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OFFSHORE ARCTIC PIPELINE OIL SPILL RISK ASSESSMENT

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ABSTRACT

While offshore arctic pipelines have been under consideration for more than 25 years, few have been built. Renewed interest in offshore arctic oil and gas has necessitated the design of pipelines capable of both overcoming the technical challenges of the arctic offshore environment and minimizing the risk to it. This paper describes a quantitative risk assessment completed by BMT Fleet Technology Limited on the risk of an oil spill for several design alternatives of the proposed Liberty Pipeline that would be used to transport oil onshore from a production site in the Alaskan Beaufort Sea.

For the purposes of the study, risk was defined as the volume of oil expected to be released over the planned pipeline 20-year life. The investigation considered the risks associated with ice gouging, strudel scour, permafrost thaw subsidence, operational failures, corrosion, third party activities and thermal loads leading to upheaval buckling. Event probabilities for these hazards were established through the development of event trees used to combine historic operational failure statistics and those estimated through engineering analysis.

A pipeline leakage consequence model was developed to quantify the oil volume released during pipeline failure events associated with rupture, through-wall cracking and pinhole leaks. The model considered secondary containment and the expected performance of leak detection and monitoring systems. The time to leak detection, shut down, and line evacuation were used in estimating the total spill volumes.

The paper provides an overview of primary elements of the risk assessment including the hazard identification, reliability analysis and consequence modeling, and describes the challenges involved in this comparative risk analysis completed for this unique environment.

INTRODUCTION AND SCOPE

The Liberty Pipeline was intended to transport oil to onshore Alaska from BP/Amoco's Liberty site, which is located inshore of the Barrier Islands in the Alaskan Beaufort Sea in 22 feet of water. The offshore portion of the pipeline is 6.12 miles long. Risk analyses were carried out for four pipeline concept designs produced by Intec, 1999; 2000:

(a) single carrier pipe;
(b) carrier pipe inside a steel pipe;
(c) carrier pipe inside a high density polyethylene pipe; and
(d) single layer composite flexible carrier pipe.

This paper summarizes the analysis techniques used to assess pipeline failure probabilities, consequences and risk of an oil spill for these design alternatives. In general, this assessment was completed in four steps as follows:

1) Risk Assessment Scope Definition
    1.1) Define Risk
    1.2) Define Scope of the Assessment
    1.3) Identify Hazards
2) Estimate Hazard Induced Failure Probabilities
    2.1) Use Historical Failure Statistics
    2.2) Calculate Failure Probabilities
        2.2.1) Establish Initiating Event Statistics
        2.2.2) Develop Pipeline Response
        2.2.3) Define Limit Response (Failure Criteria)
        2.2.4) Establish Hazard Failure Probability
3) Estimate Hazard Induced Failure Consequence
    3.1) Use Historical Spill Volume Statistics
    3.2) Calculate Spill Volume
        3.2.1) Identify Hazard Failure Mode and Location
        3.2.2) Calculate Failure Mode Oil Spill Rate
        3.2.3) Establish Oil Spill Detection Thresholds
        3.2.4) Establish Response Times
        3.2.5) Calculate Hazard Total Oil Spill Volume
4) Calculate Oil Spill Risk

The primary focus of this paper is in the description of steps 2.2 and 3.2. More detailed information on the entire risk assessment process is provided in (Comfort, Dinovitzer and Lazor, 2000) and the results of the risk assessment are outlined in (Comfort et. al. 2004).

RISK ASSESSMENT SCOPE DEFINITION

Perhaps the most important element of a risk assessment is the preliminary definition of its scope. In the Liberty Pipeline risk assessment the scope of the assessment was defined to consider the expected quantity of oil spilled during the 20-year design operating life of the pipeline. As such the total risk was defined as:

$$R_{total} = \sum (C_i * P_i) \quad [1]$$

where:

R_{total} = the total oil spill volume expected in the Liberty Pipeline 20-year life for a given pipeline design

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

With risk defined a hazard identification exercise was completed to define the hazards of interest. These hazards and the techniques used to evaluate their probabilities of failure and consequences are outlined in Table 1.

