# NORTHERN PIPELINES

# Overview of technical issues surrounding northern pipelines

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Yukon
Economic Development

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# OVERVIEW OF TECHNICAL ISSUES SURROUNDING NORTHERN PIPELINES

## A report prepared for the Pipeline Unit of Yukon's Department of Economic Development

November 2001

**Prepared by**

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Photos, taken ca. 1985, courtesy of Government of the Yukon and Bedford Institute of Oceanography.

# INTRODUCTION

The Pipeline Unit of the Yukon government's Department of Economic Development commissioned PFL Inc. Consultants of Calgary, Alberta to develop a synopsis of technical and engineering issues that pertain to northern onshore and offshore pipelines. Accordingly, this report, on a preliminary basis, identifies and summarizes a number of key issues that will be faced during northern pipeline design, construction and operation. It will also address existing northern pipeline uncertainties of estimating construction costs for two pipeline routes. They are:

- Option 1, a pipeline from Prudhoe Bay to Fairbanks and along the Alaska Highway called the Alaska Highway Pipeline (AHP); and,
- Option 2, an offshore pipeline to Mackenzie Delta and south along the Mackenzie River called the "Over the Top" route (OTT)

Known conventional onshore and offshore pipeline issues, independent of the impact of northern conditions, are outside the scope of this report.

This report will be part of a synopsis that will be used as an informational tool for non-government organizations and government, and a scientific source document for northern gas producers and pipeline companies. It will also be used by the Yukon government in order to prepare for the regulatory/approval role it will have to play over the next few years.

Also, this document is intended to be used solely as a reference for information and for further discussions of relevant and key issues related to the design, construction and operation of northern pipelines.

## Appendices

As supporting documents, the following appendices are presented with this report:

Appendix 1: Executive summary

Appendix 2: Limitations of the FTL failure probability calculations

Appendix 3: The definition of risk and use of risk analysis as a regulatory decision making tool

Appendix 4: Pipeline design objectives and comparison of the alternatives

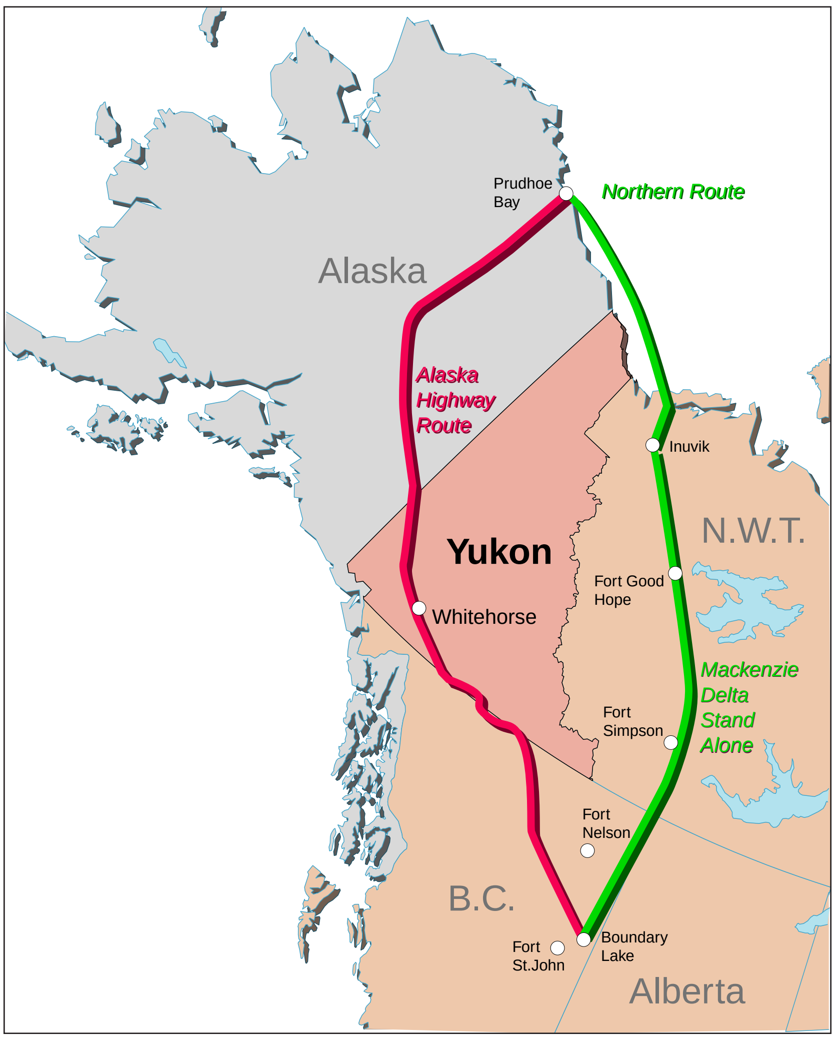
Appendix 5: References

Appendix 6: List of documents supplied by FWS

These appendices have been extracted from a report by Dr. I. Konuk of the Geological Survey of Canada, entitled Review of the Liberty Pipeline Risk Analysis and Comparison of Design Alternatives, dated August 2001.

Dr. Konuk's report was commissioned by the U.S. Fish and Wildlife Service (FWS) in order to analyze pipeline design parameters in the Independent Risk Evaluation Report completed by Fleet Technology Limited (FTL) of BP's Liberty oil field in the shallow Beaufort Sea off the Alaskan North Slope.

*Route showing the northern gas pipeline options.*



# SUMMARY AND CONCLUSIONS

## Onshore

There are no unsolved technical issues to be addressed for onshore northern pipelines.

Issues such as frost heave and thaw settlement have been studied and found to be less of a problem than anticipated. This conclusion has been reached as a result of study and research on the Norman Wells pipeline. As well, unexpected technical issues such as upheaval buckling and slope creep are better understood after 15 years of Norman Wells pipeline operation.

## Offshore

There are many unresolved and complex technical issues when considering the design, construction and operation of a northern offshore pipeline. These issues will translate into long construction delays, substantial cost overruns, and significant reliability and environmental risks.

### • *Ice scour and trenching equipment capability*

Ice scour will be a major factor in any northern offshore pipeline design. The scour depth in the Beaufort transition zone is far below the capabilities of existing (conventional, up to 2-metres depth) subsea trenching equipment. Dredging will be prohibitively expensive. Accordingly, research has indicated that pipe-in-pipe or twin pipe solutions may be necessary which will also be costly, time-consuming alternatives.

### • *Open water season and ice-strengthened equipment*

The open water season in the Beaufort is unpredictable and much shorter in duration than most cost estimates to date have recognized. In a report done for Foothills Pipe Lines Ltd., EBA Engineering Consultants determined that there is only a 50% chance of a construction window of 40 days and a 70% chance of 30 days. As well, any equipment used during construction or operation will have to be purpose-built to withstand summer Arctic ice conditions and strong enough to be stored in winter Arctic conditions.

Pipe laying or repair opportunities will, at best, be short and in some years will not occur at all. This will negatively impact offshore cost estimates as well as operational logistics.

### • *Compressor station siting*

Any offshore pipeline carrying liquid rich natural gas from Alaska's North Slope will have to include a compressor station somewhere along the offshore portion of the route. This will add complexity to the design and operation, as well as add extra costs to the project, because of the necessity of an offshore location.

### • *Accessibility*

The Beaufort Sea is covered with ice for eight to 10 months of the year. In the transition zone, the ice is constantly moving and shifting due to wind and current action. An offshore pipeline will have to be installed, in part, under this transition zone and, as a result, will be inaccessible by sea/ice going vessels for many months each year. This means that any incident, pipeline repair or, especially, a leak or rupture, cannot be attended to until the next open water season.

## Conclusions

For onshore northern pipelines, the technical issues are well known and have been solved. The cost estimating is reasonably accurate, with a high level of confidence. Cost estimating is a function of scope. The better the scope is defined, the better the cost estimate.

The same cannot be said for northern offshore pipelines.

The costs are not well understood, because the scope is unclear and numerous unknowns exist. To date, cost estimates have not taken into account these technical issues, which has resulted in inaccurate cost estimating with a corresponding low level of confidence.

For some of the technical issues, there are no known solutions yet. Operational reliability cannot be assured when access to the offshore portion of the pipeline is denied because of ice cover for several months each year.

For other technical issues, the solutions will be prohibitively expensive. To solve the ice scour problem, a pipeline company may have to resort to innovative solutions such as pipe-in-pipe or twin pipelines. While this is realistic for smaller, near-shore projects, it will prove to be economically unacceptable for a large-diameter, long-distance pipeline.

## CURRENT STATE OF TECHNOLOGY

No significant transmission pipeline construction has occurred in the northern regions of North America since the 800-mile, 2/3-elevated oil pipeline was constructed from Prudhoe Bay, Alaska to Valdez, Alaska in 1977 or the 550-mile, buried oil pipeline which was constructed from Norman Wells, Northwest Territories to Zama, Alberta in 1985. Most likely, the next northern pipeline will be one to transport natural gas.

Despite the lack of recent large-scale northern pipeline construction in North America, there is a wealth of construction, operating and maintenance experience to draw on for any new pipeline. In fact, the oil and gas industry has been ready, since the mid 1980s, with all issues resolved, or with acceptable technical solutions, for new northern onshore pipelines. Further, where applicable, reference can be made to the experience gained from the construction and operation of a number of northern onshore gas pipelines in the Russian Arctic, in particular from the Yamal Peninsula region. (See "Russian Pipelines" by V. Karianovski, et al.)

From a Canadian regulatory point of view, a Management System Approach is included in the National Energy Board's 1999 Onshore Pipeline Regulations. This is a new method of pipeline regulation that identifies issues, solutions and responsibilities regarding design, construction and operations, in which the CSA Standard Z-662 Oil and Gas Pipeline Systems is a key design reference, but not necessarily the only one.

At the moment, there are no promulgated offshore or arctic offshore pipeline regulations in Canada.

