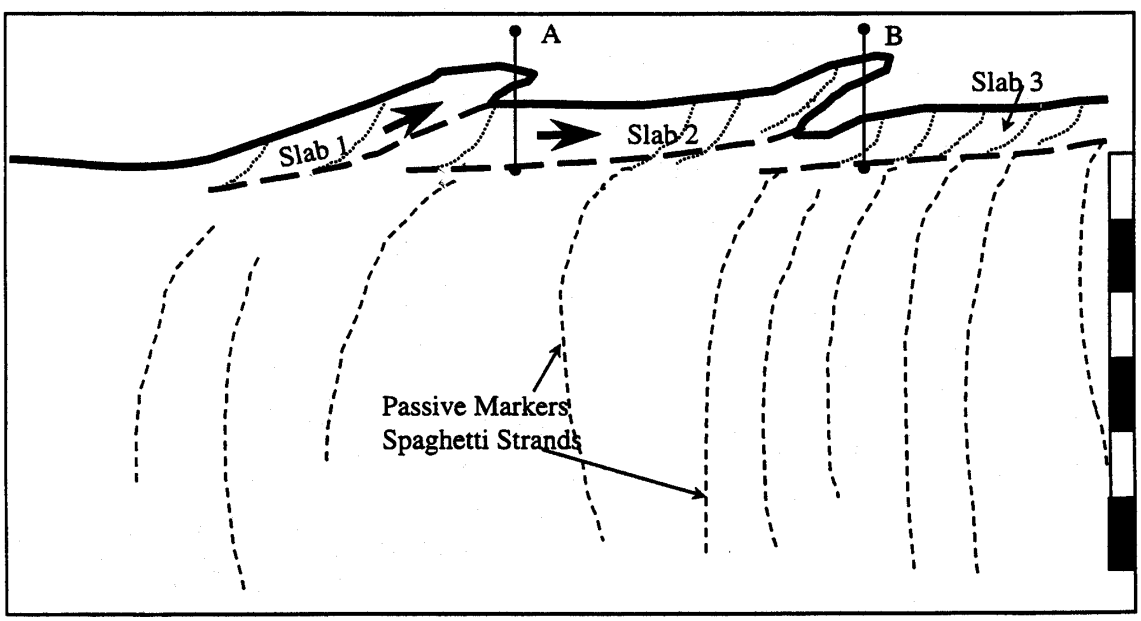

Figure 10. Vertical dissection of the clay along the sour mark centreline of the PRISE 08 model showing the stacked clay slab and sense of displacement. Measuring the horizontal distance between the nose of each thrust slab to where the basal thrust dips below the clay/sand surface it can be shown that Slab 1 has been thrust forward by 1.5m (1cm) and Slab 2 by 2.25m (1.5cm) Photograph of the centreline section (**Top**) and interpretation of structure (**Bottom**). Long dash lines trace approximately the thrust faults.

Figure A14: Subgouge Displacements During Centrifuge Tests With Sand Overlying Clay (after Woodworth-Lynas, 1999)

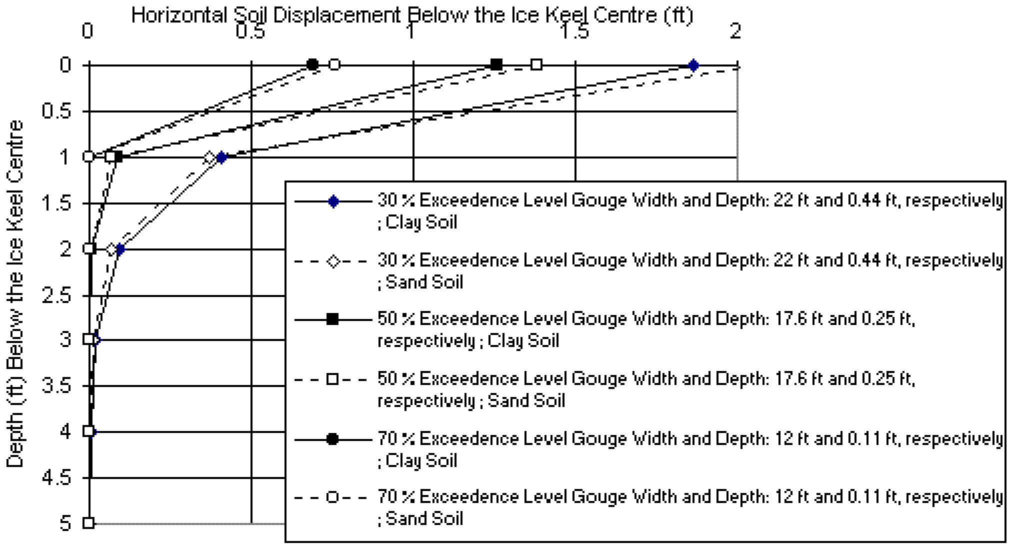

Figure A15: Predicted Horizontal Soil Displacements Below the Keel Centre

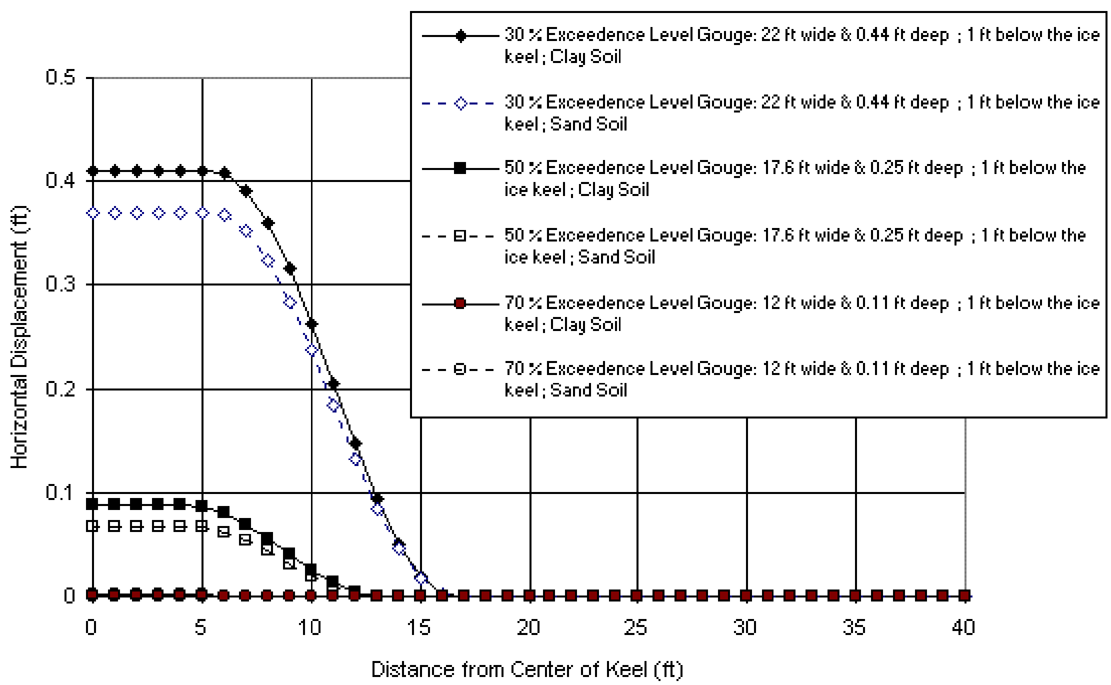

Figure A16: Predicted Horizontal Soil Displacements Along The Pipe

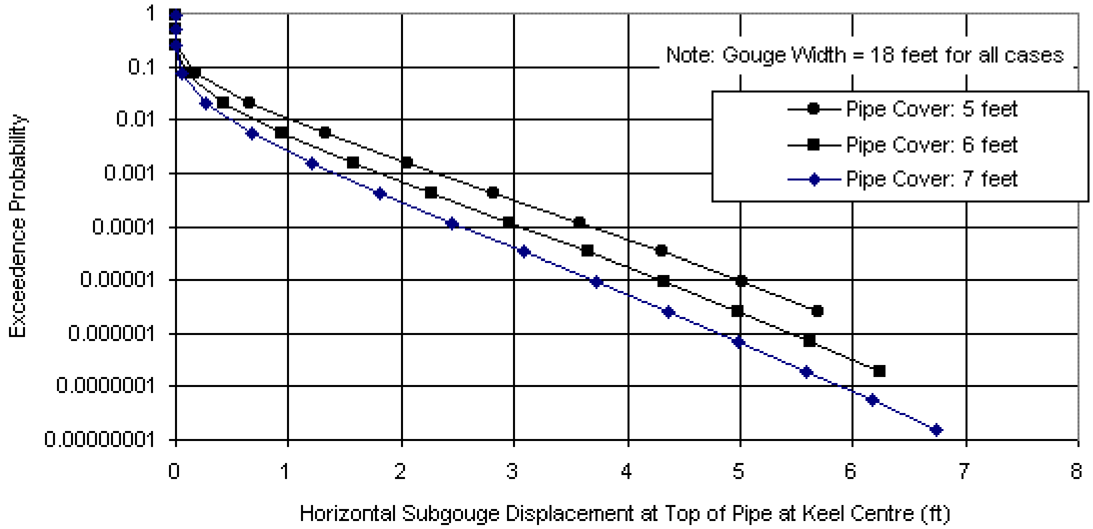

Figure A17: Subgouge Soil Displacement Distribution: 18 Foot GougeWidth

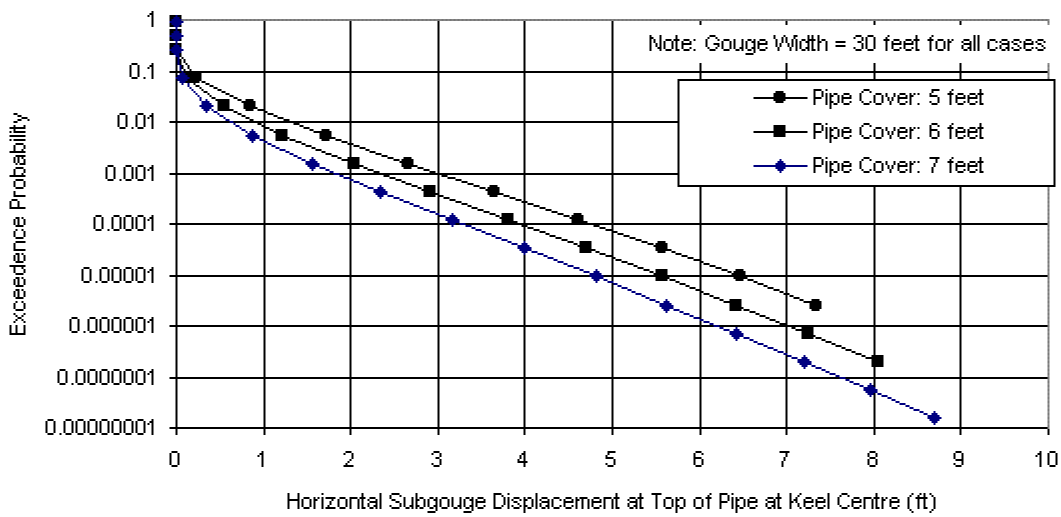

Figure A18: Subgouge Soil Displacement Distribution: 30 Foot GougeWidth

APPENDIX B

INITIATING EVENTS: STRUDEL SCOUR

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B1.0 INTRODUCTION

Because strudel scour is an environmental event that can lead to an oil release, it merits consideration as an initiating event in this project.

The strudel scour process has been described by a number of investigators (e.g., Reimnitz et al, 1974; Palmer et al, 2000; Blanchet et al, 2000). Strudel scours are produced by the drainage of surface water through the ice sheet at break-up. This process has been found to produce pits or short linear troughs in the seabed.

B2.0 SCENARIOS RESULTING FROM STRUDEL SCOUR THAT CAN LEAD TO AN OIL RELEASE

Although a number of strudel scour-induced pipeline failure mechanisms are possible, the following scenarios are believed to be of most concern:

(a) unsupported pipe - the pipe may become unsupported if the soil under it is removed by a strudel scour. In this case, the forces acting to cause pipeline failure would be the weight and buoyancy of the pipeline and its product, as well as any residual thermal stresses. This case was analysed by Blanchet et al, 2000, and Intec, 2000.

(b) partial removal of trench backfill, in turn leading to pipeline failure by upheaval buckling – although the strudel scour may not be large enough to uncover the pipe, it may remove enough cover material that failure by upheaval buckling occurs. This case was not analysed by Blanchet et al, 2000, or Intec, 2000.

Two other scenarios that were considered were hydrodynamic drag forces and fatigue resulting from oscillations produced by vortex shedding, both due to the strudel scour jet impinging on the pipeline after having been exposed by strudel scour. These have not been investigated in this project because simple calculations have shown that they are quite unlikely to lead to pipeline failure (Palmer, 2000).

B3.0 STRUDEL SCOURS: THE CONTROLLING FACTORS AND THE AVAILABLE INFORMATION

B3.1 The Controlling Factors

The factors affecting the risk (defined with respect to loss of oil containment) arising from strudel scour can be broadly categorised into environmental and soil-pipe interaction parameters. Strudel scour environmental parameters are discussed in this section. The soil-pipe interaction is discussed in section B6.

A detailed analysis of the strudel scour information relevant to the Liberty Pipeline was undertaken by Blanchet et al, 2000, in regard to the unsupported pipe case. The key issues include:

(a) the strudel scour depth distribution;
(b) the horizontal dimensions of strudel scours and their distribution;
(c) the strudel scour generation rate; and
(d) the effect of water depth.

B3.2 Strudel Scour Parameters

B3.2.1 The Strudel Scour Information Base in the Vicinity of the Liberty Pipeline Route

The available information has been analysed in detail by Blanchet et al, 2000. This reference, and the supporting information, was reviewed because their reliability have a direct effect on the accuracy of any conclusions reached.

The key points for this project include the following:

(a) Strudel scour is a highly site-specific process. This introduces significant uncertainties for applying data collected in other regions to the Liberty Pipeline vicinity. Blanchet et al, 2000's analyses were based solely on data collected in the vicinity of the Liberty Pipeline route. Although this limited the data set, FTL concurs with this approach.

(b) The only survey information specific to the Liberty Pipeline vicinity was collected during 1997 and 1998 (Coastal Frontiers Corp., 1998; 1999, respectively). This is a small data set, which introduces uncertainties regarding the confidence that can be placed in it.

(c) Variability from year to year – 1997 and 1998 were identified as "mild to average" years (by Blanchet et al, 2000) based on comparisons with parameters that are thought to affect strudel scour parameters. However, their comparisons are relatively inconclusive as clear trends were not established. They concluded that the factors and processes affecting strudel scour parameters are not well understood.

This makes it difficult to assess the actual severity of the two years surveyed, which is one of the most significant uncertainty sources, in our opinion.

Some indication of the year-to-year variability for "mild to average" years can be obtained by comparing the following strudel scour statistics:

(i) the mean depth (for circular scours) – this was more than 2 times greater in 1997 than 1998 (i.e., 2.7 ft vs 1.2 ft, respectively, Coastal Frontiers Corp., 1998; 1999).

(ii) the mean maximum horizontal dimension (for scours that were classified as circular) – this was about 50 % less in 1997 than 1998 (i.e., 26 ft vs 46 ft, respectively, Coastal Frontiers Corp., 1998; 1999).

(iii) the strudel scour generation rate – the average "adjusted average number of scours/mile^2/ year" (in Table 3.10, in Blanchet et al, 2000) varied by a factor of 7.2 between 1997 and 1998 (i.e., 7.5 vs 1.1, respectively).

No information is presented in Blanchet et al, 2000 for the expected strudel scour statistics for a "severe" year, probably because the factors and processes controlling strudel scour parameters are not well understood, which they acknowledge.

However, it can reasonably be expected that a "severe" year would produce more extreme strudel scour statistics than those measured to date. It is important to recognise that the current strudel scour data set does not encompass this range of variation (from "mild" to "severe").

On the other hand, it should be noted that there are physical limits associated with the strudel scour process which affect the size, depth and frequency of strudel scours. A purely statistical approach, in which the currently available data are extrapolated to more "severe" cases (i.e., lower exceedence probabilities, and longer return periods), would overestimate the actual risk to a pipeline from strudel scour. Unfortunately, due to a lack of information, the factors controlling strudel scour properties are not well understood. Consequently, one can not place much confidence in an approach based on physical limits although in our opinion, this will probably cause the probabilistic analyses conducted here to err conservatively.

(d) The effect of infilling – infilling is known to occur, and its effect on the measured strudel scours was considered in detail by Blanchet et al, 2000. For this project, their results have been taken as given because their approach is logical, and FTL is not able to suggest improved methods, given the available information.

Furthermore, the uncertainty associated with this part of their data reduction approach is considered to be relatively small compared to that associated with the small data set available, and the year-to-year variability that has been observed.

(e) Relic vs new strudel scours – Blanchet et al, 2000 showed that a large proportion of the observed strudel scours are relic. Their results were taken as given because they used a logical approach to investigate and quantify this, and FTL cannot suggest improved methods, given the available information.

Furthermore, the uncertainty associated with this part of their data reduction approach is considered to be relatively small compared to that associated with the small data set available, and the year-to-year variability that has been observed.

B3.2.2 Effect of Water Depth

The effect of water depth was considered in detail by Blanchet et al, 2000. This is an important issue for this project as it affects the risk associated with events initiated by strudel scour. The trends observed from their analyses were taken as given in this project as the approach they used is logical, and FTL is not able to suggest improved methods given the available information. The key points are summarised below:

(a) Range of applicable water depths – Blanchet et al, 2000 considered that strudel scours may occur over a range of water depths from 4 ft to 20 ft. This water depth range comprises about 5.25 miles (about 85%) of the total 6.12 mile length of the Liberty Pipeline route.

(b) Effect on strudel scour depth and strudel scour horizontal dimensions – neither of these parameters are strongly related to the water depth.

(c) Effect on strudel scour frequency or generation rate – clear trends were not observed. As a result, their analyses were based on a strudel scour generation rate that was applicable to all water depths where strudel scours could occur.

B4.0 STRUDEL SCOUR LEADING TO AN UNSUPPORTED PIPE

B4.1 Uncertainties

This case was analysed in detail by Blanchet et al, 2000. The uncertainty sources potentially affecting the confidence that can be placed in Blanchet et al, 2000's analyses were considered.

Uncertainties introduced by the approach used are one potential source. This type of uncertainty falls into two main types:

(a) Uncertainties produced because the full interaction between the strudel jet, the soil and the pipe was not considered. They only conducted probabilistic analyses, as they evaluated the probability that a strudel jet would produce 8 feet deep strudel pits and troughs of varying widths. They then presumed that this would lead directly to an unsupported pipe with the respective free spans.

This errs conservatively, in our opinion. It is doubtful that the strudel jet would scour "cleanly" under the pipe. More likely, the strudel jet will be affected by the pipe, which will probably lead to a "plug(s)" of soil remaining under the pipe.

It is also possible that, should a free span occur, the pipe may deflect sufficiently that it contacts the pit bottom, particularly at the sides, that high strains are not developed. This aspect was also not considered by Blanchet et al, 2000.

For these reasons, their results are expected to be conservative. Unfortunately, the available information is inadequate to make definitive evaluations, particularly with respect to the formation of "plug(s)" below the pipe. These uncertainties have been considered in a qualitative manner in this project.

(b) Uncertainties resulting from the probabilistic analysis approach. Their approach is generally sound, as efforts have been made to account for uncertainties in a manner that is both reasonable and rigorous. The approach used should produce reliable results, in our opinion.

Uncertainties in the input data used for the analyses are another potential source of uncertainty; they are introduced by two sources:

(a) Limitations in the data available for input;
(b) Uncertainties introduced by the cases selected for the sensitivity and confidence limit analyses that were conducted.

These are the main sources of uncertainty, in our opinion.

B4.2 Input Data

The available dataset is quite small, as only two years of survey data relevant to the Liberty Pipeline have been collected (in 1997 and 1998).

The uncertainties and limitations include the following:

(a) Variability from year to year and the expected strudel scour parameters for a “severe” year. The available information does not likely encompass the range from a “mild” to “severe” year.

(b) The selected cases and the number of cases used for the confidence limit analyses – the following were varied by Blanchet et al, 2000 for their analyses as follows:

(i) strudel scour dataset – 3 cases (i.e., all scours, all new scours, or all new scours > 2 ft deep);
(ii) the distribution type for scour width, depth, and length – 2 cases (i.e., either lognormal or exponential);
(iii) the annual strudel scour density – 3 cases (based on 57, 118, or 146 scours);
(iv) the year-to-year variability – 3 cases defined with respect to the strudel scour generation rate (i.e., 2.3, 4.4, or 6.5 strudel scours/mile^2/year).

This gives a total of 54 cases which were evaluated by Blanchet et al, 2000, who calculated confidence limits in relation to this total number.

Their sensitivity studies showed that the pipeline free span exceedence probability (for the base case) was not affected greatly by the strudel scour data set used. Hence the number of cases used for this parameter will not affect the results significantly.

However, this is not true for the “annual strudel scour density” and the “year-to-year variability” parameters, which are both indicators of the uncertainty in strudel scour generation rate. The maximum-to-minimum range for these respective parameters is 2.6 times, and 2.8 times, respectively. The combined total variation is 7.2 times for the 9 combinations evaluated. Different results (with respect to confidence limits) would have been obtained had this same range of variability (of 7.2 times) been divided over fewer or more cases.

The same is true for the effect of distribution type, which was also found to be quite significant. Blanchet et al, 2000 found that the base case exceedence probability varied by a factor of 3.3 depending on whether the distribution type for scour depth, width, or length was either lognormal or exponential. Again, the results from the confidence limit analyses would have been affected if this variability was spread out over more cases.

B4.3 Results and Discussion

B4.3.1 Pipeline Free Span Exceedence Probabilities Calculated by Blanchet et al, 2000

Despite the limitations described above, the analyses done by Blanchet et al, 2000 are very useful, and the following conclusions can be drawn, as follows:

(a) the importance of various parameters:

- (i) strudel scour dataset used – the results are not very sensitive to which dataset is used (for the three evaluated by Blanchet et al, 2000).
- (ii) strudel scour generation rate – this is a very significant parameter
- (iii) distribution type used to define depth, width, and length – this is a very significant parameter as well.

(b) the confidence limits associated with the calculated free span exceedence probabilities (in Figure 5.4 of Blanchet et al, 2000 – repeated here as Figure B1) can be expected to be relatively large. Blanchet et al, 2000's confidence limit analyses show that, for the base case they used, the 90 % confidence limit encompasses a range of exceedence probabilities of about 12 times (i.e., a maximum value of 2×10^{-4}/a minimum value of 1.6×10^{-5}).

This range (of 12 times) was used as one input for subsequent risk analyses conducted in this project.

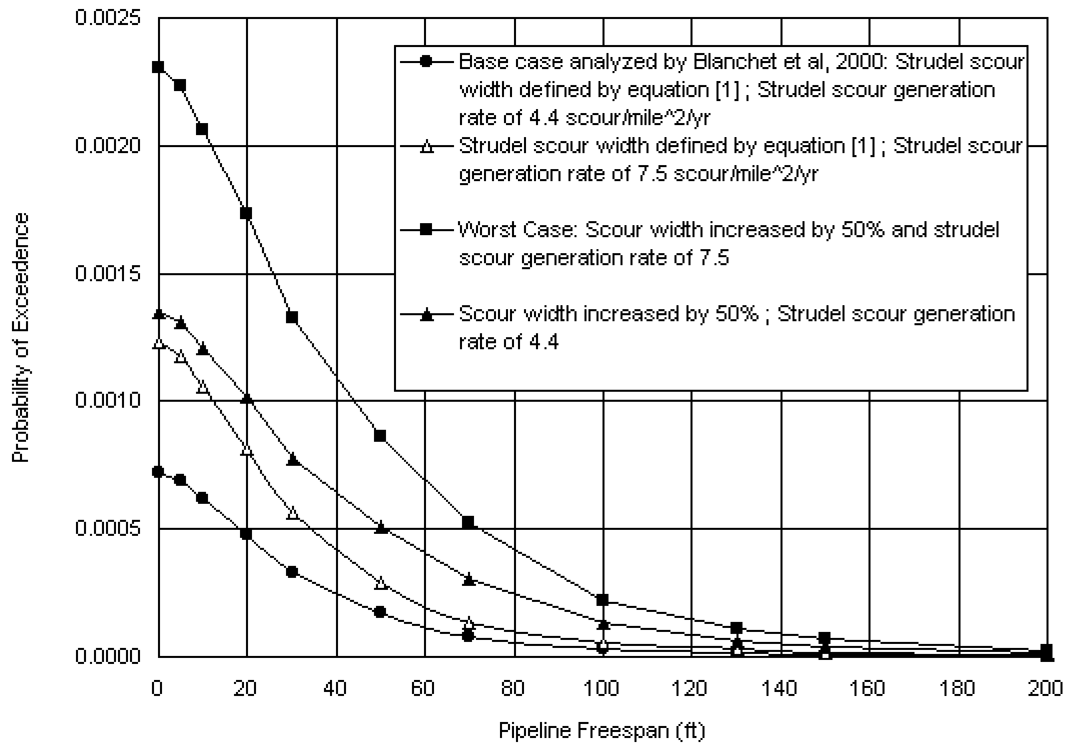

Figure B1: Probability of Strudel Scour Producing an Unsupported Pipe

Notes to Figure B1:

1. The original figure was taken from Blanchet et, 2000. Lines for all cases other than the base case were added to the figure by FTL.)
2. All calculations and plotted lines are with respect to a strudel scour depth of 8 ft.

B4.3.2 The Potential Effect of a “Severe” Year

It was suggested (in section B3) that the range of input values used by Blanchet et al, 2000 likely doesn’t encompass the range expected for a “mild” to “severe” year, as the supporting data were collected in "mild to average” years. An indication of this potential uncertainty can be obtained by presuming that the variation between an “average” and a “severe” year is similar to that between 1997 and 1998, which were classified as “mild to average” years.

The variation between the key parameters (i.e., scour width, depth, and generation rate) between 1997 and 1998 is summarised below, in relation to their expected effect on the free span exceedence probabilities calculated by Blanchet et al, 2000:

(a) strudel scour depth (for circular and linear scours) – deeper scours were observed in 1997 by a factor of about 2 (section B3). However, this variation is expected to have a negligible effect on the calculated exceedence probabilities because the scour depth distribution used for these calculations was limited to scours deeper than 2 ft. This effectively limited the dataset to primarily the 1997 data.

(b) maximum horizontal strudel scour dimension – wider scours were observed in 1998 by a factor of about 2 (section B3).

The dataset used as the base case in Blanchet et al, 2000’s study was the “new scours with depths > 2 ft” one, and it had a mean value of 20.3 ft. They fitted an exponential distribution to these data (Equation [B1]).

$$P(\text{width} > x) = e^{-0.0451(x+1.8)} \qquad [B1]$$

where: P(width >x) = the probability that a given scour width, x (in feet) will be exceeded

Sensitivity analyses were carried out by increasing the mean scour width by 50 %. This was considered to be a reasonable projection had only the 1998 data been used to establish the scour width distribution, although it should be noted that the detailed analyses required to establish definitively have not been done. This gives a mean scour width of 30.5 ft (i.e., 1.5 * 20.3 ft). Keeping the form of the distribution as exponential, the new distribution would become:

$$P(\text{width} > x) = e^{-0.031(x+1.8)} \qquad [B2]$$

The pipeline free span exceedence probability was recalculated for the wider scour width distribution (i.e., equation [B2]) using the algorithm developed by Blanchet et al, 2000. Pipeline free span exceedence probabilities were increased by about 100% (compared to Blanchet et al, 2000’s base case) as a result (Figure B1).

(c) strudel scour generation rate – this was larger in 1997 than 1998. The average “adjusted average number of scours/mile^2/ year” for the 1977 survey data (in Table 3.10, in Blanchet et al, 2000) was 7.5 in 1997 versus 1.1 in 1998. Blanchet et al, 2000 used an intermediate value of 4.4 scours/mile^2/year for their calculations.

A value of at least 7.5, and probably more, would be justifiable to account for the effect of a “severe” year, although it should be recognised that the available data is insufficient to specify this with confidence. Because the exceedence probability is directly proportional to the strudel scour generation rate, it would be increased by a factor of about 1.7 (i.e., 7.5/4.4) if a value of 7.5 scours/mile^2/ year were used. See Figure B1.

(d) Combined worst case – the above calculations have shown that the potential effect of a “severe” year would be to increase the scour width distribution, and to increase the strudel scour generation rate. Both of these factors affect the calculated freespan exceedence probabilities significantly. The worst case would be one where the potential effects of both parameters are combined.

The net effect of this would be to increase pipeline freespan exceedence probabilities by a factor of about 3.5, compared to the base case (Figure B1).

B4.3.3 Extension to Other Pipe Burial Depths

Blanchet et al, 2000’s analyses were specific to a cover loss depth of 8 ft, which represents the case where a 1 ft diameter pipe is buried with a cover depth of 7 ft. This models one of the pipe cases considered by Intec, 2000 (i.e., the “single pipe” one). The particulars for the other pipe designs (Intec, 2000) differ from this somewhat.

Blanchet et al, 2000’s analyses were not repeated for the other pipe designs because the calculated occurrence frequencies for cases that would pose a threat to the pipeline are quite small. This is discussed further in section B6.

Instead, Blanchet et al, 2000’s sensitivity analyses were referred to allow the other pipe design cases to be evaluated. For completeness, these results are summarised below in Table 1. They showed that the free span exceedence probability for cover loss depths of 6 ft and 10 ft, would be about 2 and 0.2 times the value for the 8 ft deep base case, respectively.

Table B1: Sensitivity Results: Effect of Cover Loss Depth (from Blanchet et al, 2000)

Free Span (ft)	Exceedence Probabilities for:		
	Base Case (8 ft Burial)	6 ft Burial	10 ft Burial
100	$3.4 * 10^{-5}$	$6.9 * 10^{-5}$	$6.8 * 10^{-6}$

Occurrence frequencies for the cover loss associated with the other pipe design cases were estimated by scaling from Table B1 directly. It is believed that this approach will provide adequate accuracy in relation to the overall reliability of the analyses.

B4.4 Conclusions

The case where strudel scour may cause an unsupported pipe has been analysed in detail by Blanchet et al, 2000. They have made significant efforts to analyse the available data in a logical manner, and to account for the factors affecting the data. FTL is in agreement with their approach.

However, the following factors limit the confidence that can be placed in the results obtained:

(a) the dataset is small, as strudel scours have only been surveyed in the vicinity of the Liberty Pipeline route in 1997 and 1998.

(b) 1997 and 1998 were “mild to average” years, and hence, the dataset does not encompass the range likely to be produced should a “severe” year occur. The uncertainty introduced by this is difficult to evaluate because the factors and processes controlling strudel scour parameters are not well understood.

Blanchet et al, 2000 determined the exceedence probability distribution (for free spans produced by strudel scours) using a logical approach, and FTL used them directly as one input to the risk analyses in this project.

They have also determined the confidence limits that can be placed on these results using a logical approach. Their calculations indicate that the confidence limits are relatively large. For the base case they used, the 90 % confidence limit encompasses a range of exceedence probabilities of about 12 times. This range (of 12 times) was used as another input for subsequent risk analyses conducted in this project.

The principal effect of a “severe” year would be to increase their calculated exceedence probabilities due to increases in the scour width distribution and the strudel scour generation rate. The combined effect of these two factors could potentially increase the freespan exceedence probabilities by a factor of about 3.5, compared to the base case, and this was another input for subsequent risk analyses conducted in this project.

B5.0 PARTIAL COVER REMOVAL BY STRUDEL SCOUR

B5.1 Overview and Purpose of Analyses

These analyses were set up to analyse the case where strudel scour might remove enough soil cover to induce pipeline failure by upheaval buckling. They were done in two general steps as follows:

(a) Step 1 – Evaluate Partial Cover Removal by Strudel Scour – probabilistic calculations were done to investigate frequencies of occurrence for various soil cover removal cases over the 20-year life of the Liberty Pipeline. These analyses are described in this section.

(b) Step 2 – Evaluate Pipeline Response – analyses were done to investigate:

  (i) whether or not the soil cover removed would lead to upheaval buckling for the various pipeline alternatives, and;

  (ii) should upheaval buckling occur, the stresses and strains exerted on the pipe as a result.

  These calculations and results are presented in section B6. The resulting strains were next compared against pipeline failure criteria, which are presented in section 4 of the main text of this report.

B5.2 Approach for Evaluating Partial Soil Cover Removal by Strudel Scour

<u>B5.2.1 Overview</u>

Monte-Carlo analyses were conducted using a "raindrop" model which is the same approach used by Blanchet et al, 2000. Each simulation modelled a 20-year time period, which is the expected life of the Liberty Pipeline. The Monte-Carlo simulation was repeated 4 million times to ensure reliable results.

The model had the following inputs:

(a) strudel scour depth distribution – this was random, as described in section B5.2.2
(b) strudel scour diameter distribution – this was random, as described in section B5.2.3.
(c) strudel scour generation rate – separate Monte-Carlo analyses were done for two rates as follows:
  (i) 4.4 strudel scours/mile^2/year (value used by Blanchet et al, 2000)
  (ii) 7.5 strudel scours/mile^2/year (average value for the 1997 survey data)
(d) pipeline length – this was fixed at 5.25 miles, which is the length between the 4 and 20 ft water depths for the Liberty Pipeline.