ESTIMATION OF FAILURE PROBABILITIES

The probabilities of each hazard promoting pipeline failure were evaluated based either on pipeline industry historical failure rates or calculated considering hazard event frequencies and pipeline responses to these events.

Review of Industry Failure Statistics

Although many sources (e.g., US DOT, MMS, Concawe, AEUB) were examined, the failure statistics for the TAPS

Pipeline Failure Probability Calculation

For those modes of failure not supported by historical industry statistics, failure probabilities were estimated by (Figure 1):

(a) evaluating the probabilities of occurrence of initiating events;
(b) analyzing the pipeline's response to these events, and;
(c) comparing the pipeline's response to failure criteria, that were established,

This analysis process is described in the paragraphs that follow using ice gouging (i.e., ice keel/pipeline interaction), as an example.

Probabilities of Occurrence for Ice Gouging Events

The ice-gouging hazard is difficult to analyze because a wide range of scenarios may occur, and little information is available to evaluate the ice keel-soil-pipe interaction. It is generally recognized that three interaction types are possible (Palmer et al, 1990) including:

(a) Zone 1 – the pipeline is located above the keel bottom, and thus, the moving ice keel contacts it.
(b) Zone 2 – the pipeline is below the keel bottom, and thus not contacted by it. However, large soil displacements may occur (e.g., Woodworth-Lynas et al, 1996), causing large strains in the pipeline.
(c) Zone 3 – the pipeline is located far below the bottom of the ice keel with the result that the pipeline is safe.

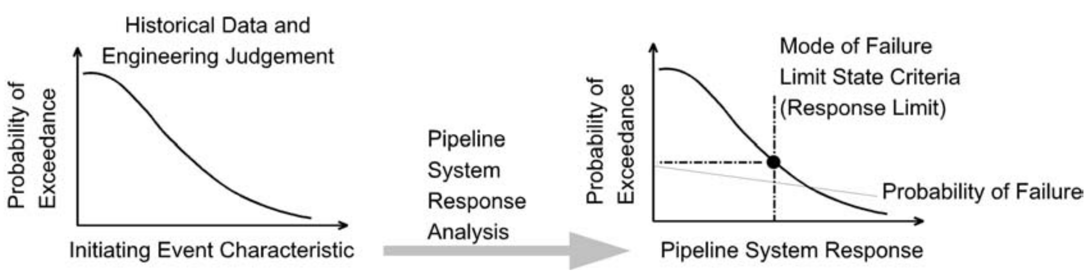

Figure 1: Failure Probability Estimation Overview

Table 1: Identified Hazards, Failure Probability Evaluation Methods and Expected Failure Modes

Hazards Evaluated	Evaluation of # of Failures in 20-Year Life of Pipeline
Ice Gouging (3 Cases Evaluated): 1. Pipe contacted by ice 2. Loaded once by sub-gouge soil displacement 3. Loaded multiple times by sub-gouge soil displacements, producing stress reversals	• Occurrence probabilities established from event trees and analysis of environmental data • Failure Mode – Pipe presumed to rupture
Strudel Scour (2 Cases Evaluated): 2. Strudel scour causes unsupported pipe 3. Partial cover loss leading to upheaval buckling	• Occurrence probabilities established from event trees and analysis of environmental data • Failure Mode – Oil flows through the maximum crack that is expected to be stable.
Permafrost Thaw Settlement	• Occurrence probabilities from failure statistics • Failure Mode – Oil flows through the maximum crack that is expected to be stable.
Thermal Loads Leading to Upheaval Buckling	• Occurrence probabilities from failure statistics • Failure Mode – Oil flows through the maximum crack that is expected to be stable.
Corrosion Operational Failures & 3rd Party Incidents – Minor incidents of less than 100 bbls	• Occurrence probabilities from failure statistics • Failure Mode–Oil flow through pinholes (seepage)
Other Operational Failures & 3rd Party Incidents – Major incidents of 100 bbls or more	• Occurrence probabilities from failure statistics • Failure Mode – Oil flows through the maximum crack that is expected to be stable.