*Single steel drilling caisson, winter ice conditions, Beaufort Sea.*

# DESIGN ISSUES

It is not the intention of this document to address or review conventional pipeline design considerations and regulations. Instead, it will look at the design of northern pipelines with regard to the following:

- hydraulics;
- route selection;
- structural integrity;
- mobilization/demobilization;
- construction equipment and installation techniques;
- operations and maintenance;
- pipeline integrity monitoring and repairs; and
- contingency plans.

Since specific design issues for northern pipelines are mainly influenced by the special environmental, topographical and meteorological considerations imposed by the Arctic, a comprehensive northern pipeline design (which includes all technical, construction and operational issues) is one that will take into account the impact of ice conditions including permafrost, extremely low temperatures, remoteness, long periods of darkness, safety aspects, and contingency plans.

## Onshore

Any northern onshore pipeline design must start with a preliminary design document that addresses all engineering issues so that the pipeline can withstand the harsh northern climate in which it will be constructed and operate. This document is referred to as the Design Basis Memorandum (DBM).

The DBM is a document that summarizes the environmental and geotechnical data and survey information along the proposed pipeline route in order to establish the design criteria for the project. The success in developing these terms of reference determines the quality of the design, as well as the level of accuracy of the project schedule and costs. Within the DBM it is of foremost importance to determine or establish the following:

- fluid characteristics;
- gas composition;
- gas supply and demand requirements;
- methods of dealing with permafrost;
- preliminary project schedule and costs;
- availability of construction equipment; and
- selection of pipeline installation techniques.

These design criteria can be achieved by dealing with the following topics:

### • *Hydraulic issues*

Ambient temperatures have a direct influence on fluid characteristics, operating pressures and pipeline flows, including the handling of Natural Gas Liquids for gas pipelines. Extreme northern temperatures drastically affect the ambient-pipe/fluid temperature interaction, including the pipe temperature gradient. For example, above-grade pipelines cool rapidly due to convection and the low ambient temperatures.

The impact on below-grade northern pipelines can be larger due to the presence of permafrost and the likely degradation of the permafrost. Permafrost degradation can occur when the temperature in the pipe is higher than the ground temperature. The main consequence of permafrost degradation is failure of the soil/pipeline interaction or pipe foundation, with consequences such as thaw settlement. To stabilize the pipe, there are a number of possible solutions, including gas chillers and different pipe/soil foundation enhancements.

The opposite phenomenon, frost heave, occurs when the pipe temperature is lower than the surrounding soil, which then causes unfrozen soil to freeze. This problem, along with thaw settlement, was found to be less severe than anticipated when experienced on the Norman Wells pipeline. Appendix 2 discusses issues such as frost heave, thaw settlement, and upheaval buckling in more detail.

### • *Route selection issues*

The design issues involved in the selection of a pipeline route are at the core of the pipeline design. Improper choices in route selection will result in extreme pipe stresses due to soil properties, slope and pipe foundation stability problems, slope creep, poor operational accessibility and abrupt changes in topography. Poor choices will also lead to the requirement for special anticorrosion requirements or higher costs due to northern logistics, remoteness, accessibility and/or socio-environmental concerns.

Complete and accurate environmental and geotechnical data and survey information must be compiled along the proposed pipeline route. Of specific interest for northern pipelines will be the presence and properties of permafrost, and overall logistics, including accessibility and existing infrastructure.

#### • *Structural issues*

In general, pipeline structural issues are related to the integrity of the pipe, including anticorrosion materials. Northern conditions such as low ambient temperatures, permafrost, physiographical features and/or electrical soils resistivity have a direct structural impact on hydraulics, route selection, pipe wall thickness, sizing and the selection/design of an anticorrosive system. Other design parameters such as internal pressure, above or below-grade pipe positioning and pipe material properties will also affect the structural integrity of the pipeline.

#### • *Mobilization/demobilization issues*

Since northern infrastructure from Prudhoe Bay exists only along the Trans Alaska Pipeline (TAPS) to Fairbanks, and from Fairbanks along the Alaska Highway to Alberta, any variations from this route must take into account logistics, remoteness, accessibility, low temperatures, darkness, construction approach, safety, required infrastructure and environmental requirements, including long restoration periods.

#### • *Construction equipment and installation techniques issues*

As mentioned, there is always a relationship between all construction activities. However, in the north, it is of foremost importance that the selection and/or evaluation of construction equipment and installation techniques deal with such problems as permafrost, slope stability and accessibility.

#### • *Operations and maintenance issues, integrity monitoring, repairs and contingency plans*

In addition to conventional risks, all risks related to northern pipeline developments must be identified and classified, including provisions necessary to mitigate or minimize their occurrence. To prepare an effective and proactive approach, provisions must be identified and implemented at the design stage. This includes identifying the facilities and/or equipment that will meet the northern operational, monitoring, and/or contingency plan conditions. The National Energy Board's Onshore Pipeline Regulations require that the operator determines the level of risks they are prepared to accept and then recommend methods and procedures necessary to mitigate such risks. Appendix 3 deals with the subject of risk analysis in more detail.

## Offshore

In most cases, the previously identified northern onshore pipeline design issues are also applicable to northern offshore pipelines. However, this section focuses on specific design issues pertinent to the structural integrity of northern offshore pipelines. Structural integrity of northern offshore pipelines is mainly influenced by sea ice conditions, including properties and probability of occurrence of ice scour, strudel scour (made by streams of fresh water flowing into the Beaufort Sea), ice zones and seasonal ice variations. Similar to northern onshore pipelines, conventional (open water) offshore pipeline design issues, such as bottom stability and structural integrity during installation or operations, are not discussed in this report. The northern offshore pipeline design issues to be discussed in this section are:

- ice/soil/pipe interaction phenomenon after installation;
- winter pipeline installation and design issues; and
- summer pipeline installation and design issues.

#### • *Ice/soil/pipe interaction issues*

Due to the presence and occurrence of ice scour at the seabed, the most important issue during the life of a northern offshore pipeline is the understanding of the ice/soil/pipeline interaction phenomenon, including pipe behavior and structural integrity due to ice scour frequency of occurrence and related risks.

There is a growing consensus that a pipe-in-pipe or a twin pipe solution may be the only method of dealing with ice/soil/pipeline interactions. Appendices 2 and 4 deal with this topic in more detail.

#### • *Winter pipeline installation and design issues*

If feasible, winter installation should rely on the ability to use the ice as a safe construction platform. If the ice is to be used to support construction equipment, main concerns will be the ice strength and ice movement, including ice management. Ice movement during winter can be a major problem during installation for proper pipe positioning and/or control of ice displacements. Excessive pipe displacements can jeopardize the structural integrity of the pipe. Based on experience, stationary and/or grounded ice during winter can be founded, made and/or maintained in shallow waters and at the shore approach.

### • *Summer pipeline installation and design issues*

In general, it is best to install northern offshore pipelines during the summer period using existing, conventional construction equipment and techniques. This method can only be used in open water conditions with no ice. However, in the Beaufort Sea, even during summer, there are always ice pans, floes and ice invasions, and sometimes, there is no open water at all. Therefore, the impact from sea ice on conventional offshore pipeline installation and design must be considered. Possible design consequences are emergency pipe abandonment and the subsequent recovery problems, excessive pipe displacements and costly contingencies for possible temporary pipe protection against ice scour. As well, ice-strengthened construction equipment will have to be utilized.

*Transition ice pack moving past the Molikpaq drilling caisson, winter ice conditions, Beaufort Sea.*

# CONSTRUCTION ISSUES

The construction of northern onshore pipelines assumes the utilization of existing and available construction equipment. Since the '70s, a number of construction techniques and equipment have been utilized under winter and summer northern conditions. The construction approach to be selected for onshore pipelines from the Arctic will be unique due to the northern location and the site-specific environmental conditions encountered along any proposed pipeline route.

Winter is the preferred onshore construction season, as the lack of proper soil conditions in most areas during the summer cannot safely support heavy equipment. Conventional equipment can be winterized and adapted to operate under extreme winter conditions, which include low temperatures, frozen soils, streams and lakes, the presence of permafrost, snow and darkness. Low ground pressure vehicles have been specifically built to operate under northern conditions.

However, no pipeline construction equipment has ever been built to operate specifically in Arctic offshore conditions except in Russia. The only proven technique used to date to install Arctic offshore pipelines is the use of conventional offshore methods in open water, ice-free conditions. Due to risks in the Beaufort Sea, and a lack of equipment suitable to withstand the ice conditions, winter construction techniques have been used only for shallow waters near shore, in less than 10 metres water depth, and for shore approaches only.

## Onshore

Onshore pipeline construction issues typical of any pipeline project ,and which are not discussed in this report, include:

- soil properties;
- physiographical and geological characteristics;
- meteorological conditions;
- proposed pipeline length and alignment;
- availability of borrow materials;
- available and existing infrastructure;
- soil properties;
- location of environmental sanctuaries and/or archeological sites; and
- construction regulations.

Specific northern onshore construction issues to be considered during route selection and construction are:

- winter or/and daylight construction;
- above or below grade pipeline;
- northern supplies, logistics and accessibility, mobilization/demobilization (mob/demob) and restoration;
- construction camps; and,
- permafrost, frozen soils, frozen water bodies and snow.

### • *Winter and/or daylight construction issues*

Selection of winter or daylight construction will require a major decision by a pipeline company. The decision will be made based on experience, available information and data. Existing geotechnical experience favours winter onshore construction. However, required daylight construction activities will also be identified and evaluated.

### • *Above- or below-grade pipeline issues*

Both approaches were developed to deal with permafrost, frozen soils and pipe heave. They are both proven technologies. Prior to a decision, the specific cost implications and technical issues of above- or below-grade construction must be properly identified and evaluated. It is expected that the final decision will meet both technical feasibility and economical viability.

### • *Northern supplies, logistics and accessibility, mobilization/demobilization and restoration issues*

In parallel with the time frame and above or below-grade issues, there are the northern supply, logistics and accessibility, mob/demob and restoration issues. Most of these issues deal with northern environmental conditions and the existing infrastructure. Identification and evaluation of the impact of environmental conditions and existing infrastructure will be required.

