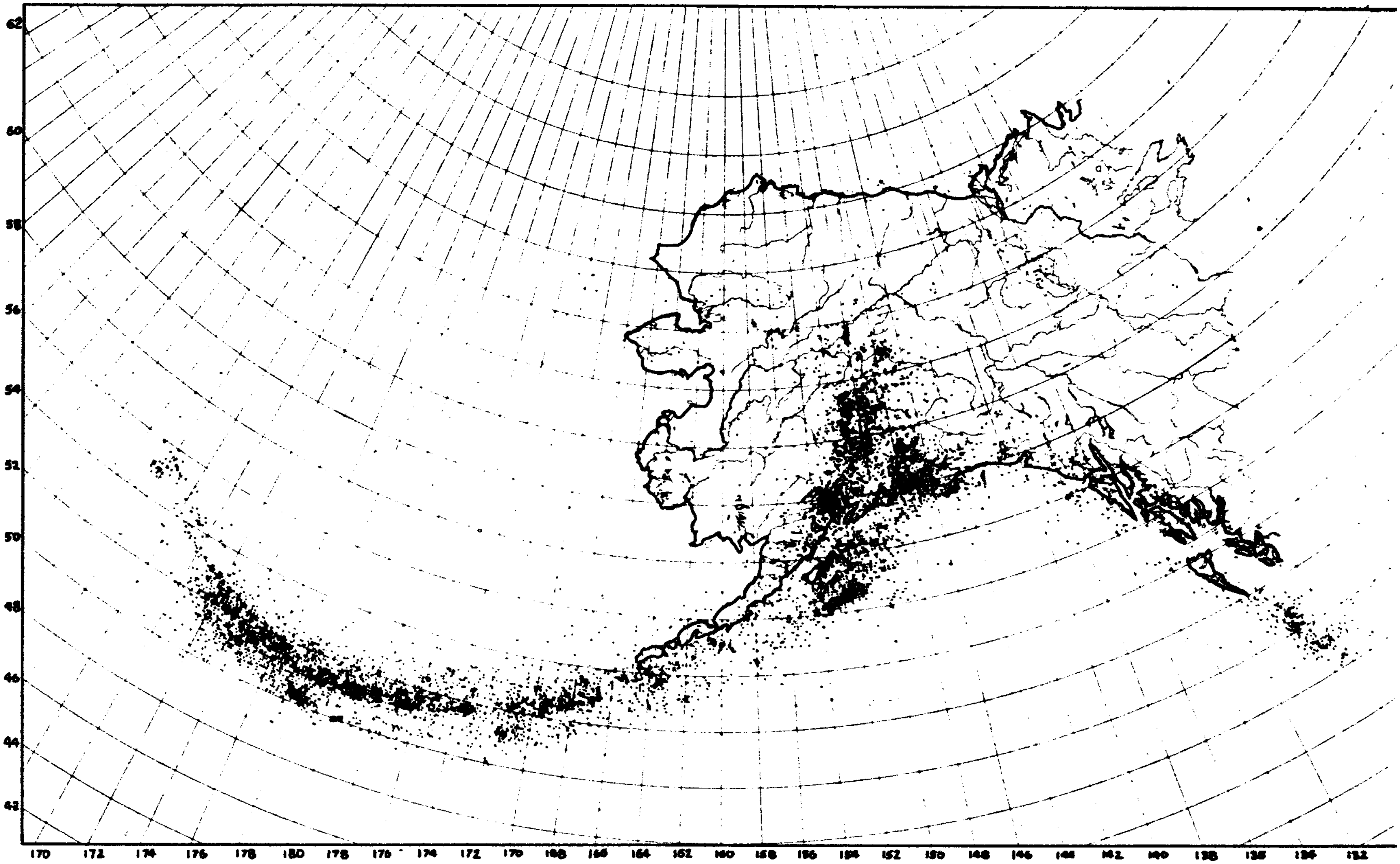
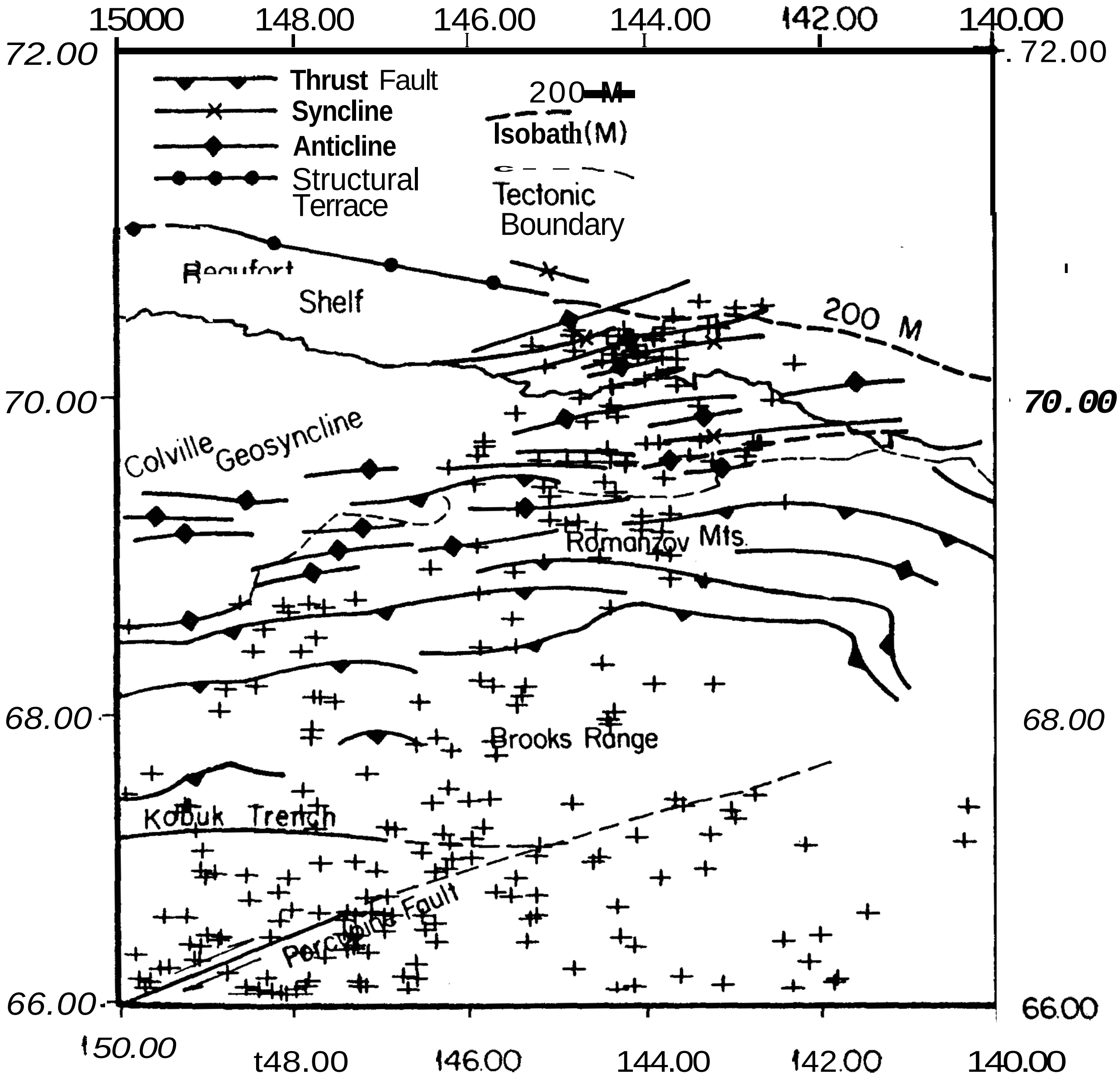


Figure 2-19. Earthquakes In and Near Alaska—Through 1974 (Barnes & Hopkins, 1978)



Epicenters (+) located by the local seismographic network having rms of travel-time residuals ≤1.5 sec plotted on an overlay of the structural traces in northeast Alaska. Epicenters shown north of 70° N. latitude are from Canadian catalog.

Figure 2-20. Northeast Alaska Earthquakes--1976-1977 (Biswas, 1977) epicenters and other tectonic features in northeastern Alaska.

The available earthquake data represent too short a time interval to determine recurrence rates for seismic events greater than magnitude 5.0 in the area. However, the data are indicative of the need to design structures able to withstand ground vibrations from a shallow earthquake of magnitude at least 6.0 (Barnes and Hopkins, 1978). A recent study prepared for the Alaska Subarctic Offshore Committee by Woodward-Clyde Consultants (1978) examined potential ground motion characteristics that might be associated with earthquakes in the Beaufort Basin area. In this study, a random earthquake source was assumed, and ground motion parameters were computed on the basis of a hypothetical seismic event with a magnitude of 6.5 and a recurrence interval of 100 years. It was found that such an earthquake would produce ground accelerations on the order of 0.05 g with associated maximum velocities of 3.1 cm/sec (1.2 in/sec). However, the authors warn that the analysis is very sensitive to the seismicity level and, should larger magnitude events occur, the accelerations and velocities could be altered appreciably.

The limited data available concerning the region's seismicity appear to indicate that the seismic hazard to pipelines is probably slight and confined to a rather small area of the Beaufort Shelf. However, additional data are required for precise delineation of the offshore tectonic structure and to compute reliable recurrence rates for larger seismic events. It should also be noted that episodic motions of small magnitudes eventually may add up to significant ground displacements over a lengthy period of time. Linear structures, such as pipelines, could be threatened by this cumulative movement and may need appropriate design provisions to accommodate these displacements in seismically-active areas.

D. OTHER ENVIRONMENTAL CONCERNS

The foregoing parts of Section II have focused on the principal issues in the design of Arctic offshore pipelines. There are several additional environmental factors which must be considered in the total design framework and which pose formidable challenges in the construction and operation of such pipelines. It is therefore appropriate to review these factors for an overall appreciation of the potential difficulties in such an endeavor.

1. Location

Remoteness and inaccessibility are fundamental characteristics of the Alaskan Arctic. The northern coastal areas are several hundred miles from industrial and supply centers and the few routes often are made impassable by weather. As a consequence of this isolation, logistic efforts will require exceptional planning and scheduling to ensure that necessary supplies and equipment are available when needed. Presently, most large and heavy items must be transported to the North Slope by barge during the brief open-water period. This mode of transport is entirely dependent upon the northward retreat of pack ice which allows barge traffic to move around Point Barrow and continue eastward to the main staging areas at Prudhoe Bay. The retreat of the pack ice is very unpredictable as is the duration of the open-water period along the coast. Westerly summer storms can drive the pack ice back into the coast in a matter of hours. If this occurs toward the end of the summer season, the pack ice may remain close to shore through the winter and prevent further navigation.

The isolation of the Beaufort coast undoubtedly will affect pipeline development strategies in many other ways. The ability to respond to emergencies, for example, will be impaired by this factor. Consequently, it may be necessary to stock a very extensive supply of spare parts on the North Slope to provide a more timely response to breakdowns, leaks, etc. From a design standpoint, pipelines equipped with highly reliable or redundant components are also important in this regard.

2. Weather

The severe Arctic weather is a major obstacle to pipeline construction and maintenance. General climatic conditions are characterized by cold temperatures (both summer and winter), small annual precipitation, and strong persisent winds. The ability of humans and machinery to function efficiently under these conditions is impaired greatly.

Temperature is probably the single greatest factor which affects Arctic working conditions and human efficiency. Table 2-3 illustrates typical temperature conditions at three North Slope coastal locations.

The sub-freezing temperatures which exist through most of the year are exaggerated severely by persistent winds which make the equivalent chill temperature much lower. At Barrow, for example, calm conditions are observed only 1.3 percent of the time. Figure 2-21 is a series of probability curves for equivalent chill temperatures in each month. These curves were developed using hourly values of temperature and corresponding surface wind reports for Barrow. However, they are generally applicable to most North Slope coastal areas. The curves illustrate the high probability of encountering dangerous temperatures at all times of the year.

With respect to pipeline development, low temperatures, or low effective temperatures, have several implications. The selection of materials, for example, may be influenced by temperature because of potential problems with brittle fracture.

Table 2-3. North Slope Temperatures

Location	Summer: Daily Seasonal Maximum °C (°F)	Summer: Daily Seasonal Minimum °C (°F)	Winter: Daily Seasonal Maximum °C (°F)	Winter: Daily Seasonal Minimum °C (°F)	Record High °C (°F)	Record Low °C (°F)	Mean Number of Days Below Freezing Annual
Barter Island	9 (48)	-8 (16)	-5 (23)	-32 (-26)	24 (75)	-50 (-59)	311
Umiat	18 (64)	-10 (13)	-6 (21)	-38 (-36)	29 (85)	-53 (-63)	---
Barrow	7 (45)	-10 (13)	-6 (21)	-31 (-24)	25 (78)	-49 (-56)	324

Source: Swift et al, 1974

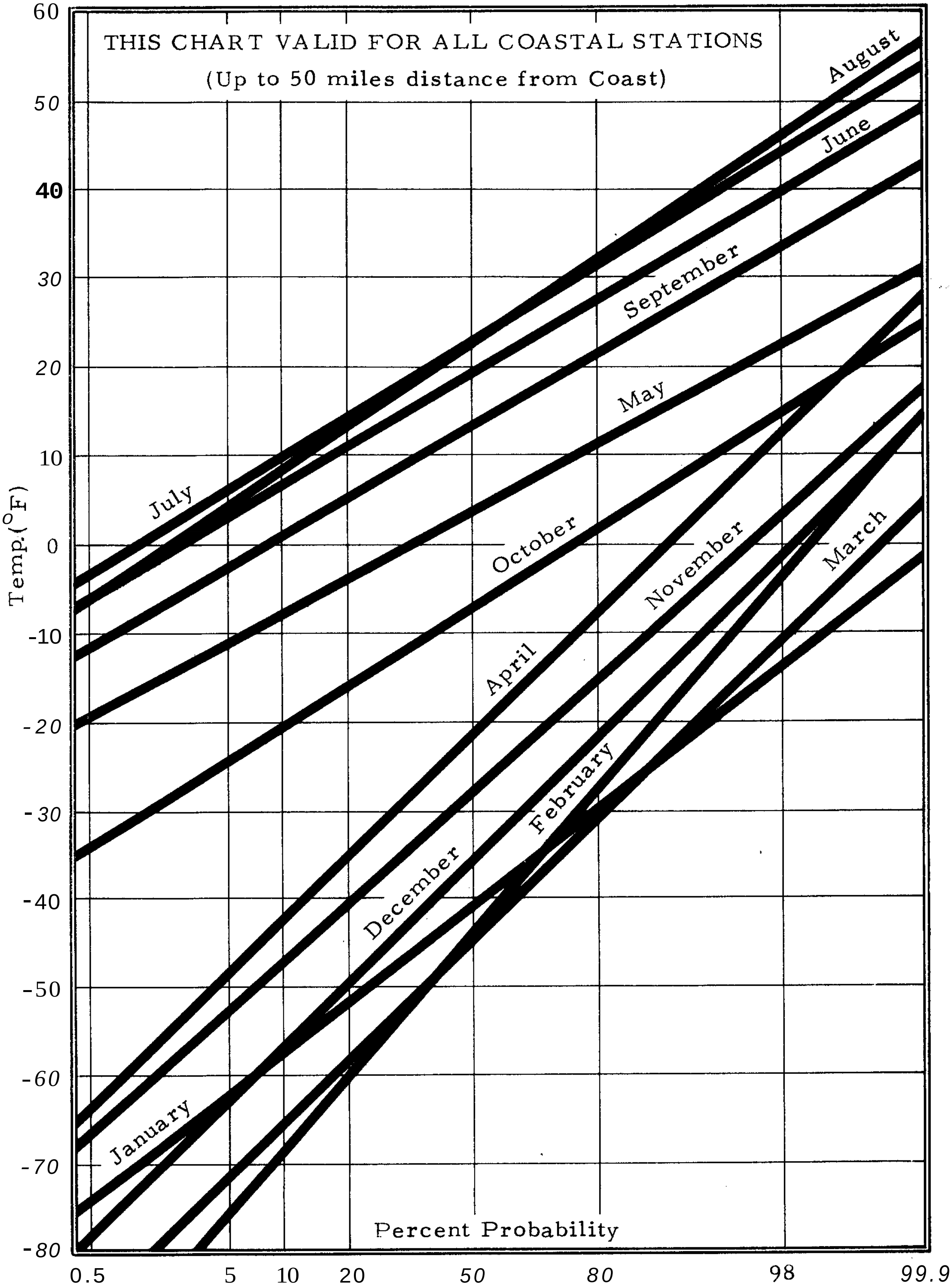


Figure 2-21. Percent Probab lity of Occurrence--
Equivalent Chill Temperature at Barrow, Alaska (Searby & Hunter, 1971)

Operating machinery such as pumps, compressors, and valves likewise must have low-temperature capability and demonstrated reliability for Arctic use. Pipeline construction will be strongly influenced by temperature. During winter, workers must be protected against extremes through the use of enclosures around work areas or with bulky clothing in exposed locations. The latter solution tends to reduce efficiency and may require additional measures to ensure adequate quality control.