The risks associated with each of these 'zones' were considered independently. A Zone 1 interaction was assumed to result in pipeline rupture, thus no structural analyses were performed. Oil spill risk was evaluated based solely upon the probability of ice-pipe contact and consequence modeling.

In a Zone 2 interaction event, the pipeline route is crossed once by an ice keel and soil displacements occur which load the pipeline. To evaluate this event, available ice gouge data were reviewed. The data set is quite small which introduces uncertainties, as ice conditions are known to vary from year to year. The greatest uncertainty was 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). The analysis suggested that gouge impact rates might vary from about 0.049 to 0.41 gouges/mile/year. As a result, event probabilities were evaluated for three impact rates spanning the expected range (Figure 2), recognizing that gouges only occur in water depths greater than 10 ft.

With the ice gouge event probabilities established, the pipeline response was evaluated by estimating the pipe strains in a Zone 2 interaction. In practice, these are governed by the soil property-dependent displacements, ice-related parameters such as the ice keel strength and the ice keel vertical uplift. However, current practice does not support precise assessment of this interaction, and thus an engineering approximation of the soil displacements was adopted (described subsequently). This soil-pipe interaction was evaluated using a displacement-controlled analysis in which the key operating environment inputs were: (a) the soil displacement field beneath the gouging ice feature; (b) the temperature differential; and (c) the pipeline operating pressure.

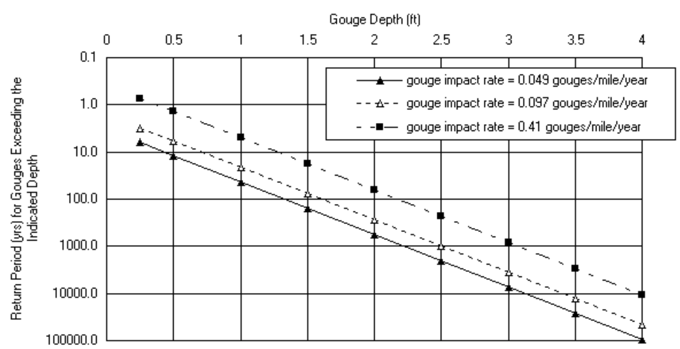

Figure 2: Estimated Gouge Depth Return Periods

Of necessity, subgouge soil displacements were calculated using algorithms based on small-scale centrifuge tests (Woodworth-Lynas et al, 1996) as these represented the only publicly available information. Subgouge soil displacement exceedence probabilities (e.g. Figure 3) were calculated for the gouge depth return periods (Figure 2), for gouge widths of 18 and 30 feet, which represent worst-case gouge widths for the pipeline. (It was found that the maximum pipeline strains and stresses were strongly affected by the gouge width (i.e., the loading width) for gouge widths in a certain range).

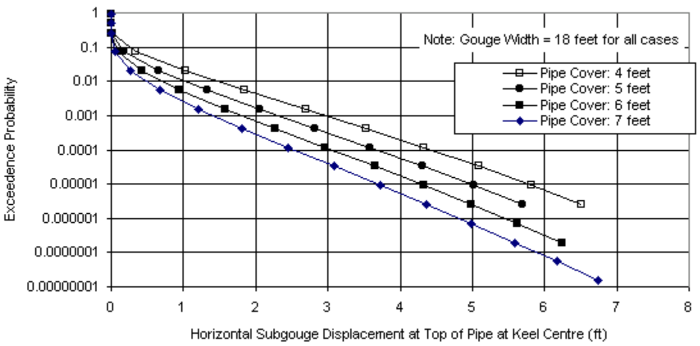

Figure 3: Subgouge Soil Horizontal Displacements

Pipeline Structural Analyses: Global Behaviour

This was used for analyzing the single pipe design.