### • *Construction camps issues*

This is another activity that needs to be evaluated in parallel with other construction activities and decisions. Northern conditions and infrastructure will affect construction camps with regard to accessibility, supply and logistics. From this analysis, it will be possible to establish a number of camp features such as location, size, access, additional infrastructure and separation between camps.

### • *Permafrost, frozen soils, frozen water bodies and snow issues*

These are key parameters that represent unique northern conditions and they have a major impact in all northern construction activities and design. The availability and gathering of data along the proposed pipeline route become crucial components of this issue. Accordingly, related risks are a function of this availability and gathering of data.

## Offshore

As discussed, northern offshore construction issues are mainly a function of pipeline route selection and the construction approach. The most important issues are:

- open water/winter construction;
- specialized northern equipment;
- equipment accessibility;
- northern supply and logistics; and,
- environmental considerations.

Ice-free or conventional offshore construction issues are not discussed further.

### • *Open water/winter construction issues*

A main concern is the ability of any conventional construction equipment to withstand ice conditions as

*The Kulluk ice class drilling rig, summer ice conditons, Beaufort Sea.*

per the *Arctic Water Pollution Prevention Act* and the Coast Guard ice classification of vessels. In an Arctic environment, the possibility of ice invasion during the open water period is high. Therefore, the vessels must be able to withstand severe ice conditions even in the summer.

To install an offshore pipeline between Prudhoe Bay and the Mackenzie Delta will require that equipment overwinter in the Arctic for more than one year in order to maximize the short open water season. Hence, to withstand ice loads during the open water season and during the winter season, any vessel in the Arctic and designed to operate in open waters will require structural strengthening and an operational ice classification certificate from the Coast Guard. This will be very expensive.

Winter construction issues are related to the ability of construction equipment and techniques to withstand ice movements and ice loads during the winter.

### • *Specialized northern equipment issues*

Regardless of the laying approach, specialized northern trenching equipment will have to be designed to trench and bury 48-inch- (or larger) pipe in a 4- to 6-metre deep ditch. This equipment does not presently exist.

The required maximum Arctic trenching depths of up to 4 to 6 metres are greater by orders of magnitude than the maximum 2-metre depths achieved with existing conventional pipeline trenching equipment. Due to expected scour depths, well over 2 metres, safe trenching depths can only be achieved by using dredging equipment.

However, for much of the route, dredging equipment will not be able to make a ditch with vertical walls. Because of the unconsolidated sands and silts of the sea floor, the equipment will be required to make a much wider excavation, disturbing a huge amount of sediment and seafloor. This will take an inordinate amount of time, much longer than making a ditch, and it will be prohibitively expensive. The ice-soil-pipe interaction behavior will also be different.

Appendix 4 suggests that one alternative to the technical challenge of trenching or dredging in the Beaufort may be a pipe-in-pipe solution.

### • *Equipment accessibility/operational window issues*

As mentioned, Arctic offshore trenching has been the proposed approach to minimize the risks from the effects of ice scour or ice loads on any pipeline in the Arctic offshore. Even if the method is used only during open water conditions, the key issue is the unproven nature of the equipment and of the technique, (trench or dredging). However, the length of the pipeline, the required or recommended trenching depth, and the ice conditions during the operational construction weather window also become an issue.

Any pipeline installation equipment, required to withstand the effects from northern ice conditions, will also fall into the category of unproven equipment. If year-round Arctic offshore equipment is to be required during construction or operations, it will need to be developed and built. Equipment required for offshore repairs will fall into this category as well and still needs to be identified, defined, developed, built and tested in situ.

At the moment, there is no offshore pipeline construction equipment available in the Beaufort Sea. Essential equipment must be brought in or exit out via Point

*Pressure ridge, Beaufort Sea.*

Barrow during the open water season for mobilization and demobilization, and must be capable of withstanding ice loads and conditions. As a consequence of this accessibility problem, and due to the relatively short length of the open water season, the effective length of the open water construction season at site will be reduced and its impact during mob/demob must be properly evaluated.

### • *Northern supply and logistics issues*

Northern supply and logistics needs during construction and operations must be developed and implemented after considering northern environmental conditions. Due to the limited open water season in the Beaufort, supply and logistics will be more complex and costly than that required of an onshore highway corridor route.

### • *Environmental considerations*

Environmental considerations will affect both open water and winter construction, and factors such as the presence of endangered bowhead whales or proximity to denning polar bears must be considered. Another environmental consideration which will have technological implications is global climate change and its impact on shoreline erosion rates along the Beaufort Sea coast. This will affect where a pipeline may come ashore and how it will be protected from advancing shoreline erosion. There are many more local environmental issues which are not addressed here.

## OPERATIONAL ISSUES

After construction, the operations and maintenance of a northern pipeline will be, as much as possible, a conventional exercise in which all northern issues or concerns, including contingencies, have been dealt with during the preceding engineering and construction phases. A northern pipeline must operate without incidents and it should not be different than any other pipeline. Accordingly, contingency plans must be implemented to include a year-round repair capability. All northern conditions that impact the operations, maintenance and contingency plans of a pipeline must be taken into consideration at the design stage. This includes logistics, surveillance, access, mobilization and demobilization of pipe repair equipment and maintenance/restoration of the environment.

While this is entirely possible with northern onshore pipelines, it will not be possible with an offshore pipeline.

A main operational issue will be the year-round capability of maintenance and/or repairs of any Arctic offshore pipeline. Any northern offshore pipeline will be inaccessible for several months each year during the ice covered winter season. The shifting, constantly moving transition ice pack will make it impossible to reach the submarine pipeline for up to nine months in any given year. Any repairs, incidents or spill response will have to be postponed until the summer open water season, if there is one.

Also, because of the proposed liquid-rich nature of the natural gas in any pipeline originating from the Alaskan North Slope, compressor station spacing will be restricted. Either the compressor station will have to be situated on an artificial island in 20 or 30 metres of water or the pipeline will have to be routed to and from the north coast of the Yukon for an on-land site. However, the western half of the Yukon coastline is covered by the Ivvavik National Park which adjoins the Arctic National Wildlife Refuge (ANWR) on the Alaskan side of the coast.

*Open leads, Beaufort Sea.*

# RISK and UNCERTAINTY

In the first place, it is necessary to identify, itemize and prioritize risk and uncertainty, including the parameters that impact them. From a technical point of view, the management of risks and uncertainty is implemented by preparing adequate contingency plans, including the ability to mobilize and have available all essential facilities, equipment and manpower. From an engineering perspective, it is impossible to eliminate all risk and uncertainty.

However, during the engineering phase it is possible to minimize some risks and uncertainties and, in some cases, eliminate them. The implementation of solutions to minimize or eliminate technical risks is a function of the level or effort of engineering. This is fundamental to the identification and prioritization of risk and uncertainty.

For a northern pipeline, due to the impact of risk on schedules and costs, it may also be important to identify risks other than technical ones. Some of these risks relate to the timing of regulatory requirements and permits, environmental screening and review processes and socioeconomic issues. Not all of these risks are itemized or identified in this report.

Since risks and uncertainty are related to return periods, statistical records of risks and associated parameters are indispensable in order to quantify all risk levels. Furthermore, in any pipeline project, it is necessary to have site-specific information. In general, for northern pipelines, the available information or data seems insufficient.

Also, as a general statement, in most cases there is more onshore than offshore data and the north is not an exception. Further, based on a preliminary impact assessment, northern environmental parameters and pipeline risks seem much higher for offshore pipelines than for onshore pipelines. The risks related to conventional parameters and conditions must also be taken into account.

## Onshore

Conventionally, the main source of northern onshore risks and uncertainties, as they relate to design, construction and operations, is the ability to deal with the effects of permafrost, winter and daylight conditions, extreme temperatures, frozen soils, snow and watercourses. A proposed management of risk and uncertainty will be based on the identification and implementation of adequate contingency plans, equipment and human resources.

## Offshore

Arctic pipelining risks have a dramatic impact on costs and on safety. Risk and uncertainty for Arctic offshore pipelines are mainly characterized by the properties and frequency of offshore ice conditions, ice scour and ice/soil/pipe interaction. Safety risk relates to the exposure of the pipeline to ice forces by ice keels, thickness of the ice and structural strength of the ice (multi-year ice).

As well, based on existing technology, another risk will be the year-round accessibility of equipment for the implementation of contingency plans or repairs of Arctic offshore pipelines. The "open" season and the "dark" season are of undetermined length. By nature, these Arctic uncertainties are stochastic, or random, uncertainties. The ice densities are also unpredictable and combined with the time element risk become a complex phenomena.

Mechanically, there are also a number of uncertainties in relation to equipment performance, efficiency and crew experience. In the case of leaks or ruptures, the phase behavior of propane at low temperatures in Arctic winter conditions also causes some uncertainty. Other environmental uncertainties of importance are soil conditions and weather (storms, low temperatures and precipitation).

Regulators and/or operators will have to determine the levels of safety, environmental and economic risk they are jointly prepared to take.

Appendix 3 deals with this subject in greater detail.

# COSTING VARIABLES and UNCERTAINTIES

The variables used to establish pipeline costs are a function of the amount of engineering, and the expected utilization or purpose of the estimate. For example, first order cost estimates, (primarily used to select routes), are called cost per diameter/inch/mile estimates. They typically require only the pipeline diameter in inches, the length of the pipeline in miles and a cost reference per region or location. Unit costs per region are the minimum site-specific estimates required in order to characterize and generalize these unit costs. However, to account for the uncertainties related to the lack of site-specific information, terms of reference and limited engineering, it is also recommended that a certain probability of occurrence to these unit costs be assigned. During the initial evaluation of options at a conceptual level, the use of unit costs is a very useful tool in the decision-making process.