A final concern regarding Arctic weather relates to weather forecasting. Reliable forecasting is most important for summer logistics and during the construction period. Unfortunately, present standards for Arctic forecasting are very poor in comparison with temperate regions. Historical weather data are incomplete and there is a lack of reporting meteorological stations, especially offshore. Furthermore, remote sensing systems, capable of obtaining high resolution data under conditions of clouds and darkness prevalent in the Arctic, have not been deployed in operational weather satellites (Weeks, 1978).

3. Low Visibility and Optical Phenomena

A major factor which influences both surface and air logistics in the Arctic is visibility. Low visibility due to darkness, clouds, fog, and other optical phenomena is a common condition along the Arctic coast.

During the winter months, the sun is continuously below the horizon from mid-November to mid-January. During the late fall and early spring months, days are comparatively short although there is sufficient twilight to carry on a number of activities without artificial light.

Cloudiness is a prevalent condition along the entire Arctic coast. More than 60 percent of the days are cloudy on an annual basis. During the summer and early fall, it is cloudy more than 70 percent of the time. During this period, overcast conditions may persist for weeks at a time.

Fog is the major restriction to visibility in the Arctic, especially in summer. Along the immediate coast, dense fog can be expected to occur 30 to 100 days each year although offshore and inland locations are less prone to fog. Fog conditions also tend to persist for long periods because of temperature inversions which prevent turbulent dissipation.

The unusual light and temperature conditions which exist in the Arctic give rise to a variety of optical phenomena which make surface and air transport somewhat hazardous on occasion. The most common of these phenomena are: terrestrial refraction (mirages), terrestrial scintillation (optical haze), ice and snow blink (sky map), whiteout, and snow blindness (nyphablepsia). Although there are no data to suggest the frequency of such phenomena, they are sufficiently common to be credited with numerous accidents, particularly those involving aircraft.

In general, the conditions described above do not pose insurmountable difficulties for pipelines. They are, however, indicative of problems which may be encountered in Arctic operations of any type which require the use of transport facilities for construction, operation, or maintenance.

4. Miscellaneous Hazards

In temperate zones, several pipeline hazards exist which may be attributable directly to human activity near pipeline installations. Two of the most common hazards are damage resulting from fishing gear and from anchors. In the Arctic, commercial fishing is nil and probably can be considered to have a negligible potential as a pipeline hazard. Damage from dragging ship anchors would appear to be a potential hazard only in areas such as Barrow and Prudhoe Bay where there is a significant amount of marine shipping. Since it is anticipated that most, if not all, Arctic submarine pipelines would be buried, the threat of danger appears minimal.

Danger from marine life such as whales also would appear to pose a very remote threat to pipelines. Although there are considerable numbers of whales found in the Arctic during summer months, they are an unlikely threat for buried pipelines.

E. SUMMARY

Arctic pipelines face a number of potential hazards unique to the region in addition to the normal hazards encountered in temperate latitudes. The problems which pose the most serious engineering challenges include ice scour, permafrost, frost heave, strudel scour, and coastal erosion. Several of these problems such as permafrost and frost heave have been encountered in Arctic terrestrial pipeline projects and appropriate engineering solutions have been developed to deal with them. The remaining problems can be mitigated or, in some instances, avoided completely by judicious route selection.

Problems in common with temperate zones include wave and current activity, seismicity, and sediment geotechnical properties such as instability. The oceanographic hazards in the Arctic have not been evaluated fully but appear to be substantially less severe than those in the Gulf of Mexico, for example. The most recent seismic history of the area shows that there have been some moderate earthquakes in the vicinity of the proposed Beaufort lease area. Analysis of these earthquakes indicates that they would produce small accelerations and other low-magnitude ground motions within the lease area boundaries. Limited geotechnical information suggests that there are no major hazards for pipeline construction. The near-surface sediments have highly-variable engineering properties, but appear to be generally stable.

111. PIPELINE SYSTEMS FAILURE ANALYSIS

A. INTRODUCTION

The failure data addressed in this section is associated with both onshore and offshore oil/gas pipelines. The bulk of the data reflects the onshore history. The offshore data are limited and are only from the Gulf of Mexico. An overview of this information was assembled because many of these failure modes could occur in addition to the postulated failure modes unique to Arctic offshore pipelines (discussed in Section IV.D with principal ones depicted in Figure 4-5).

The primary causes of pipeline failures in the United States, as classified by the Department of Transportation, are outside forces, corrosion, construction defects, material failures, and other reasons. The failure information in this section includes data from different sources which cannot be precisely compared because of reporting differences. However, the information does provide a general background of causes of pipeline failures.

1. Types of Failures Reported

Before the failures can be discussed, it is essential to define the type of pipeline failures reported. The US Department of Transportation requires certain pipeline failures to be reported.

Gas Pipelines. For gas transmission pipelines and certain gas gathering systems within most city limits, failures meeting the criteria in the Title 49 of the Code of Federal Regulations (CFR) Parts 191.5 and 191.15 must be reported on Form DOT–F–7100.2. These parts call for the telephonic notice and the written follow-up, respectively, and a gas pipeline failure is defined under these parts generally as any leak that:

(a) caused death or personal injury requiring hospitalization; or

(b) required taking any segment of a transmission line out of service; or

(c) resulted in gas igniting; or

(d) caused estimated damage of $5,000 or more; or

(e) in the judgment of the operator was significant enough for telephonic notice even though not meeting any criteria in a-d above; or, as part of the written report;

(f) required immediate repair of a transmission line; or

(g) was a test failure while testing for gas or another medium.

It should be noted that the above "individual leak or test failure reports" have been used in this report to compare to the "individual offshore leak reports" from the Gulf of Mexico. There is also an Annual Report of Gas Transmission and Gathering Systems (DOT-F-7100.2-1) which was used in preparing Table 3-1.

Liquid Pipelines. With regard to liquid pipelines, a failure that results in a loss of commodity resulting in any of the following general situations further defined in Part 195.50 must be reported on DOT Form 7000-1:

(a) explosion or fire not intentionally set by the carrier

(b) loss of 50 or more barrels of liquid

(c) escape to the atmosphere of more than 5 barrels a day of highly volatile liquids

(d) death

(e) bodily harm

(f) property damage of at least $1,000 to other than the carrier's facilities

(g) property damage of a total of $5,000 or more to carrier's and others.

It should be noted that there are also additional telephonic notice reporting requirements for liquid releases that pollute any stream, river, lake, reservoir, or other similar body of water. However, there are no annual reporting requirements for liquid pipelines and therefore no annual to individual leak comparisons are made in this report for liquid pipelines.

2. Information Sources

Because of a lack of failure histories available concerning the few kilometers of Arctic subsea pipelines now in place, data on other US pipelines are presented to give a historical background on failures. It should not be construed that the causes of failure of the temperate zone pipelines mentioned in this section are necessarily applicable to current or future pipelines in the Arctic. However, there is a strong indication that the same problems affect all pipelines with the degree of severity dependent on location and type of commodity transported. All figures cited in this section apply to gathering and transmission (gas) or gathering and trunk (liquid oil) pipelines in the US.

Offshore. Offshore gas and oil failure data are from US Geological Survey (USGS) for the Gulf of Mexico area. Failure causes appear in the USGS data verbatim from leak report forms. For the charts appearing in this section, the offshore causes were divided into categories similar to those in the DOT figures.

The number of offshore failures per year from 1970 to 1978, inclusive, range from 10 to 31 which is not a large enough field to establish meaningful trends. This can be compared against combined individual onshore oil and gas pipeline failure rates (including test failures) which ranged from 700 to 1,018 per year between 1971 and 1976, inclusive. Consequently, the offshore failures have statistically much less significance. Also, the USGS figures do not cover all offshore pipelines in the Gulf of Mexico. State governments and the US Bureau of Land Management have jurisdiction over about 7,300 miles of the approximately 12,000 miles of pipelines in the Gulf.

Gas Pipelines. Compilations of DOT Forms F7100.2 (individual leak or test failure report) and data presented in "An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines 1970 Through 1975" by the American Gas Association (AGA) provide failure totals, causes and other data concerning gas line failures.

Onshore gas pipeline mileage figures are based on AGA data. Differing mileage figures were published by the AGA (in its publication, Gas Facts), by the Oil and Gas Journal (OGJ) in its August 13, 1979 issue, and by DOT in 7100.2-1 data. It appears that the OGJ figures are based on only 103 of the approximately 150 pipelines in service. The DOT gas transmission mileage statistics are within 2 percent of the AGA figures but the DOT gathering line mileage is only about 35 percent of the AGA's field and gathering total. It appears that the latter discrepancy is caused by the limited extent of the jurisdictional authority of the DOT. Consequently, AGA gas pipeline mileage figures are used in this report.

Liquid Pipelines. For liquid lines, summaries of DOT Form 7000-1 from 1970 to 1976, inclusive, and data in a special study by the National Transportation Safety Board (NTSB) titled

"Safe Service Life for Liquid Petroleum Pipelines" are used. Mileage data are from triennial DOI Mineral Industry and DOE Energy Data reports.

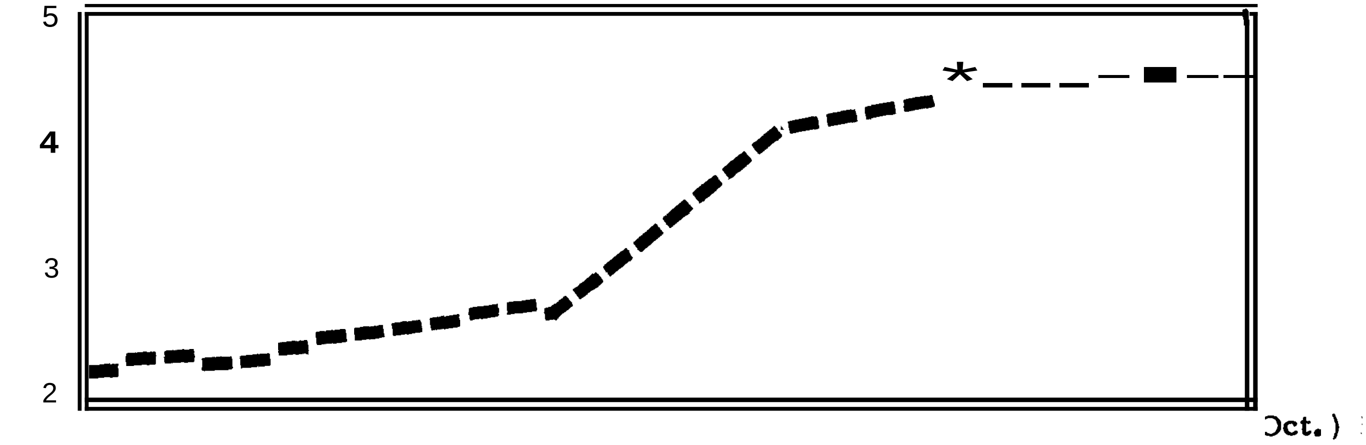
3. Failures Per 1,000 Miles

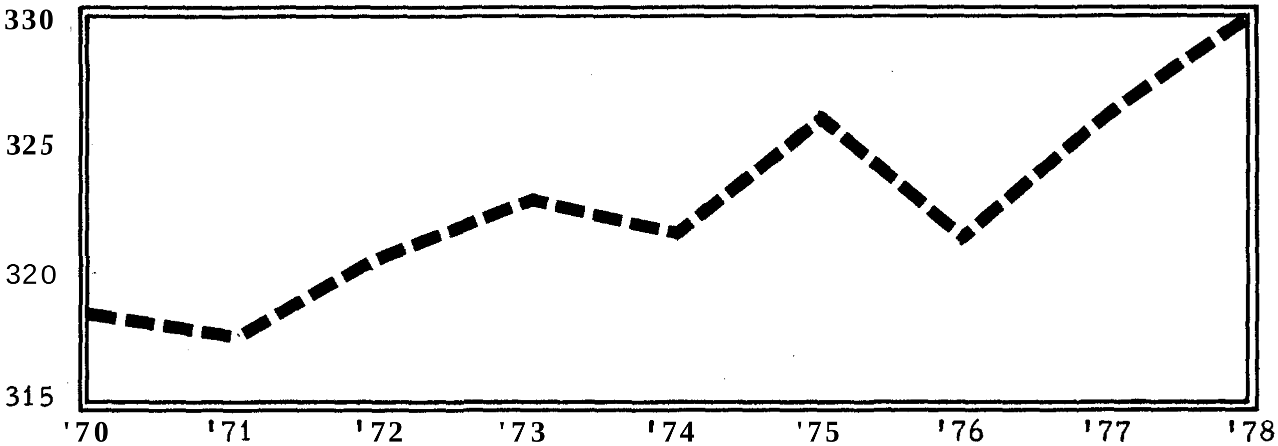
Figure 3-1 shows pipeline mileage in the United States. The total number of failures per year and the mileage for that year have been translated into figures representing failure totals per year per 1,000 miles of pipeline (Figures 3-2, 3-3, 3-4). The figures permit a rough comparison of the three categories (offshore gas and liquid, onshore gas, and onshore liquid lines). However, the fact that there are different criteria for defining and reporting leaks in gas and liquid lines cannot be overlooked.