ANSYS large displacement, non-linear finite element modeling was used to calculate pipe response (e.g., strains, stresses) in relation to the subgouge soil displacements that loaded the pipeline. This global pipeline behavior modeling (Konuk and Fredj, 2000) included the effects of internal pressure (1415 psi) and thermal strains on the pipe elements used (ANSYS Pipe 20). The pipe elements were supported by axial soil friction spring elements (ANSYS combin 39) that were loaded by the prescribed soil displacements applied at the free ends of the lateral displacement soil spring elements (Figure 4). The thermal loading due to the difference between the construction (30°F) and operating temperature (150°F) induced a compressive load that would serve to accentuate lateral deformations, while the pipe internal pressure results in an effective stiffening of the pipe section. The element sizes increased with distance from the centre of the Zone 1 model where the prescribed displacements were applied to the ends of the model.

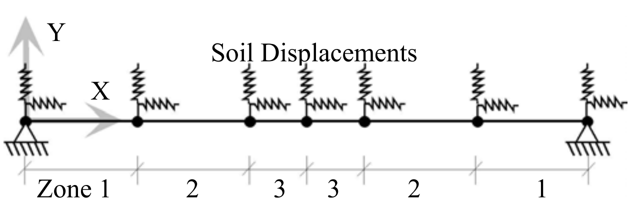

Figure 4: Lateral Deformation Global FE Model

It is noted that this model is an engineering approximation of expected pipeline behavior because the:

- potential for buckling and wrinkling that could affect the pipe stiffness was not considered,
- prescribed displacements might not be realized due to limits on the ice keel strength,
- the analysis only considered pipe displacements in the horizontal plane, and
- the effects of pipeline shutdowns or post subgouge event spring back on strain reversals were not considered.

Analyses similar to those illustrated in Figure 5, comparing pipeline axial and lateral displacements with the applied soil displacements, were developed for a range of subgouge displacement fields associated with ice gouge event magnitudes. The analyses indicated that the lateral displacement and curvature of the pipeline (bending moments) was essentially nil outside of a 40 m wide zone centred on the gouge centreline. This information was used in setting up the local detailed finite element model to investigate the effects of pipe-in-pipe construction.

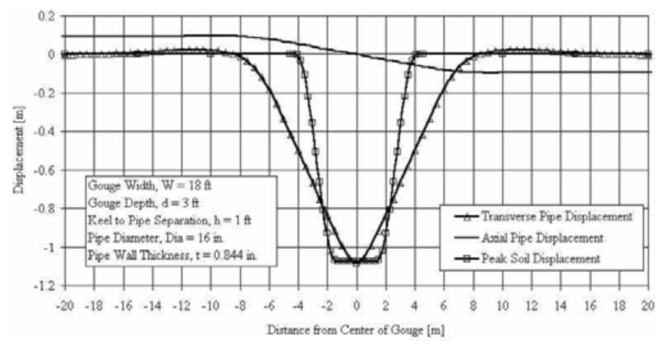

Figure 5: Subgouge Soil and Pipe Displacements

It is also noted in this case, and in others, that the peak pipe transverse displacement exceeded the soil transverse displacement due to the deformation accentuation due to the pipe compressive load resulting from temperature change and internal pressure. This exceedence of the soil displacement indicates that the pipe is buckling in its natural mode shape as the soil is displaced.

Pipeline Structural Analyses: Local Behaviour

This was used for evaluating the pipe-in-pipe designs.

For considering a cased or pipe-in-pipe design alternative, a local finite element sub-model was developed to consider the relative movement (sliding) between the carrier pipe and the outer pipe. These local models demonstrated the ability of the pipe-in-pipe systems to reduce strains on the inner carrier pipe compared to the single pipe alternative. In the pipe-in-pipe alternative the inner carrier pipe had significantly lower strains than the outer pipe as shown in Figure 6.