Uncertainty is a function of availability, quantity and quality of site-specific information and of the level or type of engineering. Costs of a diameter/inch/mile basis typically are expected to be within ± 30% from the final costs or a cost with a 70% exceedance probability of occurrence. A reduction of uncertainty requires a higher level of engineering and the corresponding improvement in the quantity and quality of site-specific information and engineering effort.

There are a number of studies in which it has been demonstrated that there is a clear relationship between cost overruns and the level or type of engineering. With the analysis from records during the construction of over 150 petrochemical plants in the early ’80s, the Rand Corporation confirmed this relationship. For different levels of engineering, they calculated or quantified the levels of uncertainty as a probability of occurrence and estimated costs during the following:

- conceptual engineering (preliminary cost assessment);
- preliminary engineering;
- final or detailed engineering; and
- as-built costs.

Uncertainty may be presented as the exceedance probability of occurrence for a specific type of engineering effort. The lower the exceedance probability of occurrence, the higher the uncertainty.

An example at a conceptual level of engineering of the diameter/inch/mile cost approach for a 48” pipeline from Prudhoe Bay to Chicago is summarized in Table 1 (next page). Accordingly, the unit costs for a pipeline from Prudhoe Bay to Chicago has been divided into the following five regions of similar characteristics: Alaska and Yukon offshore, Alaska and Yukon onshore, NWT and British Columbia, Alberta and Saskatchewan, and the lower USA states or below 49º latitude north.

The unit costs for British Columbia, Alberta, Saskatchewan and south of the 49º latitude north are based on actual published costs from the Express and Alliance Pipelines (both built within the last five years). They have been assigned an 85% to 90% exceedance probability of occurrence.

Based on the previous unit costs and on experience, the unit costs and exceedance probabilities of occurrence for the Yukon, NWT and onshore Alaska were extrapolated by PFL Inc. Consultants. As mentioned, they require additional engineering work because no major onshore pipeline has been built in the northern regions during the past 15 years.

Offshore Alaska unit costs were estimated by PFL Inc. Consultants based on internal studies, data, experience and certain assumptions. Some of these assumptions are for work conducted:

- in open water only;
- using ice-strengthened conventional and existing trenching or ditching and laying equipment; and,
- work to be conducted during three consecutive open water seasons with two overwinters in the Arctic, with the corresponding standby time and costs.

Due to the long standby of specialized vessels, Arctic offshore construction costs seem high. However, based on historical ice patterns and recent experience with relatively short, smaller diameter Arctic offshore pipelines, the assigned 65- 70% probability of occurrence may be optimistic and certainly requires additional studies and considerations.

As with any project, the number of cost variables and cost uncertainties will vary with an increase in quantity and quality of the environmental data and the general level of engineering information.

*__Table 1:__ Total cost estimates in millions of 2001 US dollars, NPS48 pipeline from Prudhoe Bay to Chicago.*

| Item - Option | LOCATIONS | | | | | Totals |
|---|---|---|---|---|---|---|
| | Offshore | Alaska and Yukon | British Columbia and/or NWT | Alberta and/or Saskatchewan | Southern USA | |
| $/inch/mile - unit cost | $250,000 | $70,000 | $52,500 | $35,000 | $45,200 | |
| Probability of occurrence | 65-70% | 75-80% | 75-80% | 85-90% | 85-90% | |
| **Option 1 - Pipeline from Prudhoe Bay to Fairbanks and Alaska Highway (AHP)** | | | | | | |
| Approximate distance in miles | 0 | 1,256[1] | 447[1] | 1,012[1,2] | 890[2] | 3,605 |
| Cost in millions US $ | 0 | $4,220 | $1,126 | $1,700 | $1,931 | $8,977 |
| **Option 2 - Offshore pipeline to Mackenzie Delta and south along the Mackenzie Valley (OTT)** | | | | | | |
| Approximate distance in miles | 368[3] | 0 | 1,149[4] | 972[2] | 890[2] | 3,379 |
| Cost in millions US $ | $4,416 | 0 | $2,895 | $1,633 | $1,931 | $10,875 |

**Remarks**

All options to reach Gordondale near British Columbia/Alberta border and then take the same route south to Chicago.
Unit costs and probabilities of occurrence provided by PFL Inc. Consultants.
Unit costs are for pipelines only and do not include other facilities.
[1]Foothills Pipe Lines December 2000 route maps
[2]National Energy Board's comprehensive study report: Alliance Pipeline Project, GH – 3 – 97, September 1998
[3]Canadian Energy Research Institute report: A Comparison of Natural Gas Pipeline Options for the North, October 2000
[4]TransCanada Pipelines presentation: Options, Expectations and Realities, Insight Conference, September 21, 2000

# APPENDICES

## excerpts from U.S. Fish and Wildlife Service, *Review of the Liberty Pipeline Risk Analysis and comparison of design alternatives*, dated August, 2001

*About the author: Dr. I. Konuk has over 25 years of experience in pipeline design, construction, and research (private and public sectors). He has degrees in Mechanical Engineering, Applied Mathematics, and a Ph.D. in Engineering Mathematics. He is currently a Senior Research Engineer and Research Program Manager for the Terrain Sciences Division of Geological Services Canada at the Department of Natural Resources Canada.*

## Appendix 1: Executive summary

British Petroleum Exploration – Alaska (BPXA) has proposed the Liberty project, an oil and gas production island and subsea pipeline that would be located east of Prudhoe Bay, Alaska, and approximately six miles offshore. Due to agency interest in the evaluation of pipeline designs for offshore production in the Beaufort Sea, the U.S. Minerals Management Service administered three independent pipeline studies relevant to the Liberty project. The *Independent Risk Evaluation for the Liberty Pipeline*, completed by Fleet Technology Limited (FTL) in September 2000, was the third of these studies and evaluated the oil spill risk associated with four pipeline design alternatives proposed for the Liberty project.

This report was prepared at the request of the U.S. Fish and Wildlife Service (FWS) to conduct an independent review of the FTL study, providing an assessment of the methods used and the results contained in the FTL final report, and the relative value of the study to the decision-making process. In addition, due to the recent completion of structural analyses of pipe-in-pipe and single pipe by Geological Survey Canada (GSC) staff under the direction of the author, Dr. I. Konuk, the FWS requested relevant findings of this work be incorporated, when applicable, in this review. The recommendations forwarded in this review are based on the assumption that the Liberty pipeline risk analysis was intended to identify the design that minimizes the risk of an oil spill.

This report points out several deficiencies in the calculation of the failure probabilities and the determination of the oil spill consequences conducted by FTL and provides recommendations for overcoming these deficiencies. These problems are significant enough to invalidate the results of this study for the purpose of comparing the different design alternatives being considered for the Liberty pipeline. These deficiencies include:

1. FTL developed detailed failure probability models only for the single pipe option, and apparently applied them to all of the design alternatives, regardless of their applicability or accuracy. The FTL report, however, includes some preliminary work for pipe-in-pipe that shows that the failure response and, therefore, the failure probability of pipe-in-pipe could be considerably different than single pipe. A comprehensive pipe-in-pipe model developed by GSC confirms this difference, showing about a ten-fold reduction in strain levels associated with the pipe-in-pipe compared to the single pipe during equivalent ice gouge events. FTL did not incorporate these findings in their final risk calculations.

2. Potential design features of the pipe-in-pipe alternatives that could lower spill risk have not been fully explored or incorporated in the FTL analysis. Even if they were, without an appropriate failure model for each design option as mentioned under (1), the benefits of these design features could not be reflected in the calculated risk.

3. An important coupled failure event, strudel scour/upheaval buckle/ice gouging, was omitted from the risk calculations. This coupled case could contribute significantly to the calculated risk of the alternatives, thus changing their relative levels of risk.

4. Most of the analysis developed or used in the FTL report relies on very limited databases and may be subject to considerable statistical error. In the case of strudel scour, data collected from the native seabed is applied directly to an analysis of the pipeline trench. Compared to the native seabed, the pipeline trench will likely respond differently to strudel scour due to its variable geometry and weaker fill material.

5. Spill consequences are calculated using very simplistic models and encompassing assumptions. The assumptions used are not consistent across different design options and different failure modes, being overly conservative in some cases and optimistic in others, especially concerning the new technologies incorporated in the single pipe design. It should also be added that as in points (1) and (2) above, these models generally do not reflect the influence of the potentially beneficial features that can be incorporated in the conceptual design alternatives.

Based on GSC's comprehensive model of pipe-in-pipe and single pipe failure response, as well as FTL's limited analysis of pipeline failure response and probability, this report concludes that further optimization of the Liberty pipeline alternatives would likely provide significant improvements in the risk performance of some of the alternative pipeline designs. Particularly, if the pipe-in-pipe alternative is further optimized, it can provide an order of magnitude better risk performance than the single-wall pipe in response to the failure modes associated with environmental and functional loading conditions. It is recommended, at a minimum, that the pipe-in-pipe alternative be further optimized for this application before a final decision is made on a design option.

Concern has been expressed regarding the corrosion potential and ability to monitor both pipes of a pipe-in-pipe system. There are effective means to create a non-corrosive environment within the annulus and to inspect or monitor both the inner and outer pipes of a pipe-in-pipe system (see Chapter 4 of this report). When these design features are incorporated in an appropriately designed risk analysis, the corrosion potential of the outside pipe of the pipe-in-pipe design should not increase the spill risk in any magnitude to affect the final comparison of risks.

Before the FTL analysis, or any further analysis, is employed in the decision-making process, it is recommended that the deficiencies highlighted above be corrected, and more specific risk objectives (acceptable risk levels) be defined for the Liberty project. Use of total spill volume as a measure of risk is not very applicable to specific environmental concerns.