Onshore. Gulf of Mexico gas and liquid lines show an increasing number of failures between 1974 and 1978 with a sharp peak in 1975 to 4.4 failures per 1,000 miles (Figure 3-2). Offshore mileage figures before 1974 are not immediately available.

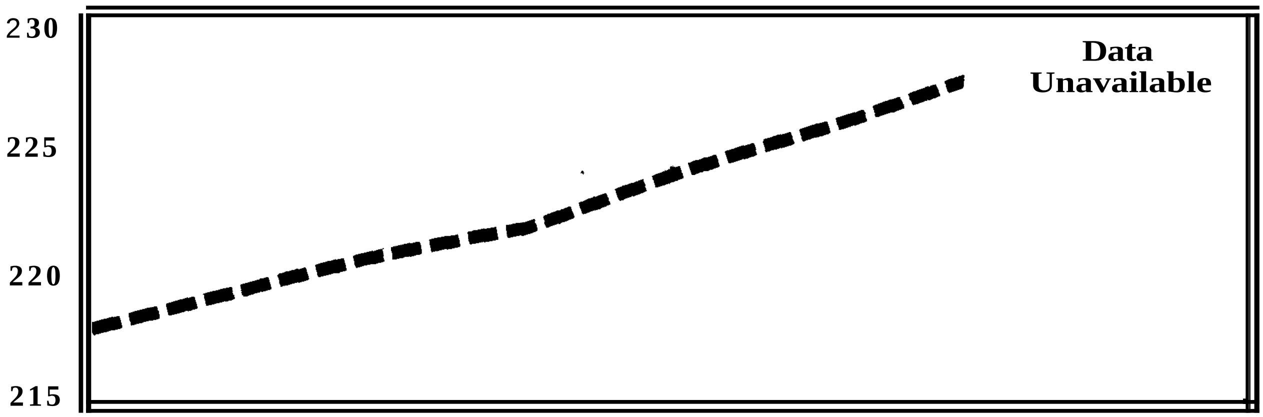
Gas Pipelines. Onshore gas lines show a high of 2.21 and a low of 1.52 failures per 1,000 miles in the period 1970-76. An overall decline in failures per 1,000 miles occurred during the 1970-76 period (Figure 3-3).

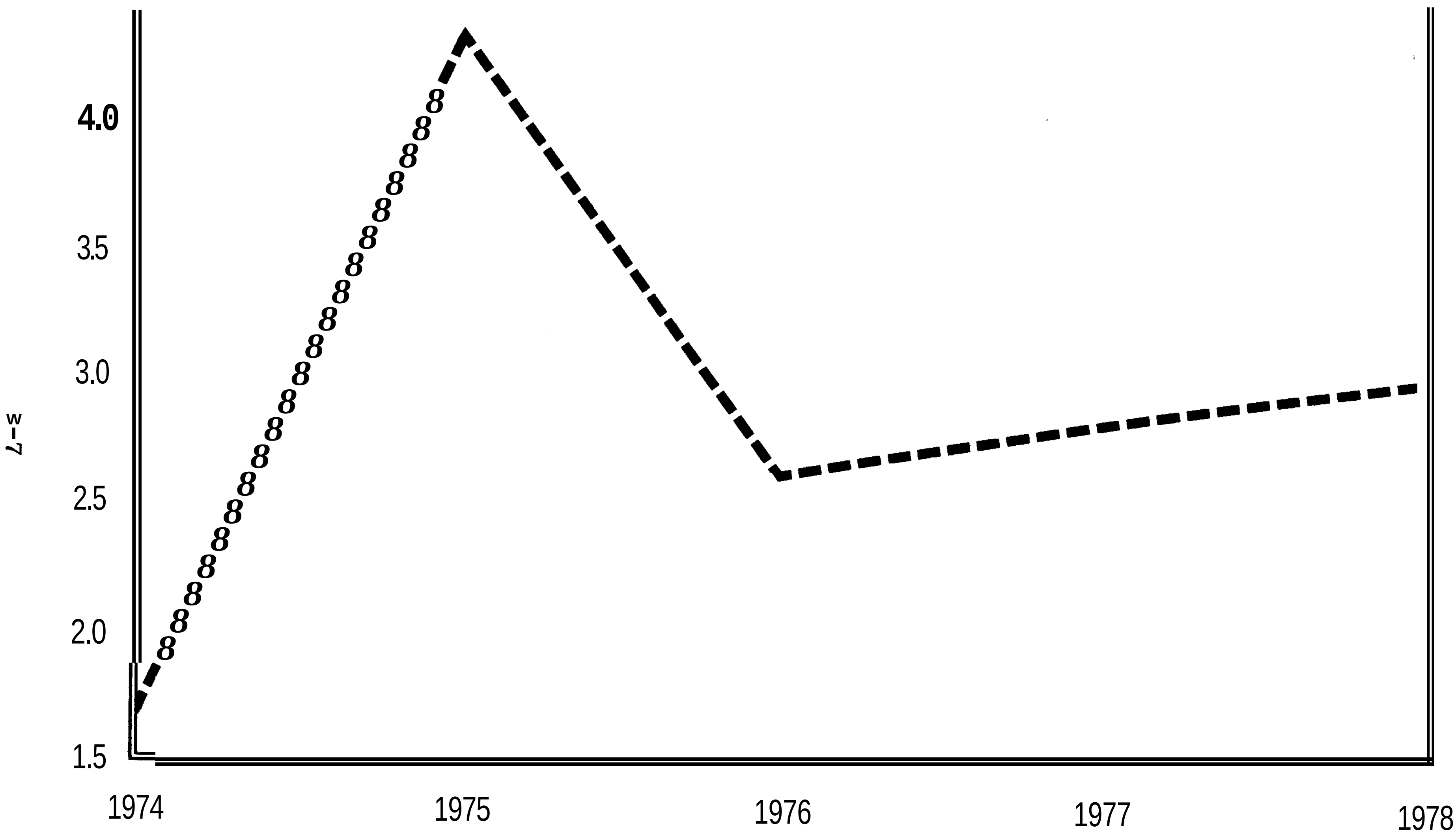
Liquid Pipelines, Onshore liquid oil pipelines also show a steady decline since 1970 (Figure 3-4) reaching a low of 0.93 failures per 1,000 miles in 1976.





Onshore Gas Gathering and Transmission Pipelines (AGA, 1979)





*USGS approved lines, Gulf of Mexico

Figure 3-2. Offshore" Gas and Oil Pipeline Failures per 1,000 Miles (USGS, 1979)

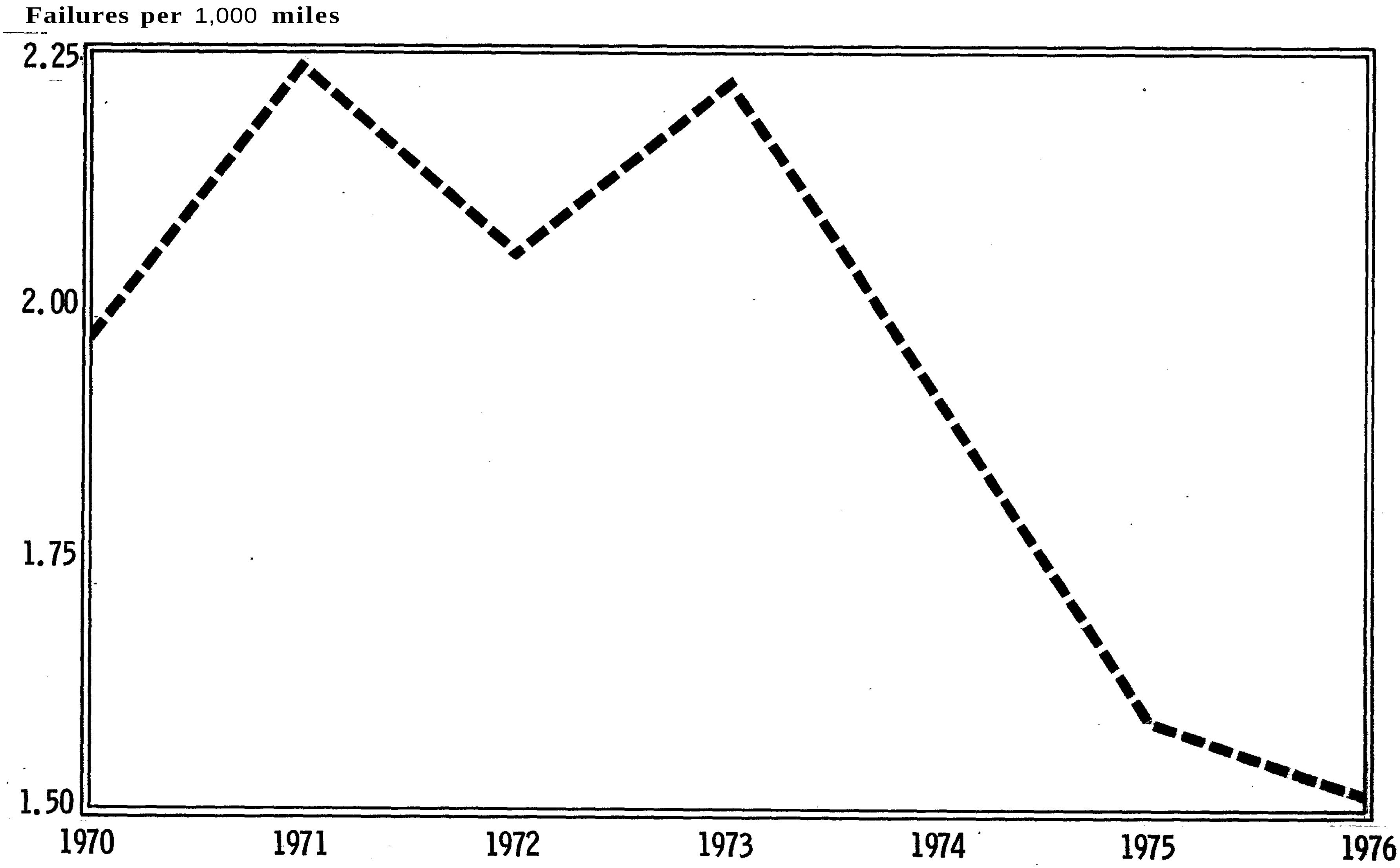


Figure 3-3. **Onshore Gas** Pipeline **Failures** per 1,000 Miles (DOT, 1978; AGA, 1979)

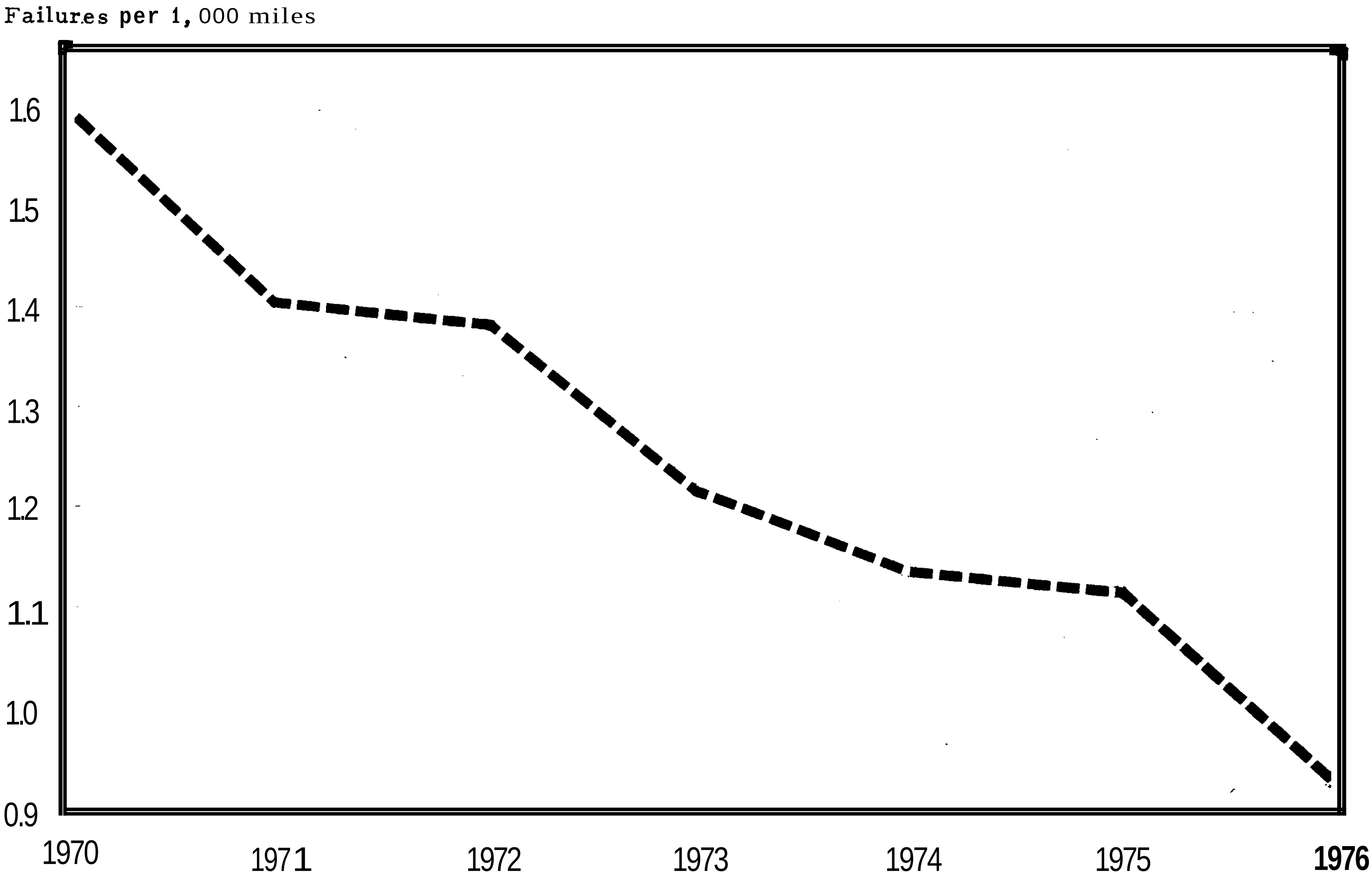


Figure 3-4. Onshore Liquid Oil Pipeline Failures per 1,000 Miles
(DOT, 1979; DOI, 1968, 1974; DOE, 1977)