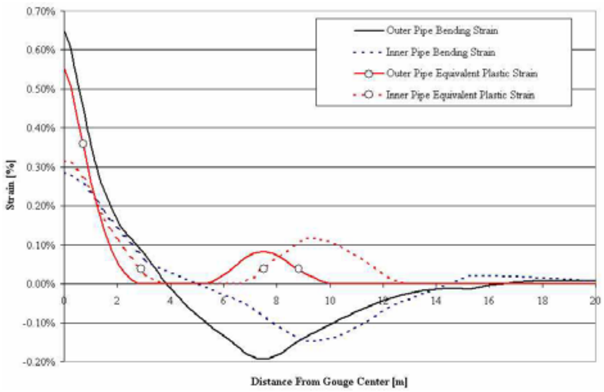

Figure 6: Pipe-in-Pipe Design Alternative Strains

The peak pipeline strains were used to develop a relationship between pipeline maximum strain and ice gouge event characteristics. This allowed the development of pipe strain exceedance probabilities for the ice gouge events.

Pipeline Structural Analyses: Failure Criteria

Pipeline material failure criteria were needed to define the limiting strain that would define the onset of failure. Traditional structural or pipeline design has been based on keeping stresses below the elastic limit; this uses yield as the failure criterion. While these are safe design criteria, they are very conservative ones for predicting the ultimate strength failure or loss of product containment for a pipeline.

Modern pipeline design standards permit small amounts of plasticity, yet they are still considered conservative with regards to a pipeline rupture criteria. It has been noted that strain limits as high as 5 to 10% plastic strain could be acceptable, and for this reason an alternate failure criteria was developed based upon full-scale pipe flexural load trials. Trials completed for the Northstar pipeline project (Stress Engineering 1998a; 1998b) included full-scale bend tests on welded pipe segments containing machined flaws of the same diameter and grade as the Liberty Pipeline. These test indicated that 10% strains could be supported without leakage. Based on these test results and others, the following failure criteria were conservatively developed:

(a) first loading cycle of the pipeline - 10% Von Mises strain limit.
(b) multiple loading events (e.g., multiple ice gouge events, in which the pipeline is crossed several times by an ice keel, producing stress reversals) - 15% cumulative Von Mises strain.

ESTIMATION OF OIL SPILL CONSEQUENCE

The consequence of failure induced by each hazard was calculated considering the susceptibility of pipeline segments to each hazard, the expected mode of failure, leak detection thresholds, pipeline design alternative secondary containment characteristics, and mitigating operational response times.

Review of Industry Oil Spill Statistics

A variety of sources (e.g., US DOT, MMS, Concawe, AEUB) were examined as an aid to developing typical oil spill volume statistics for the Liberty Pipeline design alternatives. In general, this method of estimating the consequence of a failure event has been applied to operational or maintenance failure modes (e.g. oil spilled during maintenance activities). It was noted that engineering judgement had to be applied to ensure that the hazards and failure modes were applicable to an offshore oil pipeline or the particular design alternative being considered. For example, third party damage due to excavation equipment interaction with the pipeline was considered an event that need not be considered in an offshore pipeline.

Due to these uncertainties, oil spill volumes were calculated directly for each hazard taking into account:

(a) the chain of events that would lead to an oil spill;
(b) the pipeline failure mode that would be expected for each hazard; and
(c) the effect of leak detection and monitoring systems

Calculation of Oil Spill Volume

In general the approach taken is summarized in Figure 7. The model considered a three-stage process as follows:

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

The type of breach and remedial actions taken were considered in estimating leakage (spill) rate. The type of leak detection system and operator reaction times were considered in estimated the duration of each stage in the oil spill consequence model.

Failure Modes and Oil Flow Rates

The first step in modeling these hazard induced failure consequences involved assigning a pipeline failure mode to each failure event. Three oil spill release mechanisms were considered:

- "Rupture" - complete separation of the pipeline allowing oil to spill at the design flow rate of 65000 bbls/day,
- "Leak" – the oil spill rate for this case was based upon flow through a large stable crack-like flaw, and
- "Seepage" - flow through a pinhole in the pipe.

Table 1 describes the assignment of oil spill mechanisms to each hazard-induced failure mode.