# Appendix 2: Limitations of the Fleet Technology Limited (FTL) failure probability calculations

### *2.1 Model based calculations*

The FTL report assumes for all design alternatives that the pipeline would be placed in the seabed in a prescribed depth where the soil particle movements are of a prescribed form independent of the trench geometry, backfill properties, or the pipeline parameters. In the model used by FTL, soil movements are extrapolated from small-scale model tests conducted in a model centrifuge using a solid (aluminum) indenter mounted to a rigid carriage. The methodology used in the FTL report assumes that the pipeline would be buried and covered with soil media with the same strength and properties as the rest of the seabed. It is also assumed that placement of the pipe in an irregular V-shaped trench and the presence or the size of the pipe would not significantly influence the scour process as defined by centrifuge tests conducted with a uniform seabed model without a trench and pipe. Although the model tests show vertical soil displacements in about the same order of magnitude as the horizontal displacements, only horizontal movements are considered in the model used in the FTL report. The pipeline response is based on a discrete spring-based soils representation (Wrinkler) where the soil is idealized as a collection of discrete and independent springs.

The model used in the FTL report to represent ice gouging is a large deformation theory-based two-dimensional FEM model where pipe is represented as a one-dimensional structure. This model does not capture the local behavior of the pipe close to or after a buckling or wrinkling state. Although the fact that three-dimensional and local effects can increase the pipe stresses is mentioned in the report, this effect was not incorporated in the results. Buckling would change the local stiffness of the pipe, thus forcing the global pipe response to a different and more undesirable state, but this effect was not incorporated. Also, no attempt was made to analyze the state of the pipe following the gouging process. It is possible that some of the large strains can be reversed, making use of the large strains as the failure criteria very questionable. In addition, the potential of upheaval buckling may increase after a gouging event. These effects can have a significant and unfavorable effect on the response of the pipe, especially when the pipe is placed in an irregularly shaped trench filled partially or completely with material weaker than the native seabed soil (see Figure 1). These considerations raise serious questions regarding the accuracy of the displacement functions extrapolated from a small-scale test with no trench. It should be noted that the analysis model (GSC model) used in the FTL report was developed by a team lead by the author and that FTL was made aware of these issues before the FTL report was distributed.

The GSC model used by FTL does not include uplift of the ice keel during the scour and corresponding forces (Figure 2). When such a ridge encounters a pipeline trench filled with a material with different properties than native seabed, likely the ice ridge will come down and a transient process will start, which can reduce the effectiveness of the trench as a protective measure.

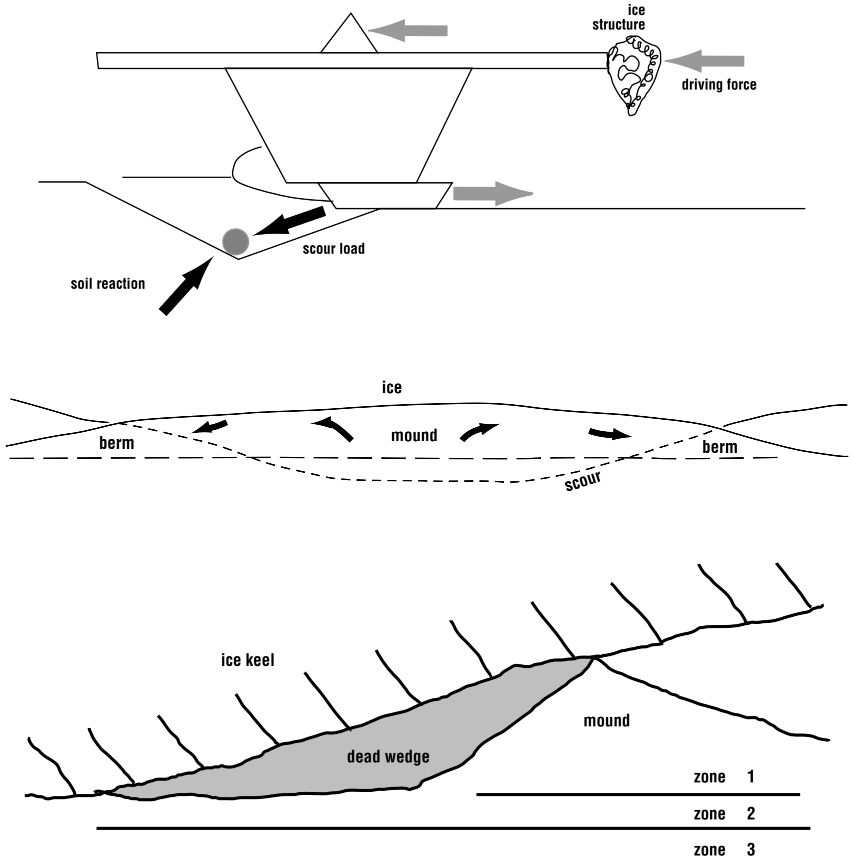



***Figure 1:*** *Illustration of the scour process.*

The FTL report does not critically evaluate the limitations of the GSC model although the possibility that some of the assumptions may introduce significant errors is implicitly mentioned. The issues raised above are likely to introduce significant errors into the results obtained by the referenced model. Most significantly, these errors are not always on the conservative side. **As a result, failure probabilities based on the GSC model cannot be argued to be conservative as claimed in the FTL report.** It should also be noted that the FTL report does not analyze the uncertainty introduced by the issues raised above.

The strudel scour failure mode was analyzed by using the scour data and statistics supplied by the project proponent. The data set for these statistics appear to be based on two sets of sample data corresponding to two distinct years. The statistical significance of these samples has not been rigorously analyzed, but it appears that there are about 20 individual scours included in the entire set. There is a good chance

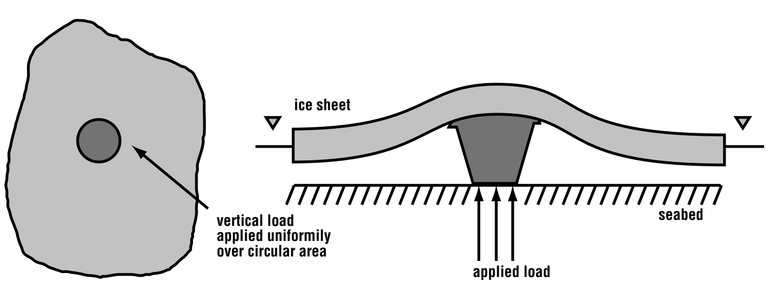



***Figure 2:*** *Response of the ice sheet.*

that the data in these data sets are grouped or episodic as they come from only two different years. Another major deficiency in the FTL analysis is that the statistical characteristics of the strudel scours were calculated without any consideration of the fact that the pipe is placed in a trench which may or may not be completely covered and which is likely to be covered with material with much lower strength than the native seabed. If one considers the actual properties of the soils material placed on top of the pipe, the rate of sediment transport and the resulting scour depths will increase for the same energy strudel, thus increasing the failure probability for the same energy strudel scours. In conclusion, **any future analysis of strudel scour events should account for the actual properties of the soils used to fill the pipeline trench.**

The structural models used in the FTL report for both the ice gouge and upheaval buckling scenarios were developed for the single pipe option. Although FTL made some limited attempt to analyze the pipe-in-pipe option, this analysis falls short of exploring the actual response of a developed pipe-in-pipe design. This may be the result of restricting the analysis to the design parameters provided by the project proponent, without consideration of potential benefits that could be achieved by optimizing the design. In fact, even the results from the limited analysis presented in the FTL report are not used in deriving failure probabilities for the pipe-in-pipe failure scenarios.

For the pipe-in-pipe option, no comprehensive analysis was conducted to determine the failure probabilities for the upheaval buckling and strudel scour scenarios. With regard to other design alternatives, no analysis was attempted for any failure scenario. Rather, the failure probability values appear to be either copied or extrapolated from the single pipe analyses. **The risk values and the failure probabilities presented in the FTL report for design options other than the single pipe option are not justified and cannot be reasonably used in any comparative exercise. To compare other design options would require more specific and optimized designs that permit calculation of risk at a consistent accuracy across different design options.**

The author of this report has modeled a potential pipe-in-pipe option that contained a carrier (inside) pipe of the same diameter as the proposed pipeline using a pipe-in-pipe model[1]. Figure 3 illustrates the displacements and strains experienced by the inner and outer pipes for a pipe-in-pipe design in response to a gouge 20 feet wide and 3 feet deep.

The design incorporates a 20-inch outside diameter outer pipe, spacers placed 16 metres apart, and burial in a trench with 4 feet of cover. In this model, the outer pipe is assumed to be at 60 degrees Fahrenheit, which is quite conservative and can be greatly reduced by a more optimal choice of insulation media in the annulus. Figure 4 shows the results from a single pipe FEM model using Shell elements, which is more accurate than the one-dimensional GSC model used in the FTL report. As illustrated by these figures, the total “true” strain experienced by the inside pipe is about 0.4% versus 13%

[1]The details of this model will be published in the future in different papers under preparation by A. Fredj and I. Konuk.