B5.2.2 Inputs Used: Strudel Scour Depth Distribution

This was defined by fitting an exponential distribution to the strudel scour depth data listed in Table 4.2 of Blanchet et al, 2000. This dataset reflects both years (i.e., 1997 and 1998) of survey data, and it is limited to new strudel scours. The distribution obtained is given below, and plotted in Figure B2.

$$P(d) = e^{-0.474\,(d-1.09)} \qquad [B3]$$

where : P(d) = the exceedence probability that a given strudel scour depth, d (in feet) will be exceeded

B5.2.3 Inputs Used: Strudel Scour Diameter Distribution

These analyses were conducted by presuming that all strudel scours are circular in shape. The strudel scour diameter distribution was defined by fitting an exponential distribution to the strudel scour width data listed in Table 4.2 of Blanchet et al, 2000. This dataset reflects both years (i.e., 1997 and 1998) of survey data, and it is limited to new strudel scours. The distribution obtained is given below, and plotted in Figure B3.

$$P(w) = e^{-0.03935\,(w-19)} \qquad [B4]$$

where : P(d) = the exceedence probability that a given strudel scour diameter, w (in feet) will be exceeded

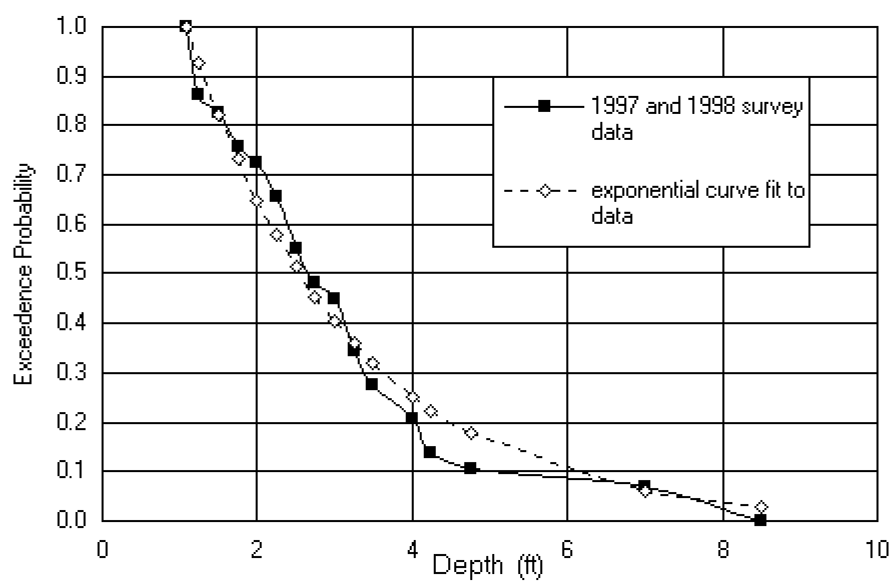

Figure B2: Strudel Scour Depth Distribution Used for Partial Cover Loss Analyses

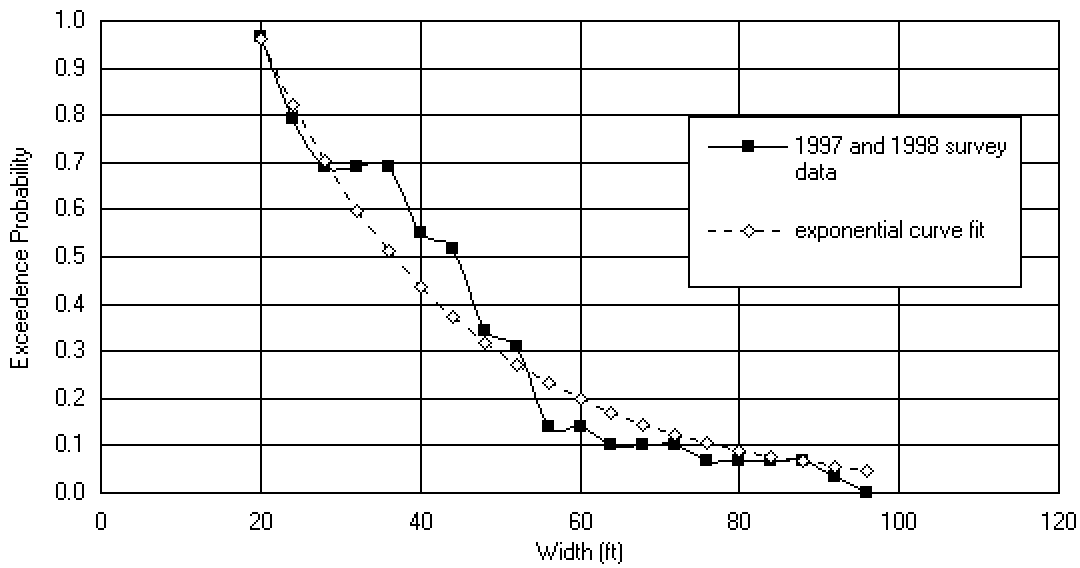

Figure B3: Strudel Scour Diameter Distribution Used for Partial Cover Loss Analyses

B5.2.4 Inputs Used: Strudel Scour Generation Rate

Separate Monte-Carlo analyses were done for strudel scour generation rates of:

(a) 4.4 strudel scours/mile^2/year - this is the average value determined by Blanchet et al, 2000 for both years of survey data (i.e., 1997 and 1998).

(b) 7.5 strudel scours/mile^2/year – this is the average value obtained from the 1997 survey data (section B3).

B5.2.5 Inputs Used: Applicable Water Depth Range

The analyses were done for a pipeline length of 5.25 miles, as this is the length of line between water depths of 4 ft and 20 ft. Strudel scours have been observed to occur over this water depth range (Blanchet et al, 2000). See also section B3.

B5.3 Results

B5.3.1 Occurrence Probabilities

The analyses were set up to determine the probability of various cover losses produced by strudel scours over the life of the Liberty Pipeline, which was taken as 20 years. Figures B4 and B5 show the results obtained for strudel scour generation rates of 4.4 and 7.5 scours/mile^2/year, respectively. Table B2 summarises the results.

As expected, strudel scour is much more likely to produce smaller cover losses than larger ones, and the occurrence probability for a given cover loss increases with the strudel scour generation rate.

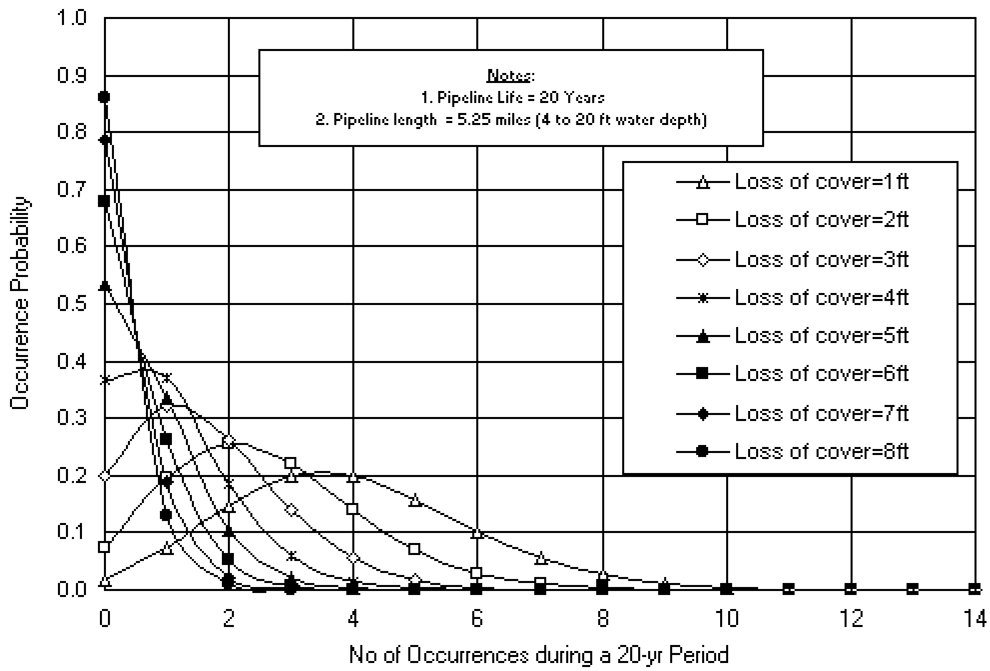

Figure B4: Partial Cover Removal by Strudel Scour: Strudel Scour Generation Rate = 4.4 scours/ mile^2 /year

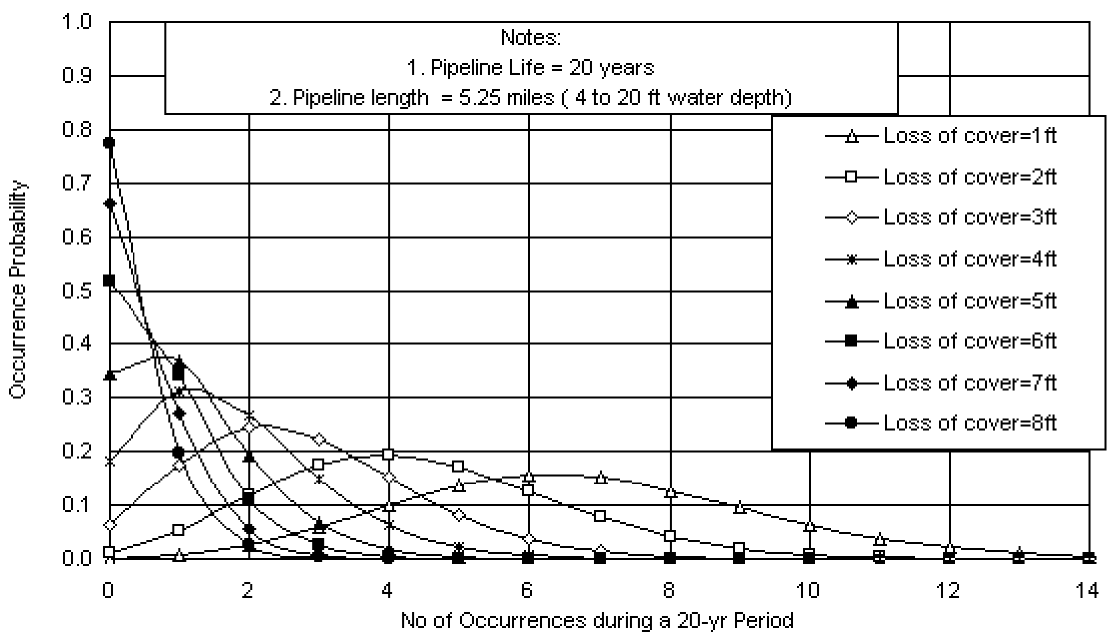

Figure B5: Partial Cover Removal by Strudel Scour: Strudel Scour Generation Rate = 7.5 scours/ mile^2 /year

Table B2: Cover Losses Produced by Strudel Scour

Cover	Number of Occurrences in 20 Years and Occurrence Probability (brackets) for:	
Loss (ft)	Strudel Scour Generation Rate (scours/mile^2/year) = 4.4	Strudel Scour Generation Rate (scours/mile^2/year) = 7.5
2	0 (0.073)	0 (0.012)
	1 (0.195)	1 (0.052)
	2 (0.255)	2 (0.118)
	3 (0.220)	3 (0.175)
	4 (0.141)	4 (0.194)
4	0 (0.367)	0 (0.181)
	1 (0.370)	1 (0.311)
	2 (0.184)	2 (0.266)
	3 (0.061)	3 (0.150)
	4 (0.015)	4 (0.063)
6	0 (0.679)	0 (0.517)
	1 (0.263)	1 (0.341)
	2 (0.051)	2 (0.113)
	3 (0.0065)	3 (0.025)
	4 (0.00059)	4 (0.004)

B5.3.2 Exceedence Probabilities

Exceedence probabilities for soil cover loss produced by strudel scour are shown in Figure B6. As expected, the following trends are evident:

(a) the exceedence probability increases for smaller soil cover losses.

(b) the exceedence probability is increased when the strudel scour generation rate is increased.

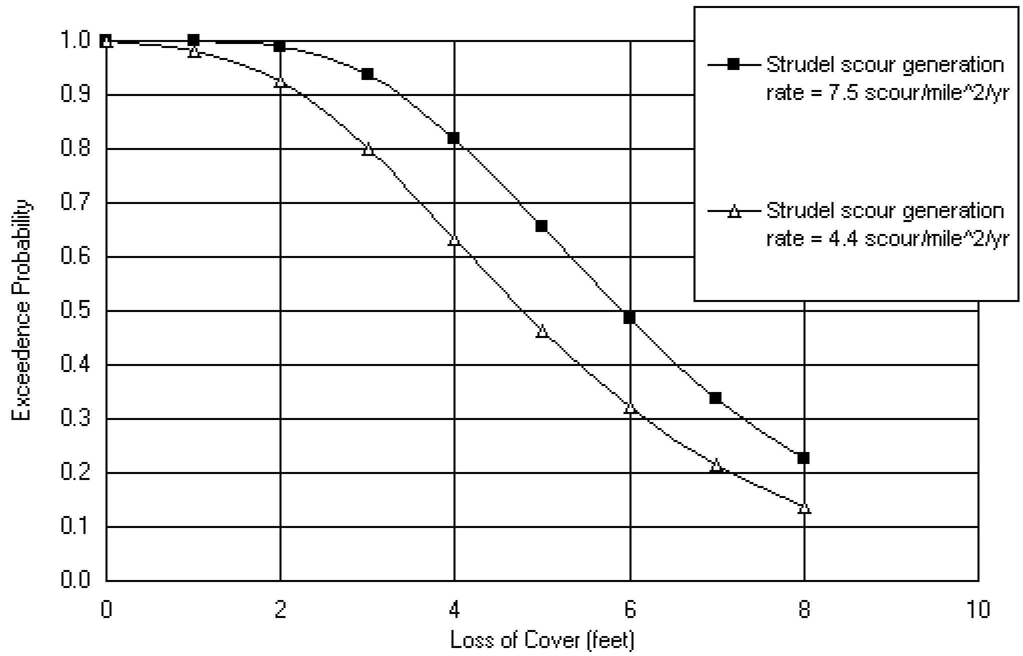

Figure B6: Exceedence Probability Distribution For Soil Cover Loss Produced by Strudel Scour Over the 20 Year Life of the Pipeline, and Over the 5.25 Mile Length Where Strudel Scours May Occur

B6.0 REFERENCES

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APPENDIX C

LATERAL DEFORMATION STRUCTURAL RESPONSE

CONTENTS

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C1.0 PIPE-IN-PIPE RESPONSE INTRODUCTION

Traditionally, the pipe-in-pipe configuration has been used as a means of insulating or bundling pipelines. However, it is recognised that this does not preclude the use of steel pipe-in-pipe designs for providing additional structural integrity or secondary containment (CCORE et al, 2000; Stress Engineering Services, 2000; Intec, 2000).

Nevertheless, it is important to recognise that the current experience base has not been developed with the purpose of providing additional structural integrity or secondary containment. Thus, one must be careful in applying past experience to the Liberty Pipeline. In practice, a designer would seek to obtain a pipe-in-pipe configuration that would be an optimum within the various constraints (of which one would be providing additional structural integrity or secondary containment).

It is important to recognise that the inner pipe will most likely not be fixed to the outer pipe (based on current practices for pipe-in-pipe designs) but rather it will be supported on internal spacers. This has two significant implications as follows:

(a) The inner pipe will sag to some extent between the spacers (due to the combined effects of the self-weight of the pipe and its contents, thermal strains, and longitudinal strains resulting from the internal pressure in the pipe). This provides a built-in "relief" system as some extension of the outer pipe will be required before the inner pipe starts to "feel" significant axial strains. This process has been termed "displacement delay" in this report.

(b) The displaced shape of the inner pipe will be affected by the presence of the spacers, and the distance between them, as it will tend to adopt a shape of minimum curvature. This may cause lower bending strains to be exerted on the inner pipe (compared to the outer one) during large displacements (e.g., caused by ice gouging). This process has been termed "curvature reduction" in this report.

Both of the above processes offer means by which a pipe-in-pipe design may, if properly designed, provide additional structural integrity compared to a single wall pipe design.

As well, the outer pipe will provide armouring that will offer some additional protection against local pressures, impact loads and third party damage.

C1.1 Objective

The purpose of this section is **NOT** to develop a new pipe-in-pipe design for the Liberty Pipeline that would optimise the additional structural integrity or secondary containment that is provided. Instead, the analyses were done to:

(a) Review past pipe-in-pipe designs. This was done to provide a "reality check" to assess the relevant range of key design parameters, such as the annulus size between the inner and outer pipe, and the expected spacer spacings.

(b) Investigate the likely benefit that "displacement delay" would provide (for risk reduction).

(c) Investigate the likely benefit that "curvature reduction" would provide (for risk reduction).

(d) Conduct finite element analyses to better understand:
   (i) the global behaviour of a pipeline exposed to large soil displacements, thermal expansion, and an internal pressure, and;
   (ii) the local structural behaviour of a pipe-in-pipe configuration.

The benefit of armouring was not investigated here because the strains and stresses resulting from global displacements are considered to be of more concern (in our opinion) than the local ones for this risk assessment.

The investigations presented here are exploratory (in keeping with analyses at the concept design level). It is noted that significant detailed design would still be required, for example, to carry the local stresses developed at the spacer contact points. It should be further noted that the above benefits (resulting from some independent movement of the inner pipe with respect to the outer one) were not accounted for by Intec, 1999; 2000 in their analyses.

C1.2 Existing Pipe-In-Pipe Configurations

Table C1 summarises most existing pipe-in-pipe configurations. A typical pipe-in-pipe pipeline configuration includes an inner and outer pipe separated by spacers as shown in Figure C1. In general, pipe-in-pipe structural configurations employ a rigid plastic (e.g., polypropylene) spacers with rollers to facilitate the relative movement of the inner and outer pipe. It is also noted that in general all pipe-in-pipe configurations take advantage of the inter-pipe annulus to reduce heat loss with insulation and/or a heat source.

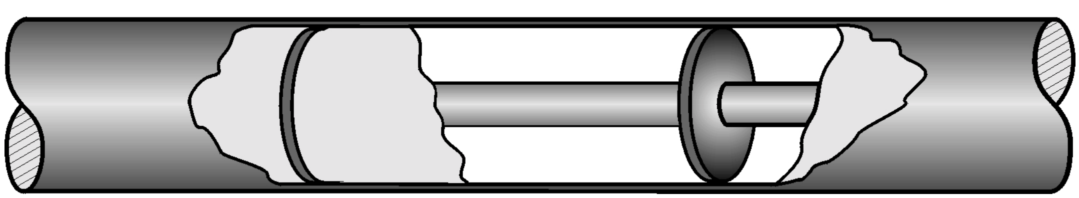


Figure C1: Typical Pipe-in-Pipe Configuration

The three most important design parameters (for evaluating the benefits provided by "displacement delay" and "curvature reduction") are as follows:

(a) the total distance between the inner and outer pipe (termed the "annulus size") – for previous designs, the annulus has been typically filled with insulating material to reduce heat loss and thus increase operational efficiency (which was the design objective). Although this can not be evaluated for many of the cases listed in Table C1 because wall thickness data are missing, the typical inter-pipe annulus (total gap between inner and outer pipes) is probably in the range of about 3-4 inches.

The annulus sizes for the two pipe-in-pipe concept designs for the Liberty Pipeline (Intec 1999a; 2000) are 1.56 and 2.25 inches, respectively (described in section C4). These annulus sizes are somewhat smaller than previous designs. The behaviour of the pipe-in-pipe configuration is expected to be sensitive to the annulus size.

Consequently, there may be some benefit in further optimisation. It may also be worthwhile to verify that the smaller annuli will not lead to constructability problems. However, both of these issues are beyond the scope or terms of reference for this project.

(b) The distance between the spacers supporting the inner pipe – typically these distances are quite short (i.e., less than 5 feet). However, recognising that the primary design objective for previous pipe-in-pipe designs was not to provide additional structural integrity, the analyses here were carried out for a larger range of spacer spacings.

(c) The design temperature response differential between the inner and outer pipes. This difference in thermal response could be achieved through the insulation of the inter pipe annulus or by using different materials for the inner and outer pipes.

Table C1: Designed, Operational and Abandoned Pipe-In-Pipe Pipe Configurations

Pipeline	Status	Length [km]	Inner Pipe Mat'l	Inner Pipe OD [in]	Inner Pipe t [in]	Outer Pipe Mat'l	Outer Pipe OD [in]	Outer Pipe t [in]	Insul'n
King - Amoco - Gulf of Mexico	existing	29	S	8		S	12		Water Heated
Nakika - Shell - Gulf of Mexico	existing	4.8	S	8		S	12		Electric Heat
Europa - Shell - Gulf of Mexico	existing	29	S	8		S	12		
Macaroni - Shell - Gulf of Mexico	existing	19.3	S	6		S	10		
Etap - Shell - North Sea	existing	22	S	10		S	16		Yes
Arnold - Marathon - Ewing Bank	existing	12.9	S	6		S	10		PUF
Gfsat - - Norway North Sea	existing	11	S	6		S	24		Yes
Roika - BP/Marathon/Shell - Gulf of Mexico	existing	2x22.5	S	6		S	10		Yes
Rocky - Shell - Green Canyon 110	existing	6.9	S	4		S	24		Yes
Erskine - Texaco - UK North Sea	existing	48.3	S	12		S	16	0.252	Yes
Caroline - Shell - Alberta, Canada	existing	39.6	S	8	0	S	6		Hot water/PUF
Du Pont Facilities - Du Pont - Del.	existing		S	3		S	8		N/A
Mobile Bay - Exxon - Alabama	existing	6.4	S	4		S			PUFHDPU
Tarwhine - Esso/BHP - Bass Strait	existing	17.4	S	10		S			HDPU
Seahorse - Esso/BHP - Bass Strait	existing	11.3	S	10		S	16		PUF
Vega - Montedison -	existing	2.4	S			S	28		PUF
Ravenna - Sone - Ravenna Italy	existing	8.1	S	22		S	26	0.406	PUF
Bouri Field - Agip - Offshore Libya	existing	8.1	S	13		S	28		PUF
Ravenna, Italy - Sone - Adriatic Sea	existing	2x8.1	S	22		Neoprene			PVC
Balmoral - Sun - North Sea	existing	4.8	S	3 (ID)		PU			PVC
Cormorant - Shell - Northern North Sea	existing	2x3.4	S	3 (ID)		PE			PUF
Rolf - Maersk - Offshore Denmark	existing	17	S	8		PE			PUF
West Delta - Mesa - Gom	existing	2x3.2	S	3 (ID)		PE			PUF
Revenna - Sone - Italy	existing	26.1	S	26, 26		PE			PUF
Cormorant - Shell - Northern North Sea	existing	2x7.9	S	8.265	0	S	14	0.31	PUF
Lucina - Shell - Offshore Gabon	existing	2x2	S	10		PE			PUF
Skjold - Danbor - Denmark	existing	11	S	6		PE			PUF
Udang "B" - Conoco - South China Sea	existing	2x4.7	S	12.74	1	S	18		PUF
Ancona - Api - Adriatic Sea	existing	3.5	S	12		S	24		PUF & Heat
Magellan Strait - Enap - Offshore Chile	existing	90.2	S	8		PE			PUF
Udang "A" - Conoco - South China Sea	existing	2x1.8	S	9	0	S	12.75		PUF
Arabian Gulf - Amerada Hess	existing		S	4, 6, 8		S	22, 22		PUF
Tokyo Bay - Tokyo Gas - Tokyo Bay	existing	24.2	S			S	24		
Jatibarang - Pertanina - Offshore Indonesia	existing	12.9	S	36		S	40		Glass Fiber
Java Sea - Iiapco - Java Sea	existing	44.8	S	14		S	18		PUF
Oyster - Marathon - Weing Bank	existing	4.83	S	4		S	6		PUF
Tahoe II - Shell - Viosca Knoll	existing	19.32	S	5		S	8		Yes
Dulang - Petronas - Malaysia	existing		S	6, 10		S	10, 14		
Iosca Knol - Oryx - Gom	existing	6.4	S	5		S	6		Yes
K8-FA-3 Platform - Netherlands Oil - N. Sea	existing	9	S	13		S	18		PUF
ARCO Alpine Colville River Crossing	existing		S	14	0.5	S	20	0.438	P.E.
Panarctic Drake 76	abandoned		S	6	0.375	S	18	0.432	P.E.
BP Exploration Troika	existing		S	10.75	0.375	S	24	0.86	3" Open cell
Elf Elgin/Franklin pipeline - UK, N. Sea	existing	10.5	S	12.4		S	17		
Shell/A.Hess/Veba Oil Triton - U.K., N. Sea	existing	30	S	13.4		S	18		
Elf Elgin Riser, U.K. Sector, North Sea	existing	0.28	S	12		S	18		PU
Shell Mallard Tie-in-spool, U.K., N. Sea	existing	0.28	HDPE	12		S	18		PU
Shell Mallard Pipeline Project, U.K., N. Sea	existing	15.3	S	8		S	16		PU
Klaipeda Naftas Oil Terminal, Lithuania	existing	1.5	S	32		HDPE	39.4		PU
NAM Gas Pipeline Ext., The Netherlands	existing	3.2	S	14		HDPE	17.7		PU
Hub River Fuel Oil Pipeline, Pakistan	existing	83.5	HDPE	14		S	18.5		

Note: Sources for Table C1: various including CCORE, 2000; Logstor Ror

C2.0 DISPLACEMENT DELAY ANALYSES

C2.1 Displacement Delay Magnitude

As outlined in section C1.0, the total inner pipe length will become longer than that of the outer pipe if it is not continuously supported. This occurs because the inner pipe will sag between the internal space supports due to the combined effects of self-weight, thermal strains, and longitudinal strains produced by the operating pressure (Figure C2). As a result, the outer pipe must undergo some axial elongation before significant axial tension strains are exerted on the inner pipe. This provides a potential means for limiting the axial strains exerted on the inner pipe.

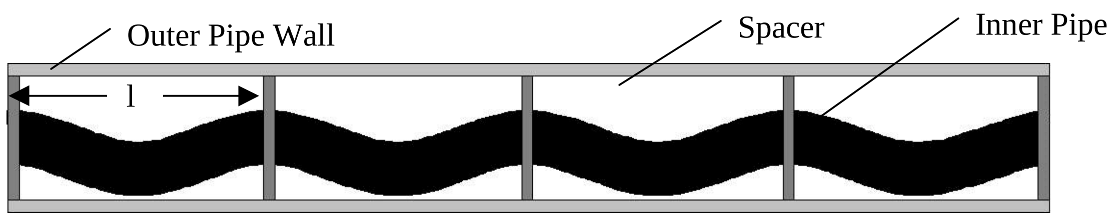


Figure C2: Inter Spacer Sagging for a Pipe-in-Pipe

If the spacers have a uniform separation (l) and the spacers are considered as roller supports, then the inner pipe may be considered a multi-span continuous beam. The inner pipe moment (M) at each spacer support is:

$$M = -0.071w\,l \qquad [C1]$$

where: w is the self weight per unit length of the inner pipe, and ;
M is obtained from the symmetry condition at the spacers (slope = 0)

The deflected shape, $\Delta(x)$, of the inner pipe over a single span may be estimated based on the equation describing the shape of a beam with a uniformly distributed load and equal

$$\Delta(x) = \frac{wx}{24EI}\left(x^3 - 2lx^2 + \frac{12mx}{w} + l^3 - \frac{12ml}{w}\right) \qquad [C2]$$

end moments (see Figure C.6).

where: E and I are the pipe modulus of elasticity and moment of inertia, respectively.

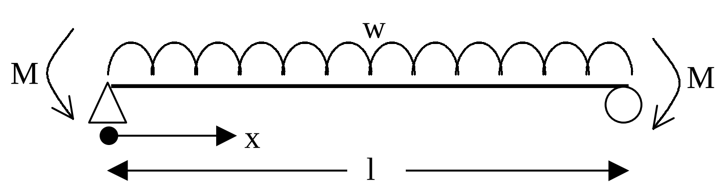


Figure C3: Beam with Uniformly Distributed Load and Equal End Moments

The change in the horizontal projection of the pipe's length (δ) for a given span (spacer separation, l) is estimated in terms of the deflected shape (Δ(x)) as:

$$\delta = -\frac{1}{2}\int_0^l \left(\frac{d\Delta}{dx}\right)^2 dx = \frac{-2.48\times10^{-5} l^3 \left(17\ l^4 w^2 + 1680 M^2 - 336\ l^2 wM\right)}{(EI)^2} \qquad [C3]$$

In addition to the gravity-induced sag deformations, the inner pipe is subjected to a thermal and effective pressure load that will induce a compressive strain. This must be overcome before tensile stresses are carried by the inner pipe. Assuming a service pressure of 1415 psi, a temperature increase of 120 °F and a coefficient of thermal expansion (α) of -6.5 x 10^{-6} mm/mm/°F, the compressive strain which will need to be relaxed is:

$$\varepsilon = \alpha\Delta T + \frac{P(1-2\upsilon)}{E} \qquad [C4]$$

By assuming that the entire length of inner pipe is free to move the outer pipe extension required to develop a tensile stress in the inner pipe as a function of spacer separation may be estimated as shown in Figure C4. Figure C4 is developed for a 12.75 OD x 0.5 in. wall steel pipe assuming a pipeline length of 6.12 miles (9.8 km). The displacement delay is not affected by the spacer spacing until sufficient displacements have occurred to match the effects of thermal expansion and internal pressure (Figure C4).

This load delay effect is magnified through the lateral deformation of the inner pipe and may be maximised by:

(a) increasing the inter pipe annulus size,
(b) increasing the spacer separation, and
(c) increasing the relative inner and outer pipe axial strains.

It is believed that Figure C4 over estimates the actual displacement delay. Friction at the inner and outer pipe contact points would likely prevent the whole offshore portion of the Liberty Pipeline from "participating" in the interaction as has been presumed here. Exploratory analyses suggest that this effect might reduce the displacement delay by a factor of about 2-4. Unfortunately, more detailed analyses were not possible within the time schedule set for this project.

Nevertheless, it can be seen that displacement delay is likely to be an important process affecting the strains and displacements exerted in the inner pipe.

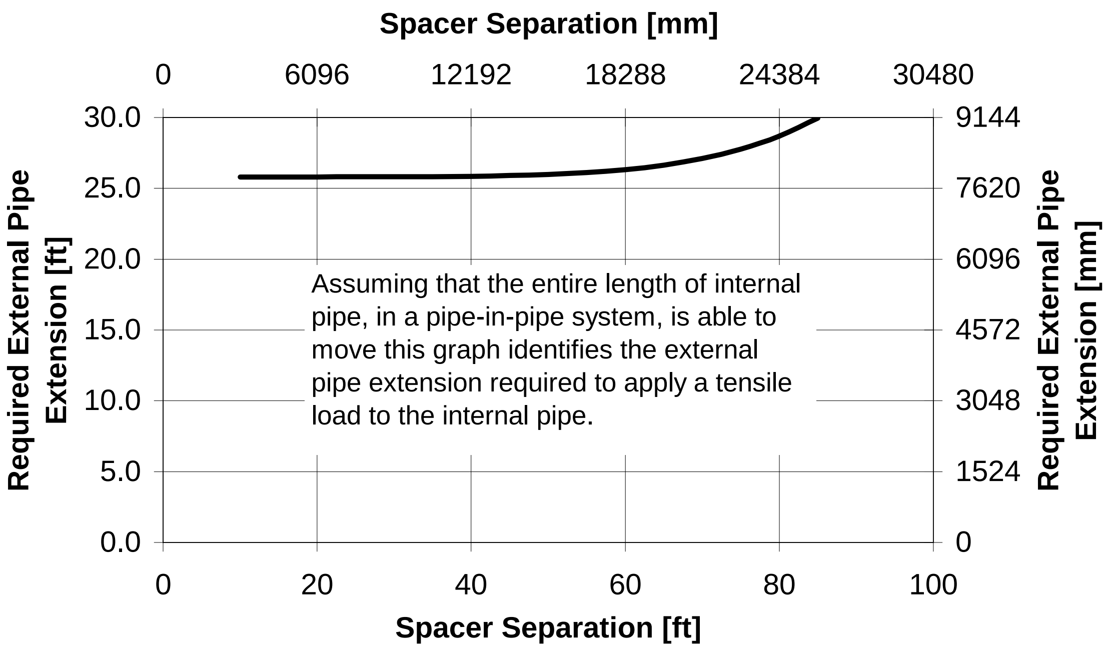


Figure C4: Outer Pipe Axial Extension Required to Develop Axial Loads in Inner Pipe

C3.0 FINITE ELEMENT ANALYSES

C3.1 Introduction

These analyses were carried out to evaluate pipeline lateral deformations due to ice gouging, as was done in the concept design done by Intec, 1999; 2000. This structural modelling was repeated because:

(a) Intec, 1999; 2000's Finite Element (FE) modelling work was performed using small deformation theory which is not considered consistent with the current loading scenarios, and;

(b) the behaviour of the pipe in pipe structural system was not considered fully in the previous work.