B. MODES OF FAILURE

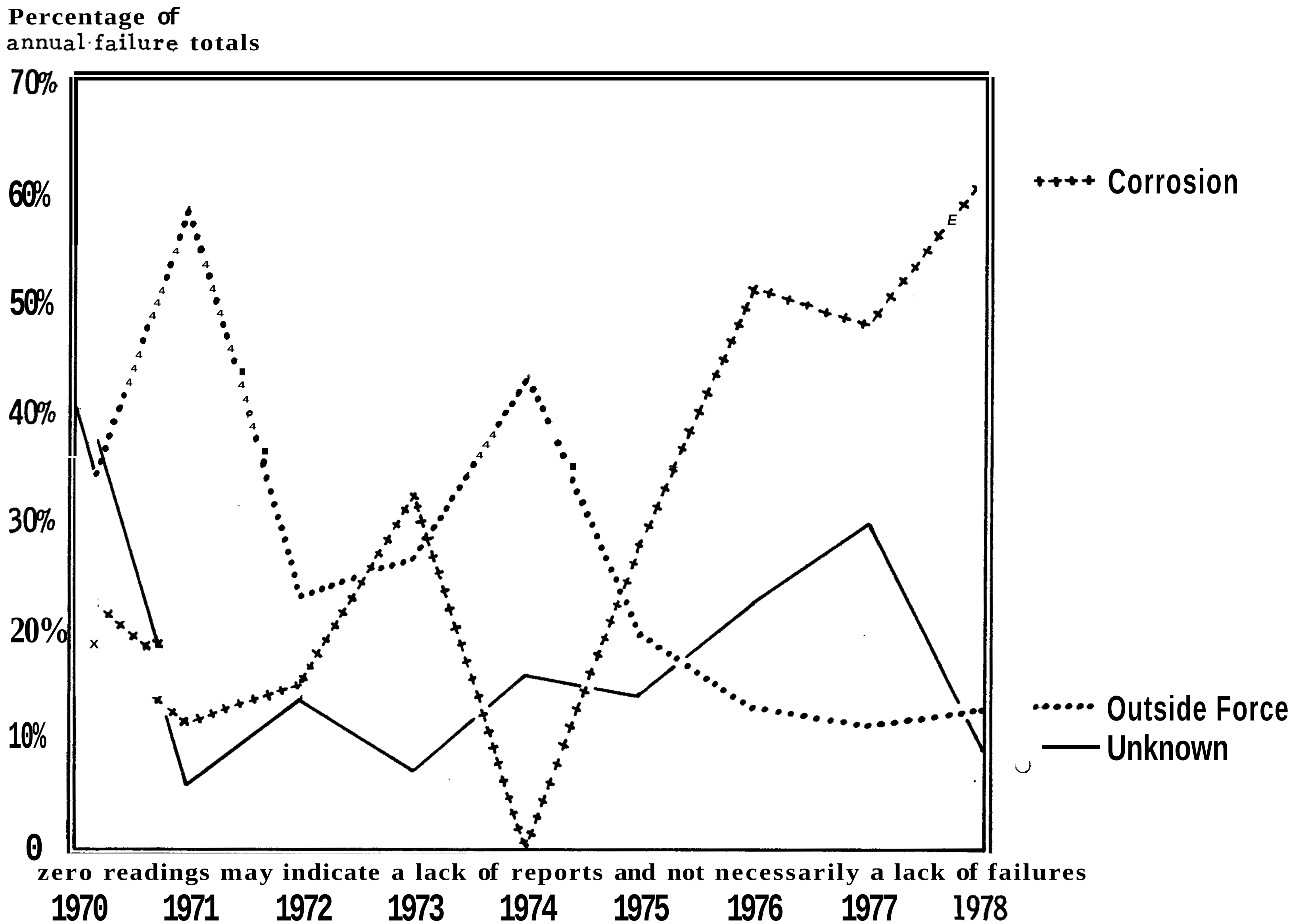
1. Major Causes of Failure

Outside force (also described as equipment rupture), corrosion, and "unknown" or "other" reasons are the three leading causes of pipeline failure (Figures 3-5, 3-7 and 3-8). Since 1970, outside force is clearly the dominant cause of onshore gas and liquid pipeline failures but for offshore gas and liquid lines, the three leading categories of causes vary in ranking from year to year.

a. Outside Forces. Pipeline ruptures, almost with exception generated by man's activities, are a major cause of pipeline failures. Typical examples of outside forces are: onshore, excavating equipment, and offshore, ship anchors and fishing trawl boards. For subsea Arctic applications, external impacts could be limited reasonably to ice scour and, to a lesser extent than in temperate waters, ship anchors.

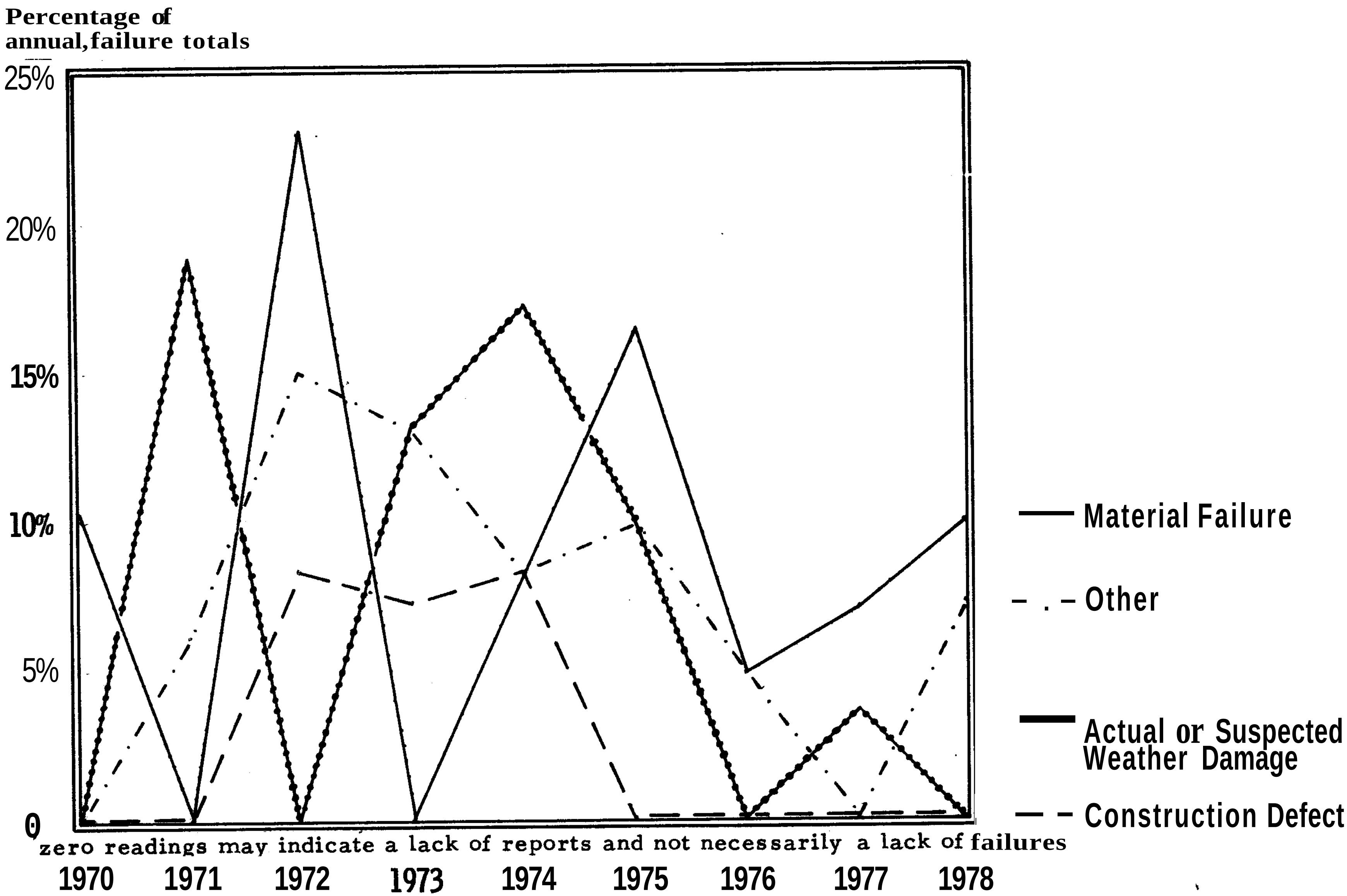
Gas Pipelines. A University of Oklahoma report for the DOT, "Analysis and Management of a Pipeline Safety Infor-Mation System," concluded that for onshore gas transmission lines, one outside force (or external impact) leak is equivalent to approximately 95 corrosion leaks in terms of potential danger. The conclusion was based on a comparison of individual and annual DOT incident reports from 1970 to 1973 and. involved a weighting factor formula too complex to be described here. The 1:95 ratio was determined by dividing the weighting factor of outside force (18.0) by that of corrosion (0.19) in Table 3-1.

Liquid Pipelines. Corrosion was the leading cause and equipment rupturing line was the second leading cause of onshore liquid pipeline failures (Figure 3-8).



*USGS approved lines, Gulf of Mexico

Figure 3-5. Major Causes of Offshore' Gas and Oil Pipeline Failures (USGS, 1979)



*USGS approved lines, Gulf of Mexico

Figure 3-6. Minor Causes of Offshore" Gas and Oil Pipeline Failures (USGS, 1979)

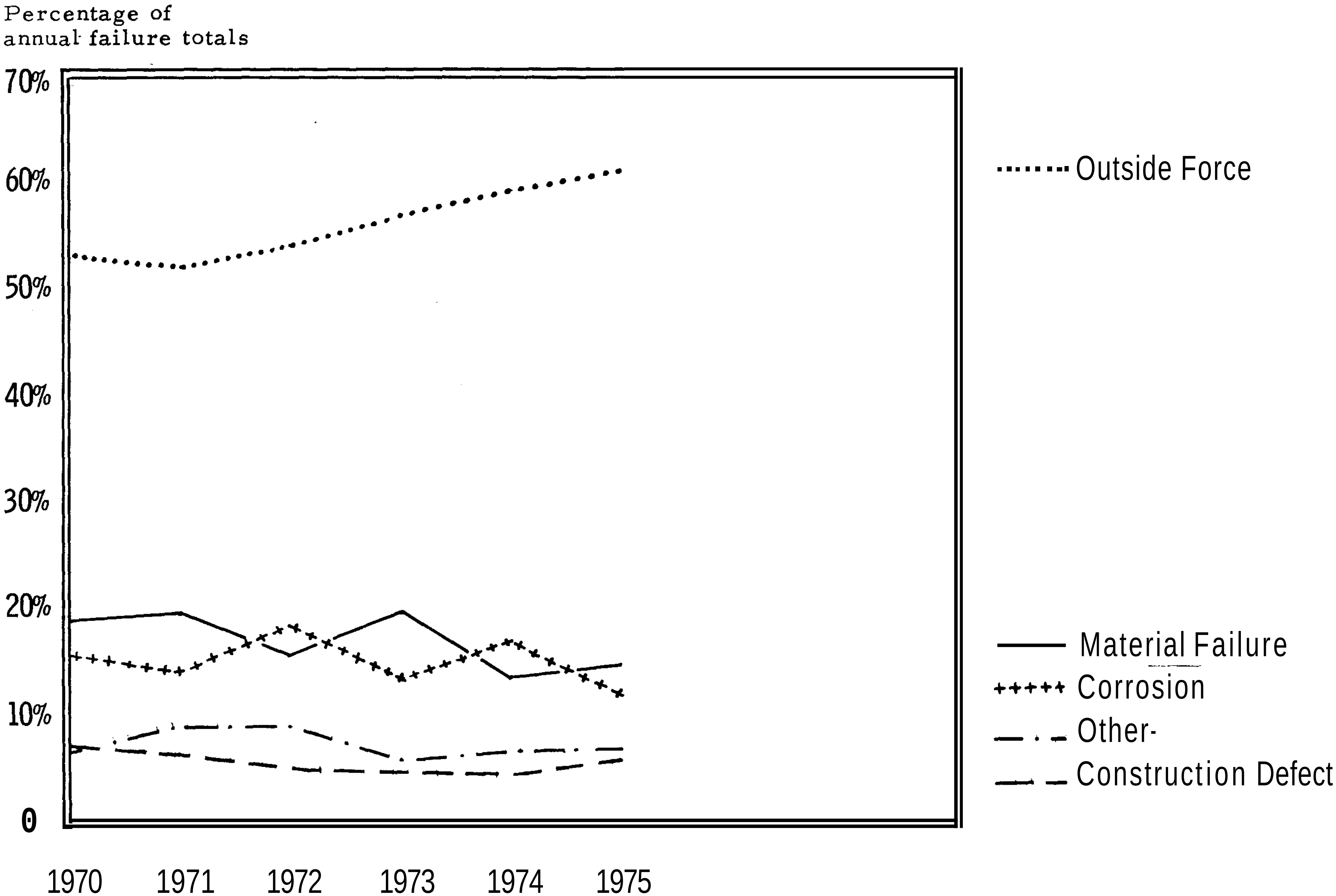


Figure 3-7. Causes of Onshore Gas Pipeline Failures (DOT, 1977)

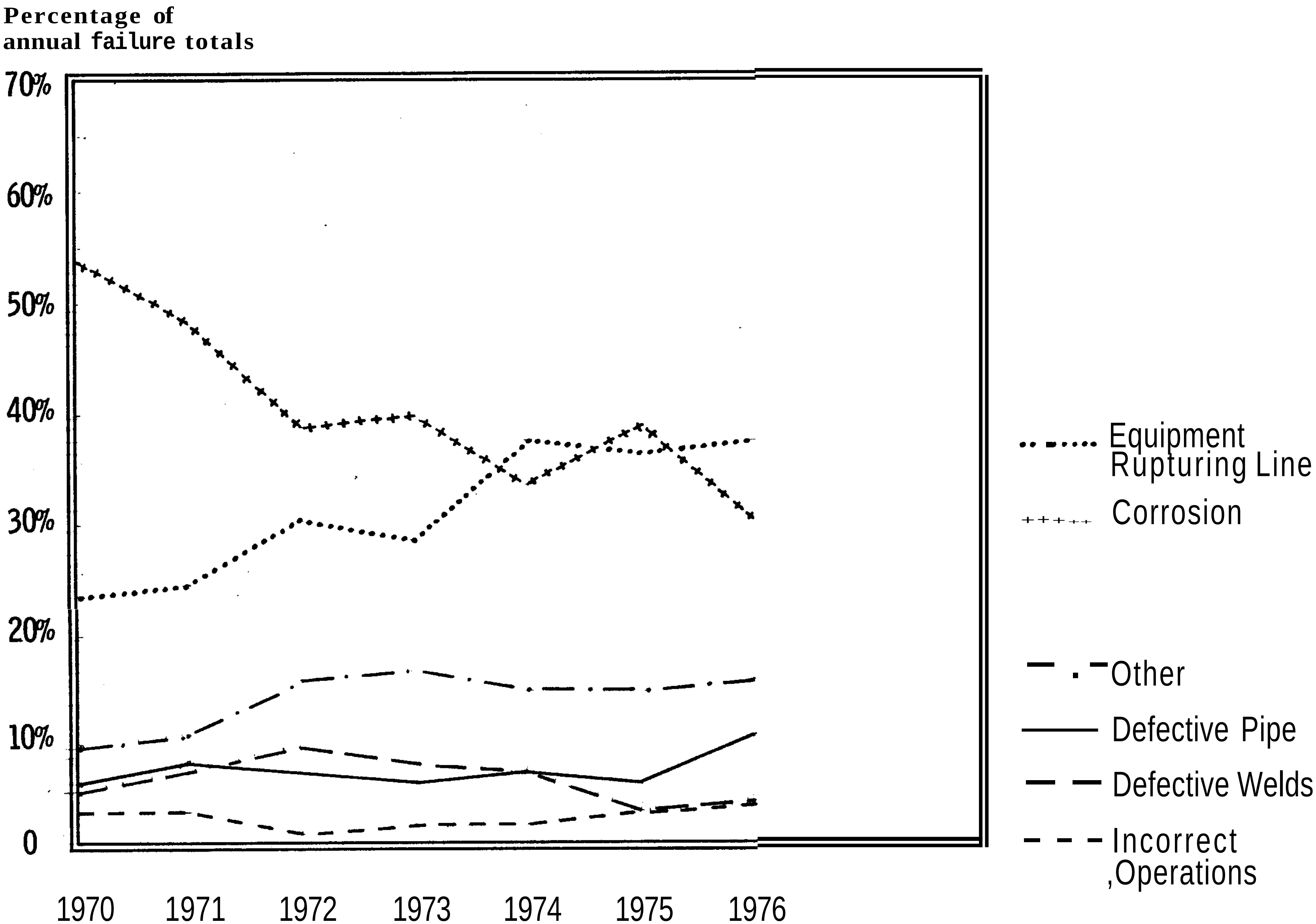


Figure 3-8. Causes of Onshore Liquid Pipeline Failures (DOT, 1978)