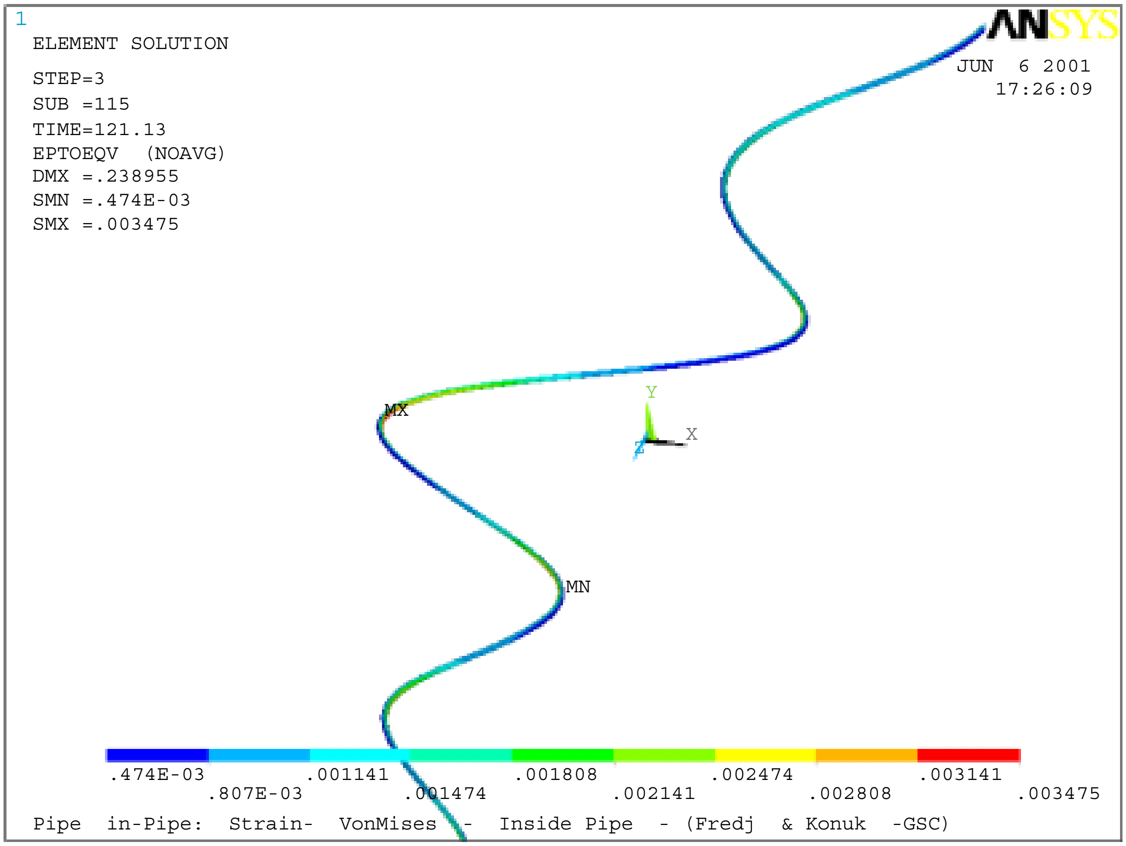



***Figure 3a:** Output (Strain) from the pipe-in-pipe model: inside pipe deformed shape (not in scale).*

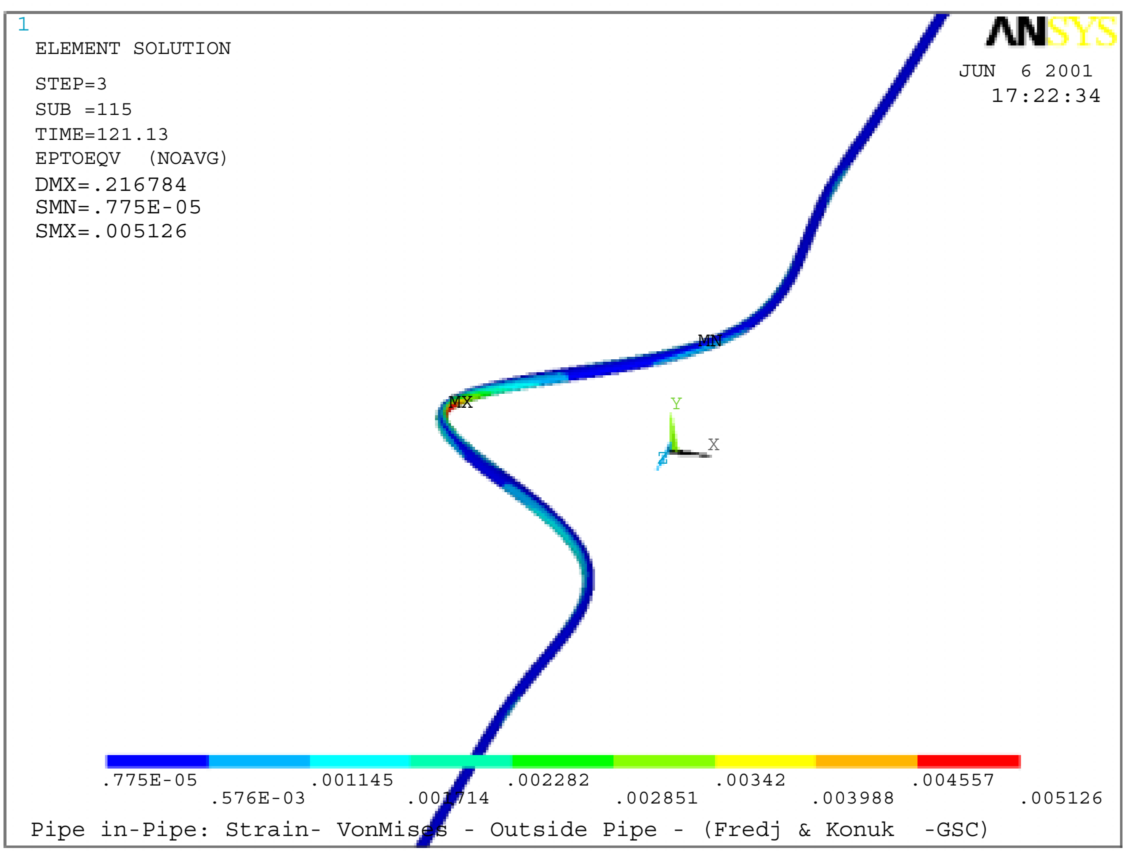
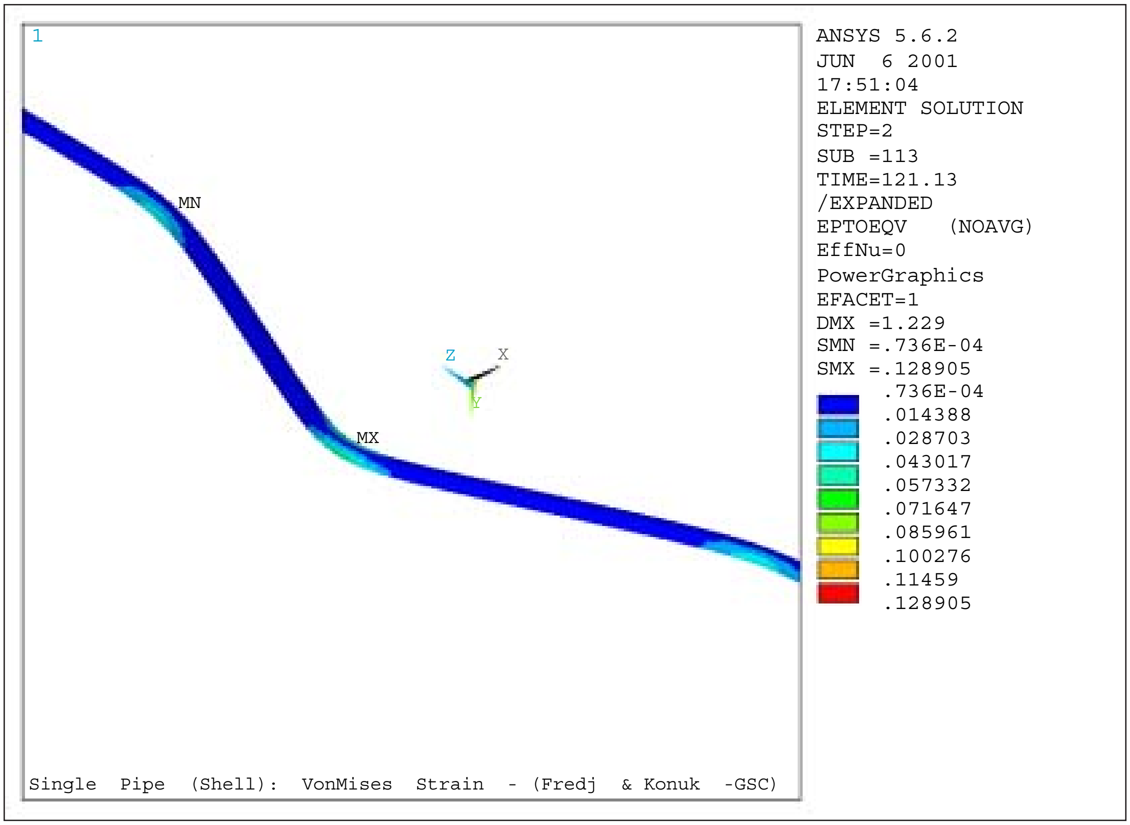



***Figure 3b:** Output (Strain) from the pipe-in-pipe model: outside pipe deformed shape (not in scale).*

***Figure 4:*** *Output (Strain) for the single pipe model (not in scale).*



for the single pipe; the strain in the outside pipe for the pipe-in-pipe is 0.5%. The 0.4% strain leaves the pipe-in-pipe almost in the elastic range whereas the single pipe incurs significant irreversible plastic strains and would be at the post-buckling or wrinkling state if the inside pressure is released or decreased.

This may have implications if the pipeline has to be shut down after a gouging event. It should be noted that these strain values would be higher if they were converted to the nominal engineering strains measured in the laboratory test. **If these strains were to be translated into failure probabilities, the failure probabilities for the pipe-in-pipe mentioned above would be at least one order of magnitude lower than for the single pipe.**

All of these analyses, including the GSC model used by FTL, are based on two-dimensional scour displacements and are not necessarily conservative, however, the model developed at GSC shows that the pipe-in-pipe option is far less susceptible to further strain increases due to 3D effects, wrinkling, and strain reversal.

The GSC pipe-in-pipe model also indicates that the upheaval buckling response of the pipe-in-pipe is very close to the upheaval buckling response of the outer pipe. Since the temperature of the outer pipe is much lower and can be controlled by providing more insulation, the upheaval buckling potential and the failure probability of the pipe-in-pipe should be lower than single pipe. This issue is very important, particularly as it relates to the coupled failure mode of strudel scour/upheaval buckling/ice gouging. This is discussed in more detail in sub-section 3.3.3.

Subsidence from permafrost degradation and unsupported spans due to seabed erosion are evaluated using small deflection theory as indicated in Section 4.5 of the FTL report. Experience from the Norman Wells pipeline in NWT, Canada, shows that thaw settlement manifests in the form of a higher mode upheaval buckling. This response can only be obtained if a large deflection model is used with the appropriate thawed soil parameters.