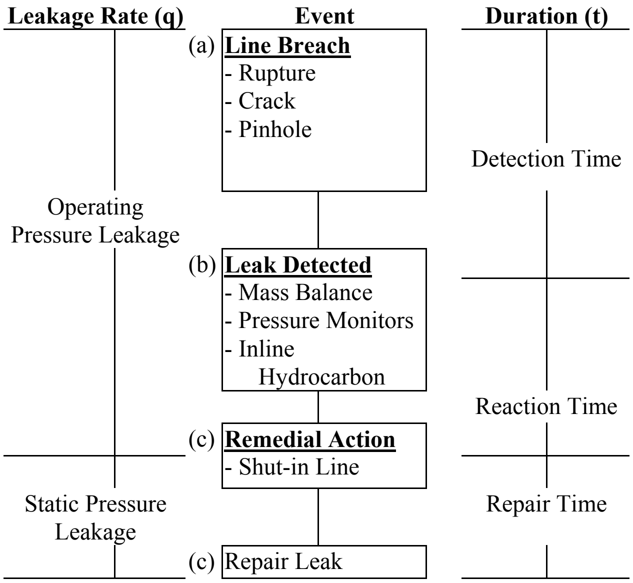

Figure 7: Consequence Model Event History

The oil flow rate associated with a rupture, prior to detection, was assumed to be 65000 bbls/day, which is the planned oil transmission rate for the line when in operation. The leakage rates through a stable crack or a pinhole are significantly lower. The largest stable crack that can be supported by the pipeline was estimated using a crack-like flaw failure assessment technique outlined in British Standard PD6493 that considers the interaction of fracture and plastic collapse failure mechanisms. The critical crack length for a pipeline is dependent on material properties and pipe geometry. While the nominal Liberty Pipeline pipe material properties (grade X52) and geometry are known, the fracture toughness (Crack Tip Opening Displacement CTOD, δ) of the base metal and weldments were not known. A sensitivity study to evaluate the impact of various CTOD (mm) values was completed (Figure 8) which demonstrated that assuming a 250mm long though-thickness flaw was reasonable.

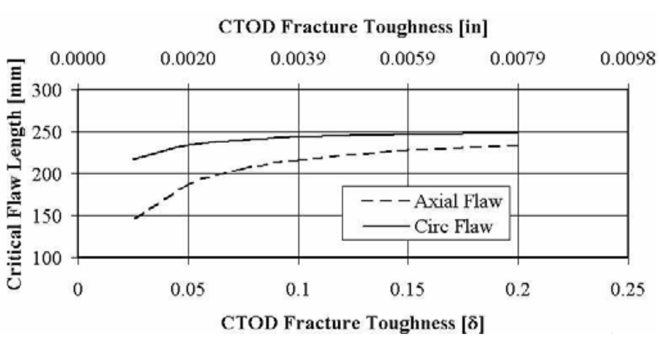

Figure 8: Estimation of Largest Stable Flaw

To calculate the pipe opening area for the critical crack lengths, one needs to establish the Crack Mouth Opening Displacement (CMOD), and for longitudinal flaws the amount of pipe wall bulging at the crack due to internal pressure is also calculated. The CMOD can be estimated (Graville and Dinovitzer, 1996) from the following equation:

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

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.

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):

$$F = \left(1 + \frac{1.255L^2}{4Rt} - \frac{0.0135L^4}{(4Rt)^2}\right) \qquad [3]$$

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 2. The crack mouth opening closes with reduced pressure, and at lower pressure, the bulging effect is neglected. The crack mouth opening displacements are transformed into opening areas, shown in Table 2, by assuming that the crack edges are parabolic arcs.

Table 2: Crack Mouth Openings and Areas

Internal Pressure	Axial Flaw (230 mm)	Circ. Flaw (250 mm)
Operating Pressure (1415 psi)	6.38 ($489mm^2$)	2.97 ($247.5mm^2$)
Shut-in Pressure (1.45 psi)*	0.75 ($57.5mm^2$)	0.30 ($25.0mm^2$)

* (10 kPa is representative of hydrostatic pressures after shut-in

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:

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

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 circular opening [m]

Equation 4 was solved for the opening areas of interest. As expected, the flow rate increases with the pressure differential and with the opening area (Figure 9).