The finite element modelling was performed in two stages for computational efficiency. The first stage was performed by Drs Konuk and Fredj of the Geological Survey Canada (GSC) and made use of a global FE model of the pipeline response, similar to that shown in Figure C5 (which is termed the GSC Model in this report). Unfortunately, a detailed report describing the GSC Model is not yet available; however, the GSC has verified that the information presented in this report is accurate (Appendix F, Section F6).

Furthermore, during the course of this project, FTL received a copy of the GSC Model and ran it for a number of cases. These runs produced the same results as those obtained by the GSC, and consequently, FTL has confidence in the reults provided by the GSC.

This approach was used as a guide the in the development of a more detailed local model, to consider the behaviour of a pipe in pipe pipeline configuration, as shown in Figure C8. In both the global and local models, the analysis was treated as a two-dimensional problem, in which displacements in the Z direction were restrained. This is not correct since the passage of a large ice feature would likely cause soil compaction and thus movement of the pipe in the Z-direction. To consider pipe submergence, the problem needs to include the displacements in both the Y and Z directions.

All of the finite element modelling in support of this investigation was completed using the ANSYS (version 5.6.1) finite element software. The finite element and analytic models used are described in the sections that follow.

C3.2 Objective

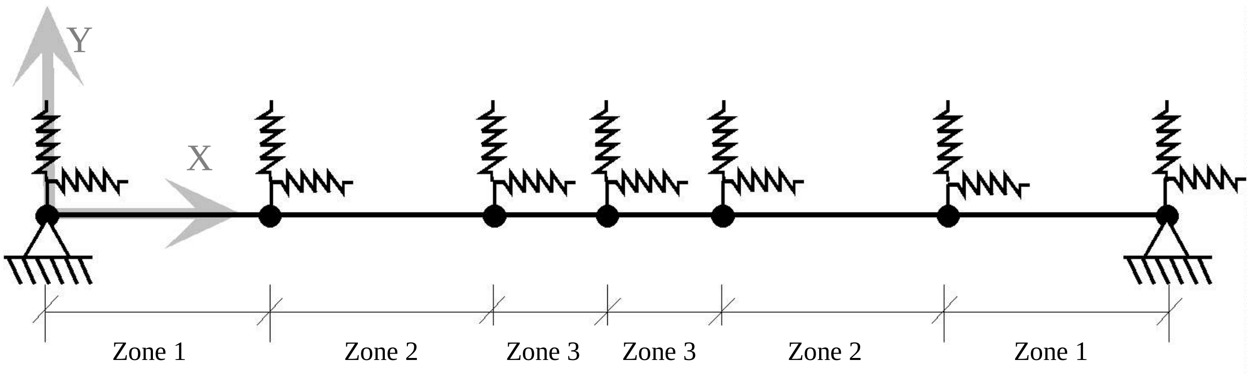
The objective of this work was twofold:

(a) to develop a better understanding of the large scale deformation analysis response of the pipeline due to ice gouging events, and
(b) to better understand the local behaviour of pipe-in-pipe systems of various configurations.

C3.3 Global Response Finite Element Modelling

This project made use of a detailed investigation by Drs Konuk and Fredj of the Geological Survey of Canada (GSC) into the global behaviour of a buried pipeline that is exposed to large soil displacements, thermal expansion and internal pressure. They developed ANSYS finite element models to analyse the global response of some of the Liberty Pipeline designs to ice gouging events. It should be noted that the GSC Model was developed totally independently from those produced by Intec, 1999; 2000, and the structure and components of the two models has not been compared in detail. Consequently, although the two models are generally similar in appearance, they may differ with respect to some details.

One major difference is that Drs Konuk and Fredj of the GSC solved it as a large deformation problem. This change acknowledges the fact that the presence of the compressive axial force will accentuate the deflections caused by a lateral load. This situation is commonly idealised in terms of the compressive force effectively reducing the stiffness available to resist the lateral loads. This effective change in stiffness or deflection magnification depends in a highly non-linear manner on the magnitude of the compressive load. In the problem at hand the axial (compressive) load is produced by the thermal and internal pressures, however, the thermal load due the difference between the installation (30°F) and operating (150°F) temperature is the most significant factor in the axial loading.



Zone	Length	Number of Elements	Element Length
1	2640 ft	44	60 ft
2	20 ft	6	40 in
3	50 ft	60	10 in

Figure C5: Lateral Deformation Global FE Model Description

The global model (Figure C5), is a beam element model including some 220 elasto-plastic pipe elements (ANSYS - element pipe 20), and 442 soil spring elements (ANSYS - element combin 39). The material properties of the pipe elements were those used in the previous study which are consistent with grade X52 pipe of the geometry of interest. For the steel pipe-in-pipe configurations, the global model pipe element geometries were based on the outer pipe. In the case of the HDPE pipe-in-pipe configuration, the structural contribution was not considered.

A soil spring element oriented along the Y-axis (transverse or soil compression spring) and one oriented along the X-axis (axial or friction springs) (Figure C5), were attached to each of the 221 pipe element nodes. The load-displacement (P-Y) curves of the springs were determined using the approach and geotechnical data given in Intec, 1999. Because the element sizes varied for each zone, different load-displacement behaviours were used for each spring in each of the three zones.

The loading applied to this model included an internal pressure of 1415 psi, a thermal expansion of 120°F and lateral displacements along the Y-axis that were prescribed using the soil subgouge displacement algorithms presented in Intec, 1999. The pressure and thermal load were applied to all of the pipe elements and their effects were automatically considered in the ANSYS large displacement analysis using pipe elements. The prescribed displacements were applied to the free end of the transverse spring elements to simulate the effects of the passage of an ice feature.

The global model was applied to sixteen lateral displacement cases (Table C2) to evaluate the effects of:

(a) Analysis type - Large vs. small displacement analysis (compare cases 1 and 16);
(b) Temperature change magnitude - Thermal load (compare cases 1, 4 & 5 or 2, 6 &7);
(c) Soil displacement magnitude - Gouge depth and width (compare cases 1, 8, 10, 12, 14 & 15 or 2, 9, 11 & 13);
(d) Pipe configuration - Effect of geometry on outer pipe behaviour (compare cases 1, 2 & 3).

Table C2: Global Lateral Displacement FE Analysis Cases[1]

Case No	Analysis (L.vs. S Displ)	Pipe[3]	Δ Temp [°F]	Gouge Width [ft]	Gouge Depth [ft]	Depth Below keel (ft)	Peak Soil Displ[2]. [ft]	Comment
1	large	Single P	120	18	3	1	3.53	Base Case
2	large	Steel P-P 1	120	18	3	1	3.53	Base Case
3	large	Steel P-P 2	120	18	3	1	3.53	Base Case
4	large	Single P	0	18	3	1	3.53	vary Δ Temp for single pipe
5	large	Single P	80	18	3	1	3.53	vary Δ Temp for single pipe
6	large	Steel P-P 1	0	18	3	1	3.53	vary Δ Temp for steel p-p
7	large	Steel P-P 1	80	18	3	1	3.53	vary Δ Temp for steel p-p
8	large	Single P	120	18	6	1	5.58	Larger gouge depth; same width
9	large	Steel P-P 1	120	18	6	1	5.58	Larger gouge depth; same width
10	large	Single P	120	18	1.6	1	2.12	smaller gouge depth; same width
11	large	Steel P-P 1	120	18	1.6	1	2.12	smaller gouge depth; same width
12	large	Single P	120	30	3	1	4.56	same gouge depth; larger width
13	large	Steel P-P 1	120	30	3	1	4.56	same gouge depth; larger width
14	large	Single P	120	30	6	1	7.21	larger gouge depth; larger width
15	large	Single P	120	30	1.6	1	2.74	smaller gouge depth; larger width
16	small	Single P	120	18	3	1	3.53	Base Case

Notes:

1. Internal pressure = 1415 psi in all cases.
2. The peak soil displacement is the horizontal soil displacement below the centre of the keel at the indicated depth below the keel bottom (of 1 foot). This was calculated as described in Appendix A using the subgouge displacement algorithms developed for clay.
3. Pipe geometry (OD x Wall Thickness) [in] - Single P = 12.75 x 0.688
Steel P-P 1 = 16 x 0.844
Steel P-P 2 = 16 x 0.5

The results of analysis case 2 are shown in Figures C6 and C7 as examples of the information collected from the large displacement analyses. Figure C6 compares the pipe axial and transverse displacements along the length of the pipe with the soil transverse displacement along the length of the pipeline.

These results and all of the results in general, indicate that the lateral displacement and curvature of the pipeline (bending moments) are essentially zero outside of a 40 m wide zone centred on the gouge centreline. This information is used in setting up the local detailed finite element model to investigate the effects of pipe-in-pipe construction.

It is also noted in this case and in others that the peak pipe transverse displacement exceeds the soil transverse displacement due to the deformation accentuation due to the pipe compressive load due to the temperature change and internal pressure. This exceedence of the soil displacement indicates that, while the soil displacement facilitates the displacement, the pipe is buckling in its natural mode shape.

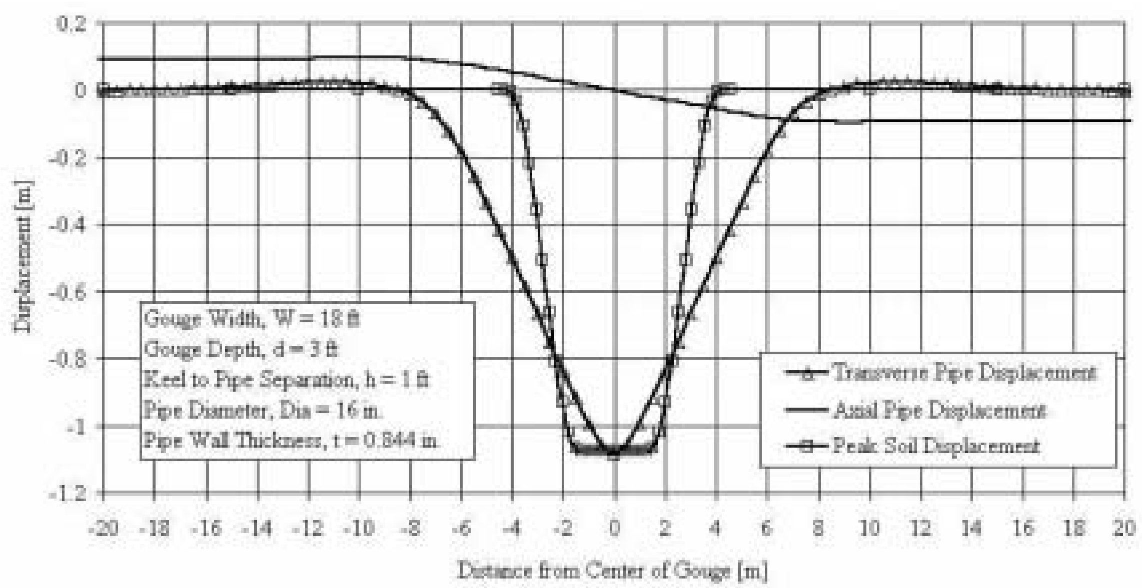


Figure C6: Typical Pipeline and Soil Displacement Results

Figure C7 also demonstrates that the global model extends far enough away from the gouge area to allow the pipe to anchor itself and that the pin supports at the end of the ends of the model do not affect the analysis results. The axial force values are similar at each end of the model.

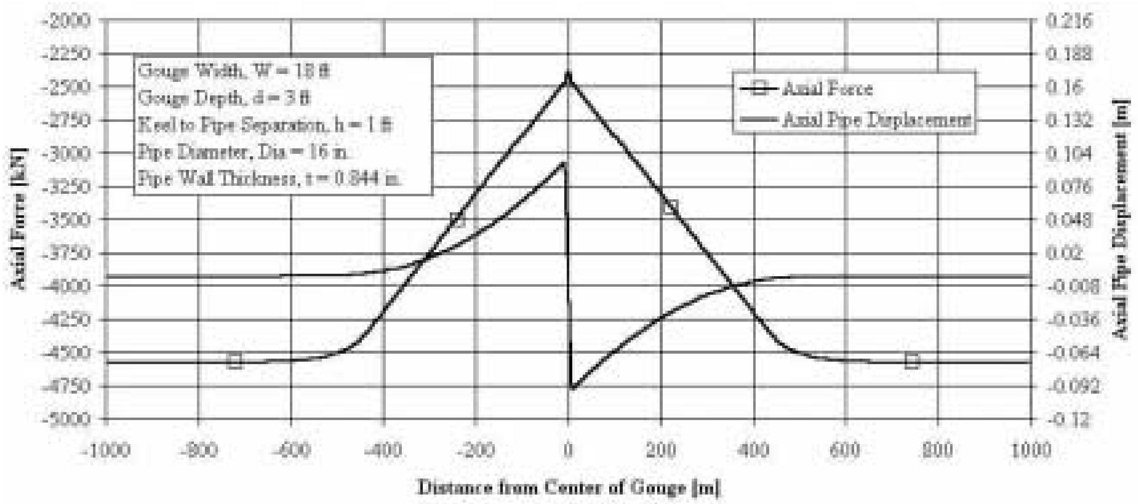


Figure C7: Typical Pipeline Axial Force and Displacement Results

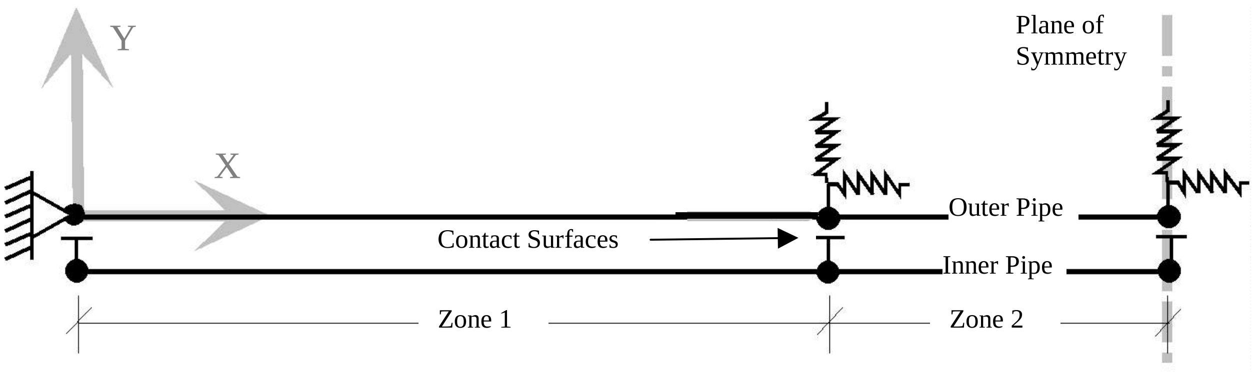
C3.4 Detailed Local Finite Element Modelling of the Steel Pipe-in-Pipe

Local FE models were constructed to complement the results of the global analyses by evaluating the local behaviour of the steel pipe-in-pipe structural configuration. The objective of this modelling work was to evaluate the significance of the mobility of the internal pipe relative to the external pipe. This issue was not considered in Intec 1999's concept design for the Liberty Pipeline, and it was believed that it may be important in certain cases.

The detailed local FE model, shown in Figure C8, is a beam element model including two collinear elasto-plastic pipe element (ANSYS - element pipe20) runs of 498 elements each, representing the inner and out pipes of the steel pipe-in-pipe configuration. The pipe element runs are connected by 166 friction spring elements (combin39) and 998 spring gap elements (combin40), simulating the pipe-in-pipe spacers and the space between the pipes. These spring gap elements allow relative axial (along the X-axis) movement, but limit transverse (along the Y-axis) displacement to a specified level. At the spacers, the specified gap (allowable transverse displacement was set to zero, while the gap elsewhere was set to the size of the inter-pipe annulus. Relative movement of the contact surface elements is resisted by frictional forces estimated to be generated by a plastic on steel coefficient of friction of 0.5 and a normal force equal to the pipe and oil weight. The material properties of the pipe elements were those used in the previous study which are consistent with grade X52 pipe of the geometry of interest.

A soil spring element oriented along the Y-axis (transverse or soil compression spring) and one oriented along the X-axis (axial or friction springs, Figure C8), were attached to each of the 181 outer pipe element nodes in Zone 2. The same load-displacement (P-Y) curves used to define the springs in the global model were applied to the local model.

The outer pipe element nodes in Zone 1 were restrained against displacement in the Y direction based on the results of the global model runs which indicated that the pipe deformations in this region did not include any flexural deformations. Thermal (120 °F) and pressure (1415 psi) loads were applied to the inner pipe while only a thermal load was applied to the outer pipe. Several analysis cases were completed considering outer pipe temperature changes of 50, 80 and 120°F.



Zone	Length	Number of Elements	Element Length
1	1800 in	180	10 in
2	38160 in	318	120 in

Figure C8: Lateral Displacement - Detailed Local Steel Pipe-in-Pipe FE Model Description

The local model was successfully applied to a range of lateral displacement cases (Table C3) to evaluate the effect of:

(a) Temperature change magnitude - Thermal load (compare cases 1, 3 & 4)
(b) Soil displacement magnitude - Gouge depth and width (compare cases L1, L6 & L7)
(c) Pipe configuration - Effect of annulus size and pipe geometry (compare cases L1 & L2)
(d) Spacer layout - Spacer separation (compare L1, L8 & L9) and spacer location (L1 & L10)

Table C3: Local Lateral Displacement FE Analysis Cases

Case No	Pipe[4]	Related Case[1]	Δ Temp [°F][5]	Gouge Width [ft]	Gouge Depth [ft]	Peak Soil Displ[3] [ft]	Spacer Separation [ft]	Gouge Center to Spacer Dist. [ft]
L1	Steel P-P 1	2	120/50,80	18	3	3.53	20	10
L2	Steel P-P 2	3	120/50,80	18	3	3.53	20	10
L3	Steel P-P 1	6	0	18	3	3.53	20	10
L4	Steel P-P 1	7	80	18	3	3.53	20	10
L5	Steel P-P 1	9	120/50,80	18	6	5.58	20	10
L7	Steel P-P 1	13	120/50,80	30	3	4.58	20	10
L8	Steel P-P 1	210	120/50,80	18	3	3.53	10	5
L9	Steel P-P 1	211	120/50,80	18	3	3.53	40	20
L10	Steel P-P 1	212	120/50,80	18	3	3.53	20	0

Notes:
1. See Table C2 for related global model descriptions
2. Inner pipe internal pressure = 1415 psi in all cases
3. Peak soil displacement at that pipe burial depth. See Table C.2 for calculation method.
4. Pipe geometry (OD x Wall Thickness) [in] - Steel P-P 1 = 16 x 0.844 - Steel P-P 2 = 16 x 0.5
5. Outer pipe temperature change investigated including 50, 80 and 120°F temperature changes

Sample results are shown in Figures C9 and C10 for analysis case L1. Figure C9 compares the inner and outer pipe axial and transverse displacements along the length of the pipe with the soil transverse displacement along the length of the pipeline. The transverse pipe displacement data is presented for the centre of the pipeline and as such the inner pipe may seem to deflect more that the outer, however, this is simply the inner pipe shifting within the outer pipe.

It is also noted in some cases that the peak pipe transverse displacement exceeds the soil transverse displacement due to the deformation accentuating pipe compressive load caused by the temperature change and internal pressure. This exceedence of the soil displacement indicates that, while the soil displacement facilitates the displacement, the pipe is buckling in its natural mode shape. The deformed shape of the pipe as described by the lateral displacement profile includes two areas of concentrated curvature: at the gouge centre and at the point at which the pipe returns to a near zero displacement (about 6m from the gouge centreline).

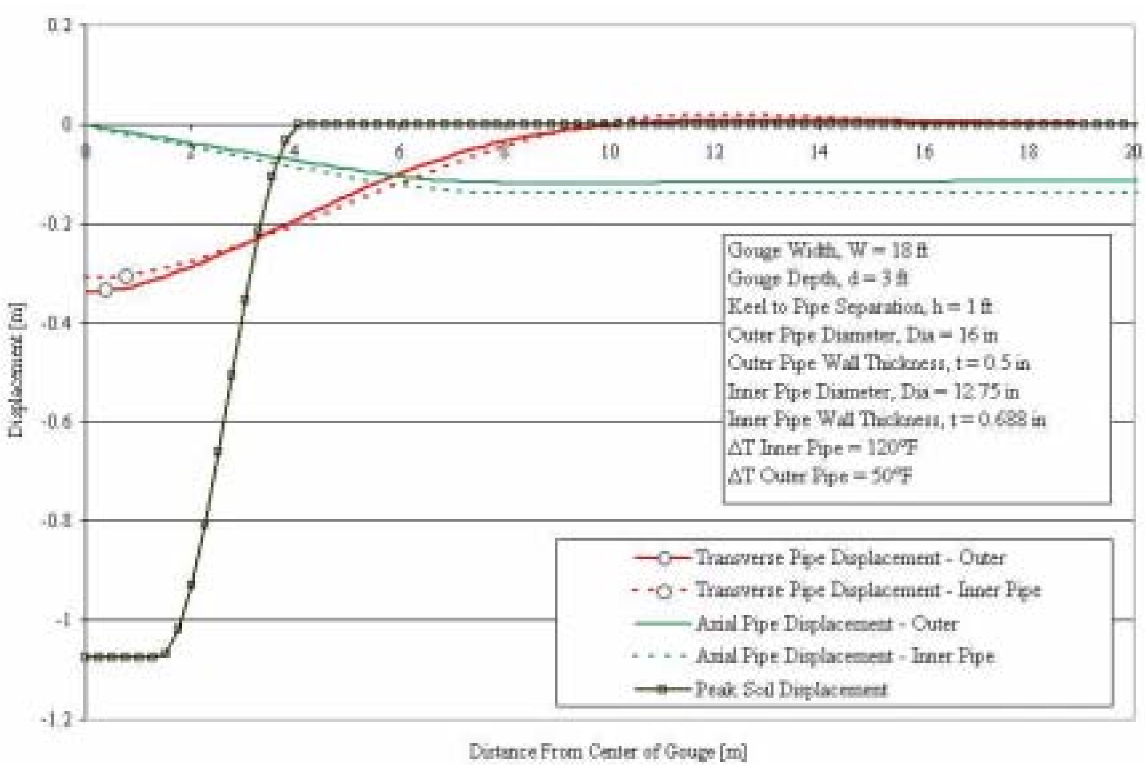


Figure C9: Local Finite Element Model Pipe-in-Pipe Displacements

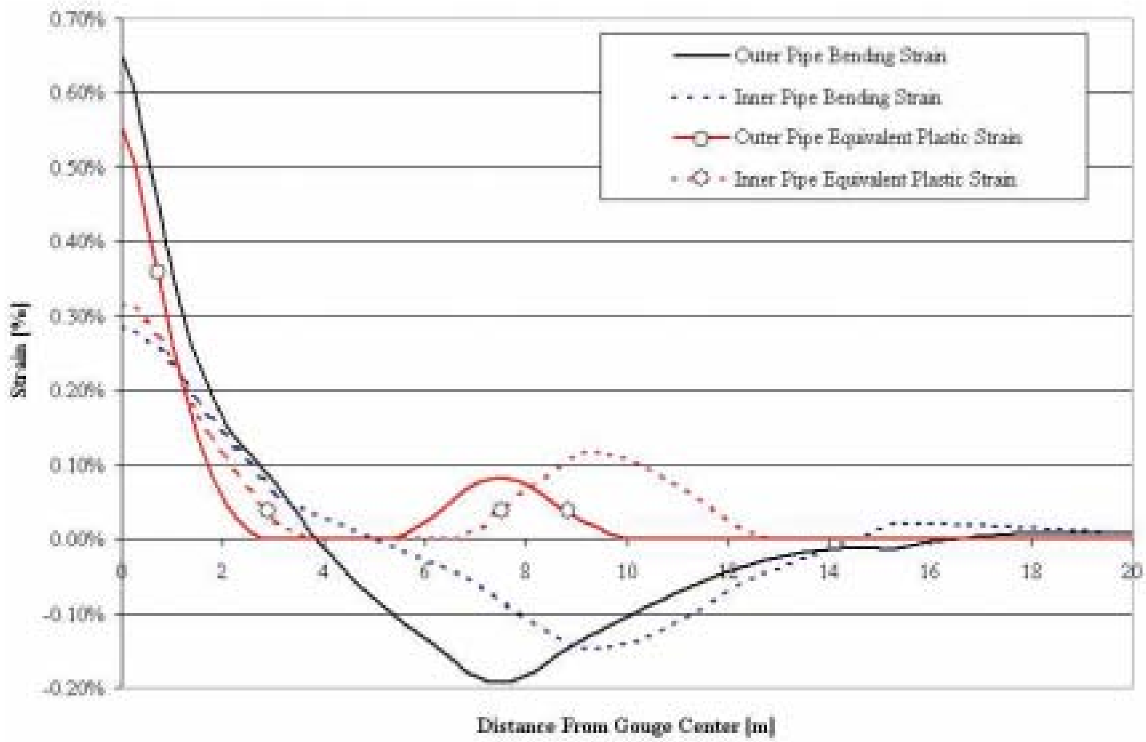


Figure C10: Local Finite Element Model Pipe-in-Pipe Strains

The strain distribution shown in Figure C9 includes two areas of concentrated bending associated with the areas of high curvature illustrated by the pipe's displaced shape. Typically the inner pipe has lower bending and equivalent plastic strains than the outer pipe as shown in Figure C10. The reduction in inner pipe strains, relative to the outer pipe is related to the spacer separation and inter pipe annulus size. Larger spacer separation or larger inter-pipe annuli can decrease the inner pipe strain relative to that in the outer pipe.

C4.0 REFERENCES

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[4] Intec Engineering, 1999b, Pipeline System Alternatives Supporting Calculations: Liberty Development Project Conceptual Engineering, Draft Report, Volume 2, submitted to BP Exploration (Alaska) Inc., Intec Project Number H-0851.02.

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APPENDIX D

UPHEAVAL BUCKLING AND UNSUPPORTED SPAN ANALYSES

CONTENTS

LIST OF FIGURES

D1.0 INTRODUCTION

This appendix presents the analyses used to investigate upheaval buckling and unsupported span bending. The analysis methodologies applied to these behaviours are described. Also, information is presented to further describe the analysis results reported in Section 4.0.

D2.0 INSTABILITY/BUCKLING

The potential for upheaval buckling and its effects on the pipe were analyzed based on a two step procedure. The potential for upheaval buckling was evaluated using the approach given in Palmer et al, 1990. Finite element analyses were then used to evaluate post-buckling effects on the pipeline.

D2.1 Evaluation of Whether or Not Buckling Will Occur

Palmer et al, 1990's upheaval buckling formulation is based upon elementary beam column theory. The downward load per unit length required to prevent buckling of an elastic beam subjected to a compressive force is given by:

$$w(x) = -EI\frac{d^4y}{dx^4} - P\frac{d^2y}{dx^2} \qquad \text{[D1]}$$

where:	w(x)	load per unit length required to prevent buckling (lb/in)
	E	elastic modulus (psi)
	I	moment of inertia (in^4)
	P	axial compressive load (lb)
	y	height of the pipeline profile as a function of x (in)
	x	position along the profile length (in)

Palmer et al, 1990 proposed a sinusoidal profile for y of the form:

$$y = \delta\cos^2\left(\frac{\pi x}{L}\right) \qquad \text{[D2]}$$

where:	δ	imperfection height (in)
	L	imperfection length (in)
	x	-0.5L < x < 0.5L

Substituting D2 in D1 and setting x = 0 (i.e. the apex of the imperfection) then the equation of the maximum load per unit length can be given as:

$$w = 2\delta P\left(\frac{\pi}{L}\right)^2 - 8\delta EI\left(\frac{\pi}{L}\right)^4 \qquad \text{[D3]}$$

Equation D3 is specific to the profile shape defined by equation D2. However, changing y will only affect the constants in the equation and not the general form. Equation D3 can be re-written in terms of a dimensionless maximum download parameter and a dimensionless imperfection length term.

$$\phi_w = a\phi_L^{-4} + b\phi_L^{-2} \qquad \text{[D4]}$$

Where:

$$\phi_w = \frac{wEI}{\delta P^2} \qquad \text{[D5]}$$

and

$$\phi_L = L\sqrt{\frac{P}{EI}} \qquad \text{[D6]}$$

Plotting values of ϕ_w versus ϕ_L using observations of full scale field observations and tests as well as the results of numerical calculations will provide the values of the coefficients a and b. Using their proprietary software, UPBUCK, Palmer et. al. 1990 were able to demonstrate that the general form of a pipeline supported by an axial force in post-upheaval mode is given by the equation:

$$\phi_w = \frac{9.6}{\phi_L^2} - \frac{343}{\phi_L^4} \qquad \text{[D7]}$$

When the imperfection height is known, but the imperfection length is not, it is assumed that the shape is dependent upon the flexural stiffness and the weight of the pipe at the time of installation. Thus the length term L = f(EI,w_o). Equation D7 can now be re-written to permit calculation of the required download, w, to prevent buckling of the pipe.

$$w = \left[1.16 - \frac{4.76}{P}\left(\frac{EIw_o}{\delta}\right)^{\frac{1}{2}}\right]P\left(\frac{\delta w_o}{EI}\right)^{\frac{1}{2}} \qquad \text{[D8]}$$

where:	w	required download per unit length (lb/in)
	E	elastic modulus (psi)
	I	moment of inertia (in^4)
	P	axial load (lb)
	w_o	weight of pipe in the installed condition (lb/in)
	δ	imperfection height (in)

The exact function for L used to derive Equation D8 is not clear in Palmer et al, 1990.

The download, w, is provided by the uplift resistance of the overburden and the submerged in-service weight of the pipe. The submerged weight of the pipe can be determined by:

$$w_s = w_{pipe} + w_{product} - w_b \quad \text{[D9]}$$

where:

where:	w_{pipe}	weight of pipe (lb/in)
	$W_{product}$	weight of the product carried in the pipe (lb/in)
	F_b	bouyancy force (lb/in)

The uplift resistance of the overburden, q (lb/in) required to prevent buckling is therefore given by:

$$q = w - w_s \quad \text{[D10]}$$

For cohesionless sand, silt and rock:

$$q = \gamma HD\left(1 + f\,\frac{H}{D}\right) \quad \text{[D11]}$$

For cohesive clay and silt:

$$q = \gamma cD \min\left[3, \frac{H}{D}\right] \quad \text{[D12]}$$

where:	q	uplift resistance (lb/ft)
	γ	submerged unit weight of the cover material (lb/ft^3)
	H	depth of cover (ft)
	D	pipe diameter (ft)
	f	uplift coefficient (0.5 for dense materials, 0.1 for lose materials)
	c	shear strength

The length of the imperfection was estimated by assuming that it was formed when the pipe was placed. In this case the pipe is idealised as a beam fixed at one end and free but guided downwards a distance equal to the imperfection height at the other end. The maximum deflection is given by:

$$\delta = \frac{w_o\left(\frac{L}{2}\right)^4}{24EI} \quad \text{[D13]}$$

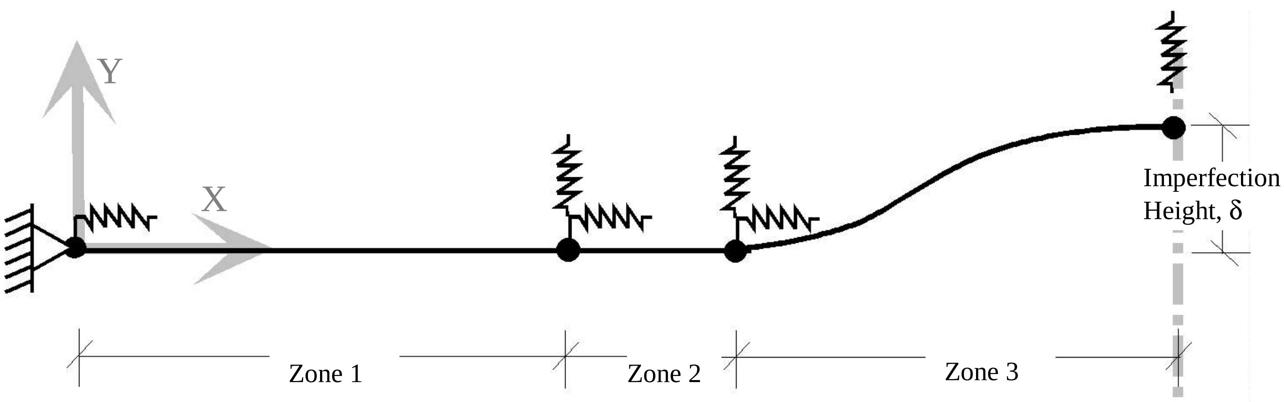
and by solving for the length of the deformed shape (L) the following expression for the imperfection length is developed:

$$L = 2\left(\sqrt[4]{\frac{24\delta EI}{W}}\right) \quad \text{[D14]}$$

where W is the submerged self weight of the pipe and δ is the imperfection height.