Table 3-1. Percentage of Total Leaks for Gas Pipelines, 1970-1973 (University of Oklahoma, 1974)

Cause	Individual	Annual	Weighting Factor
Corrosion	15.0%	77.3%	0.19
.Outside force	53.9	3.0	18.0
Construction defect	5.4	2.0	2.7
Material failure	18.9	9.6	2.2
Other	6.8	8.2	0.83

b. Corrosion

Offshore. As shown in Figure 3-5, offshore Gulf of Mexico gas and liquid lines have a rapidly increasing frequency of corrosion-caused failures from 1974 to 1978. A comparison of the quantity of offshore failures with the amount of commodity spilled shows that in 1977, 11 corrosion-caused failures spilled a total of six barrels of commodity (plus one failure that released an unknown quantity of gas). Other years indicate similar ratios. The relatively high number of corrosion-caused failures could be pinhole leaks that were discovered and repaired promptly, causing minimal pollution, according to USGS sources in Metairie, Louisiana. No reason could be given to explain why the data indicates zero corrosion-caused failures in 1974.

Gas Pipelines; Corrosion is responsible for about one-fifth of onshore gas line failures from 1970 to 1975 (Figure 3-7). The AGA "Analysis" report states that the majority (77 percent) of corrosion incidents during the six year period resulted from pitting-type corrosion as opposed to general corrosion. The AGA report also states that in incidents involving external corrosion, pipes both coated and cathodically protected had a failure rate less by large factors compared to pipes with less or no corrosion protection.

Liquid Pipelines. Onshore petroleum line data indicate a declining corrosion-caused failure rate, Corrosion failures for 1978 are about half of the 1970 rate (Figure 3-8). Summaries of DOT Form 7000-1 external corrosion data from 1970 to 1977 show mixed results when various means of corrosion protection are compared. Coated pipe with cathodic protection and bare pipe with cathodic protection have the highest percentages of external corrosion failures for 1974 through 1978. No data on the number of miles of each type of corrosion protection is available nor are explanations of why the results differ from the gas line data above.

c. "Unknown" and "Other" Causes. As the last of the leading causes of pipeline failures, "unknown" and "other" causes are, by nature, the most difficult to determine because of a lack of data.

Offshore. As shown in Figure 3-5, unknown causes vary from 8 percent to 40 percent annually. However, the small number of incidents reported (see Subsection 2, Information Sources) makes conclusions difficult, if not impossible.

Gas Pipelines. "Unknown" or "other" causes are not a major cause of onshore gas line failures.

Liquid Pipelines. Failures attributed to "other" causes are increasing and are the third largest cause of failures from 1970 to 1976.

2. Minor Causes of Failure

Material failure, incorrect operation by carrier personnel, construction defects, weather, defective welds and "other" (gas and offshore only) each account for approximately 20 percent or less of onshore and offshore pipeline failures (Figures 3-6, 3-7 and 3-8). Offshore "other" causes are listed in Table 3-2 with verbatim descriptions from a USGS Gulf of

Table 3-2. Offshore Oil/Gas Pipeline "Other" Causes

Descriptions of causes from USGS records for Gulf of Mexico

Year	No. of Failures	Description of Cause
1970	0	
1971	1	Severely kinked. Split at kink.
1972	2	1) Gas regulator malfunctioned. H.P.P. malfunctioned. Pipe ruptured. 2) Suspect previous damage to f/l due to construction.
1973	2	1) Bull plug covering 1/2" needle valve in open position had a hole in it. Possibly caused by trawling. 2) Abrasion - rubbing against another pipe.
1974	1	Atlantic Richfield's 8" line ripped off the Cobia line at the subsea tie-in.
1975	3	1) P/l kink after trying to move it away from O deco's well #6 in SS Block 119. 2) Mechanical failure. 3) Lack of communication between operator.
1976	1	(illegible)
1977	0	
1978	1	Paraffin plug pipelines.

Mexico failure report compilation. In Figure 3-6, the percentages of minor causes of offshore failures fluctuate widely. When considering data on offshore lines presented here, the caution given earlier about the total number of failures not being large enough to establish a trend should be kept in mind.

C. FAILURE COUNTERMEASURES FOR SUBSEA ARCTIC APPLICATIONS

Subsea gas and liquid petroleum pipelines in the Arctic are likely to have corrosion and outside force as the prime potential causes of failure. Because of environment-related difficulties mentioned elsewhere in this report (Sections II and IV), failures in subsea Arctic areas are more difficult to contend with than in temperate areas. Consequently, prevention of failures could be of utmost importance. Prompt discovery of failures that occur despite precautions also would be of value. However, it is beyond the scope of this report to evalute any tradeoffs between environmental protection and pipeline economics.

1. Impact Protection

Ice scour is the most formidable impact hazard affecting a subsea pipeline. As discussed in Section 11, the depth, frequency and location of scouring is not known fully. Prevention of pipeline impact from ice could be accomplished by trenching below the anticipated scour depth (Section IV.D). More research on scour depths would be of value. Damage from anchors and fishing activities probably would be small because of the ice cover which prevents ship movement for much of each year. During the open-water season, sea traffic is not expected to be of major consequence. Marking of pipeline locations on maps should be sufficient warning.

2. Corrosion Prevention

Coating and cathodic protection, as required in Parts 192 and 195 since the early 70's, would be essential for subsea Arctic steel pipeline external corrosion prevention. The potential for external corrosion would be similar for both gas and liquid petroleum pipelines. Arguments between impressed current and sacrificial anode cathodic protection quality are moot because of the maintenance difficulties that would be encountered if an impressed current system were chosen. Otherwise, external corrosion probably would not be aided or hindered by the subsea Arctic environment as compared to a temperate zone location. Although difficult to accomplish, a satisfactory electrical ground for corrosion control can be obtained in permafrost.

Internal corrosion and erosion problems would be similar, if not identical, to contemporary installations in temperate areas. Analyses of the commodity to be carried would be valuable in determining the need, if any, for internal protection. Internal pipe coating, and/or "sweetening" of sour gas or oil before contact with the pipeline are potential solutions in current practice.

Generally, the major difference in corrosion prevention between temperate zone pipelines and those beneath the Arctic seas would be the possible desire to reduce the frequency of corrosion-caused failures in the latter as low as possible. Judging from the high incidence of corrosion-caused failures in the US, and presumably elsewhere in temperate areas, considerable progress could be realized in this field.

3. Inspection and Monitoring

Reduction, if not prevention, of pipeline failures can be aided by scrupulous inspection during fabrication and installation and by frequent and thorough monitoring of the system during operation. A well-planned program for preventive maintenance is necessary to continued successful operation. Unfortunately, environmental conditions and trenched lines, if used, greatly hamper monitoring and maintenance efforts. Such considerations may justify "overdesigning" and excessive care during installation of pipelines to compensate for the possible lack of access during operation. Existing and proposed changes in inspection and monitoring requirements appear in Section VI of this report.

IV. UNIQUE REQUIREMENTS OF ARCTIC OFFSHORE PIPELINES

The Arctic environment, discussed in Section 11, presents some unique requirements for offshore pipeline design, construction and operation. The discussion in this section is a review of key requirements which, if not considered in a pipeline project, could affect its structural integrity, safety and environmental impact. The discussion of the state-of-the-art of Arctic offshore pipelines presented in Section I covered present technology and some of the problems encountered, and reference will be made to that and other sections where appropriate.

A. MATERIALS

Steel is the preferred material for Arctic applications because of high strength, suitable low-temperature properties (resistance to crack propagation) and good weldability. Title 49 (Part 195.112) permits only steel for new liquid pipelines; however, for gas pipelines (Part 192) the regulation will allow the use of cast iron or ductile iron pipes, although the use is primarily in gas distribution systems. Other alloys are not competitive with steel for large diameter or high pressure pipe. Although aluminum alloys and titanium alloys can have the same toughness ratio as steel, their strength is much lower at comparative levels. Therefore, thick walls are required for large aluminum pipes because the strength is about half that of high-grade steel, and the thermal expansion coefficient is three times as great, leading to a potentially-high thermal stress. Also, welding of aluminum pipeline sections would be more difficult and costly.

In addition to the usual specified minimum yield stress (SMYS), the safety standards for Arctic pipelines should consider steel behavior at low temperatures. Once installed on the sea bottom, such pipelines will encounter a relatively constant external water temperature of approximately minus 1.8°C (29°F). The temperature of the pipe material will be a function of the temperature of the medium flowing through the pipe. Oil in pipelines will be heated to maintain its temperature above the pour point. Generally, pipe exposure to low temperatures would not occur except during transportation, storage and installation. Any study of stresses occurring during these phases should consider steel behavior under the lowest temperatures encountered.

The gas pipes may carry chilled gas, and the pipe material temperature will result from the heat balance between the pipe interior and exterior. A pipe approaching and crossing a beach will be exposed to external ground temperatures (assuming a buried pipe) that will be subject to seasonal variations. Comments made for liquid pipelines with respect to transportation, storage and installation apply also to those used for gas.

All plain carbon steels exhibit a brittle-to-ductile transition and behave in an elastic-plastic manner above some specified temperature usually referred to as the transition temperature. Below that temperature, steels become brittle and can absorb only limited impact energy. It is in that temperature region that the steels are notch sensitive; that is, if a defect or notch exists in the steel, it may worsen to a form of brittle fracture (Azmi, 1978). Since existing material flaws sometimes are undetected, selection of material with an adequate notch toughness is important for Arctic pipelines. For that reason, it is imperative that the lowest anticipated service temperature (LAST) is above the transition temperature.

The Charpy V-Notch test is used most commonly to determine the transition temperature. The test is conducted on a temperature-controlled standardized notched specimen that is impacted by a calibrated pendulum. An absorbed fracture impact energy of 205 (15 ft-lb) generally is considered to be the minimum acceptable level for plain carbon steels at some specified temperature (see Figure 4-1). However, the Charpy acceptance test has been found to be limited in evaluating materials susceptibility to premature brittle fracture. There are cases where steels were considered to be ductile at a given service temperature because the Charpy specimens exhibited ductility at this temperature. In service, brittle fracture of the steel occurred. The difference was explained on the basis that standard Charpy testing may not accurately determine the ductile-to-brittle transition temperature. To compensate, the Charpy test specimen has been fatigue precracked to better relate results to the nil-ductility temperature (NDT), which is defined in ASTM STD E208-69.

The NDT is defined to be the temperature at which a small flaw may propagate at stresses near the yield stress. NDT+60°F (NDT+15°C) is considered the temperature above which no unstable cleavage crack propagation can occur at stresses approaching the SMYS. Other brittle-fracture criteria used in conjunction with the Charpy test are based on fracture appearance such as the drop weight tear test (DWTT); linear elastic fracture mechanics such as the critical stress intensity value; or elastic-plastic fracture mechanics such as the J-integral or critical crack opening displacement (COD).

Charpy-V Notch and DWTT impact tests were used in the selection of material for the Trans Alaska Pipeline System from Prudhoe Bay to Port Valdez (Oil and Gas Journal, 1974). Panarctic Gas Lines required a 345 *(25* ft-lb) Charpy impact value at minus 50°C (minus 60°F) (Palmer, 1979).