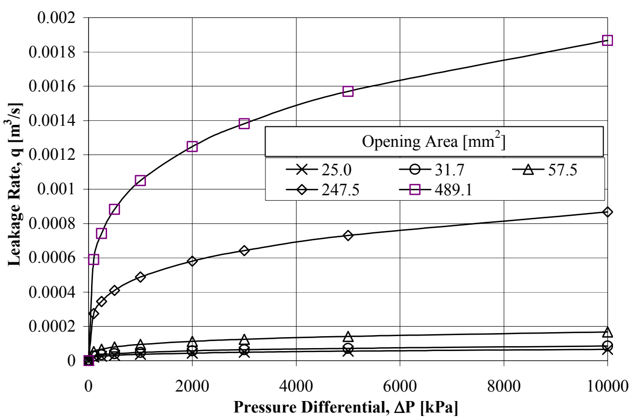

Figure 9: Leakage Rate for Cracks

Leakage rates for pinholes were determined using a similar approach with the size of pinholes being estimated at 1 to 3mm diameter based on experience and engineering judgment.

Effect of Leak Detection and Monitoring Systems

The capabilities of the leak detection or monitoring systems proposed for the pipeline were reviewed to assess the time before remedial actions are taken. It was presumed that the Liberty Pipeline would be fitted with a PPA/MBLPC (Pressure Point Analysis/Mass Balance Line Pack Compensation) and a LEOS (German acronym) monitoring system, based on Intec, 1999;2000.

The capabilities of these two systems were established by reviewing past performance and by engineering judgment where necessary. The parameters assessed included the leak detection thresholds, the alarm time, and the number of false calls. Pipeline failure by rupture or flow through a large stable crack would be detectable by the PPA/MBLPC monitoring system that would be used. 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 would be used.

Responses Once a Leak Is Detected

Once leakage is detected the primary response would be to shut in the system. The duration of time between detection and shutting in the pipeline 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. Based on industry data reviewed and operational experience it was decided that a five-minute reaction interval would be a conservative estimate of the time to start shutting in a leak as Liberty is short line and the polling rate for the detection systems 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.

After the leak has been detected and confirmed by the operator, line shutdown would be initiated, by shutting off pumps and isolating the line. This procedure would require a time period of approximately 8.5 minutes for valve closure. Leakage volumes until the valve is closed 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. 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.

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).

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.

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

- all of the oil capable of being drained from the line is released;
- the pipeline opening is repaired; or,

- 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 conservatively assuming that all oil capable of draining out of the pipeline is released.

Effect of Damage Location Along the Pipeline Route

This affected the consequence modeling in two ways:

(a) applicable water depth ranges – Each hazard was of concern for a different range of water depths. For example, ice gouging was only a concern in segments of the pipeline at water depths greater than 10ft, as gouges in shallower water were not expected to occur at the Liberty site. Hence, ice gouging was only allowed to pose a risk for deeper water depths.

(b) oil drainage from the line -The amount of oil capable of being drained was calculated 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. By considering the elevation profile of the pipeline the potential drainage volume associated with a leak at each location in the pipeline was estimated, as shown in Figure 10.

Figure 10: Oil Drainage for Each Failure Location

The oil spill consequence model developed in this assessment suggests that the total volume spilled for a detectable event will follow the time history shown in Figure 11. It should be noted that the shape of the time history curve would depend upon the nature of the line break.

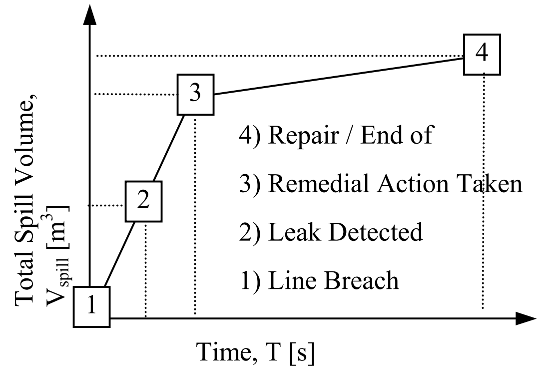

Figure 11: Total Oil Spill Volume History

The steps in the oil spill leakage volume estimation process are summarized below:

- the line is at full operation at the instant that failure occurs.
- oil is pumped into the line at the production rate of 65,000 bbls/day until:
  - the leak is detected;
  - the decision is made to initiate line shut-in; and,
  - line shut-in is commenced.
- the flow rate is reduced, as the line is shut-in and depressurized.
- oil is slowly released after shut-in as all of the oil drains from the line.