D2.2 Finite Element Analyses

Palmer et al, 1990's description of the imperfection height and width was as an input to the pipeline finite element model that was developed in ANSYS to evaluate the effects of upheaval buckling. The model is described in Figure D1. This large deformation model applies an internal pressure of 1415 psi, and thermal loads resulting from a temperature increase of 120^{o}F to the pipe to identify the deformed shape and resulting equivalent strains.



Zone	Length	Number of Elements	Element Length
1	2640 ft	44	60 ft
2	660 ft	99	80 in
3	100 ft	123	10 in

Figure D1: Upheaval Buckling Response Finite Element Model Description

The upheaval buckling model, shown in Figure D1, is a beam element model including some 266 elasto-plastic pipe elements (ANSYS - element pipe 20), and 365 soil spring elements (ANSYS - element type 39). The material properties of the pipe elements were those used in Intec, 1999 which are consistent with grade X52 pipe with the geometry of interest. For the steel pipe-in-pipe configurations, the upheaval buckling model pipe element geometries were based on the outer pipe.

Soil spring elements oriented along the Y-axis (transverse or soil compression spring) and along the X-axis (axial or friction springs), as shown in Figure D1, were attached to each of the pipe element nodes in Zone 2. In Zone 1, the pipe elements were restrained against movement in the Y direction and X-axis soil friction springs were applied to each node. The load-displacement (P-Y) curve for the springs was defined based on the geotechnical data given in Intec, 1999. Because the element sizes varied for each zone, different load-displacement relationships were used for the springs in each zone.

In Zone 3, vertical soil weight springs were applied to restrict the vertical movement of the pipe. The soil springs apply a downward force equal to a cover weight consistent with the distance between the top of the pipe and the soil surface. In other words, as the pipe deflects upwards the soil restraining force decreases. The overburden load (Figure D2) was determined for a variety of cover depths, assuming, based on Intec, 1999:

(a) that there is 1 foot of gravel immediately above the pipe, and;
(b) that the remainder of the soil cover was native material.

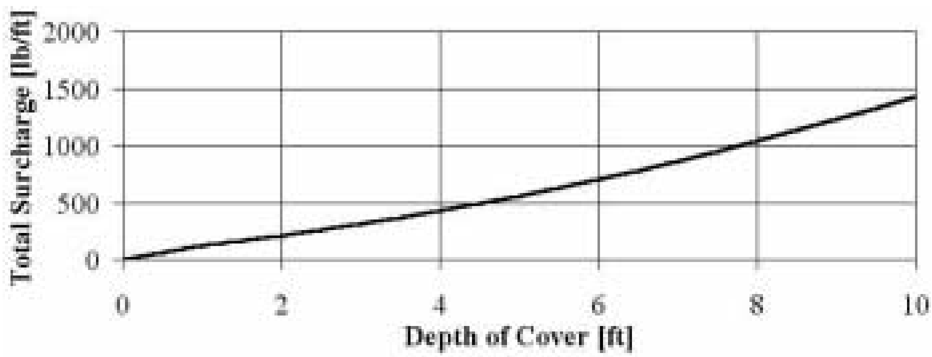


Figure D2: Estimated Overburden Loads to Resist Upheaval Buckling

The model was applied to a variety of analysis scenarios including those described as following. These scenarios were based on an initial imperfection height of 1.5 ft. The displaced shape of all the three pipe cases considered (listed below) were calculated for an internal pressure of 1415 psi, and stabilizing loads consistent with depths of cover ranging from 0 to 7 ft.

(a) a single pipe with an outside diameter of 12.75 inches and a wall thickness of 0.688 inches. This matches the dimensions of the pipe for the single steel pipe design.

(b) a single pipe with an outside diameter of 16 inches and a wall thickness of 0.844 inches. This matches the dimensions of the outer pipe for Intec, 1999's steel pipe-in-pipe design.

(c) a single pipe with an outside diameter of 16 inches and a wall thickness of 0.50 inches. This matches the dimensions of the outer pipe for Intec, 2000's steel pipe-in-pipe design.

Figure D3 presents the typical buckled shapes associated with a large and small stabilising soil overburdens. The deflected pipe geometry and the loads in the pipe are consistent with the expected behaviour of the pipe.

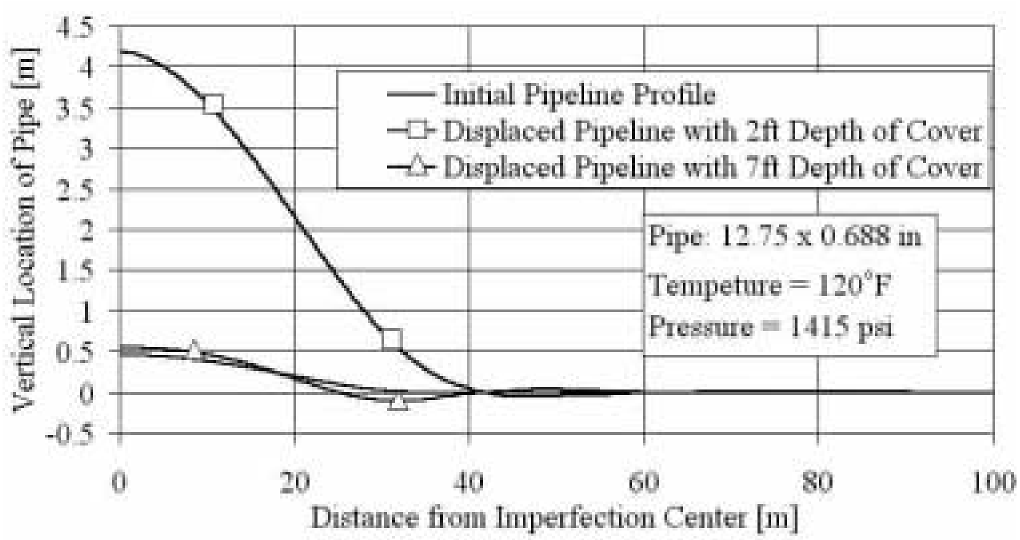


Figure D3: Sample Upheaval Buckling FE Model Deflections

D2.3 Unsupported Spans

In the event of strudel scour leading to an unsupported span, the behaviour of the pipe may be evaluated in a fashion similar to those done to investigate upheaval buckling resulting from an imperfection. In the case in which the pipe is partially supported, assuming that the soil cover remains on the pipe, the peak moment is located at the point at which the pipe bends to descend into the subsided area. This was conservatively estimated as:

$$M = 0.9413\sqrt{WEI\delta} \qquad [D15]$$

where:
W is the weight per unit length of pipe and overburden
E is Young's modulus of elasticity
I is the pipe section moment of inertia, and
δ is the subsidence depth.

The maximum moment (M) allows the calculation of the unsupported span length and the reaction at point B for various settlement depths (δ), as in Figure D4. These results assume negligible pipe axial tension, which is not necessarily the case for large settlements.

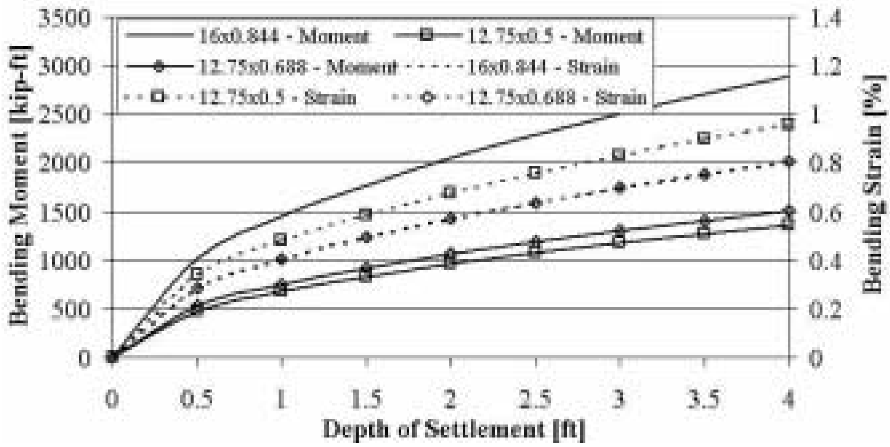


Figure D4: Maximum Moment and Bending Strain Due to Settlement

The potential for upheaval buckling subsequent to a thaw settlement or strudel scour can be evaluated based on the results of the upheaval buckling work described in the previous section.

APPENDIX E

FAILURE STATISTICS ANALYSES

CONTENTS

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E1.0 INTRODUCTION AND DATA SOURCES

E1.1 Objective

In principle, the historical data could be used to establish risks directly due to third party activities or operational failures. An approach of this type was used in the Environmental Impact Statement (EIS) prepared for the Northstar Project (US Army Corps of Engineers, 1999) based on the following exposure indexes:

(a) MMS Exposure Index: 1.32 pipeline spills exceeding 1000 bbls per billion bbls of oil transported - the Liberty Pipeline is expected to transport 0.47 billion bbls over its 20-year life (provided that the flow rate remains constant at 65000 bbls/d). This index would suggest that there would be 0.62 spills exceeding 1000 bbls over the 20-year life of the Liberty Pipeline.

(b) Concawe Exposure Index: 1.8 spills exceeding 1000 bbls per 10,000 miles of pipeline (or 0.00018 spills per mile-year) - the number of “mile-years” for the Liberty Pipeline is expected to be 122 (i.e., 6.12 miles for the offshore section x 20 years). This index would suggest that there would be 0.022 spills exceeding 1000 bbls over the 20-year life of the Liberty Pipeline.

It can be seen that the above two indexes provide significantly different results.

Upon further investigation, it was decided not to use the historical data to forecast spill volumes as the volume of oil spilled during failures is considered to be the least reliable information item in the database (MMS, personal communication). However, the historical data can be relied upon to give an indication of event probabilities, and it was investigated with this purpose.

E1.2 Data Sources

The event probabilities associated with operational failures and third party damage (e.g., construction activities, anchor dragging, sabotage, etc.) are not easily estimated. Historical operations data were reviewed in an effort to establish them.

Historical operations data from the following sources were investigated:

(a) United States Department of Transportation (DOT);
(b) The Minerals Management Service (MMS) for the Gulf of Mexico Region;
(c) Conservation of Clean Air and Water in Europe (CONCAWE);
(d) Alberta Energy and Utilities Board (AEUB);
(e) Transportation Safety Board (TSB); and
(f) North Sea experience.

While historical industry average failure rates provide a useful general check, it should be noted that they do not provide definitive information regarding the expected event probabilities for the Liberty Pipeline for several reasons:

(a) the data were collected across a large range of pipeline systems which may not be representative of the characteristics of the Liberty Pipeline. The most significant issues are considered to be the following:

  (i) failure statistics derived from existing databases reflect conditions where many more third party activities occur;
  (ii) the existing offshore pipelines reflected in the current databases are not exposed to ice or Arctic conditions.

(b) the historical data does not reflect improvements in operational, materials, construction, or monitoring technologies.

(c) the historical data do not account for improvements in operational practices or design regulations that may have been introduced as a result of past operational experience.

(d) the historical data typically contain considerable subjectivity, although it is noted that this limitation is becoming less significant. However, these improvements in reporting procedures make it difficult to compare failure statistics over the long term.

(e) care must be taken to ensure that the data is uniformly normalised to reduce the effects of the quantity and type of pipelines included in the statistics analysed.

E2.0 THE MMS GULF COAST

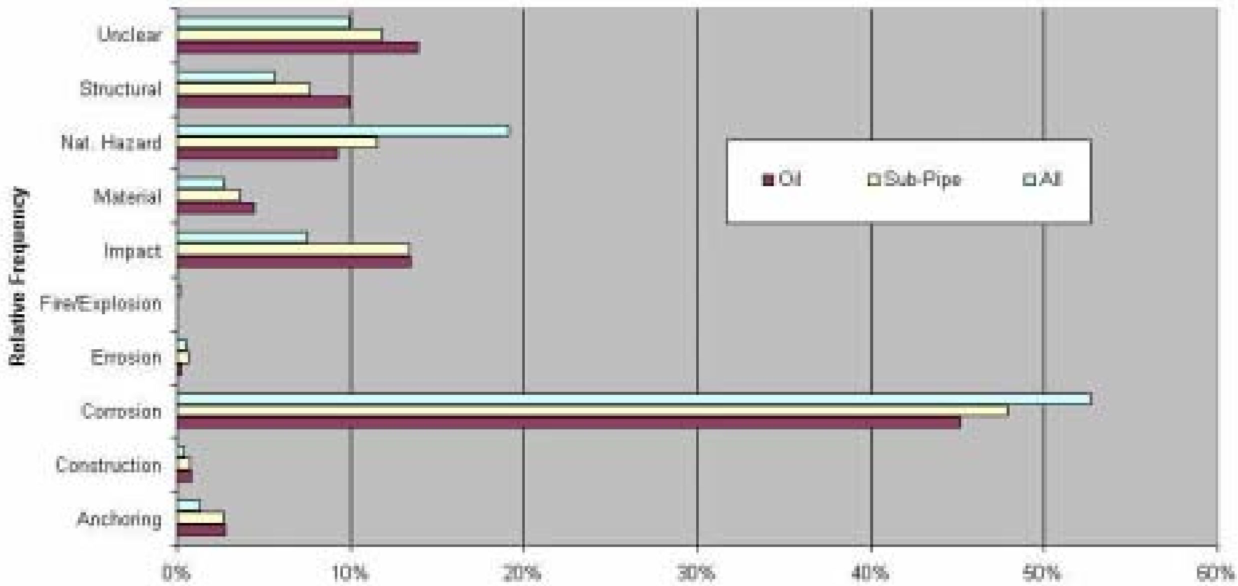
The Gulf Coast MMS Repair database reports all pipeline damages requiring repair for pipelines in the Gulf of Mexico area. The database includes data from the late 1960's to March 2000, with the most abundant and reliable data being the more recent. Therefore, this database represents roughly thirty years of offshore pipeline operational experience. This database contains 3355 damage/repair records.

The Gulf Coast MMS Repair Database was analysed to establish damage causes and damage types (Figures E1 and E2, respectively). The database was sorted by pipeline type as listed below:

(a) all of the data in the database (i.e., 3355 damage/repair records);
(b) oil pipelines (for which there are 474 damage/repair records), excluding all other product pipelines; and
(c) sub-sea pipelines (for which there are 1156 damage/repair records), excluding risers and tie-ins.

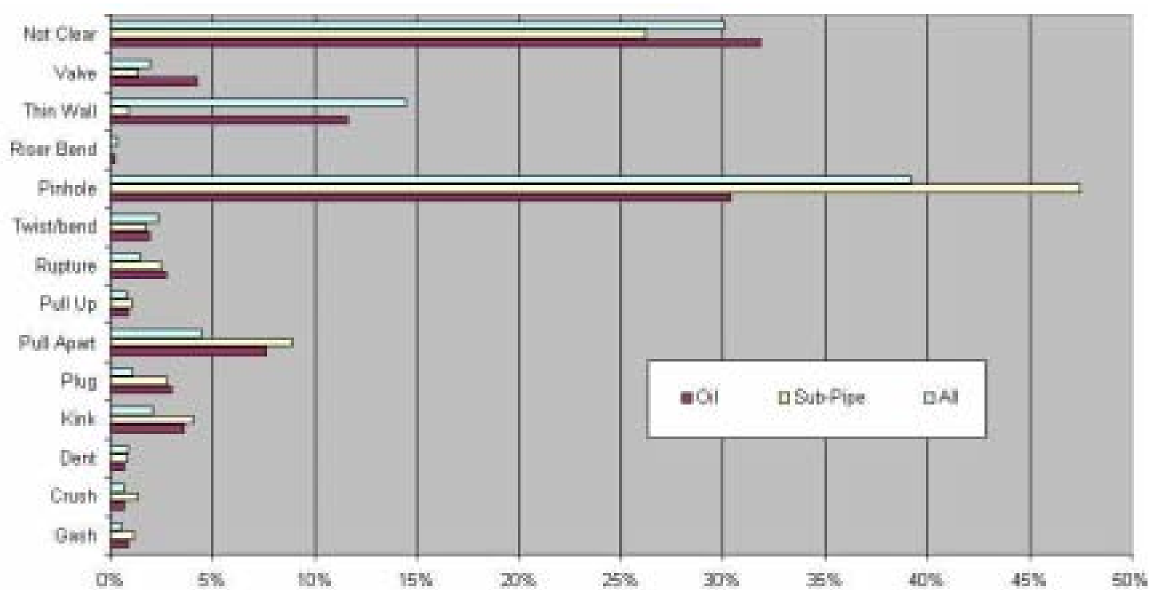
Upon review of the results obtained, it was noted that this division by pipeline type or product was not necessary since most of the relative frequencies were very similar amongst the three categories investigated.

For several records, the damage cause and type were "Unclear" and "Not Clear" (Figures E1 and E2, respectively). These categories include the data reported as "Other" forms or causes of damage, and those entries for which no entry was logged.



	Anchoring	Construction	Corrosion	Erosion	Fire/Explosion	Impact	Material	Nat. Hazard	Structural	Unclear
All	1.3%	0.4%	52.6%	0.5%	0.1%	7.5%	2.7%	19.1%	5.7%	10.0%
Sub-Pipe	2.7%	0.8%	47.8%	0.7%	0.0%	13.4%	3.6%	11.5%	7.7%	11.8%
Oil	2.7%	0.8%	45.1%	0.2%	0.0%	13.5%	4.4%	9.3%	9.9%	13.9%

Figure E1: MMS Gulf Coast Repair Database – Damage Cause



	Gash	Crush	Dent	Kink	Plug	Pull Apart	Pull Up	Rupture	Twist/bend	Pinhole	Riser Bend	Thin Wall	Valve	Not Clear
All	0.5%	0.7%	0.8%	2.1%	1.0%	4.5%	0.8%	1.5%	2.3%	39.2%	0.3%	14.4%	1.9%	30.0%
Sub-Pipe	1.1%	1.3%	0.8%	4.1%	2.8%	8.9%	1.0%	2.4%	1.7%	47.5%	0.0%	0.9%	1.3%	26.2%
Oil	0.8%	0.6%	0.6%	3.6%	3.0%	7.6%	0.8%	2.7%	1.9%	30.4%	0.2%	11.6%	4.2%	31.9%

Figure E2: MMS Gulf Coast Repair Database - Damage Type

Only 21.6% of the damages reported did not involve some leakage of product. This does not suggest that most damages leak. Instead, it probably indicates that leaking damages are most frequently reported, or that damages are not repaired until they leak. The relative frequencies obtained for leaking versus non-leaking damages should only be used as a qualifier on the damage statistics and not as a reflection on general pipeline integrity.

The damage-cause statistics indicate that the most significant cause is corrosion (Figure E1). Corrosion is more than twice as likely to cause a repair as any other form of damage and it represents roughly half of the damage incidents. The next most significant group of damage causes are: (a) Structural Damage; (b) Natural Hazards; and (c) Impact. All of these damage causes are related to factors such as weather and third party activities. Because these factors differ considerably for the Liberty Pipeline (compared to the pipelines in the database), these damage statistics must be interpreted with care.

The damage-type statistics indicate that the most likely form of damage is a pinhole (Figure E2). This is consistent with the results in Figure E1 that indicate that most damage is associated with corrosion. However, pinhole leaks are also frequently found on longitudinal weld seams, particularly Electric Resistance Welded (ERW) pipe seam welds, so the pinhole leaks are likely a combination of corrosion failures and seam weld leaks. If the “pinhole” and the “thin pipe wall” damage types are grouped, they represent 50% of all damages noted with corrosion as a damage cause.

The next most significant form of damage is a pipeline being pulled apart. It is presumed that this form of damage may be associated with anchor dragging or severe pipe dislocation events.

Table E1 illustrates the relationship between damage types and causes. The most frequent cause of damage is corrosion resulting in pinhole leaks, followed by natural hazards and impact damage causes.

Table E1: Failure Frequency Matrix of Damage Type and Cause (all values in %)

	Anchor	Constr-uction	Corrosion	Erosion	Fire/ Explosion	Impact	Mat’l	Nat. Hazard	Struct.	Unclear	Total
Gash	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.1	0.5
Crush	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.7
Dent	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.8
Kink	0.2	0.1	0.0	0.0	0.0	1.4	0.0	0.2	0.1	0.1	2.1
Plug	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0
Pull Apart	0.2	0.0	0.0	0.0	0.0	0.9	0.0	3.2	0.2	0.0	4.5
Pull Up	0.1	0.0	0.0	0.0	0.0	0.4	0.0	0.1	0.0	0.1	0.8
Rupture	0.1	0.0	0.5	0.0	0.0	0.4	0.2	0.1	0.1	0.2	1.5
Twist/bend	0.2	0.0	0.0	0.0	0.0	0.4	0.0	1.6	0.0	0.0	2.3
Pinhole	0.0	0.0	35.1	0.4	0.0	0.4	0.8	0.2	0.8	1.4	39.1
Riser Bend	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.3
Thin Wall	0.0	0.0	14.1	0.0	0.0	0.0	0.1	0.0	0.0	0.1	14.4
Valve	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.0	1.3	0.2	1.9
Unclear	0.1	0.1	0.7	0.0	0.1	0.7	0.9	1.1	0.5	25.9	30.1
Total	1.1	0.3	50.5	0.5	0.1	6.6	2.1	6.6	3.0	29.2	100

As the technology available to a pipeline operator to prevent corrosion, to reduce its growth or to detect it and deal with it, has improved over time, one would expect that the rate of corrosion-induced damage would decrease over time. However, the data indicate the opposite trend as the rate of corrosion damage is increasing with time (Figure E3). This could also be an indication that corrosion failures are being reported more frequently in recent years.

The rate of corrosion-induced damage has been increasing more quickly than the number of pipelines in service. One might interpret this to mean that corrosion control technology does not seem to be having the expected effect (in terms of reducing pipeline risk). However, more detailed analyses are required before definitive statements can be made. For example, corrosion is a time-dependent process, as it increases over the life of the pipeline, and it is not clear if this effect is fully reflected in the damage statistics. Other factors that need to be accounted for are variations in the diameters and lengths of the pipelines.

Consequently, the implication for this project is that the database is inadequate to define clearly whether or not the improvements to date in corrosion control technology will translate into reduced risk for the Liberty Pipeline.

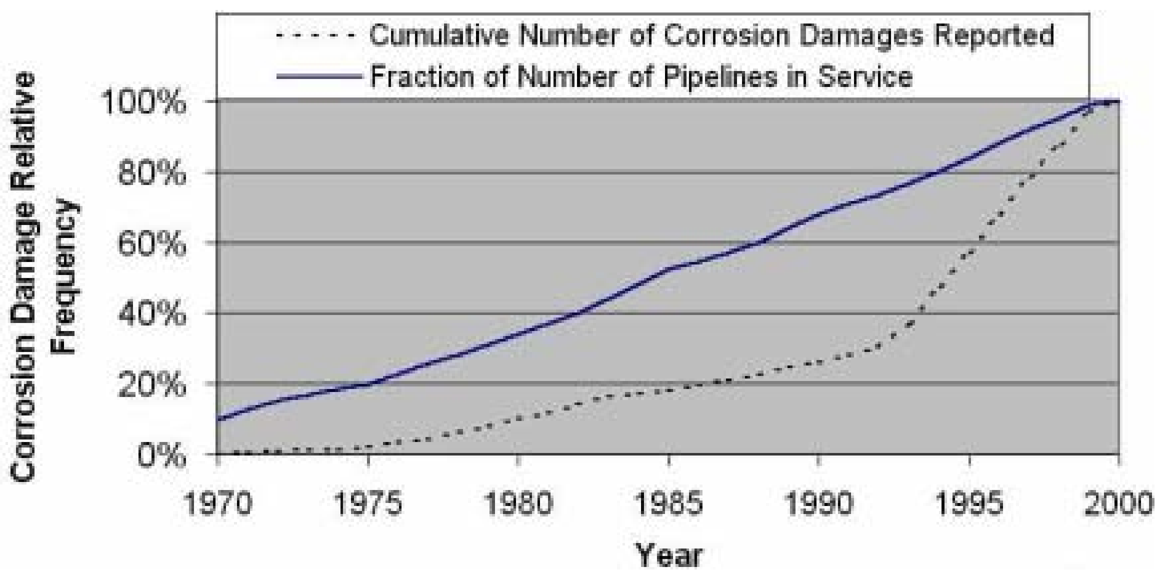


Figure E3: Corrosion-Induced Damage: MMS Gulf Coast Database

To develop failure rate data, the information describing the pipeline configurations needed to be reviewed. Typically, pipeline failure rate data is expressed in failures per unit length of the pipeline per unit time of service (failures / 1000 km / year). To develop this statistic, the length and duration of service of each pipeline needs to be known, however, the database includes some records for which no data is present, as well, several data entry anomalies were noted (i.e., dates with years 1929 or 2020).

The anomalies were corrected based on best judgement. In the estimation of the service life, it was assumed that service commencement coincided with the issue of a permit, while the end of service was associated with the current date if the line is still active or the date of last inspection/review if the line is inactive. In addition, it was assumed that the length of the pipelines, for which no length data was provided, was the average (4.35 km) length of all of the other pipelines. Based on the data reduction and the above assumptions, it was estimated that the pipeline repair database represents 718,000 km years of pipeline operational experience. By applying this result to the failure observation data the failure rates described in Table E2 are estimated.

The information contained in the MMS database has been used in many studies, such as the one by Bynum (1983), who undertook a study to establish considerations for minimising leaks in offshore pipelines. Bynum used MMS data for the years 1964 to 1981 in the outer continental shelf (OCS) of the Gulf of Mexico, a period in which there were 30 major spill incidents (>238 bbl) from all sources. The total volume of oil released was 335,851 bbl; this includes one spill of 160,639 bbl, and another of 83,895 bbl (this last one does not appear in other tables given in E3. The tables provided by Bynum are not complete in that they take subsets of the complete information. For example, the spills of 50 bbl or more in the period from 1967 to 1976 (Table E3) show that external impact accounts for the greatest volume of spilled oil, while corrosion accounted for only a single incident of 5000 bbl.

Table E2: Failure Rate (Failures / 1000 km / year) Matrix of Damage Type and Cause

	Anchor	Constr-uction	Cor-rosion	Erosion	Fire/ Explosion	Impact	Mat'l	Nat. Hazard	Struct.	Unclear	Total
Gash	0.0014	0.0014	0.0000	0.0000	0.0000	0.0167	0.0000	0.0014	0.0000	0.0028	0.0237
Crush	0.0014	0.0000	0.0000	0.0000	0.0000	0.0306	0.0000	0.0000	0.0000	0.0000	0.0320
Dent	0.0014	0.0000	0.0014	0.0000	0.0000	0.0348	0.0014	0.0000	0.0000	0.0000	0.0390
Kink	0.0111	0.0028	0.0000	0.0000	0.0000	0.0668	0.0000	0.0084	0.0028	0.0042	0.0960
Plug	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0000	0.0000	0.0473	0.0487
Pull Apart	0.0084	0.0000	0.0000	0.0000	0.0000	0.0432	0.0000	0.1476	0.0084	0.0014	0.2088
Pull Up	0.0070	0.0014	0.0000	0.0000	0.0000	0.0167	0.0000	0.0070	0.0014	0.0028	0.0362
Rupture	0.0042	0.0000	0.0223	0.0000	0.0014	0.0195	0.0084	0.0028	0.0028	0.0084	0.0696
Twist/Bend	0.0097	0.0014	0.0000	0.0000	0.0000	0.0195	0.0000	0.0752	0.0000	0.0014	0.1072
Pinhole	0.0000	0.0014	1.6370	0.0209	0.0000	0.0181	0.0362	0.0097	0.0390	0.0640	1.8263
Riser Bend	0.0014	0.0000	0.0000	0.0000	0.0000	0.0056	0.0000	0.0028	0.0000	0.0056	0.0153
Thin Wall	0.0014	0.0000	0.6598	0.0014	0.0000	0.0014	0.0042	0.0000	0.0014	0.0042	0.6737
Valve	0.0014	0.0014	0.0056	0.0000	0.0000	0.0070	0.0042	0.0000	0.0599	0.0097	0.0891
Unclear	0.0042	0.0042	0.0306	0.0000	0.0056	0.0306	0.0432	0.0515	0.0237	1.2110	1.4045
Total	0.0529	0.0139	2.3566	0.0223	0.0070	0.3104	0.0988	0.3062	0.1392	1.3628	4.6701

Table E3: Analysis of oil spills > 50 bbl in U.S. offshore pipelines, from Bynum

Cause of Leak or Break	Volume Spilled , thousands of bbls										Cumulative	
	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	Volume	No.
External Impact	161	6		25	.08			20			211,652	6
Corrosion							5				5,000	1
Equipment Malfunction			.1			3.8					3,900	2
Severe Weather								2.2			2,213	1
Unknown	.07		8.8	.07	5.8	.1				.4	15,243	12
TOTALS	161	6	9	25	6	4	5	22	0	.4	238,008	22

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An indication of the damage caused by external impact is provided by Bynum, 1983 and shown in Table E4. One can see that pipeline failures account for the majority of spills and the greatest product loss, almost 60 % of the total in the 5-year period. This number is expected to vary with different sample periods, but it is instructive in that it shows that the external damage with greatest consequence is a result of contact with the pipe.

Table E4: Spill Summary for More Than 50 Bbl, 1971-75 in OCS Gulf of Mexico

Cause	No. of spills	Total Volume, bbl
Pipeline leaks and ruptures	7	27396
Production platform equipment malfunction or misuse	6	10925
Drilling and workover mishaps	0	0
Barge spill	2	7100
Workboat spillage during transfer or collision	3	506
Other	2	320
Total	20	46247

Bynum, 1983 also looked at the spills in the category of failures of less than 50 bbl, and showed the following information:

Table E5: Oil Spills of 1-50 Bbl From 1971-75 for Gulf of Mexico OCS

Cause	No. of Spills	Volume, bbl Total	Average
Pipeline and Pump Failure:			
• Pipeline leaked	63	303.5	4.82
• Pipeline ruptured	20	161	8.05
• Discharge of transfer line ruptured or coupling failed	54	237	4.39
• Pipeline pump failed	42	211	5.02
• Pig trap leaked	12	35	2.92
• Pressure sensor failed	3	18	6.0
• Fuel line leaked	2	3	1.50
• Pump capacity exceeded	1	2	2.0
• Miscellaneous	39	152	3.9
Total	236	1122.5	4.76
Production platform equipment malfunction or misuse	536	2286	4.26
Drilling or makeover mishaps	20	64.5	3.23
Misc. equipment failure and employee errors	84	440	5.24
Total	876	3913	4.47

Pipeline spills as % of total no. of spills	=	9.5%
Pipeline spill vol. as % of total spill vol.	=	11.9%
Quantity/pipeline spill, average/spill	=	5.6 bbl
Quantity spilled from pipelines, average/yr	=	93 bbl

In the examples given for the spills of less than 50 bbl, pipeline failures continue to represent the greatest single category of failures, both in number of incidents and total volumes.

The review by Bynum, 1983, included information of spill statistics from both onshore and offshore pipelines in the U.S. between 1968-1976. The information in Table E6 shows external impacts, or third party damage as the greatest source of leaks, followed by construction and material defects, and then external corrosion. This difference represents a possible shift in the importance of the damage categories between offshore and onshore pipelines and their related failure statistics.

Table E6: Statistics for Spills from Both Onshore and Offshore Pipelines in the U.S. between 1968-1976

Cause	Avg. Volume/spill, bbl	% of total volume
External corrosion	468	12.3
Internal corrosion	562	3.2
Operational causes(1)	1662	9.6
Equipment malfunction or failures(2)	1076	3.9
Severe weather(3)	1697	3.1
Construction defects(4) or material defects(5)	1904	24.3
External impacts(6)	1038	30.3
Miscellaneous and unknown	2493	13.3
Total	1241	100

Notes:

(1) Incorrect operation by carrier personnel, surge of electricity, and surge of flow.

(2) Malfunction of control or relief equipment, malfunction of valve, pump failure, pump packing failure, and tank roof drain leaking.

(3) Heavy rains or floods, cold weather, lightning, and landslides.

(4) Defective girth weld, failure of previously repaired welded repairs, and defective weld.

(5) Defective pipe seam, failure in river crossing, ruptured or leaking gasket, threads stripped or broken, pipe failed due to buckling, ruptured or leaking seal, pipe coupling failure, defective pipe, stress crack, and wrinkle bend split.

(6) Equipment rupturing line, rupture of previously damaged pipe, freight train derailment, vandalism.

E3.0 DEPARTMENT OF TRANSPORTATION STATISTICS

Diane Hovey and Ed Farmer of EFA Technologies Inc. have published several papers over the years related to accident statistics between 1982 and 1991 that were available from the US DOT Office of Pipeline Safety. This 10-year window spanned the time over which various safety programs had been implemented in an effort to reduce the number of pipeline incidents. The statistics provided in the data include a category for failure expressed in terms of failures/1000 miles/yr, which was obtained by dividing the total number of failures in each category by the total number of failures in the study group. This was not a terribly difficult task as the length of pipeline did not change much over 10 years, due to retiring some lines and putting new lines into service.