Two important field operations in pipeline construction will be affected by Arctic environment: pipe bending and girth welding. To minimize the effect of low temperatures, such

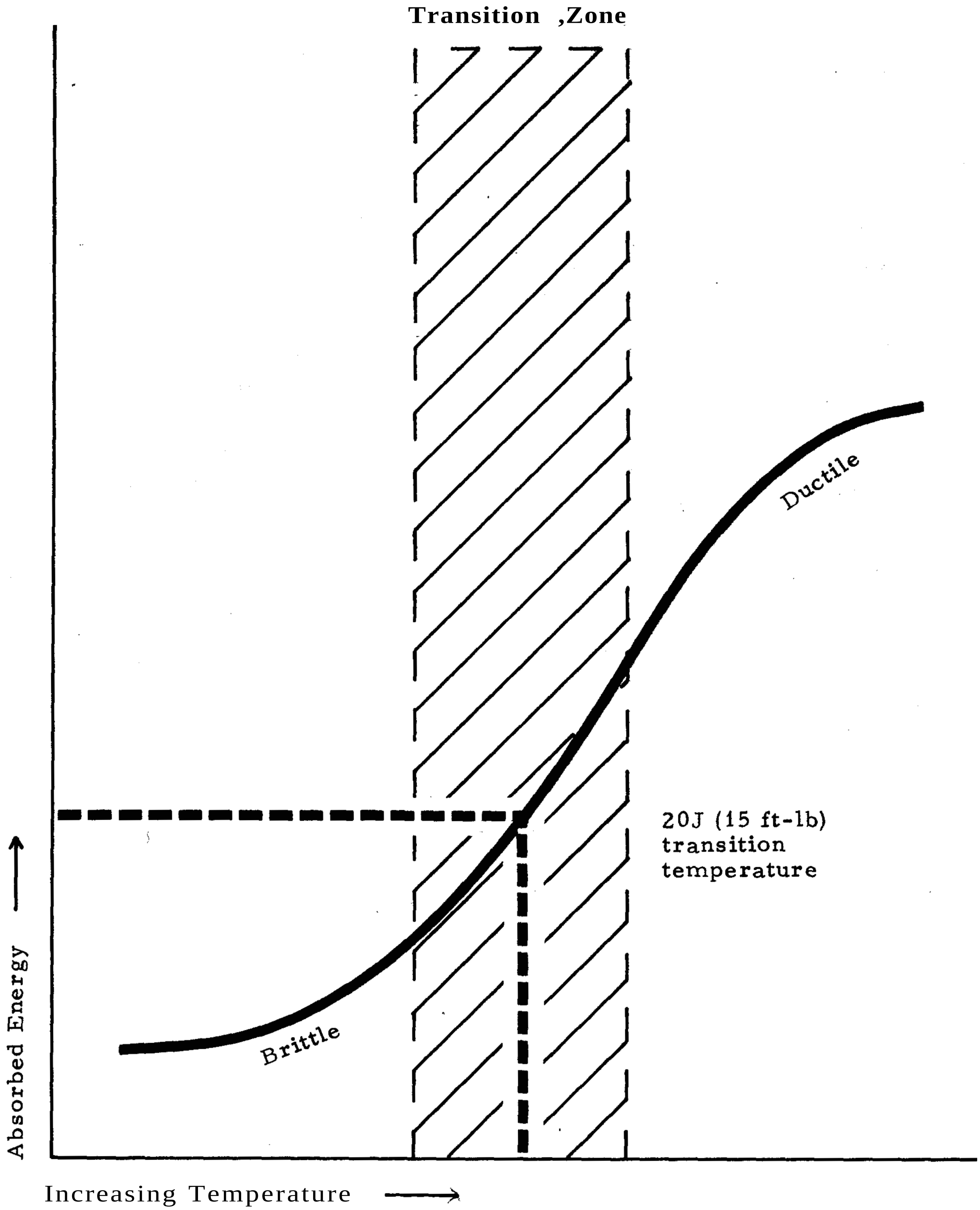


Figure 4-1. Charpy Transition Temperature (Azmi, 1978)

operations usually have been performed with a preheated pipe or in a protective enclosure (Hanamoto, 1978, TAPS experience.). In view of the particular importance of flaw-free bends and welds for Arctic offshore pipelines, and the difficulty of access, 100-percent non-destructive testing of both should be required.

The safety standards for Arctic offshore pipeline material should specify a design requirement for crack-propagation resistance at the lowest anticipated service temperature (LAST) and at the highest stresses encountered during pipe handling and field operations. However, the designer should be free to select the material-acceptance method, and a way should be left open for future material improvements.

B. PRESSURE-TEST PROCEDURES

Pressure-test procedures for milder climates are well-established from experience with many thousands of miles of gas and oil pipelines built both onshore and offshore. Special provisions must be made, however, for pressure-testing under Arctic conditions such as those experienced during the TAPS and Panarctic pipeline constructions.

Because the short Arctic summer period is the only time when temperatures are above freezing, many construction and installation activities, including pipeline pressure testing, will have to be done in winter at sub-freezing temperatures. Past experience on installed pipelines indicates that a 24-hour hydrotest is preferable to a gas test when operating above the NDT. Compared to gases, non-compressible liquids provide greater test safety, easier leak detection, and smaller pressure variations when subjected to temperature differentials. If water is used for testing at sub-zero temperatures, it must include a freezing-point depressant. consideration should be given to any environmental impact resulting from the disposal or storage of that medium.

In addition to any onshore pressure-test of pipe sections, a pipeline installed in a trench should be tested after being covered with fill material. Consideration also should be given to an additional pressure test before the pipe is covered. Although the additional test would involve increased cost and require additional time, it may be desirable in view of the difficulties involved with possible repairs of a buried pipe. Ice cover and limited accessibility warrant that all reasonable steps be taken promptly during pipeline installation to assure trouble-free future operations. Safety standards for Arctic offshore pipelines should reflect appropriate pressure-test requirements.

C. PIPELINE DESIGN AND CONSTRUCTION

Environmental hazards discussed in Section 11, and special construction and installation procedures prepared by R. J. Brown and Associates, and adopted on the Panarctic off-shore gas line in the Canadian Arctic Sea discussed in Section I, gave an insight into problems peculiar to the design and construction of Arctic offshore pipelines.

In view of these, requirements for pipeline design, construction and installation must consider:

- Unique heat transfer problems associated with offshore and onshore permafrost (Section 11. C.2).

- A detailed and realistic logistics plan for unexpected contingencies due to remoteness of the area, transportation difficulties and scarcity of local manpower and equipment.

- The effect of hostile environment (low temperature, poor visibility) on operator efficiency and ability to perform work under unprotected conditions. Therefore, training programs more stringent than those for similar work in temperate climates might be necessary.

- The need for special equipment for permafrost trenching, for some diverless operations, and for ice cutting, may require earlier design and development.

- Use of stringent safety measures to prevent fire and/or explosion if heated enclosures are used for some operations.

- Utilization of advanced non-destructive inspection techniques using hydrostatic tests, such as acoustic emission as a means of locating defects and estimating the level of severity of the defect.

A pipeline constructor with United States and/or Canadian Arctic experience building a pipeline would be cognizant of the special requirements listed above. In that case, all that might be required in the safety standards would be a general introductory comment regarding the items mentioned above.

D. EXTERNAL LOADS

In discussing external loads on Arctic offshore pipelines, attention will be focused on the effects of permafrost, ice-imposed loads, wave and current action, seismicity, and thermal expansion or contraction. (The last could be considered either an external or an internal load.) Each of these loads may add to the radial and/or axial stresses in the pipe and therefore should be considered in the pipeline design.

1. Permafrost

The discussion of subsea permafrost in the Beaufort Sea (Section II.C.2) noted that ice-rich permafrost exists in a non-continuous fashion in the shallow waters of the Arctic Ocean, and that it becomes continuous and close to the surface near and on the shore. Consequently, an offshore Arctic pipeline installed in a trench may encounter discontinuous permafrost within the depth of the trench in shallow waters and will cross continuous permafrost in its onshore approach. The subsea permafrost, being close to 0°C (32°F) (sea water temperature is approximately minus 1.8°C), is near its thawing point and its equilibrium is determined by temperature and water salinity. Thus, a small amount of heat addition or extraction may change the physical characteristics of the permafrost drastically, making it the most difficult terrain problem (Phukan, 1979). In general, disturbed permafrost either will thaw if heat is added (as with a heated oil pipe), or will grow by freezing if heat is extracted (with a chilled-gas pipeline, for instance).

The thawing of ice-rich fine-grained soils usually is accompanied by surface weakening and settlement. The settlement will be caused by the volume decrease of ice thawed into water and by the thaw consolidation of the soil. Thaw consolidation has been calculated (Crory, 1973) from measured values of specific weight of dry-frozen, and dry-thawed soil. The resulting subsidence can create down-drag loads on a pipe and must be considered in pipeline design (Huck, 1979). In discontinuous ice-rich soil situations, a warm oil pipe could behave like a beam immersed in a dense fluid with support at intervals along its length (Walker, 1978). The length of the unsupported pipe spans, and the deflection of the pipe will determine the resulting stresses. A mathematical model of such a pipe has been described (Walker, 1978), and pipe stresses due to bending, sag, temperature differential, and internal pressure were calculated.

If the thawing of permafrost results in formation of slurry with a very low shear stress, a gas pipe or an empty oil pipeline may have a positive buoyancy and, without adequate overburden weight, will tend to float and move upward. To prevent this, a pipe may be anchored to the sea bottom or provided with weight coating (usually concrete) sufficient to insure a negative buoyancy under the most adverse conditions.

A potential thaw subsidence problem was encountered in the construction of the Trans Alaska pipeline. There, in regions of potentially unstable permafrost, the pipe was elevated on vertical support members which were cooled by heat pipes to prevent local permafrost degradation, A similar solution may not be possible for Arctic offshore pipelines. Other means, such as pipe insulation or granular bedding material (Jahns, 1973) would have to be provided for pipeline safety when crossing thaw-sensitive soild. The effect of pipe insulation on the size of a thaw plug forming around a pipe is illustrated in Figure 4-2. The importance of thaw subsidence on pipe integrity can be illustrated by an incident with the Trans Alaska Oil Pipeline. Thawing of an ice lens below the ditch in one of its buried sections resulted in a sagging of the pipe, followed by wrinkling and rupture (Oil and Gas Journal, July 1979).

Frost heave can occur when a pipeline, having a temperature below freezing, crosses saturated soils with high water pore pressures. Any unfrozen Water will tend to freeze around the pipe forming a frost bulb. The increase in the volume with phase change from water to ice, and the migration of water to the frozen/unfrozen interface, may cause formation of segre‘gated ice lenses, as shown in the upper part of Figure 4-3, and results in frost heave. The increase in ice volume would

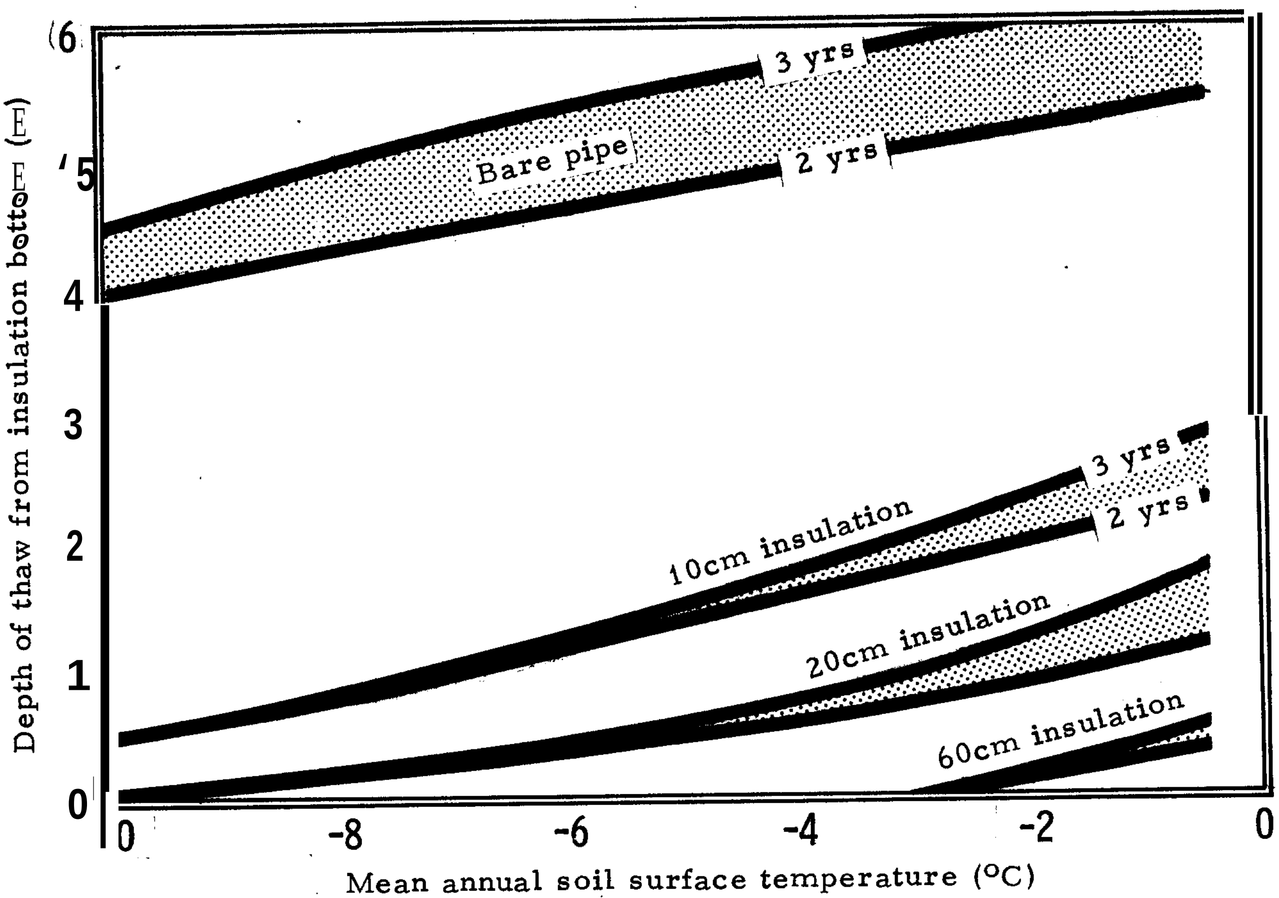


Figure 4-2. Depth of Thaw for Insulated and Bare Pipe at 2 and 3 Years (Jahns, 1973)

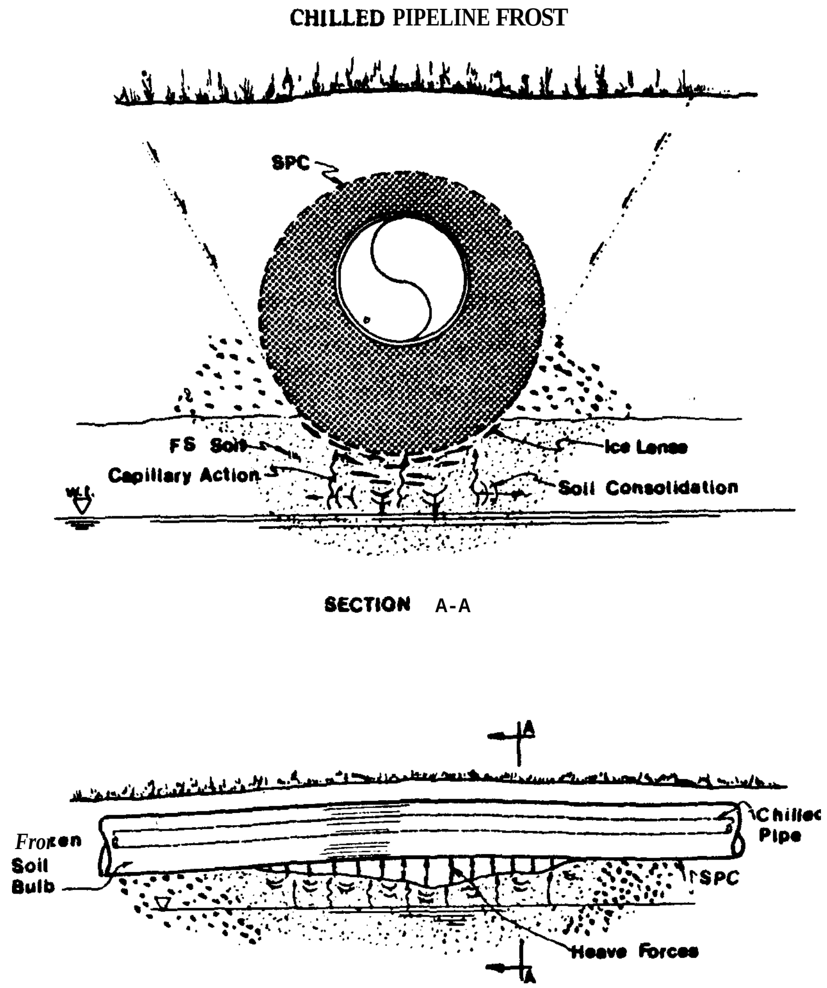


Figure 4-3. Schematic Soil/Pipe Frost Heave Relationship (Davison, 1979)

produce heave pressures acting on the pipe and might cause its movement in the direction of least resistance, i.e., upward. The frost-heave pressures will be equal to the weight of the pipe and of the overburden material. The heave displacement will, in general, decrease with an increase in the heaving pressure (Young and Osler, 1971) so that a heavier pipe with greater overburden in a frost heave situation would be displaced by a smaller amount. The heave rate increases with the rate of freezing up to some maximum, and then tends to fall off because, under high rate of frost penetration, the water cannot migrate fast enough to the frozen bulb interface (Penner, 1972). Frost heave can be a serious problem to a cold pipeline and a Russian gas pipeline failure caused by this has been reported (Tagunov, 1969).