It should be noted that the oil drainage element of the spill release process constituted the main spill volume (about 70% of the total for all hazards) in the above sequence.

CALCULATION OF OIL SPILL RISK

The oil spill risk was calculated for each design alternative is calculated using equation 1.

In order to better understand the significance of the assumptions made in the risk assessment, a variety of sensitivity studies were completed to demonstrate the impact of different assumptions. The oil spill risk estimated for each design alternative is presented in Table 3 along with the results of the more significant sensitivity studies including:

(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 operational failures and 3rd party activities; and
(e) the assumptions made regarding the pipeline failure mode.

Table 3: Oil Spill Risk and Sensitivity Analysis Summary for Each Design Alternative

Case	Single Steel Pipe	Steel Pipe-in-Pipe[2]	Pipe in HDPE[2]
Base Case (best estimate for all inputs)	28	8; 13	24; 24
Failure Mode: All by rupture All by oil flow through the maximum stable crack All by seepage through pinholes	153 109 8.7	39; 75 28; 54 2.2; 4.4	154; 154 110; 110 8.8; 8.8
Worst operational & 3rd party failures case	69	18; 22	65; 65
No secondary containment	28	28; 28	28; 28
Expected worst-case monitoring system performance	51	14; 26	51; 51
Worst case water depth for each hazard	35	9; 15	31; 31

Notes:
1) All risk values are in bbls.
2) The values listed are for steel pipe-in-pipe, and pipe-in-HPDE each consider two alternate designs

Results

The following results were obtained from the analyses:

(a) the steel pipe-in-pipe designs had less risk than the other ones.

(b) the reduced risk for the steel pipe-in-pipe designs was due primarily to the effects of secondary containment. All designs had the same risk if it was presumed that there was no secondary containment (Table 3).

(c) the water depth at which the different hazards occur affects the risk, as it controls the total oil drainage. Although not shown clearly in this paper (due to space limitations), consequence modeling showed that drainage caused the majority of the oil loss associated with pipeline failure. This finding also highlights the importance of quick action once a leak has been detected. For example, the study showed that the oil spill risk could be reduced substantially by purging the line once a leak had been detected, thereby preventing full drainage.

(d) the failure mode, as expected, has a very strong influence on the total volume of oil that can be lost, with the greatest volumes resulting from a rupture, followed by flow through a stable crack, and lastly by seepage through a pinhole.

(e) the performance of the leak detection monitoring systems has an important effect on the risk for all design alternatives, as the total risk in each case is approximately doubled by a reduction in the monitoring system performance. As expected, the steel pipe-in-pipe design was least sensitive to this assumption owing to the effects of secondary containment.

(f) although not discussed in this paper (due to space limitations), operational failures and third party activities were the most significant hazards for all designs.

(g) although not discussed in this paper (due to space limitations), the total risk was found to be relatively insensitive to parameters such as: the ice gouging frequency, the subgouge soil displacement algorithms, the strudel scour generation rates and their size, corrosion, occurrence probabilities for thaw subsidence and upheaval buckling.

CONCLUSIONS

A detailed analysis has been carried out to determine the risk (defined as the amount of oil spilled over the pipeline's 20-year life) for alternative concept designs for the Liberty Pipeline. This analysis demonstrated that quantitative risk assessment could be carried out to compare design alternatives. Where historic performance data was not available engineering models were used to evaluate the probability and consequence of failure.

The risk assessment demonstrated the primary differences in the performance of the proposed design alternatives and allowed the key factors affecting the oil spill risk to be identified.

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