The failures in Table E7 show that outside force remains the greatest cause of failures, followed closely by corrosion, and then all of the other causes are 6% of the total or less. The expected number of failures from all causes is 0,888 failures/1000 miles/yr; this can be used to compare other failure statistics summarized in a similar manner. FTL has added the right hand column to provided information on failure statistics for use in the body of the report.

The costs for pipeline accidents were also collected by Hovey and Farmer (1992), using 1991 dollars. They note that there was a substantial trend toward increasing property damage cost per accident towards the end of the study period.

Table E7: DOT Failure Statistics (from Hovey and Farmer, 1993)

Cause	Total Accidents	%of 10 year Total	1986 to 1991 statistics		Failures/ 1000 miles/year	No. of Failures/ 7.5 miles/ year
			total	% of total		
Outside Force	581	31			0.271	0.0020325
Damage by others			265	73	0.206	0.001545
Damage by operator			43	12	0.033	0.0002475
Natural forces			20	6	0.016	0.00012
Other outside force			18	5	0.014	0.000105
Ship Anchor			4	1	0.003	0.0000225
Washout			3	1	0.002	0.000015
Landslide			2	0.5	0.002	0.000015
Subsidence			2	0.5	0.002	0.000015
Frost heave			2	0.5	0.002	0.000015
Fishing operations			2	0.5	0.002	0.000015
Earthquake			0	0	0	0
Mudslide			0	0	0	0
Corrosion	523	27			0.244	0.00183
Other	496	26			0.232	0.00174
Operator Error	107	6			0.050	0.000375
Pipe Defect	98	5			0.046	0.000345
Weld Defect	54	3			0.025	0.0001875
Relief Equipment	42	2			0.020	0.00015
Totals	1901	100			0.888	0.00666

Hovey and Farmer, 1992's review of failure statistics led them to conclude that there had not been any statistically significant trends in either the accident frequency or the spill volumes over the 10-year study period. If these conclusions can be shown to be valid to the present time, one can use their statistics to predict failures on the Liberty system.

E4.0 WESTERN EUROPEAN PIPELINE 25-YEAR PERFORMANCE STATISTICS

The data collected and reported in the summary report (Concawe, 1998**)** includes twenty-five years (1971 to 1995) of event data for oil pipelines (longer than 2 km) throughout Western Europe excluding under-sea pipelines. The database includes all spills greater than $1m^3$ as opposed to the 100 barrel ($15m^3$) spill threshold used in the USA. The following statements can be made in regard to the current study:

(a) the database includes 341 spill events over the 25-year period;
(b) over the 25-year period, only 8 spills were caused by malicious damage by a third party and account for roughly 5% of the total volume of spills;
(c) the frequency of spillage events has been reduced from 1.2 per year to about 0.4 over the 25-year period. This is not the case for heated oil pipelines that have a much higher spill rate due to corrosion (Table E8).
(d) an annual breakdown in spillage frequency by cause (third party, natural hazard, corrosion, operational, and mechanical failure as described in Table E9;
(e) less than 5% of all spills (16) were the cause of 50% of the spilled volumes. If the spill rate is reported in terms of spills in excess of 100 barrels the spill statistics change from 341 (0.65 spills per year per 1000 km) over the 25-year period to 199 (0.38 spills per 1000 km) spills in the same time period;
(f) spill detection method is reported for pipelines and it is found that 45% of the spills were detected by a third party while pipeline instrumentation was only involved in 26% of the spill detection events. This data suggests either that electronic leak detection is not widely used or that it is ineffective. The most recent data (1998) has been added for comparison with the 25-year data set (see Table E10).

Table E8: Spill Frequencies Over a 25-Year Period

	All Causes	Corrosion		
		All	Cold Oil	Heated Oil
25 y Avg. Pipeline Length (1000 km)	20.83	20.83	20.24	0.59
Number of Spills	341	102	52	50
Spills Per Year	13.64	4.08	2.08	2.0
Spills / y / 1000 km	0.65	0.2	0.01	3.39

Pipeline failure statistics from Western Europe (Concawe, 1998) from 1971 to 1987 were reviewed to determine if their failure histories were similar to those observed in the U.S. experience. The data is collected by the Concawe Oil Pipelines Management Group, and includes onshore crude oil and petroleum products pipelines, but does not include pipelines from offshore production facilities or tanker unloading facilities. The Concawe database covers approximately 19,000 miles, less than 1/10th of the length of the lines in the U.S. reports, so they cannot be compared directly by the numbers of incidents. However, we can use the number of incidents/1000 miles as a benchmark for comparison.

Table E9: Breakdown of Failures by Cause

General Cause	Detailed Cause	Number	% of Total
Third Party	Accidental Malicious Incidental	86 8 18	25 2 5
Natural Hazard	Land Slide / Subsidence Flooding Other	10 2 2	3 1 1
Corrosion	Internal External	18 84	5 25
Operational	System Human	10 15	3 4
Mechanical	Construction Materials	32 56	9 16

Table E10: Summary of How Leaks Have Been Detected

	25Year Data			1998 Data		
	Number of Spills	% of Total	Average Gross Spill (m^3)	Number of Spills	% of Total	Average Gross Spill (m^3)
Right of way survey by pipeline staff	26	9	254	2	22	22.5
Automatic Detection System	18	6	215			
Third Party	133	45	119	3	33	83.5
Routine Monitoring By Pipeline Staff	59	20	392	3	33	334
Pressure Testing	20	7	136			
Contractor working for Pipeline Company	5	2	482			
Pipeline Maintenance Staff	14	5	58	1	11	30
Third Party Worker	17	6	128			
Pipeline Internal Inspection	3	1	6			
Total	295[a]	100	195	9	100	147.5

(a) The remainder of the 341 spills occurred at the pump stations

The Concawe results include 341 spills over a 25-year period, 13.64 spills/yr., or 0.717 spills/1000 miles/yr. The U.S. total spill frequency is slightly higher at 0.888 spills/1000 miles/yr. While the U.S. data remained fairly constant over the 10-year period, the Concawe results started at 1.93 spills/1000 miles/yr. and decreased to 0.64 spills/1000 miles/yr. In all fairness to the U.S. information, the Concawe failures came down quickly between 1971 and 1981, remained constant over the 1982 to 1991 period (same time frame as Hovey results), and then came down slightly in the last 4 years. Therefore, the failure rates are comparable even though the Concawe study does not include offshore lines. The Concawe report includes appendices which give the lengths of lines in each age category, and provides details of each of the spills such as the cause, the pipe diameter, how the leak was located, and total volumes of spills.

Pipelines in the Concawe study group continue to show an improvement in spill statistics, for in 1998 the failure occurrences were 0.47 spills/1000 miles/yr. (Concawe, 1999).

The Concawe 25-year summary report includes an appendix that lists all of the failures, enabling one to obtain the following statistics:

Table E11: Spill Cause Categories for Concawe Results

Failure Cause	Total Volume m^3	No.	Avg. volume m^3	% of total volume
Mechanical failure	140	6	23.3	0.23
Construction fault	7520	26	289.23	12.43
Materials fault	13498	56	241.04	22.31
Operational				
System malfunction	433	10	43.3	0.72
Human error	1399	15	93.27	2.31
Corrosion				
External corrosion	7353	87	84.52	12.15
Internal corrosion	3751	18	208.39	6.20
Natural hazard				
Landslide/subsidence	1553	12	129.42	2.57
Flooding	625	2	312.5	1.03
Other	630	2	315	1.04
Third party activity				
Direct damage-accidental	14623	85	172.04	24.17
Direct damage-malicious	2481	8	30.13	4.10
Incidental damage	6493	18	360.72	10.73
TOTAL	60499	345	175.36	100.00

This exercise was completed primarily to separate the numbers of external and internal corrosion defects; the results show that failures from external corrosion occur 5 times more frequently than failures due to internal corrosion.

E5.0 NORTH SEA EXPERIENCE

The reviewed literature includes data for 137 pipelines in the North Sea over an 18-year period. The objective of this paper (de la Mare, et al, 1993) was to demonstrate a means of predicting the probability of pipeline failure based on its characteristics as opposed to simply its length. The data upon which the results are based includes the failure event data presented in the table below.

Table E12: North Sea Failure Incidents

Cause	Near Platform	Open Sea	Near Shore
Material	1	3	0
Construction	3	10	0
Corrosion	4	0	0
Anchors	5	7	0
Fishing Activity	0	1	0
Scour-Vortex	4	4	2
Manufacturer	1	0	0
Constructor’s Equipment	2	2	0
Total	20	27	2

The characteristics of the pipeline system which are assumed to affect the probability of failure include: diameter, wall thickness, concrete cover, duration of service, steel quality, length, operating pressure. The sensitivity of the failure probability to changes in each of these characteristics is described in the table below:

Table E13: Failure Probability Sensitivities

Characteristic	Change to Increase Probability of Failure	Pf Coefficient
Length	Increase	1.3 / km
Wall Thickness	Decrease	-4.7 / in
Concrete Thickness	Increase	0.39 / cm
Duration of Service*	Decrease	-0.11 / y
Steel Quality	Increase	0.26 / API quality level
Diameter	Increase	0.02 / in
Operating Pressure	Increase	0.003 / bar

* the longer a pipeline had been in service the lower its probability of failure

The most important factors influencing the probability of pipeline failure are length, wall thickness, concrete cover, and duration of service.

E6.0 DISCUSSION AND CONCLUSIONS

Failure statistics from several sources have been reviewed to determine the most common causes of pipeline failures and to establish the probabilities of failures that would be expected for the Liberty Pipeline over its lifetime. There were some differences amongst the failure summaries that are indicative of the types of pipelines included in the data set, and it was necessary to make a judgement as to what would best apply to the Liberty Pipeline. For example, the MMS failure statistics show that the majority of failures are attributable to corrosion. With current technology being able to provide coatings that can provide protection, and the fact that Liberty will utilise internal inspection tools to monitor corrosion, failures due to corrosion are not expected to be a problem. This leads us to mechanical damage as the most likely failure cause for buried pipelines, which is consistent with the statistics from both the DOT and Concawe.

One of the limitations of the data is that it is not possible to determine the age of the pipelines at the time of failure, and thus one has to take this variable out of the predictions. The time issue is important mainly for the corrosion failure statistics as this is the main time dependent mechanism that can lead to failure.

Notwithstanding the limitations inherent in the data, we were able to utilise the statistics and determine failure probabilities that can be used for subsequent consequence modelling.

E7.0 REFERENCES

[1] D. Bynum, Jr., 1983, Minimise Marine Pipeline Oil Spill, MMS Contract No. 14-12-0001-30116, 22 June 1983.

[2] Hovey, D.J., and Farmer, E.J., 1992, Trends in the Incidence and Cost of Liquid Pipeline Accidents from 1982 to 1991, EFA Technologies, Sacramento, CA, July 1992.

[3] Hovey, D.J., and Farmer, E.J., 1993, Pipeline Accident, Failure Probability Determined Form Historical Data, Oil & Gas Journal, July 12, 1993, pp 104-107.

[4] Concawe, 1998, Western European Cross-Country Oil Pipelines 25-Year Performance Statistics, Report No. 2/98, Concawe, Brussels, June 1998.

[5] Concawe, 1999, Performance Of Cross-Country Oil Pipelines In Western Europe, Statistical Summary Of Reported Spillages – 1998, Report No. 3/99, Concawe, Brussels, November 1999.

[6] US Army Corps of Engineers, 1999, Final Environmental Impact Statement Beaufort Oil and Gas Development/Northstar Project.

[7] de la Mare, R.F., Bakouros, Y.L., and Tagaras, G., 1993, Understanding Pipeline Failures Using Discriminant Analysis: the North Sea Application, Reliability Engineering and System Safety 39, pp. 71-80.

APPENDIX F

COMMENTS RECEIVED REGARDING FTL's DRAFT FINAL REPORT

CONTENTS

F1.0 COMMENTS RECEIVED BY SOURCE

This appendix lists the comments received. Responses to these comments are provided in Appendix G. Comments were received from the following organizations:

(a) Dennis Hinnah of the MMS – letter dated August 21, 2000 – see section F2.0
(b) Larry Bright of the US Fish and Wildlife Service – memorandum dated August 21, 2000 – see section F3.0
(c) Peter Hanley of BP Exploration – letter dated August 16, 2000 – see section F4.0
(d) Mike Paulin of Intec Engineering – letter dated August 30, 2000 – see section F5.0
(e) The MMS through a conference call held on Sept. 5, 2000 – see section F6.0

The following sections provide responses to each comment from each source. The comment numbers in the left column have been assigned by FTL as an aid in preparing the responses. The first letter from Dennis Hinnah on 21 August has been assigned the prefix MMS(1); responses from Larry Bright are prefixed with FW; the responses to Peter Hanley begin with BP; Intec is used to identify the Mike Paulin comments; and comments from the second letter from Dennis Hinnah on 5 Sept begin with MMS(2).

F2.0 COMMENTS FROM DENNIS HINNAH OF THE MMS

Comment Number	Comment
Preamble	The Minerals Management Service (MMS) has reviewed your draft report "Independent Risk Evaluation for the Liberty Pipeline" dated July 2000. The conclusions reached appear to generally confirm the work that has been done by INTEC Engineering. That is, that all four of the pipeline designs have very low risks of failure, with steel pipe-in-pipe having the lowest relative risk of leaking oil. The MMS appreciates the efforts you have made in attempting to accurately describe the risks, especially considering that there is very limited historical data and its applicability to the Liberty Project is questionable.
MMS(1) – 1	Terms such as risk, risk analysis, risk evaluation, risk sources, hazard sources, frequency of occurrence, etc. need to be defined and used consistently throughout the report.
MMS(1) – 2	Enclosure 1 is a study by Hart Crowser Inc. (2000). Estimation of Oil Spill Risk from Alaska North Slope, Trans-Alaska Pipeline and Arctic Canada Data Sets. MMS has concerns about using the statistics in the Hart Crowser report. However, the report confirms there have been 9 TAPS spills ≥ 100 barrels from 1977 to December 1999. Review this report and update your failure summaries in section 3.9.2(c).
MMS(1) – 3	Please recalculate the number of spills based on the 9 TAPS spills ≥ 100 barrels. You should consider dropping any average spill volumes or spill rates for TAPS spills <100 barrels. The data in table 3.6 is not accurate without obtaining information directly from Alaska Department of Environmental Conservation. Even then the reliability of the data is questionable at best.
MMS(1) – 4	In section 3.93 the pipeline mile/years need to be weighted. They should be (19X800) + (15X540) not 34X1340. There are 10 spills (9 Alyeska and 1 Norman Wells) and 23,300 mile/years. The occurrence rate is 0.0004291 spills/mile/year.
MMS(1) - 5	In section 7.5.3, section (b), clarify how 0.01065 occurrences was derived from Table E-5 in Appendix A. If this number was derived from Table E-5 these occurrence rates are only applicable to spills of 1-50 barrels.

MMS(1) – 6	In section E.4, unless the spill size cut off is the same for both the CONCAWE and the U.S. databases then you can't compare failure rates, even if you set the pipeline mile variable the same. The previous section E.3.0 did not discuss the size parameters for the Hovey and Farmer data so it is impossible to know if their database reporting criteria is $1m^3$. See page 13 of the CONCAWE report, section 4.2.2.
MMS(1) – 7	Make narrative changes to reduce jargon and make the document more readable for the general public. This is probably most important for the executive summary which will probably be used in it's entirety in the Liberty Project Environmental Impact Statement. For example, the difference between total risk of single steel pipe and steel pipe-in-pipe needs to be explained in terms the public can relate to.
MMS(1) – 8	Please add the following statement near the beginning of the report. "The opinions, findings, conclusions, or recommendations expressed in this report or product are those of Fleet Technology Limited and do not necessarily reflect the views of the U.S. Department of the Interior. "
MMS(1) – 9	Provide some narrative on how the findings of your study compared to the findings of the INTEC study. Where do they agree, disagree, and why are they different, if known.
MMS(1) – 10	The report warrants further discussion on the absolute risk of any of the pipeline designs.
MMS(1) – 11	Operational failures are primarily caused by over pressuring the pipeline, leading to a rupture. The greatest pressure source in the Liberty pipeline system is about 5,000 psi. This is well below the minimum rupture pressure of either the single or pipe-in-pipe steel pipelines. The ANSI Class #600 valves on the ends of the pipeline appear to have the lowest burst pressure in both steel pipeline systems. Providing scenarios that could lead to operational failure would be helpful for readers to understand this concept. Also, for the steel pipe-in-pipe design, it would be helpful to provide some likely scenarios that don't fail the valve bodies, yet fail the inner pipe and not the outer pipe. How can we be so sure of the integrity of the outer pipe considering the inability to use inline inspections tools?
MMS(1) – 12	Third-party failures are due to an outside force acting upon the pipeline. How does burial depth effect this for each design? Again, some example scenarios specific to the Liberty Pipeline of this type of failure would be helpful.
MMS(1) – 13	Are there changes that could be made to the single-wall design, such as increasing wall thickness, bury it deeper, etc. that would make it's risk equivalent to the steel pipe-in-pipe design?
MMS(1) – 14	Clarify the source of the data presented in tables 1, 2, 1.1, 1.2, etc. There is confusion as to whether the numbers were generated by INTEC or Fleet.

MMS(1) – 15	The validity and reliability of using the minimal historical design or practical field experience to make judgements about these conceptual designs needs further discussion.
MMS(1) – 16	The validity of the assumption that the secondary containment, of the steel pipe-in-pipe design, was always 100% available and reliable. Why was this same assumption not made about pipe-in-HDPE?
MMS(1) – 17	Does the steel pipe-in-pipe analysis include any risk of an oil spill during the process of trying to remove the oil from the annulus or does it assume that it can all be removed prior to repairs?
MMS(1) – 18	Can you elaborate upon the recommendation that a third party verify the finding that operational failures and third party activities are the most significant hazards?
MMS(1) – 19	It appears that because of the assumptions made about pipe-in-HDPE and flexible pipe, these two designs didn't get an equitable evaluation.
MMS(1) – 20	Page E-1 makes reference to a personal communication with MMS. Appendix E also references the Gulf Coast MMS Repair database. Please provide complete references.
MMS(1) – 21	As you suggested and working within the scope of the contract, please provide some cost-benefit analysis for each of the alternatives.
Closing	Also comments from BP Exploration (Alaska) Inc. are enclosed (Enclosure 2). They asked that the MMS allow direct communications between INTEC Engineering and Fleet Technology Ltd. The MMS has granted this request by letter to Peter Hanley, BPXA, dated 8/17/00, which was carbon copied to you. I expect comments from other agencies, but have not received any yet. I will forward agencies comments to you as soon as I get them. Please consider them to be an enclosure to this letter. Timely consideration to all of these comments is of utmost importance to the MMS.

F3.0 COMMENTS RECEIVED FROM LARRY BRIGHT OF THE US FISHAND WILDLIFE SERVICE

Comment Number	Comment
General Comments	Fleet Technology Limited (FTL) and the Minerals Management Service (MMS) are to be commended for a significant body of work on the relative risks of pipeline designs being considered for the Liberty project. This is difficult, technical work with the understanding of numerous assumptions very important to the interpretation of results. It is apparent that a great deal of work has gone into the presented results, however, more effort is needed to describe and explain these results. In general, the report presents significant results and conclusions, but fails to adequately explain and discuss those results in terms that are meaningful to decision makers and the public. The results should also be supported with sufficient analytical details within the report so that they can be verified in a meaningful way. The report needs to more effectively tie together data (or the assumptions made if data is lacking), results, and conclusions. Confidence intervals are needed throughout the analysis. It is very difficult to understand the relative confidence of risk figures associated with given hazards when event probabilities, the effectiveness of leak detection, and other factors are provided without a range of confidence. As an example, confidence may be relatively high with regard to spill volume (the probability of a spill volume occurring is much higher that of the other volumes), but low with regard to event probability (the probability of the given hazard leading to failure). If this is not clear, false conclusions are easily reached or the benefits/weaknesses of given designs can be masked. A greater focus needs to be placed on the consequences of failures associated with the identified hazards, the distribution or probability of those consequences (e.g., what are the probabilities associated with 1, 10, 100, and 1000 barrel spills as a result of operator error?), and then the probabilities of specific hazard events. By evaluating the consequences of hazards separately, before combining them into a single risk value, decision makers will be able to more readily identify the relative strengths and weakness of designs with regard to the hazards of greatest concern. More specific recommendations regarding this issue are found below associated with Chapter 8.

General Comments cont...	It should be made clear, in the Executive Summary and the Introduction, that the study is addressing the relative risk of seven pipeline designs, of which only one has been optimized (the steel single-walled design) for the given application. Optimization almost certainly would reduce risk associated with the two double-walled designs further, but have less of an impact on the risk figures associated with the manufactured flexible pipe. In some cases, FTL may be too generous when accepting Intec's assumptions regarding corrosion rates, the time that will elapse between leak detection and operator action, and most importantly, the dependability of leak detection systems. FTL should review assumptions related to the dependability of LEOS and include an analysis of other low-level leak detection systems, particularly through-the-ice sampling.
FW – 1	Pages ii - v, Executive Summary. These pages simply present findings and recommendations for future study. The Executive Summary should include a clear explanation of what was analyzed (including a description of the seven pipeline designs under review), a simple discussion of how the work was accomplished (methods, and degree of approximations and assumptions), and a more thorough discussion of the significance of the findings (including confidence intervals). In general, the reader has little chance of understanding the Executive Summary without reading the entire report. Elements of the Executive Summary that need further elaboration include:

FW – 2	- A thorough explanation of the term “risk” is needed, particularly in terms of barrels of oil expected to be released over the life of the pipeline. This term can be very misleading without emphasizing that risk figures are ultimately the product of a long string of calculations and assumptions, many of them using best engineering judgement (rather than detailed analysis), to produce a single number. Due to the dependence upon assumptions and the lack of hard data in the arctic, these figures are more relative than absolute. They are helpful, however, in comparing different pipelines used in similar circumstances and different designs proposed for the same application. Risk, as defined in this study, is derived by multiplying the volume of oil that would be expected to be released in a given event, times the probability of that event occurring. With any reasonably designed pipeline, event probabilities will be very small, which provides a risk figure (in barrels of oil) that is very small. However, if any one, significant event occurs, such as a weld crack, pipeline rupture or a small leak that goes undetected for several weeks or months, the actual spill volume will be much higher than the predicted risk. This discussion should provide the reader with estimates of expected spill volumes for given events as a means to illustrate the difference between risk and what to actually expect should a failure occur. The probability of the expected spill volume would also be informative here.
FW – 3	- It appears that all third party failures are included in the analysis, but the reader finds out later in the report that this is not the case. The third party activities which are considered in the analysis should be described in the Executive Summary. Third party induced failures would appear to be few in the arctic. An explanation should be provided regarding why third party failures are considered more significant than environmental hazards (ice gouging, etc.).
FW – 4	- Paragraph (b) under Uncertainties on page iv appears to discredit all findings regarding secondary containment. If included, this paragraph needs thorough explanation. The assumptions used to define the performance of secondary containment (Chapter 7) are relatively straightforward and within reason. It is unclear why these assumptions make the evaluation of secondary containment any less definitive than other elements of the analysis that are also based on numerous assumptions.
FW – 5	- The recommendations need clarification. The last paragraph is particularly confusing. It appears to be making a statement about pipeline design and construction, when the first several paragraphs focus on future study/evaluation.

FW – 6	- The combination of uncertainties and recommendations that focus on future study leave the reader concerned about the significance of the study. The findings appear to be qualified to such an extent that a simple conclusion could be that the study was rendered meaningless due to the lack of real data. We do not believe this to be the case, but if it is, the authors need to say it more definitively.
FW – 7	Page 1-1, Tables 1.1 and 1.2. The risks figures in these tables do not appear to be in barrels of oil, as labeled. Explain why the risk figure for single-wall pipe is different in Tables 1.1 and 1.2 if that design did not change between 1999 and 2000.
FW – 8	Page 1-3, paragraph 1.2(e). Mention should be made here that LEOS has never been used in subsea conditions and is considered a prototype for the Northstar project (see Northstar EIS).
FW – 9	Page 2-10, section 2.6.2. A reasonable approach would be to factor in the potential that LEOS will fail at Liberty, and the primary low-level leak detection system proposed for Northstar, through-the-ice sampling, is used in its place.
FW – 10	Page 2-11, last paragraph. Does the phrase Amore rational design basis refer to pipeline design or study design?
FW – 11	Page 3-5, third paragraph. Define a sub-gouge displacement exceedence probability. One of the cases analyzed in the report is for 4-feet of cover. Figure 3-4 should also contain this case. Is the case for 5-feet of cover analyzed? If so, show the results in Chapter 4.
FW – 12	Page 3-6, first 2 paragraphs. The uncertainty of the ice gouge displacement fields is very important, yet the assessment of this issue is not clear. Clearly explain what FTL did to address this issue, including a range of confidence in the data used.
FW – 13	Page 3-26, last paragraph. The last sentence of this paragraph, “this analysis indicates that there will be 0.0134 and 0.0349 spills of more than and less than 100 bbls” is not particularly enlightening. Explain the significance of these figures.
FW – 14	Page 3-27, Table 3.6. It is not clear how the projected occurrences illustrated in this table are used to determine risk. More explanation is needed here to explain how these figures are used and their significance.

FW – 15	Page 4-1, Chapter 4, Pipeline Response and Failure Criteria. The most significant problem with this chapter is an apparent disconnect between figures presented here and figures presented in Appendix C. According to the investigation conducted by Konuk and Fredj (2000) on the behavior of a buried pipeline exposed to ice gouge, the calculated strain for the inner pipe of the Intec 2000 pipe-in-pipe design was significantly less than the calculated strain for the steel single-wall pipe, given the equivalent ice gouge event. This would equate to approximately an order of magnitude advantage for pipe-in-pipe for the hazards of ice gouge and upheaval resistance, as compared to the single-walled design (I. Konuk, pers.comm.). The only information provided in Chapter 4 comparing predicted levels of strain between pipeline designs is Table 4.4. This table is hardly relevant, however, for it simply demonstrates equivalent strain on the outer pipes of the double-wall designs as compared to the single-wall design (inner pipe strain would be far more instructive). In Appendix C, Figure C10 provides inner and outer pipe strains associated with varying distances from the ice gouge center. The greatest strain observed, approximately .65%, was equivalent plastic strain on the outer pipe. This is an apparent contradiction to the equivalent strain figures provided in Table 4.4 of 8.29% and 10.00% (and 24.5% and 22% in Table 4.5) for the two outer pipes of the Intec 1999 and 2000 pipe-in-pipe designs. FTL needs to clearly illustrate their approach and reasoning in determining failure criteria for each design. Presenting a table similar to Table C2 with strain levels for each carrier pipe may be useful, as well as providing a Figure C10 for all cases. At a minimum, a graph is needed comparing predicted strain for the pipe-in-pipe and single-walled designs.
FW – 16	Page 4-2, Section 4.2.2. Several parts of the ice gouge and upheaval buckling failure scenarios were left out of the analysis, such as the occurrence of wrinkling, upheaval potential after ice gouging, and the progress of upheaval buckling after shut down and start-up cycles. It is quite possible that the scores for these failure modes are not necessarily conservative.
FW – 17	Page 4-6, Section 4.2.3(c). Paragraph (c) of this section states in a pipe-in-pipe design, due to the insulating effect of the annulus, the outer pipe will be cooler than the inner pipe. This advantage of a pipe-in-pipe system can only be quantified through a thermal analysis of the pipe configuration. It was ignored here (for simplicity and to be conservative) by assuming that the outer and inner pipes remain at the same temperature. Numerous unquantified assumptions have been made relative to other factors influencing the consequences and event probabilities of these analyses (e.g., leak detection system dependability). Temperature of the outer wall of a pipe-in-pipe system clearly is a major factor in structural response to soil displacement, and could be conservatively estimated for the purposes of this analysis.

FW – 18	Page 4-10, Section 4.3.2. After an effective discussion of the issues surrounding the local behaviour of pipe-in-pipe configurations in Section 4.3.1, this section fails to deliver any data (i.e., results and backup calculations or figures) that the reader can understand and/or compare with the structural behaviour of the other designs. Therefore, it is unclear whether FTL used any of the information in Table 4.5 to determine failure criteria for the pipe-in-pipe designs. This discussion needs to be expanded and Table 4.5 modified to provide a means to compare the data in the table with data relative to other designs. The cases identified in Table 4.5 should also be defined.
FW – 19	Page 4-11, Section 4.3.3 and Figure 4.4. This is an interesting and useful discussion, but once again, the strain values do not correspond with values provided in Table 4.2. These values are closer to the figures provided in Figure C10, but not equivalent. Please explain the discrepancies.
FW – 20	Page 4-12, Section 4.3.4, paragraph (c). This paragraph should clearly state the calculated structural response differences between pipe-in-pipe and the other designs, and explain how those differences were factored into the development of failure criteria. Please provide the actual scenarios and corresponding probabilities. It is not clear what conservative bound is being referenced, or how it is being used.
FW – 21	Pages 4-13 through 4-17. It is unclear why no detailed analysis was carried out for strudel scour, permafrost thaw subsidence, and upheaval buckling for each of the pipeline designs. In addition, these pages do not clearly identify the method used to determine failure criteria for each of these hazards. Apparently, one method was used to produce one risk value for all designs for thaw subsidence and upheaval buckling (Table 8.3). A different method was apparently used for strudel scour.
FW – 22	Page 5-1, Section 5.1, Internal Corrosion. Confidence intervals associated with the assumptions made here would help put the issue of internal corrosion in the proper context, as compared to other hazards being assessed.
FW – 23	Page 5-2, Section 5.2, External Corrosion. Different in-line-inspection (ILI) tools have apparently provided different results on the TAPS (Vieth et al. 1997). Are confidence levels available for current ILI tools and can we expect more consistent monitoring on Liberty?
FW – 24	Page 5-5, Section 5.4.1. FTL needs to defend the 10-fold decrease in failure frequency due to improved coating, and the 100-fold decrease due to comprehensive ILI. These figures need to be explained and supported with data and/or analysis versus simply stated. What data are being used to support these adjustments to existing failure statistics?

FW – 25	Page 5-7, Section 5.4.2. Damage frequencies presented here associated with steel pipe-in-pipe are higher than single-wall due to the assertion that the inner pipe cannot be cathodically protected, and thus corrosion is a higher risk. Stress (2000) pointed out that the inner pipe could be cathodically protected using either sacrificial plates or aluminum coatings. Furthermore, C-Core (2000) points out that by managing and monitoring the annulus, corrosion could be essentially eliminated within the annulus. It has been argued (C-Core 2000) that the existence of the annulus would decrease risk due to corrosion (as compared to single-wall pipe), instead of increasing it. In light of the C-Core analysis, acceptance of the Intec approach by FTL needs justification.
FW – 26	Pages 5-5 and 5-8, Tables 5.5 and 5.6. These tables are misleading. Damage frequencies for internal pipe corrosion are provided for single-wall and flexible pipe in the top row of these tables along with figures for external pipe corrosion (of the inner pipes) for the double-wall alternatives. These damage frequencies are not comparable and need to be separated in different rows of the tables. In addition, the damage frequency provided in Table 5.6 for the inner pipe of pipe-in-pipe is incorrect, according to the figure provided in Section 5.4.2.
FW – 27	Page 5-8, Section 5.5, Damage Frequency Summary. FTL has accepted Intec reasoning regarding the potential for corrosion with the inner pipe of the double-wall steel design. FTL should review their approach in light of the C-Core findings or at a minimum, note that there is a different approach to this issue as illustrated in the C-Core 2000 Report.
FW – 28	Page 6-1, Section 6.1, Leak Detection Systems. This section fails to consider and evaluate through-the-ice sampling as a leak detection system for Liberty. BPXA is required by permit condition to use through-the-ice sampling as the primary low-level leak detection system for Northstar while installing LEOS as a prototype system. Because LEOS has not been tested in an arctic subsea application and no other alternatives have surfaced, LEOS will continue to be viewed as a prototype if installed adjacent to the Liberty pipeline. This is a serious weakness in the approach FTL has taken with regard to leak detection and the potential size of spills due to seepage. If LEOS fails, and through-the-ice monitoring is the only low-level monitoring system used, the potential spill size would certainly increase. This is a very real scenario that has not been considered by FTL.

FW – 29	In addition to the lack of analysis of through-the-ice sampling, FTL appears to assume that all of the leak detection systems will be operational 100% of the time. All of the leak detection systems proposed for Liberty, with the exception of through-the-ice sampling, are complex, computer driven systems. It is not only possible, but likely that these systems will fail on occasion and require maintenance regularly. A reasonable estimate of down-time for these systems and the associated risk should be an integral element of this analysis. The expected spill volumes that are tempered by the existence of monitoring systems can hardly be viewed as conservative without this type of analysis.
FW – 30	Page 6.2, first paragraph. What is the minimum spill rate for MBLPC? The discussion of mass balance technology detecting a 225-barrel leak is confusing. The spill rate at which leak detection would occur would be helpful here.
FW – 31	Page 6-12, Section 6.3.3, LEOS System for Northstar. This discussion is inadequate because it fails, in any quantitative fashion, to estimate the likelihood of LEOS failing in an arctic subsea environment. The statement ...they (Intec) made significant efforts to develop a sound, safe design that would mitigate against leaks developing, and hence the LEOS system being required (Owens, 2000)≅ does not provide a quantified assessment of the effectiveness of LEOS. Subjective statements by Intec declaring LEOS as the Best Available Technology, also lend little to the discussion and have not been supported by any experience in the arctic (or in sea water).
FW – 32	Page 6-14, Section 6.3.5, LEOS System for Liberty. The last paragraph on this page states that the risk analyses are conducted based on the presumption that LEOS can be safely installed, which appears to be the experience of Northstar. How did FTL come to this conclusion? To our knowledge, the LEOS tube at Northstar is not yet functional. Being the first such installation in an arctic, subsea environment, this is a tenuous assumption without supporting evidence.