Various frost heave mitigation measures were studied in the past (Davison et al, 1979; Phukan, 1979). They included reduction in the heat flow between the pipe and the surrounding soil, increase in overburden weight (deeper trench or a berm over the pipe), replacement of soil around the pipe for a thermally-stable, redirection of the freezing front (by the use of vertical heat pipes), and combination of those.

Ditching or trenching in permafrost preparatory to the pipe burial, requires special equipment. As with ice, the strength of permafrost increases at lower temperatures. Fortunately, in the Arctic offshore the subsea permafrost in shallow waters will be close to its thawing point, i.e., relatively weak. Mellor (1978) and Hironaka (1974) discussed various types of trenching equipment for permafrost which included traverse rotation cutting, ripping and dozing, water and air jetting, impacting, thermal cutting, and blasting. In the case of the TAPS, Hironaka (1974) quoted recommendations for: trenching in permafrost using ditching machines in silt, clay, peat and sand regardless of moisture content; ripping followed by backhoeing for gravels with moisture less than 10 percent; and in drilling, blasting and excavating in gravels' with moisture contents above 10 percent. Oriard (1979) discussed controlled blasting in permafrost to provide clean, well-defined trenches.

It is quite possible that for "soft" subsea permafrost, trenching with underwater ploughs, rippers, or high-pressure water jets could be considered, but the selection of the most suitable equipment will be guided by economics and by the local geotechnic and oceanographic conditions.

2. Ice

Ice phenomena of the Arctic Ocean have a profound effect on all phases of pipeline system construction. This discussion of ice effects will consider surface ice activities, sea bottom ice scouring, and ice accretion on offshore structures. Ice problems in the Beaufort Sea were reviewed in Section II.B of this report, and the discussion here will be focused on the effect of ice on pipeline safety.

The Arctic Ocean and the Alaskan Beaufort Sea are covered with ice nine to 10 months a year allowing only two or three summer months for maritime transportation in some ice-free water. Consequently, conventional pipe-laying techniques, even with barges having reinforced hulls, must be confined to that period. This means that a pipe-laying barge would be winterized near the projected pipe corridor to take full advantage of the narrow, operational windows available. In the winter months, the shallow part (up to 60 ft depth) of the Beaufort Sea is covered completely with ice which is in almost continuous motion. The size and rate of this motion depend on the distance from the shore and the location relative to islands and winds. Thus, the pipe-laying operation from ice, employed by R. J. Brown and Associates in the Panarctic gas line (see Section I), may not be feasible in those parts of the Beaufort Sea not protected by offshore islands.

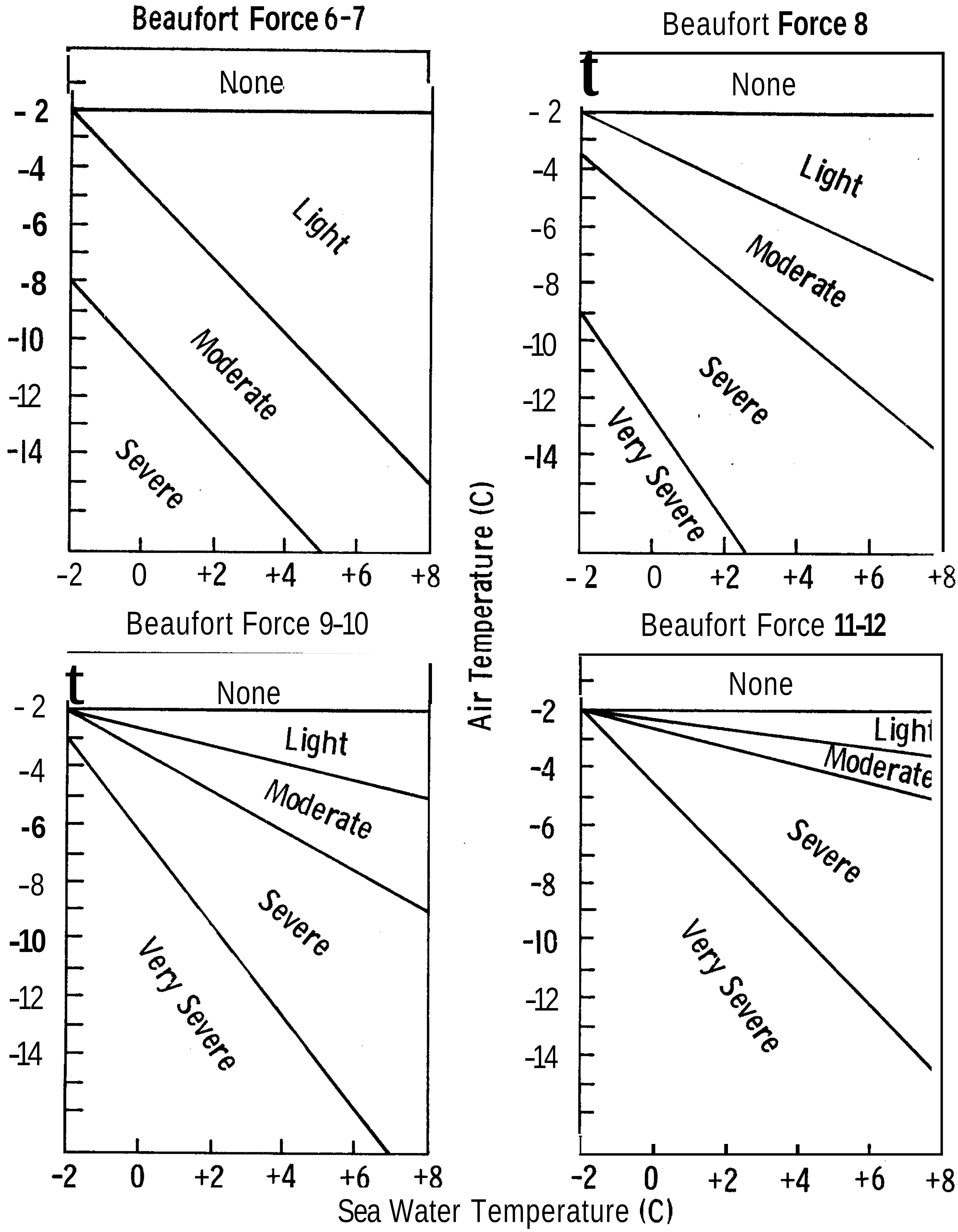
In the spring break-up period, or in the freeze-up during the fall, accessibility by barges is not practical. Thus, pipe-laying in the Arctic offshore requires careful planning and provision of contingency for many operations. These include transportation, field work, pipeline installation, and check-out procedures. The technology to do the work is available, but it should be used in an imaginative, innovative and well-planned manner.

Ice scour, discussed in detail in Section II.B, is a real hazard to pipelines in shallow parts of the Beaufort Sea. As illustrated in Figure 2-7 (Section II.B.3), the depth of scour and its frequency are a function of water depth, scours becoming deeper but less frequent in deeper waters. Some of the moving blocks of ice, with large mass and inertia, could scrape the sea bottom, affecting the safety of pipelines and cables unless special protection is provided (Section I).

Ice accretion, as related to pipeline systems, may affect the operation of pumping stations by blocking compressor inlets, a problem encountered in the Prudhoe Bay development. The rate of ice accretion depends on air, on sea water temperature and on the wind force, as shown in Figure 4-4. Ice accretion is discussed further in part J.2 of this section. Pipeline failure modes due to permafrost and ice are shown in Figure 4-5.

3. Waves and Currents

Waves and currents in the Beaufort Sea were discussed in Section II.A, which said the normal waves and currents are small when compared with mid-latitude areas. Table 2-1 shows estimates of maximum (storm) wave heights for various return periods. These values are also considerably lower than those



Degree of Icing:	Light	1-3 cm/24 hr	Severe	7-14	cm/24 hr
	Moderate	4-6 cm/24 hr	Very Severe	15+	cm/24 hr

Beaufort force is a measurement of wind speed; i. e. force 11=64-72 mph

Figure 4-4. Icing on Fishing Vessels at Low Speeds (Mertins, 1968)

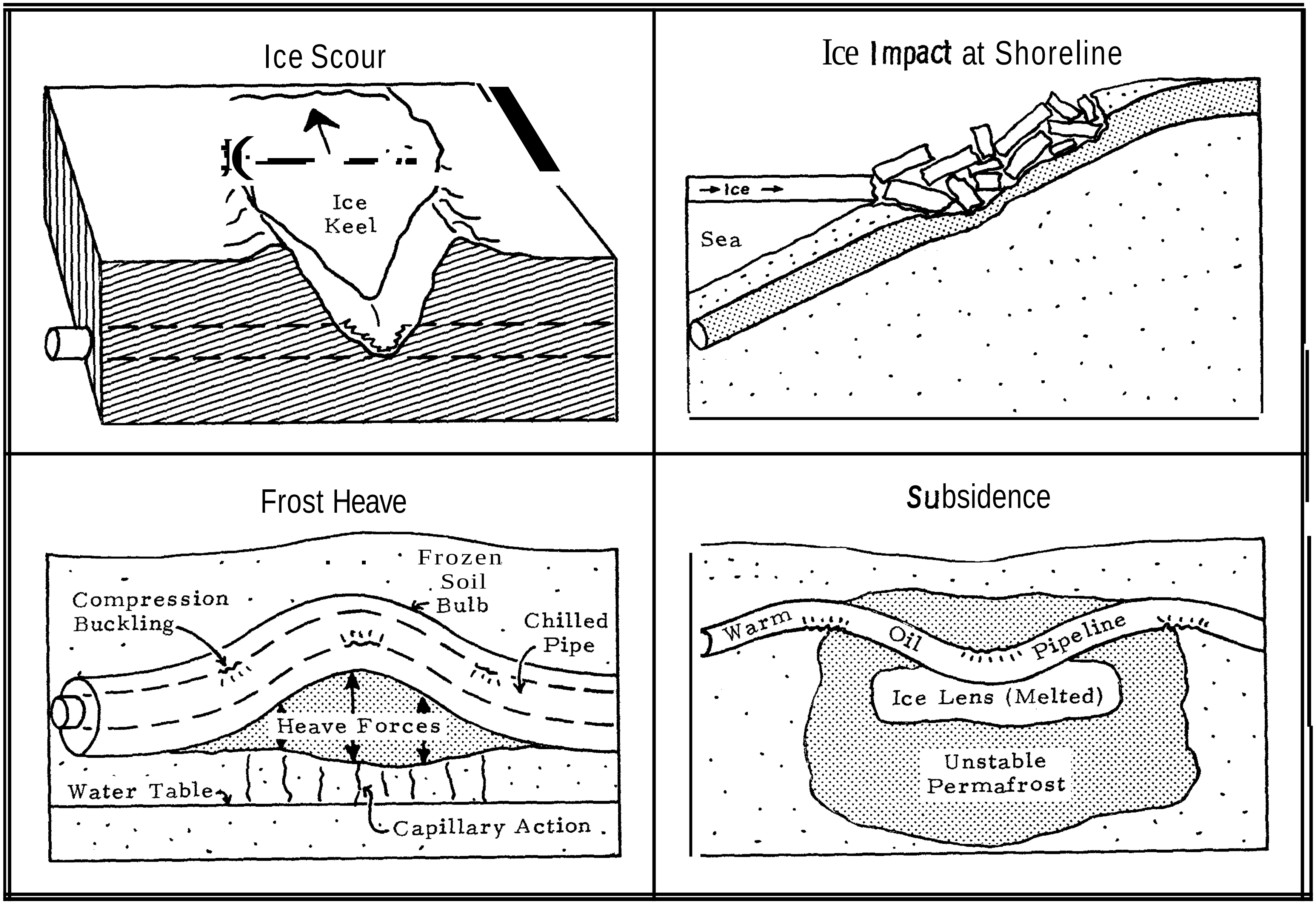


Figure 4-5. Arctic Offshore Pipeline Failure Modes Due to Ice and Permafrost

expected in other OCS locations. Pipeline buried in the ground or otherwise protected against ice forces would not be affected by waves and currents except in the surf zone. Here, a pipe may be subjected to soil mass movement or vertical erosion of several feet per year, as reported in the Outer Continental Shelf Environmental Assessment Program (OCSEAP Synthesis Report, 1978). In the near-shore area off the surf zone, waves also may induce cycling stresses in the sea bottom which may cause a progressive buildup of pore pressure, leading to soil liquefaction and loss of support for a pipe crossing such a region (Seed and Rahman, 1977). Consequently, during its period of operational life, the burial depth must be large enough to prevent pipe exposure in all such locations.

Perhaps the most significant effect of waves and currents would be during the pipe-laying operation. The technology of dealing with this problem was established in the Gulf of Mexico and North Sea operations. The additional hazard of floating ice in the Arctic offshore may require some further precautions and contingency measures.

4. Seismicity

The seismic characteristics of the Beaufort Sea offshore have been reviewed in Section II.C.4. In the southern part of Alaska (the Anchorage, Port Valdez area) high-intensity, seismic events were recorded, and had to be considered in the design of the Trans Alaska pipeline. On the other hand, the estimated seismicity of the Beaufort Sea is of low magnitude, with a predicted 100-year return period and maximum lateral accelerations of only 0.12 g (EIA, 1979). No active faults were identified in the Beaufort Sea offshore. Consequently, pipelines designed to withstand the external loads discussed previously should be able to resist predicted seismic events.

5. Thermal Expansion or Contraction of a Pipe

Although thermal expansion or contraction may not be considered an external load in a buried and restrained pipe, such stresses will be generated as a result of pipe-to-soil interaction. Luscher et al (1979) analyzed the case of fully-restrained, thermally-expanding pipelines. The longitudinal force F_l generated in such a case is:

$$F_l = A_s \times (E \times \alpha \times \Delta T - \nu \times \sigma_H + 0.5 \times \sigma_H)$$

$$F_l = A_s \, (E\alpha\Delta T - \nu\sigma_H + 0.5\, \sigma_H)$$

A_s - Pipe wall cross-section area

E - Pipe material modulus of elasticity

α - Pipe material coefficient of thermal expansion

ΔT - Temperature differential

ν - Poisson's ratio

σ_H - Hoop stress caused by a net internal pressure

The first term in the above equation represents thermal force, the second the Poisson's ratio effect, and the third the axial force caused by internal pressure.