**When the design alternatives are optimized to the same consistency, the appropriate analyses are conducted, and the appropriate revisions required to overcome the other shortcomings mentioned in this report are applied, relative and absolute risk values will likely change significantly.**

### *2.2 Historical data based calculations*

FTL used data derived from other projects to make predictions about the performance of the Liberty pipeline. This can be misleading and lead to serious errors, especially where the source of the data is not fully investigated and proven to reflect that:

- the data is derived from pipelines with similar conditions, materials, and components, and is operated in a similar way;
- the data reporting procedure and its source are reliable; and
- the data can be uniformly normalized to reflect different pipe or operational parameters.

There are rigorous methods to test or determine the accuracy of the generalizations made from limited observations or data. The techniques that provide information concerning the discovery and testing of patterns from associative data fall into the statistics of sampling theory (See Reference 3). Due to the technical complexity, this problem will be covered in a separate publication. Risk from the failure-modes-based historical data is likely to be significantly affected by posterior knowledge. **The risk contribution from the failure modes that will be significantly influenced by further development of pipeline operational policies should not be added to the scenarios driven by environmental or functional events (such as ice gouging and strudel scour) until such policies can be incorporated in the calculation of risk.**

### *2.3 Coupled events*

Although a basic assumption is that most failure scenarios are independent, the FTL report contains detailed calculation of the pipeline failure probabilities due to re-gouging at the same location, and concludes that this adds little to the total risk.

FTL did not consider the sequence of the strudel scour/upheaval buckling/ice gouging scenarios. Assuming 7 feet of cover over a single wall pipe and using the strudel scour statistics provided in the FTL report, one would estimate ~50% annual probability for the loss of 5 feet of cover (Figure 3.8 from the FTL report). This probability must then be combined with the upheaval buckling analysis presented in Appendix D of the FTL report. When only 2 feet of cover is left, upheaval buckle causes the pipeline to move upwards by about 4.25 feet, leaving about 2.75 feet of clearance between the top of the pipeline and the seabed floor. If one assumes that all of the 2.0 feet of cover stays on top of the pipe, it can be extrapolated that the probability of exceeding the 3-foot ice gouge displacement is between $10^{-1}$ and $10^{-2}$. When this is combined with a 50% chance of initiating this event by a strudel scour, we get a return period between 20 and 200 years for failure from this coupled scenario. This is a relatively low number and normally would be considered a high risk for an engineering system. If the strudel rates are adjusted to correspond to the actual cover material properties and cover depths, and it is recognized that 2 feet of soil may not remain on top of the pipe during an upheaval event, the return period would decrease and the failure probability would increase. The risk from this scenario can be greater than any other risk component considered in the FTL report.

Upheaval calculations conducted for the single pipe cannot be directly applied to other design options such as pipe-in-pipe. When coupled scenarios are analyzed for the pipe in-pipe and other options, appropriate upheaval buckling models must be used to determine any potential of upheaval. Pipe-in-pipe is much less prone to upheaval buckling and therefore the contribution of these scenarios to the total risk is expected to be less for the pipe-in-pipe option when the design is properly optimized.

**It is recommended that the coupled strudel scour/upheaval buckling/ice gouging case be included in the total risk calculations. Strudel scour rates and cover depths should be appropriately revised to match the actual or expected design conditions. Upheaval buckling potential should be calculated using models appropriate for each design option.**

# Appendix 3: The definition of risk and use of risk analysis as a regulatory decision making tool

As mentioned in Section 3.2, the results of a risk analysis can vary significantly depending on the damage or loss for which the risk is being calculated and also on how risk is defined. This section illustrates and discusses different risk definitions and their uses and limitations. The two risk definitions stated earlier are grossly different in terms of what they express, how they can be utilized, and how they are calculated.

Definition #1 typically requires the determination of the probability density function (probability vs. the total spill volume) or cumulative probability function for the total oil to be spilled over the design life. Figure 5 illustrates a beta distribution, which happens to be a skewed distribution. The probability density function can be used in several ways. If a threshold can be derived in terms of total oil spill volume corresponding to an environmental damage or loss condition, then this curve can be used to determine the likelihood or the probability of that threshold value being exceeded, with specified environmental loss occurring, during the project life. Another way to use this information is to determine the confidence intervals or limits. In Figure 5, the arrow illustrates the use of this curve to find the total spill volume that would not be exceeded with a given confidence (e.g., 95%). Another use for this function is to conduct sensitivity analyses to determine how much the curve and a given confidence limit change when project design parameters are revised. This can be a very useful tool in a design optimization exercise.

This function, however, would not carry sufficient information to study a given environmental damage or loss scenario if such a scenario is more a function of the size of the individual spills rather than the total spill volume during the project life. In order to make such decisions, one would need information about the conditional probabilities $\{p_i, v_i\}$ mentioned in Section 2.2 and information about the frequency of

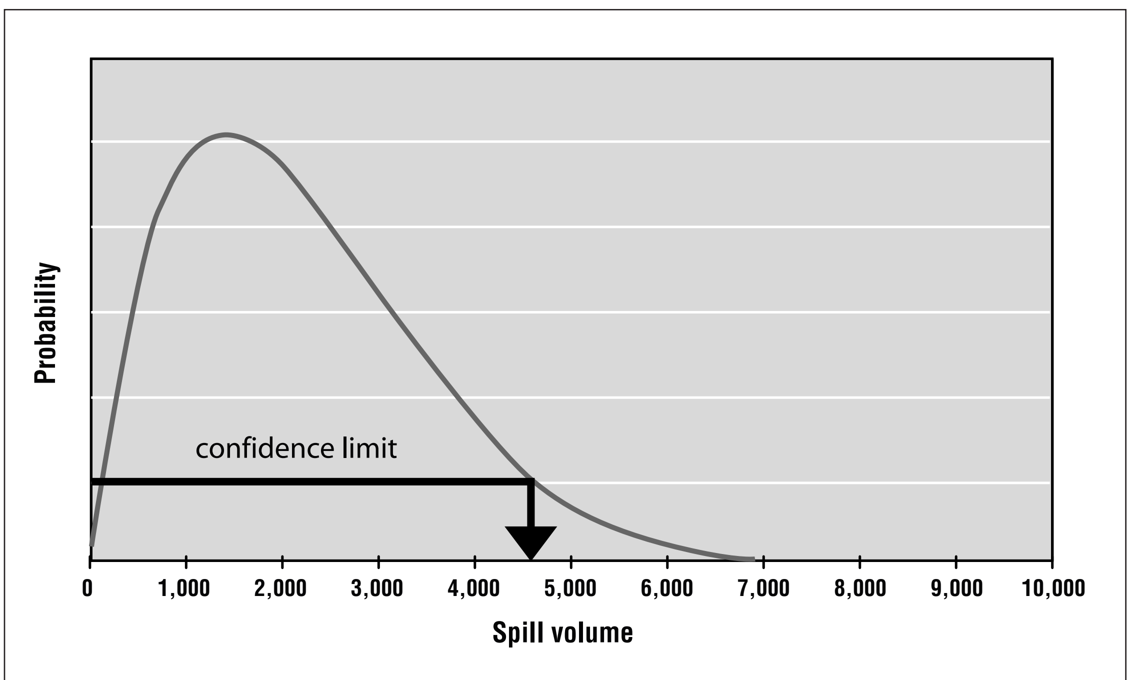



***Figure 5:*** *Illustration of the oil spill density function (risk as per definition #1).*

spills or the oil spill time series characteristics along with the relationship between the spill volume and the associated environmental damage $d_i(\ )$ caused. The expected (mean) total damage (risk) then can be calculated by the formula $F\ \{\sum p_i d_i(v_i)\}$ where i changes from 1 to N and F is the mean frequency of oil spills expected to occur within the project design life.

If one wishes to examine confidence levels on the damage likely to be done by the individual oil spill events, one would need to study the characteristics of the oil spill or pipeline failure time series. If the sequence of more than one spill or episodes were important for determining the environmental damage, one would have to study the same time series. The methods are available in the theory of stochastic processes to study such issues (see Reference 4). If one is interested in the thresholds, such as an extreme spill size which may lead to the extinction of certain species, the renewal theory in the stochastic processes presents tools to determine when, and if, a random variable (population of certain species) would, in probabilistic terms, return back to its original state after it is affected by an outside factor such as an oil spill.

For low probability events (such as less than 1%), the frequency parameter F can be approximated by the probability of the event in the formula given for the expected damage. This transforms the damage formula to $\sum p_m\{\sum p_{im}\ d_i(v_{im})\}$ where $p_m$ represents the probability of a given scenario m occurring during the project life. If all $d_i$'s were the same for all spill volumes and f was a linear function f(v)=Cv of v, where C is a constant (in units of damage per volume), then the formula can be simplified to $[\sum p_m\{\sum p_{im}\ v_{im}\}]\ C$. The term in the square brackets is the risk as per Definition #2. Closer examination of the above formula would reveal that the purpose of Definition #2 is to encapsulate both the properties of the time series as well as the statistics of the random variables involved in one number. However, it only provides information about the mean or most probable outcome and it is based on a significant assumption (damage function d being linear and universal) on the