FW – 33	Page 6-17, Section 6.5.4, Expected Worst Case Leak Detection Capabilities. Using Northstar permit stipulation 18 (32.5 bbl/day) as the worst case leak detection limit provides a false sense of security. The figure of 32.5 bbl/day was a random choice, selected largely as a means to encourage the applicant to improve the proposed through-the-ice monitoring system. Regardless, 32.5 bbl/day should be easily achievable by LEOS, if LEOS is functional. The problem, as mentioned earlier, is that LEOS remains untested in arctic subsea conditions. Currently, through-the-ice sampling is the primary low-level leak detection system for Northstar, with LEOS being installed as a prototype system. Without actual experience with LEOS in the arctic, regulatory agencies are unlikely to alter this approach with Liberty. Through-the-ice sampling represents the worst case leak detection capability because confidence levels are low, and it is within reason to expect a small leak to go undetected for a period of up to 60 days (see Northstar EIS).
FW – 34	Page 6-18, last paragraph. An 87-barrel spill volume is not a conservation worst case scenario. Reconstruct this scenario using through-the-ice sampling with a larger spill rate undetected for 60 days.
FW – 35	Page 6-18, Table 6.8. A spill <u>rate</u> for MBLPC would be helpful in this table.
FW – 36	*LEOS System Summary*: It is our hope that the LEOS system proves to be a robust, dependable monitoring system for use in the arctic. However, it is our opinion that FTL has been too generous with the LEOS technology. FTL needs to make clear to the reader that this technology is untested in the proposed application, and use a more conservative analytical approach using through-the-ice sampling as the worst case leak detection capability.
FW – 37	Page 7-11, Section 7.3.2. A 5-minute elapsed time between leak detection and line shut-down appears overly optimistic. Does data exists from historical line breaks that would support or refute this assumption? Does FTL have information that the operator is clearly committed to a policy that the pipeline would be shut down within this period whenever there is an alarm, regardless of the apparent cause?
FW – 38	Page 7-15, Table 7.6. Why is the maximum drainage volume (1690 bbl) over the range of applicable water depths for ice gouging <u>less</u> than the drainage volume (1880 bbl) estimated for ice gouging in 10 feet of water?
FW – 39	Page 7-15, Section 7.3.5. As discussed earlier, we believe seepage volumes are flawed due to the fact that they do not consider failure of the LEOS system and use of through-the-ice sampling as a back-up and worst case leak detection capability.
FW – 40	Page 7-23, Section 7.5.3, paragraph 5. Why is it assumed that no oil would drain from the line once shut-down is accomplished? A small hole may or may not close upon depressurization, and it will take considerable time to purge the line of oil.

FW – 41	Page 7-23, Section 7.5.3, paragraph 6. Is a seepage event defined as oil reaching the environment, or simply escaping the carrier pipeline? The total number of seepage events occurring for pipe-in-pipe is given as .01565. Does this figure include seepage contained within the annulus?
FW – 42	Page 8-6, Section 8.1.3, paragraph (b). The comparison of pipe designs is far too brief. This is the heart of your work, and the reader needs to know more about how these figures were derived. We suggest you include a separate table here, similar to Table 8.3, which defines the failure mode associated with each hazard, and the expected spill volume and its probability for each failure mode.
FW – 43	Page 8-6, Table 8.3. The risk values provided in this table require explanation. According to discussions in Chapter 4 and Appendix C, steel pipe-in-pipe provides significant advantages over single-walled pipe with regard to its resistance to soil displacements associated with ice gouging. The analysis provided by Konuk and Fredj (2000) predicts an order of magnitude improvement in the structural response of pipe-in-pipe relative to the single-wall design (I. Konuk, pers. comm.). It appears reasonable to expect if pipe-in-pipe exhibits structural advantages in the case of ice gouging, this design would exhibit similar advantages relative to soil displacements associated with strudel scour, permafrost thaw subsidence, and upheaval buckling. The calculations used to derive the values in this table need to be provided within the text of the report. Identical risk values for all designs in the categories of thaw subsidence and upheaval buckling are particularly troubling. Please provide the database, results and figures for these calculations and explain their derivation.
FW – 44	Page 8-9, Section 8.2.5. It would be helpful in this section to provide a better understanding of the degree of confidence in the assignment of pipeline failure modes to the identified hazards (for base case). One possibility would be to add tables that supply probabilities for all failure modes and scenarios connected with each hazard, if this information is available via failure statistics. It would also be helpful to illustrate the probability of spill volumes (e.g., 1, 10, 100, 1000, and 2000 barrel spills) associated with each failure mode.
FW – 45	In summary, the Service believes the FTL study has provided valuable information for use in selecting the safest possible pipeline design for Liberty. The Service appreciates the opportunity to comment on this draft report, and looks forward to receiving a copy of the final report. In addition, we request a meeting with the contractor and other agencies prior to FTL's revision of the draft report. This work is not easily understood by agency personnel and the general public, and thus a chance to ask questions and openly discuss the presented findings would be tremendously helpful for everyone involved. In addition, a meeting with the contractor prior to the release of the final report would provide the contractor with additional input and clarification before finalizing the report

F4.0 COMMENTS RECEIVED FROM PETER HANLEY OF BP EXPLORATION

BP EXPLORATION

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RECEIVED
Anchorage, Alaska
AUG 16 2000
REGIONAL SUPERVISOR
FIELD OPERATION
MINERALS MANAGEMENT SERVICE

August 16, 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

Liberty Development Project (OCS-Y-1650) -
Submittal of Comments to the Fleet Technology Limited Report
Independent Risk Evaluation for the Liberty Pipeline

Dear Mr. Walker:

BP Exploration (Alaska) Inc. is pleased to submit comments for the draft Fleet Technology Limited report "Independent Risk Evaluation for the Liberty Pipeline" dated July 2000 prepared for the Minerals Management Services. Given the size of the document, this is our initial review comments only. We can provide a more in depth evaluation if given an additional two weeks to complete the review. We are also requesting authorization for INTEC to contact Fleet directly to discuss and to clarify some of our key issues and questions. If MMS is willing to authorize direct contact, we would be willing to detail our discussions with Fleet for you and allow Fleet to confirm our understanding of the discussions or to include MMS in the teleconference.

The following are our key points and main comments to the draft report.

BP - 1 The technical evaluation report by GSC should be reviewed and we are requesting a copy for our review.

BP - 2 An object set of risk evaluation conclusions should include a statement that all total risk values are low. As indicated in Table 1, the total risk numbers vary from 1 to 26 barrels, which are considered low.

BP - 3 Fleet's recommendation to better define pipe-in-pipe (PIP) response to loading events (pg. v) exemplifies the uncertainties associated with the

Part of the BP Amoco Group

Mr. Jeff Walker
August 16, 2000
Page 2

more complex PIP system design. The authors suggest that the behavior of steel pipe-in-pipe that is exposed to 3rd party activities and operational failures should be investigated further. This is an increased risk factor for PIP systems, which does not appear to be accounted for in the Fleet evaluation. It is unclear if this report accounts for this increase risk factor and should be explained.

BP - 4 Study of Table 8.3 (Risk Breakdown by Hazard for Each Design of the Base Case) indicates that the main differences between the Overall Total Risk for the steel pipe-in-pipe and the other designs are the risks associated with the "Operational and 3rd Party Activities". If this category of risk is taken to be the same as for steel pipe-in-pipe, there is essentially no difference between the Overall Total Risk for the designs.

The data for the risk of "the "Operational and 3rd Party Activities" was obtained from failure data from the Alyeska and Norman Wells Pipelines. Efforts to apply TAPS and Norman Wells pipeline failure data to the Liberty sub sea line should restrict causes to only leaks from the pipe body and welds since this is all that will be installed sub sea. Inclusion of leaks from valves, flanges and fittings will overestimate the risk for the other three Liberty pipeline design alternatives and may distort the conclusions. Please provide additional information and data on the causes of the leaks listed in Table 3.5.

The Alyeska pipeline is a different design (high D/t ratio) and is therefore of limited relevance when compared to the low D/t of the single wall and single wall in HDPE options. The report should account for the differences in design. Objective discussion of operational (overpressure) errors leading to leakage of a sub sea pipeline with no flanges, valves or fittings should include discussion of the beneficial effects of wall thickness greater than necessary for internal pressure design. Also, the differences in the level of inspection during construction for the Alyeska and Norman Wells pipelines and the more stringent inspections planned for the Liberty pipeline needs to be considered.

BP - 5 Historical pipeline failure data for permafrost thaw subsidence presumably refers to 2 events on TAPS, which has a very different design (high D/t ratio) and is therefore of limited relevance for Liberty. Also, if thaw settlement was covered in Section 3.4 of the report, these statistics need to be removed from the risk determination as summarized in Tables 3.5 and 3.6. As stated in Section 3.4.3, permafrost thaw settlement poses very little risk to the Liberty pipeline.

BP - 6 Please provide detailed calculation showing how the values in Table 8.3 were arrived at. It is not clear from the report how to reproduce the numbers.

Mr. Jeff Walker
August 16, 2000
Page 3

BP - 7 The assumption that the pipe-in-pipe will mitigate all operational and third party activity risk appears to be unreasonable. The fact is that extra safety provided by additional wall thickness with respect to burst limit state is not taken into consideration for the single wall pipe design.

BP - 8 The additional quality control/quality assurance for a pipe-in-pipe construction, for the increased activities, the extra personnel, etc. when compared to the single-wall pipe design warrants the question: will the actual as built pipe-in-pipe have the same level of reliability as the single wall pipe?

BP - 9 Total risk is never zero, or can never be eliminated. A discussion of acceptable level of risk, or the ALARP (as low as reasonably possible) region needs to be incorporated in a risk analysis.

BP - 10 It is also pointed out in the report that the risk category which provides the greatest difference between the resulting overall total risk for the designs (Operational Failures or 3rd Party Activities) is considered by the authors to be the greatest source of uncertainty (p. 9-3). Therefore, the comparative risk between the different alternatives should be closer than which is presented here.

BP - 11 The applicability of existing data from the Norman Wells and Alyeska Pipelines to the proposed Liberty pipeline is an extrapolation. The Liberty pipeline wall thickness is several times that required for pressure containment, has no valves, flanges or fittings along its sub sea portion, and is proposed to have 3 independent leak detection systems. This needs to be accounted for in the evaluation of the operational failure and 3rd party activity risk.

BP - 12 Also, the authors acknowledge the full containment assumption made can not be evaluated definitively for the most significant hazard (operational failure and 3rd party activities). We assert the one could just as easily make the assumption that a third party fails both outer and inner pipes.

If you have any questions or need additional information, please call either Luke Franklin at 907/564-5048 or myself at 907/564-5202.

Sincerely,

Peter T. Hanley

Peter T. Hanley, Manager Permitting
HSE-Alaska

F5.0 COMMENTS RECEIVED FROM MIKE PAULIN OF INTEC ENGINEERING

F5.1 Summary Comments

Comment Number	Comment
Preamble	This letter presents INTEC Engineering's comments on the Draft Final Report, “Independent Risk Evaluation for the Liberty Pipeline”, dated July 2000. This document was prepared for the Minerals Management Service by Fleet Technology Limited, Kanata, Ontario (5095.DFR). The Fleet authors have obviously put a great deal of effort into their report and have offered some valuable insights for the Liberty pipeline alternative review process. We greatly appreciated this opportunity to review their draft report. INTEC’s detailed comments, questions, and information requests are outlined in the attached document.
Intec – 1	All calculated total risk values are low and should be noted as such.
Intec – 2	Study of the “Risk Breakdown by Hazard for Each Design of the Base Case” indicates that the main differences between the Overall Total Risk for the steel pipe-in-pipe and the other designs are the risks associated with the “Operational and 3rd Party Activities”. If this category of risk is taken to be the same as for the steel pipe-in-pipe, there is essentially no difference between the Overall Total Risk for the designs.
Intec – 3	The data for the risk of “the “Operational and 3rd Party Activities” was obtained from failure data from the Alyeska and Norman Wells Pipelines. Efforts to apply TAPS and Norman Wells pipeline failure data is believed to have limited relevance to the Liberty subsea pipeline.
Intec – 4	The assumption that the pipe-in-pipe will eliminate all corrosion, operational and third party activity risk is an opinion. The authors acknowledge the full containment assumption made can not be evaluated definitively for the most significant hazard (operational failure and 3rd party activities). This assumption is a major factor leading to fleets conclusion that pipe-in-pipe has a lower risk.
Intec – 5	The risk category which provides the greatest difference between the resulting overall total risk for the designs (Operational Failures or 3rd Party Activities) is considered by the authors to be the greatest source of uncertainty.
Intec – 6	Fleet’s recommendation to better define PIP’s response to loading events exemplifies the uncertainties associated with the more complex PIP system design.

Intec – 7	The authors indicate that the findings of their report should be verified through further investigation. The purpose of this independent risk assessment of the Liberty pipeline was to perform just that investigation. It would be appropriate for the authors to indicate what should have been done to verify the results of the report and why this verification could not be carried out under the terms of the current scope of work. The increased design/construction complexity and lessor industry experience with systems other than the single wall pipeline will always suggest some issues which could be studied further. Some of these issues may have to remain as partially defined risks to avoid each evaluation concluding that more evaluation is needed. INTEC believes that this is an underestimated and not fully recognized advantage for the simpler single wall pipeline alternative.
Intec – 8	As pointed out during the concluding remarks of the MMS Alaskan Arctic Pipeline Workshop (Dr. Andrew Palmer, Nov. 1999), during risk analysis, there is pressure to obtain risk numbers. Dr. Palmer cautioned that if obtaining these numbers involved judgement, or extrapolation, you could have "a number pretending to be a fact, which is actually just an opinion".
Intec - 9 Closing	Please contact us at your convenience if you have any comments or questions regarding our review. We look forward to receiving Fleets response to our questions and comments, or discussing our concerns with them if the opportunity arises.

F5.2 Detailed Comments

Comment Number	Comment
Intec – 10	Page i – Technical evaluation report by GSC is requested for review, as it is a significant data source for the Fleet evaluation.
Intec – 11	Page ii – The risk evaluation conclusions should include a statement that all total risk values are low. As indicated in Table 1, the total risk numbers vary from 1 to 26 barrels, which are considered low.
Intec – 12	Page ii – The statement is made that the operational and 3rd party failures hazard was considered to be inconsequential for the steel pipe-in-pipe design because it is expected that oil released due to these hazards would be contained in the annulus. The authors should justify this assumption. It may be appropriate to indicate that this expectation is primarily supported by author's assumptions, as noted in the body of the report, and not on calculations.

Intec – 13	Page ii – The assumption is made that all oil is contained within the annulus for the PIP as the result of a leak. Some comment would be appropriate from the authors regarding whether all of this oil would also remain contained during repair and eventual pipeline decommissioning.
Intec – 14	Page iv – The very limited industry experience with oil releases from operational failures or third party activities for offshore arctic pipelines has been handled by considering a database with an unclear applicability to the Liberty pipeline (as stated by the authors). The authors also state that this hazard was found to pose the vast majority of the risk for the Liberty pipeline. It would be appropriate that the authors indicate that the applicability of this database to the Liberty pipeline is based primarily on their opinion.
Intec – 15	Page iv – The authors state that operational failures and third party activities were found to be the most significant hazard but go on to state that the findings should be verified through further investigation. It may be beneficial if Fleet could explain what further investigation is required.
Intec – 16	Page v – Fleet's recommendation to better define a pipe-in-pipe's (PIP) response to loading events exemplifies the uncertainties associated with the more complex PIP system design. The authors suggest that the behavior of a steel pipe-in-pipe that is exposed to 3rd party activities and operational activities should be investigated further. This is an increased risk factor for PIP systems (also noted on Page 1-4) which is not accounted for in the report. Some account for this uncertainty and analysis of available statistics associated for pipe-in-pipe systems (e.g. number of miles, number of failures, number of leaks) would be beneficial to the report.
Intec – 17	Page 1-1 – Risk values in Tables 1.1 and 1.2 should reference the INTEC report. The main difference between the 1999 report and the 2000 Addendum report was that the 1999 depth of cover was designed for each case individually and the 2000 Addendum used an arbitrarily constant depth of cover. This lowered the risk for PIP but was not supported by conventional extreme event loading design criteria (e.g. designing for 100-year design event return periods).
Intec – 18	Page 1-1 – The flexible pipe explanation provided in Section 1.1 suggests that only the outer cover is flexible where in fact the entire pipe is flexible. This should be clarified.
Intec – 19	Page 1-3 – In the Historical Perspective (or in another part of the Introduction), the beneficial effects of low D/t for the Liberty pipeline should be acknowledged through comparison with the D/t's for the Arctic projects mentioned and for pipelines in general.

Intec – 20	Page 1-3 – The authors state that there is very little historical design or practical field experience that can be referred to with respect to pipe-in-pipe configurations designed to provide improved structural reliability or secondary containment. This implies that there is some information available. If the authors have information (for example, the Erskine PIP failure), then this should be referenced in the report.
Intec – 21	Page 1-4 – It is not clear from the report if the authors have reviewed the Northstar FEIS and the treatment of the risk data sets in that document. Can the authors clarify if the information contained in that document was reviewed and used in the present study?
Intec – 22	Page 2-5 – INTEC believes that the coupled loading cases presented are highly unlikely and should not be presented as design cases. A discussion on the probability of a strudel scour occurring over a significant pipeline overbend and multiple gouging events causing full stress reversal in the pipeline would be beneficial.
Intec – 23	Page 3-4 – The very small data set for ice gouges also reflects the very low occurrence rate for ice gouges in the Liberty area. The Alaskan SPCO in fact has recently concluded that ice gouging is not a significant loading condition for the Liberty pipeline. (See Blanchet et al., 2000).
Intec – 24	Page 3-6 – Discussion of subgouge soil displacement uncertainties is unbalanced in that only the potential for unconservative predictions is mentioned, while in fact the predictions may also be conservative due to factors such as ice keel shape, width and approach angle. A similar bias for making even more conservative assumptions than used in the INTEC report is noted in multiple locations in the Fleet report. Conservative assumptions are generally good during a design process but if they are not acknowledged during a risk evaluation, they can lead to inaccurate conclusions.
Intec – 25	Page 3-6 – The authors estimate that the published subscour deformation algorithms might underestimate the actual values by up to a factor of about 10. It would be appropriate for the authors to indicate how the published information indicates that the results are subject to significant uncertainty. It could be noted in the report that Blanchet et al. (2000) in their analysis of ice gouges stated "More recent confidential tests … has shown that the presence of a pipeline in the ground considerably reduces sub-scour deformations and loads".

Intec – 26	Page 3-6 – Discussion of multiple gouging case is overemphasized and should not be presented as a design case due to factors such as: a) A low probability of significant gouges occurring at the same location (as noted in Fleet report), b) A short pipe length experiencing peak strain values, c) A strain reversal will return the pipeline to a zero net strain condition or in other words impose both tensile and compression conditions which have different limit state conditions, and d) Multiple strain reversal cycles of similar magnitude are commonly experienced without failure during pipeline reeling installations.
Intec – 27	Page 3-6 – The assumption that a multiple gouging event would damage the pipeline assumes that no surveillance of the pipeline will take place, when in fact there will be considerable surveillance of the pipeline.
Intec – 28	Page 3-8 – What does the tem "risk" mean in this context? The authors should define terms at the beginning of the report and be consistent throughout. Also, the basis for the barrel of oil risk quantification should be explained.
Intec – 29	Page 3-9 – The partial loss of pipeline trench backfill risk evaluation makes no mention of factors needed to predict the joint probability of two extreme events (strudel scour and pipeline overbend) coinciding to produce a potential upheaval event. Other relevant factors include strudel hole diameter, design safety factors and actual operating conditions during a scour event.
Intec – 30	Page 3-17 – Historical pipeline failure data for permafrost thaw subsidence presumably refers to 2 events on TAPS. It would be appropriate for the authors to point out that the TAPS pipeline has a very different design (high D/t ratio) and address the limited relevance for Liberty.
Intec – 31	Page 3-17 – The authors indicate that permafrost thaw settlement poses very little risk to the Liberty Pipeline, provided that soil displacements are taken into account at the design stage. However, later in the report, in Table 3.5, "pipe settlement" failures are included in the failure history summary, which should have no relevance to the Liberty pipeline design. Please confirm in the report if these pipe settlement causes of failure were due to thaw settlement or some other mechanism.
Intec – 32	Page 3-17 – Hovey and Farmer (1993) indicates 0.5% of the total number of failures listed in their paper as being attributed to subsidence. Please confirm in the report that this subsidence referenced in the Hovey and Farmer (1993) paper was attributed to thaw settlement and not some other mechanism.

Intec – 33	Page 3-18 – The authors imply that Hovey and Farmer (1993) list failures from thermal loads on pipelines as 0.5% of the total number of pipeline failures. Please confirm that the statistics presented by Hovey and Farmer for thermal loads and whether or not the loading condition refers to upheaval buckling. The authors might also indicate if they have come across any other data for failures attributed to thermal loads/upheaval buckling for single wall or pipe-in-pipe systems.
Intec – 34	Page 3-19 – Objective discussion of operational (overpressure) errors leading to leakage of a subsea pipeline with no flanges, valves or fittings should include discussion of the beneficial effects of wall thickness greater than necessary for internal pressure design. As indicated later in the report, Section 4.7.4, even accidental overpressure would not lead to failure.
Intec – 35	Page 3-22 – The authors point out that it is questionable how applicable the failure statistics presented in Appendix E would be for the Liberty pipeline due to the fact that the population density is low and the line is offshore. The same comments could also be made about the applicability of the Alyeska and Norman Wells data to the Liberty pipeline. It would be appropriate for the authors to comment on this in the report.
Intec – 36	Page 3-24 – The comment about how pinhole leaks are essentially only found by aerial or foot patrols does not give credit to advances in leak detection technology such as that proposed for the Liberty pipeline.
Intec – 37	Page 3-24 – It is stated in the report that offshore lines require that 100% of welds be nondestructively examined but that onshore pipelines have a requirement that only 10% of welds must be tested. The authors should comment on whether 100% of the Alyeska and Norman Wells pipeline welds have been tested as operational and 3rd party failure data from these two pipelines is assumed to apply to the Liberty pipeline.
Intec – 38	Page 3-24 – The authors make seemingly contradictory statements: “It was recognized at the outset that the failure statistics would be of limited applicability” and then “Nevertheless, the database review done in this project provided useful information regarding the types of failures that might be expected and their relative frequency of occurrence”. If this information is used, commentary is warranted regarding the relevance and limited applicability of the data.

Intec – 39	Page 3-25 – The authors outline why they consider the Alyeska and Norman Wells failure histories apply to the Liberty pipeline. However, it would also be appropriate for the authors to indicate differences in the lines such as the facts that: the Liberty pipeline will be offshore; the Liberty pipeline will be buried over its entire offshore route; the D/t of these lines may be significantly different from that proposed for the Liberty pipeline; and the Liberty pipeline will also incorporate supplemental leak detection strategies.
Intec – 40	Page 3-26 – The authors assign one incident per year to spills less than 100 barrels. The authors should justify their assignment of these numbers or more clearly acknowledge that it is an assumption.
Intec – 41	Page 3-27 – Efforts to apply TAPS and Norman Wells pipeline failure data to the Liberty subsea line should restrict causes to only leaks from the pipe body and welds since this is all that will be installed subsea. Inclusion of leaks from valves, flanges and fittings will overestimate the risk for Liberty and may distort the conclusions. The authors should also provide additional details on the causes of the leaks presented in Table 3.5 (e.g. valves, flanges, fittings) and how, if present, these types of leaks are addressed in the risk analysis.
Intec – 42	Page 3-27 – As thaw settlement was addressed in Section 3.4 of the report, the authors should comment on why the two pipe settlement statistics were not removed from the failure histories data presented in Table 3.5 and the risk determination as summarized in Table 3.6.
Intec – 43	Page 3-27 - As indicated above, the authors should indicate was the level of inspection during construction for the Alyeska and Norman Wells pipelines and indicate if the level of inspection/testing was as stringent as is planned for the Liberty pipeline? The Liberty pipeline will also be subject to 2 state of the art leak detection systems as well as supplemental leak monitoring. Also, it would be appropriate for the authors to comment on the fact that the Liberty pipeline will be remote and buried 7 feet beneath the seabed. Finally, the Alyeska pipeline is a different design (high D/t ratio) and is therefore of limited relevance when compared to the low D/t of the single wall and single wall in HDPE options and this should be addressed. All these factors should be addressed in the report and the effects on the risk obtained from the data presented in Table 3.5 assessed.

Intec – 44	Page 4-2 – As indicated in INTEC's response to Stress Engineering's evaluation of the Liberty pipeline alternatives, INTEC agrees that non-linear geometry effects should be included at a preliminary engineering level. ANSYS pipeline modeling results with and without large deflection effects indicated that small deflection theory was adequate for conceptual modeling of the Liberty pipeline load cases.
Intec – 45	Page 4-3 – The authors state that "Upheaval buckling could be one possible result". This is not considered a likely event as the axial driving force is removed by the pipeline translating laterally and warrants further discussion by the authors.
Intec – 46	Page 4-3 – The authors state "the minimum radius of curvature would be small enough to cause a buckle or wrinkle, especially for narrow gouges". This does not take any account for the observed aspect ratio for keel depths to their width. This is documented for the Northstar project area as a minimum ratio of 10. Further discussion on this topic is warranted since "narrow" gouges are the ones suspected of leading to leak formation.
Intec – 47	Page 4-9 & C-1 – Fleet's "displacement delay" discussions relate to development of net axial tension in the inner pipe. Net axial tension is a minor component of the net strain leading to exceeding pipe tensile limit state conditions, compared to bending induced axial tensile strains. Therefore, this effect is minimal and should not be portrayed as a benefit for PIP systems. The discussion of this effect should also include the negative effects of the corresponding net compressive on the outer pipe.
Intec – 48	Page 4-9 & C-1 – Fleet's "curvature reduction" discussions relate to peak inner pipeline bending strain development at spacer locations. In this case, Fleet makes an unconservative assumption that the peak bending strain (maximum curvature) will be at a point away from a spacer and therefore the inner pipe strains will be reduced, rather than increased locally, due to the localized loading on the inner pipe (33% increase for the low strain cases of 2 and 212 on Fleet Table 4.5). This could be addressed in a reliability based design evaluation but is inconsistent with the overall conservative Liberty pipeline design approach applied by BPXA.
Intec – 49	Page 4-10 – It does not appear that the analysis to calculate the strains on the inner and outer pipes characterizes the 'critical length' for each system, which is the conservative approach that INTEC adopted. Most of the work is related to much smaller aspect ratios than for those expected in the field. It would be appropriate for the authors to address this in the report.

Intec – 50	Page 4-12 – The authors note that the annular gap in the INTEC PIP concepts was less than most PIP configurations. It is pointed out that most PIP configurations have been designed for thermal insulation and field construction procedure purposes. Increasing the annulus or gap would require a larger outer pipe. This in turn would be heavier, would require additional welding, and would attract more load as the result of subgouge deformation.
Intec – 51	Page 4-12 – The authors focus on the potential benefits of larger spacer separation and larger annulus. However, this potential benefit has not been clearly documented. There are also practical implications of these system optimizations, which the authors may wish to discuss in the final report.
Intec – 52	Page 4-12 – The authors state that it is not necessarily true that an ice gouge event that fails the outer pipe, fails the inner pipe. The supporting sensitivity study work for this statement is not apparent. It could also be argued that an ice keel event would not rupture the outer pipe or a single pipe. However, for this conceptual level assessment, it is important that the failure scenarios are not arbitrarily defined.
Intec – 53	Page 4-12 – One of the major differences in observed inner and outer pipe strains is pipe diameter. For example, for a PIP system bent around a constant radius, the ratio of the maximum strains in both the inner and outer pipe will be mainly governed by the ratio of the pipe diameters.
Intec – 54	Page 4-15 – As indicated previously, it would be appropriate for the authors to comment on the assumption that an upheaval buckle forms when more than 1 foot of backfill is lost. This is not considered an issue for pipeline sections, which are not at the crest of the maximum allowable imperfection or overbend prop
Intec – 55	Page 4-27 – Section 4.8.4, see previous comments on upheaval buckling as the result of loss of soil cover due to strudel scour.
Intec – 56	Page 5-1 – The calculated flow velocity should be closer to 6 feet/sec.
Intec – 57	Page 5-3 – The authors arrive at a critical corrosion depth of 0.236 inches for the single steel pipeline and suggest that this would be reached approximately 12 years after installation. It would be appropriate for the authors to indicate that this level of corrosion would be highly unlikely for the Liberty pipeline given the level of testing prior to installation, monitoring during operation, and the state of technology regarding inspection tools.
Intec – 58	Page 5-6 – The authors state that the Concawe data most closely matches the Liberty case. Some narrative on why this data set can be applied to the Liberty pipeline (without modification or a subset) would be appropriate. For example, the proportion of Concawe statistics composed of small diameter lines, which can not be pigged or other data which might not be relevant to Liberty.

Intec – 59	Page 5-6 – It appears that the authors meant to state in the final paragraph that the internal corrosion is 5 times less (not more) likely to occur than external corrosion.
Intec – 60	Page 7-2 – The oil drainage (item d) will also be limited by the nature of the failure; i.e. if the leak is a hairline crack and the line is depressurized, then the loss of oil is limited by the size of hole and the time required to purge the line. This warrants further discussion in the report.
Intec – 61	Page 7-4 and Figure 7.3 – Further comment on the logic for defining critical flaw sizes investigated should be included in the report. These potential defect sizes are not realistic based on full NDE of the pipe body, full NDE on all weldments, and a hydrostatic test pressure of 1.25 times MAOP for 8 hours. Instead, they appear to be worst case scenarios, prior to full separation of the pipeline
Intec – 62	Page 7-5 – The authors state that they expect a lower bound CTOD of 0.125mm. INTEC would consider this to be conservative for girth welds but over-conservative for the pipe body. A conservative CTOD for the pipe body would be considered to be 0.040 inches.
Intec – 63	Page 7-7 – Please confirm that Equation 7.9 is dimensionally correct.
Intec – 64	Page 7-9 – The Fleet report endorses previous approaches to determine oil release potential based on leak detection and operator response times but then assumes a worst case; that all oil capable of being drained out of the line, is spilled from the line.
Intec – 65	Page 7-13 – As indicated above for Page 7-2, drainage will also be dependent on the nature of the failure after the line has been depressurized.
Intec – 66	Page 7-16 – In the second paragraph, the authors indicate that failure statistics were used to establish seepage events probabilities (Section 7.5). This section then refers to Appendix E, Table E-5 that is for the Gulf of Mexico. The authors should include some commentary as to why these statistics apply to the Liberty pipeline.

Intec – 67	Page 7-15 – Table 7.6 presents maximum oil drainage volumes for each hazard. Table 7.13 presents pipeline failure modes versus hazard. It is observed that the failure mode for several hazards is through seepage through the maximum stable crack. As pointed out previously, if the line was depressurized, the amount of oil that could leak out of that failure would be limited to the length of time until temporary repair or purging is completed. However, the “Maximum Drainage” presented in Table 7.12 comes from Table 7.6, which assumes that all of the oil capable of draining out of the pipeline is released. If the crack opening areas of Table 7.2 are used in conjunction with Equation [7.9], the drainage after depressurization can be calculated for a reasonable period of time until the line is purged. Given this method, what would be the times for the “Maximum Drainage” volumes presented in Table 7.12? . Further explanation and rationale for choosing the maximum possible drainage for cracks and seepage is recommended.
Intec – 68	Page 7-22 – The first line of Section 7.5.2 should apparently read “failure by cracks or flaws” not “failure by rupture”.
Intec – 69	Page 8-1 – The combined probability for a corrosion-induced leak to release oil to the environment is very low but should not be taken as zero.
Intec – 70	Page 8-2 - The assumption that the pipe-in-pipe will mitigate all operational and third party activity risk appears to be unreasonable. The extra safety provided by additional wall thickness with respect to third party damage and burst limit state should be taken into consideration for the single wall pipe design.
Intec – 71	Page 8-2 and Table 8.2 – The authors assume no loss of oil from the pipe-in-pipe system for major incidents as a result of operational or third party activities. The authors also acknowledge that this full containment assumption can not be evaluated definitively. If it is a major incident, then it can be argued that both the inner and outer pipe could be damaged. The assumption that the pipe-in-pipe will eliminate all operational and 3rd party activity risk appears to be unreasonable.
Intec – 72	Page 8-6 and Table 8.3 – As pointed out before, the relevance of the Norman Wells and Alyeska operational statistics to the Liberty pipeline is limited. For the subsea portion of the Liberty pipeline, 3rd party activity cannot be considered a significant hazard because the pipeline is buried 7 feet below the seabed. Such a hazard will have a very low frequency of occurrence and thus a very low risk from this hazard.