As a result of the longitudinal compressive force, a pipe may buckle in the direction of least restraint. The interaction of the surrounding soil during the overbending, sidebending and sagbending of a pipe has been studied (Luscher et al, 1979). The pipe movement will be restrained by the combination of its own weight, the overburden weight, and by soil shear strength. Once a bend starts in a buried pipeline, large radial forces can develop which are resisted by the surrounding soil. To quote Luscher et al (1979):

> ...as radial displacements occur at the bend, the pipe tends to move longitudinally through the soil toward the bend, and in so doing mobilizes longitudinal shear stresses which reduce the longitudinal and hence the transverse force at the bend. Satisfactory design of the bends requires that the actual radial bend force is in equilibrium with the resisting forces provided by the surrounding soil, and that pipe stresses and pipe strains are within allowable limits for reasonable pipe displacements.

Should the compressive stresses in the bend exceed the yield strength of the pipe material, a wrinkling of the pipe may occur. US safety standards allow no wrinkle bends in highly-stressed pipes (above 30% of SMYS, Sec. 192.315 and above 20% of SMYS, Sec. 195.212). Therefore, safe design must ensure a maximum bend curvature below the critical curvature of wrinkling. For such an analysis, soil properties and the location of possible thaw subsidence (or frost heave) areas must be known.

In a recent failure investigation of the TAPS (Oil and Gas Journal, July 1979), it was postulated that the line sagged, wrinkled and fractured because of the existence of unknown ice lenses below the pipe. These thawed eventually, and the pipe, covered with a heavy overburden, sagged and buckled.

The geometry of an unburied pipe usually allows sufficient movement so that thermal stresses are not significant.

In a cooled pipe (pipe temperature lower in operation than during installation) the first term in the equation in D5 will be negative. Thermally induced compressive stresses in the pipe then will be lower or even may disappear. Thus, the possibility of pipe buckling may be greater for warm buried pipes than for others. Analytical tools, in the form of finite element three-dimensional computer programs, are available for stress analysis. Information on soil characteristics and soil interaction must be available and should be verified by field measurements.

E. REMOTENESS AND INACCESSIBILITY OF ARCTIC OFFSHORE

Northern Alaska is devoid of roads for terrestrial transportation except for the recently built Alyeska highway. There is a brief seasonal period of possible access by marine barges, and a few landing strips for propeller aircraft exist. However, there are no engineering or industrial centers, except the Navy Arctic Research Laboratory (NARL) and the recent Prudhoe Bay development. The largest community is at Barrow, with 300 inhabitants. Consequently, any major engineering operations, such as laying offshore pipelines, must consider logistics, transportation, communications, surveillance, and monitoring.

F. LOGISTICS AND TRANSPORTATION

The limited accessibility to the northern Alaska offshore and the severe climate require careful planning for the transportation of materials, heavy equipment and personnel for the support of pipeline construction. However, unexpected changes in weather may upset the best plans. For example, Prudhoe Bay Sea Lift pipeline barges unexpectedly were stranded offshore during August and September 1975 as a result of an unusually heavy ice invasion along the Arctic coast. Consequently, logistics planning always should provide for such contingencies. The existence of the Alyeska highway from Fairbanks to Prudhoe Bay improves the situation, but it still is necessary to transport the material from Prudhoe Bay, to bring in the heavy equipment by barges, and to shuttle the personnel.

The construction of the TAPS and the Prudhoe Bay production facilities has provided valuable experience in Arctic, logistics (Jahns, 1978). Marine transport by barges through the Beaufort Sea is economical, but it relies on an ice-free water path in summer. In some years, this may not occur. For barge unloading, causeways may provide the safest and least economically damaging means of heavy load transfer to onshore sites.

Both fixed wing aircraft (Hercules 130, Twin Otter) and helicopters (Bell 205) frequently were used for transport of loads (up to 20 tons in the case of the Hercules). This mode is expensive, requires construction of landing strips or pads, and is sensitive to weather conditions.

Rolligons are the off-road vehicles most used on the North Slope. They can cross the tundra after it dries, and can operate on ice as thin as 0.6m (2 ft) because of the low ground pressure they exert.

Except for limited use of the Canadian Bell Voyager and air-cushioned barges, air-cushion vehicles (ACV's) have had relatively little use in Alaskan oil/gas operations.

Existing transportation means are now adequate to support exploratory activities, but are not sufficient for year-round support of operations in offshore oil/gas fields. For that purpose, construction of additional permanent roads, causeways, and perhaps a wider use of more reliable ACV's would be required. Table 4-1 presents a listing of transportation means, concerns, and gaps still existing in technology and baseline data.

Summarizing the transportation problem, four modes of transport can be considered:

Table 4-1. Logistics Support

TYPE	EXAMPLES	CONCERNS	TECHNOLOGY NEEDS	DATA NEEDS
MARINE	● SURVEY SHIPS ● SUPPLY BARGES	● SUMMER ICE o ODER. COST ● HAZARDS	o	● IMPROVED ICE FORECASTING
ICE SURFACE	o TRUCKS ● SLEDS ● ROLLIGON	o ICE THICKNESS ● SNOW DRIFTING ● ICE MOVEMENT RIDGING	● RIDGE-CROSSING TECHNIQUES	———
AIR	● FIXED-WING o HELICOPTER	o RUNWAY ● WEATHER ● DOWNTIME COST	———	———
AMPHIBIOUS	o ACV	o RELLABILITY o ICE RIDGE CROSSING	● IMPROVED RELIABILITY ● INCREASED GND. CLEARANCE	———
ALL-WEATHER YEAR-AROUND	● CAUSEWAYS	o ICE PRESSURE ● ICE OVERRIDE o WAVE EROSION ● GRAVEL AVAIL. ● MARINE BIOTA	———	● ICE PRESSURE OVERRIDE ● OCEANOGRAPHIC ● BENTHIC LIFE

- Marine, By Ships, Barges and Tankers. The constraint on this mode is the short season (approximately 60 days) and the shallowness of the water in the gently sloping Beaufort Sea which puts a limitation on the draft of floating vessels.

- Terrestrial-Overland, There are constraints on this mode of transportation. From late spring until the early fall (June to early October) travel across the tundra with'heavy-wheeled and tracked vehicles is not permitted. The fragility of the thawed active vegegation layer above the permafrost would be affected by the passage of any high-ground-pressure wheels or tracks. Only air cushion vehicles and special low-ground-pressure rolligons could be considered.

- Terrestrial Over Snow or Ice. This mode of transportation is possible in winter when the sea ice is thick enough to support moving loads. Additional support also may be gained at some locations by constructing ice roads or ice aggregate pads permitting winter transportation of equipment and supplies.

- Air. One constraint in this mode of transportation using fixed-wing aircraft or helicopters is weather (visibility, wind, precipitation). A second is the availability of landing and takeoff strips, for fixed-wing aircraft, which in winter could be built on ice, but in summer would require a substantial amount of sand and gravel.

G. COMMUNICATIONS

The communication between offshore and onshore facilities related to pipeline operation concerns safety and structural integrity of pipeline and associated equipment; pipeline performance and oil/gas flow control; and personnel safety and health.

In view of the difficulty in transportation and accessibility discussed above, reliable communication channels, impervious to Arctic weather conditions are important. Because of this, it would be prudent to provide a backup to the primary communications system, an approach usually taken by pipeline operators. For instance, the TAPS communications system consists of primary microwave stations, a network backed up with satellite-transmitted signals (Merrett, 1979), and radio. In the proposed Alaskan Arctic Gas Pipeline project, the communication concept used microwave systems consisting of five primary communication sites and four repeater sites, one located between each of the primary sites (Alaskan Arctic Gas Pipeline Co. 1974). A similar approach, utilizing some of the microwave channels of the TAPS was proposed by Alcan Gas.

In the operation of pumping stations, development is under way to automate some of the functions to reduce the number of personnel in remote outposts (Schaferman, 1974). Any automated function would need reliable transmission of signals to and from a control center.

The required technology and experience in communications in the Arctic environment is available, and it would be desirable for pipeline safety standards to emphasize the importance of this function and to stress the reliability aspects.

H. SURVEILLANCE AND MONITORING

The status of technology for surveillance and monitoring was described briefly in Section I.F. Performance of these functions for Arctic offshore pipelines is constrained by severe environmental conditions. Approximately 80 percent of the time, the Beaufort Sea is covered with non-stationary ice. Consequently, the most practical way to perform surveillance for any leaks is by aerial means. However, gas leakage from a pipe would not be visible unless in sufficiently large volume to form a vapor cloud capable of forcing its way through ice cracks. Another possibility is that a visible depression might be formed if the leakage was sufficient to rupture the ice. Monitoring of pressure and flow-rate measurements on both an offshore platform and an onshore gas receiving point also would indicate a major leak, but not its location. Probably minor gas leaks would not be detected in winter and would not be found until underwater inspection was feasible.

Oil leakage would be easier to detect even in the winter season, If the ice cover is porous and subject to crackling during its movement, oil could find its way to the surface and be visible until covered by snow. Oil accumulated under ice would be detectable in the future when infra-red sensors, radar, or sonic devices are developed more fully.

The effect of corrosion can be monitored by pumping a "pig" with the fluid, equipped with sensors to measure wall thickness. Reduction in thickness thus can be detected before causing the leak.

During summer months (August, September) ice-free waters may exist in the pipeline corridors. In the foreseeable future, such areas would be confined to shallow waters up to a 20m (66 ft) depth. These are the tracts earmarked by the federal government to be sold by the state of Alaska in the

Beaufort Sea. During summer, aerial surveillance would be supplemented by underwater inspection, using divers operating from a ship, or manned or unmanned submersibles.

Periodic underwater inspection also would be necessary to examine trenched pipe stability, erosion of pipe cover, ice scouring and pipe exposure. The corrosion-protection devices also could be examined during underwater inspection and current measurement could be made if deemed necessary.

I. PIPELINE INSTALLATION AND REPAIR

The existing technology of trenching, pipe-laying, and installation in Arctic offshore areas was discussed in Section I of this report. Here, attention will be focused on special requirements imposed by the Arctic offshore pipeline in the application of present technology.

During pipe-laying operations, a pipe could encounter its most severe stressing (Freund, 1977). The danger lies in pipe buckling and subsequent failure (Small and Wallin, 1971). After the pipe is deposited on the sea bottom, lowering it into a trench and guiding it across trench elevations or depressions results in bending stresses. These can be analyzed using one of the existing computer programs (Mousselli, 1977). Stresses encountered will depend mainly on pipe diameter and wall thickness, method of laying, water depth, and waves and currents encountered during the laying operations. Close inspection of the pipeline installation (not covered explicitly in 192 and 195 standards) is therefore important for enhanced assurance of pipeline safety.

The above comments apply to any offshore pipes. What is unique for Arctic offshore is the existence of a narrow "window" in which trenching and pipe-laying operations can be performed. Only a two-month (August, September) ice-free period can be expected during which a lay barge can be used (Figure 2-4). If trenching and pipe-laying is done from ice, the operation will be limited by ice movement which increases in magnitude with the distance from the shoreline (Section II.B). In the North Sea, pipe-laying operations frequently are curtailed by storms, but a warning of several hours usually is provided. On the other hand, ice movement in the Arctic cannot yet be predicted with sufficient accuracy, and the warning time may be short or nil.

The same comments apply to operational pipe repairs. Equipment required should be immediately available to take advantage of the free water in summer or the near-stationary thick ice in the late winter. In some cases a pipe may not be repaired for a period of weeks or months, and this should be taken into account in considering the economics of an Arctic offshore pipeline. Dual pipelines might be justified.

In summing up, the technology for pipeline installation in the Arctic offshore is available, but careful planning and logistic support is necessary for safe and economic performance.

J. ENVIRONMENTAL CONSIDERATIONS

1. Gas and Oil Leaks

The environmental impact of pipeline installation, operation, and possible gas or oil leaks caused by a failure in the pipeline is considered for all US offshore pipelines. The unique problem associated with Arctic offshore installations is the detection, containment and collection of any oil leak in ice-covered or ice-infested waters (EIA, 1979).

There are four distinct seasons in the Beaufort Sea ice cycle which demand different approaches to an oil spill.

- In winter months (December through April) the ice gets thick enough to support heavy equipment, and forms a cover over any spilled oil which then is contained under the ice in a relatively small area.

- During the spring months (May through July) ice breakup occurs and offshore areas, in general, are not accessible for transportation of equipment either on the ice surface or by marine transport. Any oil spilled during that time would spread between the pieces of floating ice and could travel a long distance.

- In summer months (August, September) the shallow area of the Beaufort Sea could be ice-free and methods of oil containment and collection applicable to open waters would apply.

- During the fall months (October, November) ice freeze-up takes place, but the ice is too thin to support heavy equipment. Consequently, the offshore areas would not be accessible by ice surface transportation nor by marine with exception of ice breakers. Any oil spilled would either collect under the ice or penetrate to the surface through cracks and leaks formed in the weak ice.

The environmental impact of an oil spill could be damaging to the Arctic marine biota if it is allowed to drift to biologically-active areas such as beaches, deltas, and some islands. Because of the difficulty in containing spilled oil, and due to the remoteness of the Arctic offshore areas discussed earlier, it would be prudent for pipeline safety to have a prepared plan for emergency measures. This would consider the pipeline location, seasonal ice variability, and procedures for oil-leak control as well as the subsequent repair work.

The impact of a gas leak would, in general, be small. There could be an asphyxiation and explosion hazard if refrigerated gas forms a cloud drifting over the ground to areas of human'activity. The probability of this happening is remote because refrigerated natural gas, warmed to ambient air temperature, is lighter than air and will be dissipated quite rapidly in the atmosphere. Thus, the most important problem for a defective gas pipeline would not be the environmental impact of a gas leak but the need for expeditious repair work.

2. Pumping Stations

A unique problem in both the Arctic onshore and offshore is the freezing of air inlets in the turbines driving the pumps (Stenson, 1972). There are two types of icing phenomena: one is caused by wind-carried snow (particles) which clog the turbine inlet. The other is due to ice fog forming at temperatures below minus 23°C (minus 10°F) causing adfreezing of ice particles to air inlets. Technology was developed to deal with both problems, as evidenced by satisfactory operation of Prudhoe Bay pumping stations. It probably would be desirable to call attention to this factor when considering Arctic offshore pipeline safety standards.

Pump station noise is another consideration, but it is outside of the scope of pipeline safety standards.

K. CORROSION PROTECTION

Corrosion protection is an important part of a pipeline installation. However, there are no unique requirements for the Arctic offshore and the existing technology and procedures for other offshore waters are applicable if the salinity and oxygen content of Arctic ocean water is taken into account (see also Section V.C.5). Maintenance of anti-corrosion devices is a part of pipeline monitoring and surveillance and was mentioned in Section IV.H.