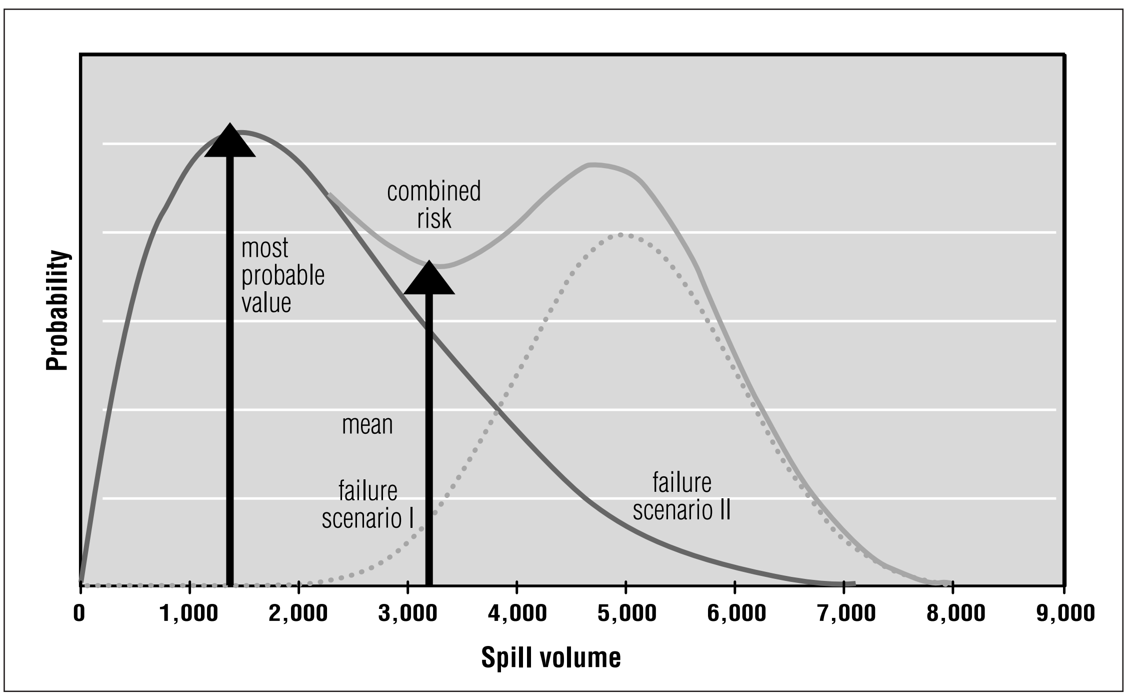



***Figure 6:*** *Illustration of the different risks (graphs as per definition #1).*

relationship between the spill volumes and environmental loss. Unfortunately, this assumption is almost never valid in ecological or environmental risk problems such as the one being studied. It is quite evident, for example, that the damage to a whale population from a 1000-barrel spill is not 1000 times the damage posed by a 1-barrel spill. In addition, the damage from a given size spill will vary depending on when the spill occurs.

Based on the above discussions, it is very difficult to understand how the results obtained using Definition #2 can be meaningfully interpreted or used. It is recommended that **before attempting further risk assessment of the Liberty pipeline, a formal statement of risk objectives be prepared and this statement contain a clear description of how the results are intended to be used.**

In the last decade, the application of risk analysis to regulatory decision-making has grown exponentially both in science and range of applications. Beer and Ziolkowski (Reference 1) provide a comprehensive list of such applications. In addition, many publications were issued by US agencies (see References 5, 6, 7, 8, 9). As mentioned in Reference 1, although there are many variations of the risk definition including the classical mathematical definition by Kaplan and Garrick (see Reference 10), most of these documents use or rely on risk definitions derived from Definition #1.

In addition to the potential for large errors in the determination of the risk for environmental damage or loss, the use of Definition #2 can lead to misleading conclusions. For example, if we consider a combined spill risk as per Definition #1 illustrated in Figure 6, using Definition #2, and assuming that the probability for the most probable value is .005, depending on how the expected consequences are calculated, one would get a risk value of 0.005 x 1500=7.5 barrels. If one uses the mean, one would get 0.0035 x 3100=11 barrels. However, if we relied on these numbers to inform us about the range of risks, we would have missed the fact that there is a very high probability spill volume at about 5100 barrels rather than 1500 or 3100 barrels. Not only that, the risk posed by that point is about 0.005 x 5100= 25 barrels. This example is included to illustrate how much uncertainty and variability is included in the numbers obtained using Definition #2, even if all the correct steps were to be followed. It also illustrates that it is possible to miss quite significant damage scenarios.

**It is recommended that: (1) more specific risk objectives be defined, and (2) either risk Definition #1 or the time series characteristics of the pipeline failures are studied before any risk studies are employed in the decision-making process.**

## Appendix 4: Pipeline design objectives and comparison of the alternatives

This section presents a very brief discussion of some of the specific design choices that are available to the design engineers and how these choices may influence the oil spill risk. The intent is not to present a comprehensive design alternatives study, but simply to demonstrate, by providing examples, the kinds of issues that should be studied at the next decision-making step.

It is assumed that the objective of commissioning the FTL study was to determine the risks posed by different design options and lead the project proponent towards the development of an optimal design from the view point of specific environmental (and safety) risks. The proponent in the process can combine these risk objectives with the financial risk objectives to make a decision to proceed with the proposed project design and convince the regulators that the design provides an acceptable level of risk. The discussion on the design alternatives is provided to help FWS to participate in such a process.

As was discussed in earlier sections, this author recommends that the contribution from operational errors should be studied separately from the risks induced by the environmental and functional loads or effects. In this section, only these risks will be covered. Only the single pipe, pipe-in-pipe and flexible pipe options will be covered. It is also assumed that the size of the carrier pipe and product temperature and pressure are the same for the three options.

Since the damage is measured in volume of spilled oil, it has to be assumed at this point that the objective from an optimal design is to reduce the likelihood (probability) of expected (mean) total spill volume for the project life. Environmental loads considered include ice scour, strudel scour, soils settlements. The functional loads include temperature, pressure, electrochemical processes (corrosion). The designer can achieve the objective of risk reduction (or minimization) either (1) by optimizing the design to reduce the probability of failure from the environmental or functional loads, or by including a design feature that (2a) prevents, or (2b) minimizes the consequence.

In the first category, for the single pipe, the designer has the following parameters to optimize a design: burial depth, material used to cover the pipe, wall thickness, pipe material or grade. For the pipe-in-pipe, the designer can vary wall thickness of both pipes, the diameter of the outside pipe, the spacer locations, the pipe materials or grades, and material to fill the annulus. For flexible pipe, there are many parameters that can change the performance of the pipe. Since this requires studies beyond the scope of this report, the flexible pipe optimization is not discussed here although it may be included at a future stage unless it is decided to exclude that option for economical reasons as it would be expected that the cost of such an optimized design would be an order of magnitude higher than the other two options.

Operational parameters can also be incorporated in the optimization of the design such as the performance of the internal inspection procedures and the corrosion protection system. As seen from many pipeline bundles installed around the world, it is possible to maintain electrical isolation between the outer and inner pipes and regular impressed current or sacrificial anode systems can be employed to protect the inside pipe of the pipe-in-pipe option at a level equal or better than what is possible with single pipe. Internal inspection procedures are available to inspect the carrier pipes for both options. The inspection of the outer pipe can be achieved by pressure testing the annulus at regular intervals. As described below, if these tests are conducted at the appropriate pressure and the outside pipe fails, it can be repaired without interrupting the production and releasing any oil in case of a test failure. Along with this test capability, as with any bundle, the annulus can be maintained at an electrochemically neutral state or filled with a neutral substance. **When the failure probabilities and the expected consequences are computed in a proper way while incorporating these design options in a meaningful way, the corrosion of the outside pipe for a pipe-in-pipe design should not increase the spill risk in any magnitude to affect the final comparison of risks.**

Burial depth decreases the chance of the failure from strudel scour or ice scour for both pipe-in-pipe and single pipe. The cover material density and depth of cover over the pipe would help with strudel scour and upheaval buckling. However, for the same level failure probability, pipe-in-pipe would require much less burial or for the same depth, pipe-in-pipe failure probability would be about one order of magnitude lower than single wall pipe. The pipe-in-pipe response can be further improved by optimizing the diameter of the outside pipe, the location of spacers, and also the material used to fill the annulus. There is no comparable design optimization possible for the single pipe. The same factors, especially the insulation feature of the annulus, would also improve the upheaval response of the pipe-in-pipe, reducing or eliminating the risk from the coupled strudel scour — upheaval buckle — ice scour scenario. The only parameter, other than cover material available for optimizing the single pipe, is the wall thickness of the pipe. However, increasing wall thickness provides only a small improvement as already demonstrated by the FTL report.

It should be noted that due to shallow permafrost, the design optimization with respect to the trench depth would be constrained. Experience from the Norman Wells pipeline shows that thaw settlements manifest themselves with higher mode upheaval buckling of the pipe.

**The design parameters provided to FTL for the pipe-in-pipe indicate that no attempt was made to take advantage of several features of the pipe-in-pipe to optimize its failure performance. It is recommended that it be so done at a future stage.**

With respect to secondary containment of leaked oil, pipe-in-pipe and flexible pipe can be designed to provide a secondary channel to lead the oil leaked from the carrier pipe to a retainer tank or a berm on land or on to the production site. If one provides a pressure relief capability at the one or both ends of the pipe and designs the spacers accordingly, the pressure that outer pipe has to carry till the annulus is completely full will be less than 100 psi. For larger leaks, the pressure would gradually increase at a rate that would depend on the leak size, its location, and the design of the spacers. For smaller leaks, this pressure would be expected to stay at low levels at all times.

It would be expected that the leak detection system (SCADA) would detect a large leak before the pressure exceeds the capacity of the outside pipe. The outside pipe can be tested to ensure its pressure integrity at a level significantly higher than required for the release pressure (e.g. 500 psi). This would give sufficient time to detect a corrosion defect on the outside pipe before it grows to a through-the-thickness-failure. The outside pipe wall thickness can be chosen to ensure that any failure that occurs during the regular pressure testing of the annulus would be by yielding, rather than fracture. This would simplify repairs for the outer pipe.

Also it should be recognized that it is possible to incorporate into the annulus of the pipe-in-pipe, a system to evacuate any oil leaked from the carrier pipe after a failure of the inner pipe and before any repairs are attempted. Single pipe provides no such features and optimization possibilities.

With respect to minimizing failure consequences, all options can benefit from external leak detection systems. In addition, **in the case of the pipe-in-pipe alternative, additional leak detection systems can be installed in the annulus.**

## Appendix 5: References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## Appendix 6: List of documents supplied by U.S. Fish and Wildlife Service

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