Intec – 73	Page 8-6 & Page 8-7 – Please provide details on how the numbers in Table 8-3 and 8-4 were calculated. It may be appropriate to include these calculations in an appendix. In Section 2.7.1, it was stated that risk is the product of "any risk source" event probability, Pi, and its consequences, Ci. Provide Ci and Pi for all hazards, as well as the calculations requested above.
Intec – 74	Page 8-6 & Table 8.3 – The results presented indicate that the main differences between the "Overall Total Risk" for the steel pipe-in-pipe and the other designs are the risks associated with operational and 3rd party activities. As indicated in Section 9.1.8, the information on these failures is very limited and is thus the greatest source of uncertainty. It would therefore seem appropriate for the authors to point out this uncertainty. Additionally, point out that if this category of risk is taken to be the same for a single wall and pipe-in-pipe, there is essentially no difference between the "Overall Total Risk" for the designs.
Intec – 75	Page 8-6 – Because of the burial depth requirements for the Liberty pipeline, any 3rd party damage is most likely to occur during installation. This is considered unlikely given the construction technique proposed. The single wall steel pipeline can be inspected with a geopig or other smart pig and any significant pipe wall or geometry anomaly would be detected. If not detected, the damage could lead to corrosion in the long term but this would be easier to detect in the single wall steel pipeline than in the outer pipe of a PIP system which cannot be monitored.
Intec – 76	Page 8-6 & Table 8.3 – Some commentary on the sensitivity of risk with respect to wall thickness (when predicting the frequency of failure due to operational hazards) of the single wall steel pipeline would be a beneficial addition to the report. The maximum operating pressure for Liberty leads to a hoop stress of only 25% of SMYS, and thus, at least 4 times MAOP is necessary to yield the pipe. The extra safety provided by additional wall thickness with respect to burst limit state should be taken into consideration for the single wall pipeline evaluation.
Intec – 77	Page 8-6 – There is additional quality control/quality assurance required for a pipe-in-pipe construction, increased activities and extra personnel during construction, and there is increased complexity of the pipe-in-pipe design, when compared to the single-wall pipe design. This can lead to other potential failure modes and it is not possible that the actual "as-built" pipe-in-pipe will not have the same level of reliability as the single wall pipe.

Intec – 78	Page 8-6 – The steel pipe-in-pipe will cost more to build. The discussion on risk reducing measures, or additional safeguards should note that for the same (or less) additional cost, the risk of the single wall design could be further reduced. Just because the Liberty single wall pipe concept already exceeds conventional industry safety requirements does not preclude making it even safer.
Intec – 79	Page 8-6 – Some discussion is warranted about the possibility of having oil in the annulus of the pipe-in-pipe or pipe-in-HDPE systems and the probability of a spill during repair and/or decommissioning.
Intec – 80	Page 8-8 – The authors indicate the statistics used to define the occurrence frequency (for the single wall steel pipeline, pipe-in-HDPE, and flexible pipe) include those that are related to shore-based facilities. There is a risk to the pipe-in-pipe system at the shore-based facilities where the pipe exits the casing pipe and this could be considered a major risk augmentation factor. The risk is about the same for all pipes but could be increased for the pipe-in-pipe system. This should be discussed by the authors in the report.
Intec – 81	Page 8-12 – As the single wall steel pipeline is assigned the most risk to start with, compounding of risk in this manner could negatively bias the single wall steel pipeline in the analysis of maximum expected risk.
Intec – 82	Page 9-2 – The authors state that the other options had significantly more risk (maximum expected) than the pipe-in-pipe. This is mostly due to the evaluation assumptions made on the effectiveness of the outer pipe for secondary containment. As indicated before, the authors should point out that the overall risk is low. In addition, is a spill risk difference between 11 and 34 barrels considered a "significant" difference based on the accuracy of the evaluation?
Intec – 83	Section 9 – Total risk is never zero, or can never be fully eliminated. What is an acceptable level of risk, or the ALARP (as low as reasonably possible) region? Such a discussion should be incorporated by the authors into the risk analysis.

Intec – 84	Page 9-4 - The authors indicate that the findings of their report should be verified through further investigation. The purpose of this independent risk assessment of the Liberty pipeline was to perform just that investigation. It would be appropriate for the authors to indicate what should have been done to verify the results of the report and why this verification could not be carried out under the terms of the current scope of work. The increased design/construction complexity and lessor industry experience with systems other than the single wall pipeline will always suggest some issues which could be studied further. Some of these issues may have to remain as partially defined risks to avoid each evaluation concluding that more evaluation is needed. INTEC believes that this is an underestimated and not fully recognized advantage for the simpler single wall pipeline alternative.
	Comments on Appendix A – Initiating Events: Ice Gouging
Intec – 85	Section A2.0, p. A-2 – Fleet presents a multiple gouge scenario with second feature travelling in opposite direction with respect to the first feature. This scenario is considered unlikely since <u>all</u> observed ice gouge seafloor incisions are oriented on the prevailing wind and current direction (ref: Coastal Frontiers Liberty Report drawings).
Intec – 86	Section A2.0, p. A-2 – A similar comment can be made regarding Fleet's comment about pipeline stress reversal.
Intec – 87	Section A5.2.3, p. A-15 – The statement is made that there is a 74% probability that Liberty pipeline will be re-gouged at some point along its length over its 20-year life, by gouges at least 0.25 ft deep. Please define in terms of the re-gouged second gouge width overlapping the first gouge width by at least 70%, 50%, 5%, etc. This is relevant because ice gouges surveyed in the immediate vicinity of liberty shows ice gouge widths 30-feet or greater (mostly greater), the maximum strained regions along the pipeline are of the order of 10% of the gouge width (or three feet long). Therefore, even if a re-gouge occurs, if the overlap is not 70% or greater, the maximum pipeline strained length will not overlap. Also, the relevance of a 0.25 ft deep gouge forming over a pipeline with a 7-foot depth of cover is questionable.
Intec – 88	Section A5.3.2, p. A-16 - It has been assumed by Fleet that 50% of the re-gouging leads to stress reversals. The potential stress reversals are based on an ice-gouging event travelling in the opposite direction of the first one. This is an assumption and is considered highly unlikely and would warrant further investigation and support before this comment can be made.

Intec – 89	Section A6.2.2, p. A-22 (second paragraph) - Fleet states that the actual sub-gouge displacement may have been underestimated by a factor of 10. However, this is only an opinion. There is no basis for this opinion since all the evidence presented by Fleet suggests quite the opposite, e.g. that the modeled displacement is greater than actual displacement. The evidence listed by Fleet includes: Soil displacements are significantly reduced if pipeline is present [see (c), p. A-20]; Sub-gouge displacements were based on tests with a rigid indentor [see (d), p. A-21]; The effect of ice-keel failure has not been included. Additional evidence includes: The conservative selection of worst-case gouge impact rates leads to a deeper design gouge depth; The assumption that all the length of Liberty pipeline can be gouged (instead of a more reasonable length, say 50%) leads to a deeper design gouge depth, and thus larger displacement field.
Intec – 90	Section A6.4, p. A-24 - Fleet's conclusion that the displacement field is qualitative in nature does not take into account the extensive research done in this area. A more appropriate conclusion is that the displacement field is a conservative quantitative description of the phenomenon, well documented in independent research (reference PRISE reports). The opinion-based factor of 10 on the actual displacement is also not supported by engineering analysis. The actual displacement field may already be overestimated by the design displacement field (see comment above)
	Comments on Appendix B – Initiating Events: Strudel Scour
Intec – 91	All Sections - In general, Fleet reviewed and agrees with report by Blanchet et al. (2000). INTEC in general also does not take exception with referenced report. Such report concludes (indirectly) that INTEC's design strudel scour dimensions are conservative.
	Comments on Appendix C – Lateral Deformation Structural Response
Intec – 92	Section C1.0 – The Fleet work focuses on the potential system integrity benefits of relative motions of inner pipe to outer pipe in regard to bending. The approach appears to be selective of pipe response scenarios. For example, a main conclusion is that increasing the spacer separation reduces the strain in the inner pipe for the same lateral displacement. However, the report does not address the potential strain increase due to column buckling of the inner pipe under the locked in compressive force.
Intec – 93	Table C1 – Fleet presents a table summarizing existing PIP configurations. Please provide references for the database. For example the King and Nakika pipelines have not been built.

Intec – 94	Section C2.1 Fleet presents calculations of deflection of inner pipe. Calculation does not appear to include the additional displacement caused by the compressive loads in the inner pipe.
Intec – 95	Page C-15 - Conclude large difference between inner and outer pipe strains is due to the spacer separation and annulus size. Large difference in strains is mainly due to difference in diameter between inner and outer pipe.
	Comments on Appendix D – Upheaval Buckling Analysis
Intec – 96	Page D-4 to D-6 – Fleet presents work to develop a method to predict the pipe displacements if movement occurs. The accuracy of this work needs to be validated. The other issue is that if upheaval occurs, the pipeline depth of cover criteria will be not be met and so it is likely that corrective action will be taken. A pipeline upheaval is not expected to directly cause a leak in any of the systems considered.
Intec – 97	Page D-6 – Fleet presents an unsupported span assessment. The approach used does not add significant value to the assessment because spanning is considered to be a very minor risk to pipeline integrity.
Intec – 98	Page D-7 – Fleet makes the statement "The upheaval buckling subsequent to a thaw settlement or strudel scour can be evaluated based on these results of the upheaval buckling work described in the previous section". It is not clear how this would be applied. If a pipe deflects due to that settlement or a strudel scour, the local axial compressive force is relieved and there is less driving force present to cause an upheaval buckle.
	Comments on Appendix E – Failure Statistics Analyses
Intec – 99	All Sections - Fleet reviewed several pipeline failure reports. The applicability of such reports to the proposed Liberty pipeline is an extrapolation. The Liberty pipeline wall thickness is about 2.7 times that required for pressure containment (plus additional safety factors from the design codes), has no valves, flanges or fittings along its subsea portion, and is proposed to have 3 independent leak detection systems.

F6.0 COMMENTS RECEIVED FROM THE MMS VIA CONFERENCE CALL

Conference Call Summary

Date: Sept. 5, 2000
Participants: Jeff Walker (MMS)
Dennis Hinnah (MMS)
Wallace Adcox (MMS)
George Comfort (FTL)
Aaron Dinovitzer (FTL)

Prepared by: G. Comfort (FTL)

Comment Number	Comment
Preamble	The agenda for the call followed that given in D. Hinnah's email of August 31,2000.
MMS(2) –1	FTL's recommendation (in its draft final report) that further investigation of operational and third party failures was warranted – This recommendation was questioned because the MMS felt that this was an important objective of the study. FTL stated that this recommendation was made because the Liberty Pipeline has only been developed to the concept design stage, and key items such as operator training, and surveillance and monitoring plans remain to be completed. These items affect the risk associated with this hazard. In the absence of such information, FTL was forced to rely on failure statistics from other pipelines. FTL will explain the basis for this recommendation in its final report. This led into a wide-ranging discussion that included the following points: (a) The aftermath of an event was not considered. It is likely that should pipeline failure occur, the pipeline could not be restored to its original integrity. This is believed to be more problematic for the steel pipe-in-pipe design, than for the single wall pipe design. (b) The risk associated with pipeline repairs was not considered. (c) The study did not adequately account for the risk associated with the fact that the condition of the outer pipe (for the steel pipe-in-pipe design) can not be monitored. (d) Operational and third party failure statistics should be separated for clarity. A check should be done to ensure that all events included in these statistics are appropriate with respect to the Liberty Pipeline. (e) There is no reflection of the increased risk to the interior pipe should the annulus become filled with sea water. FTL was tasked to consider these items in its final report.

MMS(2) – 2	GSC Report – FTL's draft report is unacceptable now because it references a document (i.e., "Konuk and Fredj, 2000") which is in press and not yet available. FTL explained that the GSC's model was used for the study to avoid duplication, which freed up project resources for other parts of the study. A number of options were discussed. I. Konuk was contacted by telephone after the conference call, and the following was established: (a) The GSC report (which FTL referenced as "Konuk and Fredj, 2000") will not be available until about 4 months time. (b) The GSC will not make input files available to third parties who wish to duplicate their results because: (i) The GSC report (when it is eventually published) will contain sufficient information for third parties to duplicate the results; (ii) FTL's draft report contains sufficient information to allow third parties to duplicate the results; (iii)Considerable effort has been spent (by the GSC) to make the model run efficiently and to make it converge faster. This information would be released to third parties if the input files were released. Furthermore, this information is only valuable for commercial purposes (eg., for minimizing computer resources) and is not required to meet the objective of allowing third parties to duplicate the results. (c) I. Konuk is in agreement with the description in FTL's draft report regarding the GSC Model, the inputs used, and the results obtained. I. Konuk will send FTL confirmation stating that FTL's draft report provides an accurate description of the GSC Model, the inputs used, and the results obtained. A copy of the email received from Ibrahim is attached for your information. FTL proposes to do the following to address the concern raised regarding the accessibility of a referenced document: (a) FTL will remove all references in its report to the "Konuk and Fredj, 2000" report. (b) FTL will report that the GSC Model was used by GSC to analyse the soil-pipe interactions of interest. (c) FTL will include I. Konuk's confirmation in an Appendix. FTL will state that it has received and run the GSC model for a number of cases, and obtained the same results. Hence, FTL has confidence in the full set of results obtained from GSC.
MMS(2) – 3	Delivery Date for Final Report – FTL will deliver the final report by Sept. 11,2000.

APPENDIX G

RESPONSES TO COMMENTS RECEIVED
REGARDING FTL's DRAFT FINAL REPORT

CONTENTS

G1.0 RESPONSES TO COMMENTS RECEIVED BY SOURCE

This appendix provides brief responses by the authors of this report to the comments received. The original comments are provided in Appendix F. Comments were received from the following organizations:

(a) Dennis Hinnah of the MMS – letter dated August 21, 2000 – see section F2.0
(b) Larry Bright of the US Fish and Wildlife Service – memorandum dated August 21, 2000 – see section F3.0
(c) Peter Hanley of BP Exploration – letter dated August 16, 2000 – see section F4.0
(d) Mike Paulin of Intec Engineering – letter dated August 30, 2000 – see section F5.0
(e) The MMS through a conference call held on Sept. 5, 2000 – see section F6.0

The following sections provide responses to each comment from each source. The comment numbers in the left column have been assigned by FTL as an aid in preparing the responses. The first letter from Dennis Hinnah on 21 August has been assigned the prefix MMS(1); responses from Larry Bright are prefixed with FW; the responses to Peter Hanley begin with BP; Intec is used to identify the Mike Paulin comments; and comments from the second letter from Dennis Hinnah on 5 Sept begin with MMS(2).

G2.0 RESPONSES TO COMMENTS FROM DENNIS HINNAH OF THE MMS

Comment Number	Response
Preamble	No response required
MMS(1) – 1	This will be addressed during editing of the final report.
MMS(1) – 2	The failure summary in section 3.9.2(c) (Table 3.5) was developed by taking only those failures in the 100 bbl or more on land and water category that we felt directly related to pipeline operations. This reduces the 9 failure events reported by Hart Crowser (2000) to five relevant events. This excluded the valve failures and station piping failures. The 1978 spill from a bullet hole was not included as the offshore section of Liberty is buried, and we consider that similar incidents of sabotage would not occur. Upon further review the “pipe settlement” events listed in Table 3.5 of our report will also be excluded.
MMS(1) – 3	We have recalculated the risk due to major operational and third party hazards (>100 bbl.) based on the relevant TAPS spills. The spills < 100 bbl were included to obtain an event occurrence for a pipeline leak. It is recognized that this was an approximate approach, but it was felt necessary to proceed in this manner so that we could establish a risk for a small leak. The average consequence of any spills < 100 bbl was estimated at 25 bbl, and in our experience we felt that this was typical for a leaking type of failure.
MMS(1) – 4	The occurrences that we calculated in the draft report used the same approach as given by Hovey and Farmer (Oil & Gas Journal, July 12 1993, pp104-107), where the DOT failure statistics are divided by the total mileage of all pipelines regulated under their jurisdiction. The DOT ‘Accident Report – Hazardous Liquid Pipeline’ Form OMB No. 2137-0047 does not have a requirement to list the total length of the pipeline that has failed, so the failure information typically used cannot normally be ‘weighted’ as suggested. The suggested change will be implemented.
MMS(1) - 5	‘Table E-5’ should read ‘Table E-7’. From Table E-7, read the No. of failures/7.5 miles/year for the pipe defect and weld defect, and multiply each by the 20-year life of the line to obtain 0.0069 and 0.00375; adding these two numbers together gives 0.01065. To this number, add the number of corrosion occurrences from Table 5.6 for each of the pipe designs to obtain the numbers shown.

MMS(1) – 6	The Hovey and Farmer analyses were based on DOT statistics, where the reporting requirements are given in DOT Part 195.50. The reporting limit is not exact in that there are several required reporting guidelines. For example, if there was a fire or a serious injury to a person, the reporting limit could well be less than 1 m3. It was recognized that there are differences in the reporting requirements between the DOT and CONCAWE statistics, and the comparison was used only to observe that trends were similar between databases, i.e. that corrosion and third party activities were the leading failure causes. It is also noted that the Hovey and Farmer data were used only to establish failure rates for weld and pipe defect failure rates in the risk analyses.
MMS(1) – 7	This will be addressed during editing of the final report. Since no target or threshold risk values, indicating acceptable risk levels, are available in design standards and none are offered in by BP or the US Department of the Interior it would be difficult to say in an absolute sense the significance of these events FTL agrees that work to define the significance of the calculated risk values (with risk being defined in terms of the volume of oil spilled) is needed to make the results meaningful to decision makers and the public. Unfortunately, this is beyond the scope of the current project.
MMS(1) – 8	This will be addressed during editing of the final report.
MMS(1) – 9	This will be addressed during editing of the final report.
MMS(1) – 10	See response to MMS(1) - 7.
MMS(1) – 11	The pressures at 100 % of the SMYS of the Grade X52, 12.75 in. OD x 0.5 or 0.688 in. WT pipe are 4078 psi and 5612 psi, respectively. These are below and above the 5000 psi maximum pressure given above, and the 5000 psi is well above the 1440 psi rating of a 600 lb. valve. It is noted from Intec, 1999 that the MAOP of the Liberty Pipeline is 1415 psi. In section 3.6, two situations that could possibly lead to operational failures associated with overpressure events on the pipeline were provided; this section was not intended to be a comprehensive description of all possible failures that might be encountered. For the steel pipe-in-pipe design, it is possible to fail the inner pipe during an overpressure event after the pipe has experienced some degradation such as corrosion. It is expected that the use of a fusion bond epoxy coating and sacrificial anodes would control external corrosion, while the annulus would be controlled to maintain a non-corrosive environment. The integrity of the external coating can be determined on the basis of anode condition and current readings.
MMS(1) – 12	The possibility of contact from outside force decreases with increased burial depth for all pipeline designs. Examples of possible contact sources include ship groundings and anchor strikes.

MMS(1) – 13	Increasing the single pipe wall thickness and its burial depth would reduce the risk. The calculations to establish at what point this equivalence occurs are outside of the scope of this project. The approach used in this report, based on historical data, would not be sensitive to these modifications and thus a new approach would need to be taken to assess this sensitivity.
MMS(1) – 14	This will be addressed during editing of the final report.
MMS(1) – 15	Until more experience with the operation of offshore arctic pipelines is obtained, the first principles approach used in this project is felt to be the most reliable method for a risk assessment of this type.
MMS(1) – 16	Assumptions concerning the failure modes and secondary containment can be found in section 8.1.2(c).
MMS(1) – 17	The base case risk assumes that all of the oil is contained in the annulus. Potential leakage due to the repair process was not considered in the draft report. Further consideration of this factor are provided in the final report in section 8. Section 8.2 discusses how the risk changes when secondary containment is not included.
MMS(1) – 18	The recommendation has been presented to identify that there has been limited operational experience with pipelines in environments such as along the Liberty Pipeline route. It might be found that operating practices include safety measures and planning that would reduce the percentage of operational failures and third party damage. This can not be evaluated for the Liberty pipeline because it has only been developed to the concept design stage. A study of the failures along the pipeline system on the North Slope could provide insight into how these measures influence failure statistics.
MMS(1) – 19	This is a correct observation. These alternatives were not considered in detail in the initial design report (Intec 2000) and thus little information was available regarding their construction. The grade of HDPE or the exact materials used in the flexible pipe were not specified in the preliminary design document (Intec 2000).
MMS(1) – 20	The MMS Gulf of Mexico “Leaks” database was obtained in hardcover and electronic formats. The database itself is a tremendous resource and holds a great deal of potential to support risk based analysis of offshore pipelines. The data in this database was reviewed and MMS staff were consulted to ensure appropriate interpretation of the data. In obtaining the data and its subsequent review the project team spoke with Alex Alvarado, Joseph Hennessey, Frank Tores and Warren Williamson, amongst others. In these informal discussions it was noted that the spill volumes reported in the database are not considered reliable since: - they may be reported by third parties - they are often visually estimated - the spill volume field in the database is not consistently filled.
MMS(1) – 21	The cost benefit analysis is outside the scope of this project.
Closing	No response required

G3.0 RESPONSES TO COMMENTS RECEIVED FROM LARRY BRIGHT OF THE US FISH AND WILDLIFE SERVICE

Comment Number	Response
General Comments	Since many of the comments expressed in this section are repeated in the detailed comments section, they are not dealt with in any detail here. FTL agrees that work to define the significance of the calculated risk values (with risk being defined in terms of the volume of oil spilled) is needed to make the results meaningful to decision makers and the public. Unfortunately, this is beyond the scope of the current project. Confidence intervals were not analysed because these would be very difficult to establish reliably, as in many cases, a large number of assumptions would be necessary to allow the analyses to proceed. The sensitivity analyses conducted in this project are a substitute as they were selected to provide information regarding the effect of the expected range of variation on the calculated risk. FTL agrees that it would be helpful to list the available information to define the consequences and event probabilities for each hazard (as opposed to just listing the risk for each hazard). The final report has been revised accordingly. The study was limited to the pipeline designs developed by Intec, 1999; 2000. FTL agrees that differences in the extent to which each design has been optimized will affect the results.
FW – 1	The Executive Summary will be revised to strike a better balance between making it more readable without making it too long.
FW – 2	The report will be revised to provide a more informative description of the risk calculation process.
FW – 3	The pipeline failure statistics have been analysed to only include events that are applicable to the Liberty Pipeline, as described in responses elsewhere. It was found that the combination of 3rd party activities and operational failures constituted a greater risk than did ice gouging, as opposed to just 3rd party activities as you suggest. In fact after reviewing the TAPS and Norman Wells failure statistics used to establish third party and operational failure rates, all of the incidents can be characterised as operational failures. The minimal significance of ice gouging reflects the fact that all of the designs for the Liberty Pipeline will be buried deeply, which greatly reduces the risk associated with ice gouging.

FW – 4	This paragraph was included to indicate that the secondary containment performance attributed to PIP systems was based on engineering judgement. In the final revisions to the report, this statement will be expanded to avoid discrediting the issue of secondary containment.
FW – 5	This paragraph will be revised in the final revision of the report to provide more details on the possible risk control practices which may be implement in the design phase.
FW – 6	The executive summary will be modified to be more definitive in its statements.
FW – 7	The risk values in Tables 1.1 and 1.2 are taken directly from Intec, 1999 and Intec, 2000, respectively, and they are in units of barrels of oil.
FW – 8	A comment of this nature is made in section 6.3.3.
FW – 9	The effect of monitoring system performance on oil spill risk was evaluated and discussed in section 8.2.3. The results of this evaluation indicate that for a single pipe system oil spill risk would increase by about 30% (see Table 8.4) if the LEOS system failed to perform. The steel PIP system was insensitive to LEOS operation due to secondary containment, while the HDPE system risk was estimated to increase by 10% in the event that the LEOS system failed to perform. See also responses to comments FW - 28 to FW - 36.
FW – 10	This statement was intended to refer to pipeline design. It was removed in the final report as it does not contribute to the overall findings or conclusions of the project.
FW – 11	This will be addressed in the final report. Figure 3.4 will be replotted to show a 4 foot cover depth. The case for 5 feet of cover was not analysed explicitly. It was interpolated based on other analysis results.
FW – 12	The factors causing uncertainties in the available information to define subgouge displacements are described in Appendix A. The effect of these uncertainties was addressed by conducting sensitivity analyses, as described in section 8.
FW – 13	This will be explained further in the final report.
FW – 14	This will be explained further in the final report.

FW – 15	The GSC model, described in section C.3.3, did not explicitly consider the inner pipe of the pipe-in-pipe configuration. The work reported in section C.3.4 completed by FTL for this project did consider strains in the inner pipe and it was found that the pipe-in-pipe configuration would experience lower strains than the single wall pipe for a given ice gouge event. The magnitude of the benefit of the pipe-in-pipe system would depend on the size of the inter-pipe annulus and the separation of the pipe spacers. No generalisation on the magnitude of the strain reduction benefit was developed in this project due to project limitations related to time, budget and the scope which did not allow the consideration of redesigned pipe-in-pipe systems. Section 4.2, which contains Table 4.4, describes the behaviour of single pipe systems with geometries similar to those used as the outer pipes of the three systems. This analysis conservatively assumes that the inner pipe of the pipe-in-pipe system does not contribute structurally. An effort will be made to provide a side by side comparison of the carrier pipe strains for the single and double wall pipe designs in the final revision of the report. Figure C10 refers to the FTL analysis of the pipe-in-pipe design while the data presented in Table 4.4 which refers to analysis results based on the GSC model which as mentioned before does not include the inner pipe. The wording of the report and organisation of the data will be improved to avoid this form of misinterpretation.

FW – 16	The scenarios noted were not considered. Wrinkling was not considered explicitly in the analysis due to the computational cost associated with the evaluation of the pipe wall strains in the wrinkled state. Several limit state equations exist to indicate the formation of a pipe wall buckle or wrinkle, however, they do not provide the post wrinkle deformed shape and thus the strains which are need to determine if failure (leakage) occurs. Currently, numerical modelling of the pipe wrinkling process is the focus of R&D work at FTL amongst others. Based on the results obtained it became evident that ice gouging and upheaval buckling were not the most significant hazard in the risk assessment. The budget and time afforded to the Liberty Pipeline risk analysis project would not permit the completion of the analysis work required to evaluate the potential for wrinkling induced failure. It was shown numerically, that the strains induced in an upheaval buckling process were not large enough to cause failure (leakage). For this reason, the potential for upheaval buckling subsequent to an ice scour was not pursued. This point will be highlighted in the final revisions to the report. The draft report did include several qualitative comments regarding the potential progress of upheaval buckling after start-up and shut down events. However, more complete treatment of this potential problem which would be applicable to all pipeline designs was not dealt with numerically. This would have required more time and resources than were available in this project's budget considering the relative significance of the upheaval buckling and ice gouging hazards. In addition, this form of analysis would require an assumption with respect to the future operation of the Liberty pipeline (frequency of shut down) to draw any conclusions.
FW – 17	Paragraph (c) is incorrect and will be revised in the final report. The temperature change of the outer pipe of the pipe-in-pipe system was investigated and the results are shown in Figure 4.2. An outer pipe operating temperature of 50 degrees was used in the stress analysis work which forms the basis of the risk analysis (see section 4.3.2). Based on this assumption, the risk analysis treats the pipe-in-pipe system fairly.
FW – 18	More information will be provided in this section to describe the analysis results. The cases referred to in Table 4.5 are those described in Table C.2. The analysis results described in Appendix C will be brought forward to Section 4.
FW – 19	As discussed in the response to comment FW - 15, the results presented in Figure 4.4 are based on FTL's modelling work which explicitly included the inner pipe of the pipe-in-pipe system while Table 4.2 relates to the GSC model which does not include the inner pipe. As noted in the previous response Section 4 will be revised to provide more detailed results and description.
FW – 20	More details of the analysis results will be included in the final draft of the report. The significance of Table 4.5 will be described in more detail.

FW – 21	It was shown numerically that the strains induced by upheaval buckling and strudel scour events do not pose a risk to the integrity of the pipe. This point is noted in section 4.8.4.
FW – 22	Confidence intervals have not been assigned to the hazards, as there are insufficient data points to calculate these intervals.
FW – 23	ILI service companies list minimum detection capabilities and do not provide confidence levels over the range of metal loss depths. Liberty would have to establish its own specific confidence levels as the tool capabilities are influenced by the tool speed, the product being transported, and the steel quality (inclusion distribution). It is expected that Liberty would be able to develop a consistent monitoring program.
FW – 24	The enhanced performance that has been assigned to improved coatings and inspection is consistent with the risk assessment techniques that have been implemented over the past decade. The increasing failure rate due to external corrosion that has been observed and is reflected in the databases is considered to have resulted from the use of thin film polyethylene tape in the 1970s. The current epoxy coatings are expected to perform at least 10 times better than the polyethylene tape. Similarly, many failures within the data are on lines that do not have traps for launching and receiving internal inspection tools. If traps are available and have been used in the past, one would expect a tenfold improvement in failure rates with the inspected line. With the current improvements in high resolution inspection tools, it is expected that pipeline operators can expect an additional tenfold improvement in failure rates, particularly with the inspection schedule that will be implemented for Liberty.
FW – 25	It is recognized that the exterior surface of the inner pipe can be coated and cathodically protected. Fleet believes that the protective coating has a high likelihood of being damaged during installation or operation due to relative pipe movement. Also, there is no guarantee that the internal CP system will deliver protective current to the damaged area. The lower corrosion potential for the C-Core analysis assumed that the annulus would be packed with nitrogen. This is a possible design, but it has not been finalized. As the designs of the pipe-in-pipe alternative had not been finalized, it was decided to err conservatively in agreement with the Intec approach for external corrosion of the inner pipe.
FW – 26	These tables will be revised in the final editing of the report.
FW – 27	The approach suggested by C-Core will be included during editing of the final report.

FW – 28	Through-the-ice monitoring as ‘the’ method of low level leak detection would increase the potential size of spills as one cannot be assured that the sampling will coincide with the pool of oil, and there are uncertainties related to ice access and weather conditions. Furthermore, through the ice monitoring is not applicable for the whole year. The focus of this study was to compare the four design alternatives. If one were to rely on through the ice monitoring, the effects of secondary containment would become much more significant in the risk analysis. (see also comment FW - 34)
FW – 29	It was recognized that all of the leak detection systems would not be operational at all times, but it was presumed that at least either the MBLPC or PPA would be working, and that LEOS will draw a sample once per day according to its regular monitoring schedule. Information from the LEOS installation on Northstar suggest that there is a very high likelihood that the system will perform as expected.
FW – 30	The MBLPC system would be expected to be able to detect a 225 bbl discrepancy between readings taken at a 5 minute interval. As the time interval is increased, the detection capability will improve to the 100 bbl discrepancy over a 24-hour period. The spill rate has been revised and changes have been made to the final report.
FW – 31	There have been no installations in this environment from which to obtain information to quantify the likelihood of failure. However, based on review of the literature describing the system and its growing use for leak detection, it is considered that this technology has matured to the point where any field problems can be remedied and the system is expected to function as intended. In an attempt to include this uncertainty in our analysis the expected worst case performance for the LEOS system was defined (see Table 6.8) and this data was used to define one of the sensitivity studies presented in section 8.2.3.
FW – 32	The conclusion that the LEOS system can be safely installed was reached following personal communication with Peter Bryce who spearheaded the LEOS design for Northstar. The successful installation was demonstrated through pneumatic testing. More details are given in section 6.3.3. We agree that the LEOS tube is not yet functional and this point is noted in the report in section 6.3.3.
FW – 33	See response to item FW - 34.
FW – 34	Another scenario related to LEOS failure and subsequent through the ice detection after 60 days of leakage will be considered. Table 6.8 will be revised, for the sake of comparison, to include a 32.5 bbl/day leak for 60 days generating a total spill volume of 1950 bbl. This is the same order of magnitude consequence as a rupture event. These comments will be noted in the final report in the sensitivity studies in section 8.
FW – 35	The table will be revised to show a spill rate of 112.5 bbl/day.

FW – 36	Our investigation into this technology showed that LEOS technology has been around for many years and is now becoming widely accepted (and installed) as a proven leak detection technology (see section 6.3.2). There have been obstacles to overcome with design changes over the years and these have been successfully developed. The only uncertainty remaining with the Northstar installation has to do with the background hydrogen level that arises from the use of cathodic protection. This will be overcome with the Northstar trials, and the system should be better than a prototype when installed on Liberty. The significance of this assumption will be investigated further and reported in section 8 of the final report.
FW – 37	Based on the high level of scrutiny that this project and the Northstar project have received, FTL expects that the Liberty pipeline would be operated with due diligence. The information presented in section 6.2.1 indicates that a 5-minute interval would be a conservative estimate of the time to detect a leak as Liberty is short line and the polling rate is less than 1 second. The PPA system would confirm the initial leak warning within a minute and it is expected that line shutdown would be initiated. The consequences of a longer response time are explored in Table 7.11. The total oil spill volume is not very sensitive to this response time because the great majority of the oil release is due to drainage of the line after shut down.
FW – 38	Table 7.6 will be revised to show a maximum drainage volume of 1880 bbl.
FW – 39	Our opinions have been presented above and this will be addressed in the final report.
FW – 40	This assumption was made because small defects would tend to close upon depressurisation and in any event the pressure head across the opening is small thus the leakage rate would be very low.
FW – 41	A seepage event has been defined as oil escaping the carrier pipe. The 0.01565 figure includes seepage to the environment in a PIP system.
FW – 42	The description of these results will be given more attention in the revised final report.
FW – 43	This will be addressed in the final report
FW – 44	This will be considered in revising the final report. Consideration to the significance of the uncertainties was completed as part of the sensitivity studies in section 8.
FW – 45	FTL agrees that a final report presentation and discussion session in the form of a workshop would prove to be a valuable means of further disseminating the results of this work.

G4.0 RESPONSES TO COMMENTS RECEIVED FROM PETER HANLEY OF BP EXPLORATION

Comment Number	Response
BP – 1	The report will not be published for another 4 months. FTL has changed the report reference to a more appropriate reference to the GSC model.
BP – 2	Since no target or threshold risk values, indicating acceptable risk levels, are available in design standards and none are offered in by BP or the US Department of the Interior it would be difficult to say that the risk is low. It is noted, however, that the calculated oil spill risk values estimated by FTL are more than three orders of magnitude higher than those estimated by Intec (Intec 2000).
BP – 3	See response to comments made by the MMS during the Sept. 5 conference call (section G6) and section 8 of the report.
BP – 4	This conclusion was noted in the draft report and is the basis for the recommendation that the potential for control of operational and third party risks be investigated. It is felt that these sources of risk can be effectively controlled through: - sound operating practice and operator training (as discussed in section 3.6.2), - good public relations and awareness, and - capable modern pipeline control systems. Since no information on the above topics was provided in the preliminary design, no judgement on their effect was possible. It is suggested that it is well within the capability of the Liberty Pipeline operator to virtually eliminate these sources of risk through investment in the three mitigation strategies listed above. The failure statistics for the Alyeska and Norman Wells pipelines were scrutinized and only the ones considered to be applicable to the Liberty pipeline were used to draw conclusions. The operational failures from Alyeska and Norman Wells focused on the pipe body and welds, at least for any failures over 100 bbl. The failures less than 100 bbl did not have any causes listed with them and it is recognized that this no doubt overestimates the failure occurrences. Nonetheless, since the volumes released are very small in relation to the total volume spilled, this represents only a small increase in risk. The increased wall thickness and comprehensive inspection schedule for the Liberty Pipeline have been included in the corrosion failure estimates.
BP – 5	The two failures for permafrost thaw subsidence were not for the TAPS events. The two “pipe settlement” events for TAPS were caused by slope instability as opposed to permafrost thaw. The source of the permafrost thaw subsidence events was the DOT database as discussed in section 3.4.3. Failures due the thaw subsidence would not likely occur, and this is reflected by the low risk associated with this failure mode.

BP – 6	Table 8.3 and the text describing it will be expanded in the final report to demonstrate how the final risk values are developed.
BP – 7	The reasoning behind the secondary containment argument is discussed in section 8. The increased wall thickness and comprehensive inspection schedule for the Liberty Pipeline have been included in the corrosion failure estimates.
BP – 8	The study was based on the presumption that each design would be built and maintained to high standards. An analysis of the reliability of various construction methods was considered beyond the scope of this project. Consequently the additional QA activities were not considered in our analysis.
BP – 9	An "As Low As Reasonably Practicable" ALARP approach to risk management is used effectively in a variety of industries to avoid having to define acceptable risk levels for design. In this approach the feasibility and cost of risk control techniques are considered to eliminate as much risk as possible with the resources and technologies at hand. The acceptable level of risk has not been discussed in the final report because this is a multi-faceted, complex issue that was not investigated in this project because it was beyond the scope of the work. (see response to item BP - 2 as well)
BP – 10	The uncertainty expressed in this section relates to third party and operational failure rates. The difference in risk is developed based on both these failure rates and the expected secondary containment performance of the PIP systems. Therefore the difference in system performance would exist regardless of modifications to the operational and third party failure rates. This comment will be considered further in the final revisions to the report in section 8.
BP – 11	The wall thickness and inspection has been considered in the corrosion failure occurrences. The absence of valves, flanges, and fittings has also been considered through the removal of associated failures from the failure database. One cannot generate operational histories for pipelines which do not exist, therefore, in the design process it is necessary to estimate the expected performance of a pipeline based on the most relevant experience base available. As noted in the report the operational failure database used in the risk analysis was developed considering the operational histories of the two most representative pipelines. The applicability of this historical data, its modifications to consider pipe configuration differences and the removal of inappropriate events were noted in the report text in several locations. In preparing the final draft of the report, these comments will be highlighted and expanded upon.
BP – 12	Of the combination of operational failures and third party activities, operational failures represent essentially all of the events used to generate the analysis statistics. Hence the assumption regarding whether or not a third party activity would fail both the inner and outer pipes, of a PIP system, or not would not change the conclusions significantly.

G5.0 RESPONSES TO COMMENTS RECEIVED FROM MIKE PAULIN OF INTEC ENGINEERING

G5.1 Responses to Summary Comments

Comment Number	Response
Preamble	No response necessary
Intec – 1	Since no target or threshold risk values, indicating acceptable risk levels, are available in design standards and none are offered in by BP or the US Department of the Interior it would be difficult to say that the risk is low. It is noted, however, that the calculated oil spill risk values estimated by FTL are more than three orders of magnitude higher than those estimated by Intec.
Intec – 2	Agreed.
Intec – 3	As outlined in the report, the data represents the most relevant data available to the design project. This data was reviewed to remove irrelevant failure events. In the absence of industrial historic performance data for offshore arctic pipelines, the Norman Wells and TAPS pipelines offer thermal, structural and operational conditions which are closely related to the Liberty pipeline.
Intec – 4	The corrosion failure rate reduction in a PIP system is based on the fact that more wastage must be realized to produce a through wall corrosion feature, resulting in leakage.[PARA]This issue is considered further in the revised section 8 of the final report.
Intec – 5	Agreed. The project team's best engineering judgement was applied. Until completion of the detailed design of the operating system (including operator training, monitoring systems and operational procedures) oil spill risk can not be evaluated with more certainty. In a similar fashion, the potential for third party damage can not be more definitively estimated without either more operating experience or a better understanding of the public acceptance and/or awareness of the project.
Intec – 6	See response to comments made by the MMS during the Sept. 5 conference call (section G6) and section 8 of the report.
Intec – 7	The recommendation has been presented to identify that there has been limited operational experience with pipelines in environments such as along the Liberty Pipeline route. It might be found that operating practices include safety measures and planning that would reduce the percentage of operational failures and third party damage. A study of the failures along the pipeline system on the North Slope could provide insight into how these measures influence failure statistics.
Intec – 8	Agreed. Details of all data and calculations are provided in the report and its supporting appendices. Effort has been expended in identifying opinions as such.
Closing	No response necessary

G5.2 Responses to Detailed Comments

Comment Number	Response
Intec – 10	The report will not be published for another 4 months. FTL has changed the report reference to a more appropriate reference to the GSC model. (see section G6)
Intec – 11	See comment Intec - 1.
Intec – 12	Refer to Section 8.1.2(b and c) in which these statements are made. Operational failures are typically characterised by uncontrolled pressure events. As such they affect the integrity of the pressure retaining pipe (e.g. over pressure leading to leakage at a girth weld flaw) oil spills should be contained within the annulus unless the location and timing of the operational failure coincides with some other damage mechanism such as a corrosion based outer pipe loss of water tightness. This combined event will have a relatively low probability of occurrence due to its multiple failure mode requirement and due to the reduced corrosion rate on the outer pipe as discussed in item Intec - 4. This topic is discussed further in section 8 of the final report.
Intec – 13	See section G6 for more discussion on this comment.
Intec – 14	One cannot generate operational histories for pipelines which do not exist, therefore, in the design process it is necessary to estimate the expected performance of a pipeline based on the most relevant experience base available. As noted in the report the operational failure database used in the risk analysis was developed considering the operational histories of the two most representative pipelines. The applicability of this historical data and the removal of inappropriate events was noted in the report text in several locations.
Intec – 15	It is possible to group failures as design and operational based on how their risk is mitigated. Operational, including most third party, risks are mitigated and possibly eliminated through: - sound operating practice and operator training (as discussed in section 3.6.2), - good public relations and awareness, and - capable modern pipeline control systems. No information on the above topics was provided in the preliminary design and thus no judgement on their effect was possible. Therefore, it was suggested that further investigation into these mitigation techniques could be pursued.
Intec – 16	See response to MMS(1) - 18. This is considered further in section G6 and section 8 of the final report.
Intec – 17	Appropriate reference to these tables is given in the text, however, for clarity, a reference will be attached to the tables. The risk level variation for the designs which do not change from one report to another can not be explained by the authors.
Intec – 18	This description will be clarified to read “a layered composite flexible carrier pipe”.

Intec – 19	While in general, low D/t pipe geometries represent stiffer pipes, they also represent more costly configurations. The general costs and benefits of a range of pipe D/t ratios was not considered in this project and thus a general comment on their advantages for offshore arctic pipelines would be inappropriate. The scope of this project was to estimate the risk posed by the four designs put forward in the preliminary design, not to redesign the pipeline.
Intec – 20	No response required.
Intec – 21	The information in the FEIS was reviewed and was used as supporting information where appropriate. The information used was properly referenced.
Intec – 22	These coupled loading events are shown to be low probability events. However, this was not known to be the case when the investigation was initiated and due to the short duration of the project there was no time to do a first level screening of insignificant hazards. The results of this analysis were included for the sake of completeness, had they been left out their absence could have been questioned. The report does contain a discussion of these events, however, in response to this comment, the authors will review the clarity and completeness of the discussion.
Intec – 23	Agreed. However, the fact that site-specific surveys have only been done in 2 years (i.e., 1997 and 1998) is the major reason for the small data set.
Intec – 24 & Intec – 25	Subgouge soil displacements – For the base case risk analysis, FTL used the same subgouge algorithms that were used by Intec, 1999; 2000 (section 8). The uncertainties associated with the information available to define subgouge soil displacements were investigated to establish an appropriate range for this parameter for the sensitivity analyses done as part of the risk evaluation (in section 8). For analyses done with this purpose, it is necessary to focus the investigation on the expected uncertainty that would lead to higher soil displacements than the values predicted by the soil displacement algorithms used. The potential sources of error are identified, presented and discussed in Appendix A, and summarized in Table A3 of the report. A value higher than 10 would be obtained if the worst-case combination of all error sources were taken. However, it is unreasonable to expect that this worst-case combination would in fact occur. FTL selected a factor of 10 for the sensitivity analyses to provide an upper-range value. It should be noted that the calculated risk for each pipeline design was insensitive to this assumption, as the risk due to ice gouging was found to be a very small proportion of the total risk. The comment by Blanchet et al, 2000 (regarding the effect of a pipe on subgouge soil displacements) is already included in the report (pg A-20). Unfortunately, the detailed information on which this comment is based is not available to BP or FTL (Blanchet et al, 2000) which makes it impossible to include an allowance for the effect of the pipe in this quantitative risk evaluation, as stated on pg. A-20.

Intec – 26	a) Repeat of item Intec - 22 b) It does not matter how small a length of pipe experiences the peak strain value since failure, separation of the pipe, occurs at a single plane section which by definition has zero length. If the failure mechanism is considered, the potential buckling or wrinkling damage in a pipe section will facilitate and possibly concentrate future deformation at this damaged location. c) Repeated post yield load reversal will consume a materials limited ability to deform (ductility) as is the case in a fatigue type of failure. It would be unconservative to disregard the potential for a low cycle fatigue type of failure. In addition, the ovalisation and potential buckling or wrinkling which may be associated with excessive flexural deformation does not simply reverse to produce a zero strain state. Reversal of post yield deformation effectively reduces the yield strength of a material, as described by the Bauschinger effect, thus facilitating gross section collapse. d) The project team was not prepared to incorporate this form of anecdotal information. Please note that the design strain limits used in this study are based on physical trials and are viewed by the authors as conservative, yet they are considerably larger than those used in the preliminary design process.
Intec – 27	Multiple gouge events do not assume a lack of surveillance, they assume that the pipeline has not been repaired prior to the second event. This lack of repair could results from both ice gouge events occurring during a single ice season.
Intec – 28	Risk is defined in sections 2.1 and 2.7 as the expected volume of oil spilled from the pipeline over its 20 year life. This quantity is estimated as the sum of the all of the risks associated with each failure mode. When considering a single hazard, risk is defined as the expected volume of oil spilled from the pipeline over its 20 year life due to the mode of failure of interest. This point will be clarified in the report.
Intec – 29	It was noted that this mode of failure was shown to be remote as indicated by the comment. Therefore the probability of coincidence of a pipe overbend and a strudel scour was not pursued to save project resources instead the probability of an overbend given a strudel scour was conservatively assumed to be 1.
Intec – 30	The failures attributed to thaw subsidence were listed by Hovey and Farmer, 1992 as having occurred in 1988 and 1991. (Note: Any of the Hovey and Farmer references are limited to analysis of DOT data between 1982 and 1991.) The TAPS events occurred in 1979 and they were not caused by permafrost thaw subsidence. An analysis of how the pipeline dimensions influence the likelihood of thaw subsidence was beyond the scope of this project.

Intec – 31	The two pipe settlement failures reported in Table 3.5 are related to slope movements. This is based on the information collected from the Alyeska web site concerning the two failures in question: - June 1979 - MP 166.43 - north side Atigun Pass; hairline crack caused by buckle. Covered with 56-in. dia., 6-ft. welded split sleeve; 19 steel supports installed. Pipe reburied. - June 1979 - MP 734.16 - 1 mi. north of PS 12; hairline crack caused by buckle in pipe. Covered with 56-in. dia., 6.1-ft. welded split sleeve; 7 steel supports installed. Pipe reburied. The two pipe settlement incidents included in the draft version of Table 3.5, were considered to be caused by pipe movement down a steep slope, not thaw settlement. This conclusion is based on both occurrences being located in mountain pass regions (see the elevation drawing at the bottom of this web page http://www.alyeska-pipe.com/factbook/fact_2e.html). Upon reflection, slope movement based failures are not applicable to the Liberty pipeline and thus these two failure events will be removed from Table 3.5. The remainder of the report will be revised to reflect this change.
Intec – 32	Other than the fact that the Hovey and Farmer thaw subsidence failures were not the same failures as the two Alyeska pipe settlement failures, no additional information is available at this time.
Intec – 33	The 0.5 % of the total number of failures included subsidence and frost heave together as both are related to temperature effects on the pipeline. The authors are aware of other data related to pipe movement attributed to thermal loads on the Norman Wells Pipeline, but there have been no failures associated with this line due to thermal loads.
Intec – 34	Most pipelines will be designed to have wall thicknesses in excess of that required for internal pressure design when a potential for external loads exist. It is believed that the text in section 4.7.4 is misquoted in this comment. The pipe geometry reduces or makes the probability of failure low, just like the probability of an ice gouge. The beneficial effect of the thick walled single pipe option is considered in the analysis.
Intec – 35	See section 3.9.2.
Intec – 36	This comment reflects typical situations for land-based pipelines. However, the risk calculations in the report do give credit to the monitoring systems that will be put in place by using their expected performance to define the consequences of a seepage failure. Further discussion of this point is included in section 8.
Intec – 37	Amongst other reasons for using the Alyeska and Norman Wells data was the fact that 100% of the welds were inspected as would be the case in an offshore pipeline. This point will be clarified in the text.
Intec – 38	These statements taken out of context do in fact sound contradictory, however, as noted in a previous response (Intec - 14), one can not fabricate operational history statistics. Operational performance is generally inferred from that exhibited by systems which are similar. See section 3.9.1.
Intec – 39	See section 3.9.2 in the revised report.

Intec – 40	This assumption is acknowledged in the text. Furthermore the total risk will not be sensitive to this assignment.
Intec – 41	Every effort was made to separate out inappropriate failure events, such as those associated with valves, flanges and fittings. However, some of the failure events, did not have a clear cause associated with them, thus they were conservatively retained. Removing this event data could potentially underestimate this element of risk.
Intec – 42	See Intec - 31. The sensitivity analyses on page 8-10 state that thaw subsidence and upheaval buckling did not influence the total risk. These concerns were presented for completeness in the analysis, but were later determined not to influence the total risk. The Hovey and Farmer thaw subsidence failures were not the Alyeska failures.
Intec – 43	The level of inspection (100% weld inspection) for the three pipelines in question were the same. The effect of leak detection systems could not be conservatively considered in the statistical data reduction process, however, it is noted that (see section 7) leak detection systems were not entirely effective in reducing the volume of oil spilled due to leakage after line shut-down. The differences between the Liberty pipeline will be discussed in section 3.9.2.
Intec – 44	The analyses completed in this work seem to contradict this comment. The analysis results indicate that the treatment of the problem as a large displacement analysis change the results significantly as discussed in Appendix C.
Intec – 45	This point relates to the behaviour of the pipe after the deformation and identifies upheaval buckling as a potential reaction to the reduction in pressure and cooling of the pipe associated with a shut down. This comment will be reviewed and clarified.
Intec – 46	The comment in question was added to provide further information regarding the interaction process, and its analysis. This effect would be most important if the pipe were to be buried relatively close to the seabed surface. The text in the main report will be clarified.
Intec – 47	The axial strain delay indicates that the internal pipe is somewhat longer than the outer pipe and thus the outer pipe would experience higher strains than the inner pipe. It is noted that the discussion referred to is intended to describe a benefit which may be attributed to a PIP system regardless of how sub-optimal it is. While, the suggestion to ignore a benefit of a competing pipe configuration because it is small seems rather odd, in fact, this benefit was not considered in the FE upon which the risk analysis is based.

Intec – 48	It is more likely for the location of maximum curvature to be located at some location other than at a PIP spacer, than it is for the PIP spacer to precisely coincide the location of peak curvature. This potential source of nonconservatism was recognised and thus full advantage of the curvature reduction is not taken advantage of as described in Section 4.3.4. This area of the report will be reviewed and clarified. The “conservative Liberty pipeline design approach applied by BPXA (INTEC)” was not followed since it treated all of the pipe configurations and single walled pipes, thus eliminating any potential for realising the benefits of a PIP system.
Intec – 49	The project was not intended to develop new designs, but rather it was focused on evaluating the existing designs. The evaluation of the “critical length” was not addressed in this project.
Intec – 50	Noted. The purpose of the comparison of the annular gap was to provide a check with respect to existing configurations. It showed that the annular gap for the Liberty PIP system was considerably less than existing PIP systems.
Intec – 51	The scope of the project did not permit the comparison of pipeline designs other than those offered by Intec. Some of the benefits were described in Appendix C, however, the authors agree that PIP system optimisation has not been fully explored in this or any other study.
Intec – 52	All of the PIP analysis cases indicate that the inner pipe experience lower strains than the outer pipe. It is believed that this demonstrates the fact that the outer pipe would reach a critical tensile strain state before the inner pipe. It is noted that there is no arbitrariness in failure mode selection involved here. This statement applies to all of the cases investigated.
Intec – 53	The inner pipe in a PIP system is free to follow a different displaced shape than the outer pipe and therefore will tend to adopt the lowest energy deformed shape possible. Based on this note the authors disagree with this comment. For the Intec design with a small annulus this comment is correct, however, if a larger annulus were allowed between the inner and outer pipes the curvature of the inner pipe could be significantly less than that of the outer pipe. It is noted that the separation of the spacers will also effect the reduction in inner pipe curvature.
Intec – 54	This assumption is made to simplify calculation process, since the resulting strains are insignificant in terms of the pipe failure strain. This statement in the report will be reviewed and revised for the sake of clarity.
Intec – 55	See response to Intec - 54.
Intec – 56	This revision will be made in the final report.
Intec – 57	It is unclear how inspection tools will reduce the corrosion rate. They could be used to monitor and measure corrosion and this be used to indicate when maintenance would be required. However, no information was given regarding the proposed maintenance management process which would be applied to the Liberty pipeline, thus it could not be considered.

Intec – 58	The Concawe data is considered to match the Liberty case on the basis of the corrosion failure rates. The MMS and DOT statistics included many small diameter lines that were not regularly inspected, or were subject to high failure rates as they had high water contents or low flow rates. The Concawe pipelines included more large diameter lines which were regularly inspected, and thus were considered to be the most representative of the Liberty Pipeline.
Intec – 59	This editorial error was noted shortly after the draft final report was submitted and will be corrected in the final report.
Intec – 60	The wording in this area of the report will be improved to recognize that the amount of oil lost after remedial action has been initiated will depend on the size of the opening in the pipe.
Intec – 61	The intention was to determine the maximum spill volume that could occur through a stable crack. Therefore the maximum stable crack size was calculated.
Intec – 62	INTEC is correct in suggesting a base metal CTOD of 0.04 inches, however, it would be unconservative to use this value in the analysis since the failure location is not known. Research has shown that in high strain situations, plastic strains can be concentrated at welded connections in which the weld metal strength over matches the base metal. This result also suggests that the use of a base metal CTOD value would be unconservative.
Intec – 63	This equation will be checked.
Intec – 64	Leak detection systems identify that a leak is occurring, however they do not stop the leak. A well trained operator will respond to the leakage reported by the leak detection system and shut down the pumps and isolate the line. This action does not however stop leakage, it slows it by reducing the pipe internal pressure. Leakage will continue until the pipe is emptied either through leakage or purging.
Intec – 65	This comment is correct and was considered in the analysis. The nature of the failure will determine the time required to empty the pipeline. The intention of this comment is unclear.
Intec – 66	The reference to Table E-5 should be changed to E-7. This editorial error will be corrected in the final report revisions. FTL used the failure occurrences from Hovey and Farmer for the DOT failure statistics as they provided the most likely estimate of event occurrences that could be applied to Liberty from the failure statistics that were examined.
Intec – 67	This point was noted in the report in section 7.5.2. This assumption was made to conservatively estimate the failure consequences and because there was insufficient time in the project schedule to investigate it in detail.
Intec – 68	This editorial error will be corrected.
Intec – 69	This point will be addressed in section 8.

Intec – 70	This comment is not clear. It compares the consequence mitigation capabilities of the PIP system to the thickness of the single wall pipe which has no means of consequence mitigation in the event of leakage. If this comment is in reference to the relative probabilities of failure, then it is noted that multi-layered surfaces are much more difficult to penetrate than single layered surfaces of equal or greater thickness. This difficulty of penetration could be related to fatigue, fracture or impact forms of damage and is related to the fact that in a multi-layer surface multiple cracks need to be initiated to breach the surface and crack initiation requires a significant amount of mechanical energy. This comment will be addressed further in section 8 of the final report.
Intec – 71	Short of an explosion, the annulus volume would provide sufficient space for the fluid to expand and thus depressurise before causing damage to the outer pipe. Based on this information the assumption is not considered unreasonable. This point is discussed further in section 8.
Intec – 72	This is a valid comment. As stated previously, the vast majority of the failures comprising the combination of third party and operational failures are due to operational failures.
Intec – 73	This additional information will be provided.
Intec – 74	Agreed.
Intec – 75	Third party damage constitutes an insignificant portion of the total risk. See comment on Intec - 72.
Intec – 76	While it is true that the single wall pipe is much thicker than needed to contain the internal pressure, this comment is unclear since none of the failure modes considered relate to bursting the full thickness pipe section. The only overpressure events considered are related to reduced pipe wall sections due either to corrosion or weld flaws. Credit was given for the thick wall of the single pipe alternative when considering corrosion related failures.
Intec – 77	The study was constrained to the pipeline designs provided by Intec (Intec 2000). Given the high level of scrutiny that this project has received to date one would expect that designs that suffer these problems would not be put forward. Therefore the study was conducted based on the presumption that the designs could be built reliably.
Intec – 78	Consideration of pipe system cost was beyond the scope of this project.
Intec – 79	Agreed. See section G6.
Intec – 80	The land based portions of the pipeline were not included in the scope of this project. In addition, the reduced safety of the PIP system associated with the inner pipe exiting its casing would be analogous to the reduction of the single pipe section to a thinner walled pipe for the onshore section of the pipeline.
Intec – 81	Table 8.5 is intended to estimate an upper bound on risk for all configurations. No bias is understood to exist in this table. The adverse effects of changes to analysis input data are used to modify the risk associated with the base case (assumed input data) risks. The base case risk for the steel PIP estimated is simply modified to consider adverse changes to the input data.
Intec – 82	See response to BP - 2.

Intec – 83	See response to comment BP - 9.
Intec – 84	This is the same comment as Intec 7. See the response to Intec 7.
	Responses to Comments on Appendix A – Initiating Events: Ice Gouging
Intec – 85 & Intec - 86	The field survey data are incapable of distinguishing the direction of travel of the ice feature that created a particular gouge although they do define the orientation of the gouge. It is recognized that gouges will tend to be aligned with the wind and current direction, especially winds. However, it is known that winds are variable, and thus the multiple gouging scenario is possible. This would cause a stress reversal on the pipe.
Intec – 87	Further analyses of the multiple gouging scenario are not considered to be useful for the Liberty Pipeline in view of the fact that this hazard is a very small component of the total risk for the Liberty Pipeline.
Intec – 88	We agree that the “50 %” is an assumption. The most conservative assumption would be to assume that every re-gouging event leads to a stress reversal. This is believed to be overly conservative in our opinion, as was stated in the report. We believe that the “50 %” assumption will prove to be more reasonable although more investigation is required to confirm this. However, further investigation of this assumption is not warranted because this will not affect the overall conclusions of the study as the risk associated with ice gouging is a very small proportion of the total risk.
Intec – 89	See reply to Intec-24.
Intec – 90	This statement is incorrect. FTL stated that the published information available from field observations (for verifying the C-CORE centrifuge results) is mainly qualitative in nature. As stated in the report, only the summary information that has been published was reviewed. The PRISE reports were not available to the project team, therefore, they were not reviewed.
	Responses to Comments on Appendix B – Initiating Events: Strudel Scour
Intec – 91	No response required
	Responses to Comments on Appendix C – Lateral Deformation Structural Response
Intec – 92	It is believed that the stress analysis work performed as part of this project fairly treated all of the alternative designs. It would be possible to say that the treatment negatively biased the results towards the steel PIP system by not considering the full curvature reduction benefits or the benefits of axial “deflection delay” of the PIP system. The comment regarding the “strain increase due to column buckling” is not reasonable in the case of the small annulus PIP design put forward as a design alternative for the Liberty pipeline. This configuration as such a small annulus between the inner and outer pipe that only a very small amount of deflection of inner pipe would be possible before contact with the outer pipe provided lateral support.

Intec – 93	The references for the table entitled “Designed, Operational and Abandoned Pipe-in-Pipe Pipe Configurations” are noted below the table. As denoted in the table some of the pipelines represent designs which are not yet in service. The listing will be reviewed to try and reduce any confusion. Logstor Ror pipeline information may be collected from their web site www.lrindustri.com. This table is only used as an indication of the pipe configurations considered by others and demonstrates the peculiarity of the small annulus proposed in the INTEC steel PIP solution.
Intec – 94	This comment appears to be incorrect in light of the treatment of the problem using equation C4 which considers pressure and thermal loads.
Intec – 95	It is agreed that in the case of the small annulus PIP design put forward by INTEC that most of the difference between the inner and outer pipe strain is due to the difference in pipe diameters. This would not be the case if the PIP design were optimised to take advantage of a larger annulus to reduce inner pipe curvature. This steel PIP configuration optimisation, which was beyond the scope of this project, was the subject of the recommendations of this project.
	Responses to Comments on Appendix D – Upheaval Buckling Analysis
Intec – 96	No information concerning in-service maintenance programs was available in the preparation of the report thus the restoration of pipe cover was not considered. The authors of the report agree with the comment that upheaval buckling is not a concern in terms of pipe leakage. This point was demonstrated in the report numerically for the sake of completeness and then reported as an insignificant mode of failure.
Intec – 97	The calculations were included in the report to numerically demonstrate that this mode of failure is not significant, and thus rule out any future comments regarding the omission of this mode of failure in the analysis. In preparing the report it was decided to document all calculations for the sake of completeness which FTL feels is good practice.
Intec – 98	This statement will be modified to denote that the consideration would be conservative. The application of these results would over estimate the expected bending strains. This conservative simplification is used since this behaviour would not produce a leak and thus it did not merit detailed analysis.
	Responses to Comments on Appendix E – Failure Statistics Analyses
Intec – 99	The wall thickness and inspection has been considered in the corrosion failure occurrences. The absence of valves, flanges, and fittings has not been considered in the review of the Appendix E data. However, Appendix E data was not used in the risk assessment.

G6.0 RESPONSES TO COMMENTS RECEIVED FROM THE MMS VIA CONFERENCE CALL

G6.1 Brief Responses To Comments

Comment Number	Response
Preamble	No response required
MMS(2) –1	Additional sensitivity studies were performed to consider the post damage event performance of the various pipeline systems. This additional information is presented in section 8 and in section G6.2.
MMS(2) – 2	Reference to the GSC report was removed and replaced with a reference to the GSC model which is described in the FTL report. A letter from GSC has been included in this report, indicating the description of the GSC model and its results are accurate. See section G6.3
MMS(2) – 3	The report will be delivered electronically on September 11, 2000 with hard copies following by courier.

G6.2 Discussion of Additional Sensitivity Studies

MMS(2) – 1 (a) and (b) – The aftermath of an event could affect the risk in a number of ways:

(a) Oil could be released during the process of repair. This is discussed in section 8.1 of the main report.

(b) The pipeline might not be restored to its original integrity by a repair. Its effect on risk was not investigated as repair techniques were not specified by Intec, 1999;2000 because their designs were only developed to the concept stage. Furthermore, an analysis of this issue was beyond the scope of the current risk investigation. Hence, statements based on quantitative analyses are not possible, especially within the short time frame available to address this question.

It is our opinion that, although this effect will increase the risk, the overall conclusions of the study will not be influenced greatly because:

(i) failures arising from the hazards are infrequent events, and hence, the probability of a combined event, in which two failures occur in the 20-year life of the Liberty Pipeline, is quite remote.

(ii) this is a concern for each of the pipeline designs.

MMS(2) – 1 (c) – The risk due to corrosion was higher for the steel pipe-in-pipe design to account for the fact that the condition of the outer pipe can not be monitored.

The unknown condition of the outer pipe will also affect the risk for hazards due to corrosion, minor incidents involving third party activities and operational failures (<100 bbls), and major incidents involving third party activities and operational failures (>100 bbls). This has been considered further. See section 8.1 of the main text.

MMS(2) – 1 (d) – The available information to define failure rates resulting from operational failures and third party activities are inadequate to allow the two hazards to be separated. However, they are considered to be adequate for determining the risk due to the combination of these two hazards.

MMS(2) – 1 (e) – The increased risk for the steel pipe-in-pipe design due to the annulus flooding with seawater was not considered because the study was based on the presumption that each design would be built and maintained to high standards. Thus flooding would not be expected to occur during construction.

It is recognized that flooding would occur as part of the aftermath of a failure event, and that the integrity of the pipeline may not be fully restored by repairs done. The effect of this on the pipeline's risk can not be evaluated as repair techniques have not been specified. Nevertheless, given the high standards that the Liberty Pipeline project would likely be required to meet, it is reasonable to expect that any repairs would be done to a level that would restore the Liberty Pipeline to close to its original condition. In this case, it is unlikely that seawater flooding into the annulus would affect the study conclusions greatly, recognizing furthermore, that failure events are rare occurrences.

A similar concern could be raised for the other pipeline designs as well (regarding the effectiveness of a repair).

G6.3 E-Mail From Dr. Konuk

Email

Sent by : Dr. I. Konuk (Geological Survey of Canada)
Date: Sept. 5, 2000
Subject: Use of the GSC's Work in FTL's Risk Evaluation Project for the Liberty Pipeline

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George:

This will confirm our telephone conversation and agreement that Fleet is
permitted to use the results, that we have provided, in their report as long
as appropriate credit is given to GSC where it is used as done in July 2000
draft of your report and we are not in any way limited in the publication of
this work. We intend to publish more detailed information on our work in this
area including the models and input files both for ANSYS as well as my own
FEM code through regular scientific methods. Until then, we do not intend to
release information beyond what is provided in the Fleet Liberty Risk
Analysis Report - July 2000 draft.  I would truly encourage any other party
to contact me if they have interest in our work or collaborating with us in
this area.

I also would like to add that the description of our model and the results
quoted in the July 2000 draft of the Fleet report accurately reflects what we
have provided to Fleet technology.
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I truly appreciate your collaboration in this very interesting project and confidence on our results. We hope to continue this collaboration in the future.

Best regards;

Ibrahim

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