Report No.

STUDY OF THE FACTORS AFFECTING THE SAFETY OF ARCTIC PIPELINES

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FINAL REPORT

Prepared for

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400 Seventh Street, SW
Washington, DC 20590

Gentlemen:

FINAL REPORT
STUDY OF THE FACTORS AFFECTING THE
SAFETY OF ARCTIC PIPELINES
CONTRACT NO. DOT-RL-92050

We are pleased to submit this final report on the study. The report has been revised in accordance with DOT comments transmitted by letters of September 30, 1980 and September 8, 1981.

Inputs to the study came from our consultants, from published technical information, and from a survey of knowledgeable individuals active in the pipeline industry, as well as from our own experience. The report documents the consensus of opinions of the Woodward-Clyde Consultants project team.

Sincerely,

Ulrich Luscher
Vice President

cmk

Enclosure

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16. Abstract

This report provides a detailed assessment of current practices employed in the design, construction, testing, inspection, operation, and maintenance of arctic pipelines which provide for safety to the public and protection of the environment. Existing research project pertaining to arctic pipelining problems are summarized. Hazards to pipelines that are unique to or accentuated by the arctic conditions are reviewed. A comparison is made between existing Canadian and U.S. regulations as they apply to arctic gas pipelines. The results of the study provide a basis for considering revisions to U.S. regulations for gas and liquid pipelines that may be applicable in arctic and subarctic areas. Recommendations are made for further research that is needed to enhance arctic pipeline safety.

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METRIC CONVERSION FACTORS

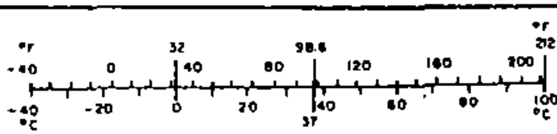
Approximate Conversions to Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
in	inches	*2.5	centimeters	cm
ft	feet	30	centimeters	cm
yd	yards	0.9	meters	m
mi	miles	1.6	kilometers	km
		AREA		
in^2	square inches	6.5	square centimeters	cm^2
ft^2	square feet	0.09	square meters	m^2
yd^2	square yards	0.8	square meters	m^2
mi^2	square miles	2.6	square kilometers	km^2
	acres	0.4	hectares	ha
		MASS (weight)		
oz	ounces	28	grams	g
lb	pounds	0.45	kilograms	kg
	short tons (2000 lb)	0.9	tonnes	t
		VOLUME		
tsp	teaspoons	5	milliliters	ml
Tbsp	tablespoons	15	milliliters	ml
fl oz	fluid ounces	30	milliliters	ml
c	cups	0.24	liters	l
pt	pints	0.47	liters	l
qt	quarts	0.95	liters	l
gal	gallons	3.8	liters	l
ft^3	cubic feet	0.03	cubic meters	m^3
yd^3	cubic yards	0.76	cubic meters	m^3
		TEMPERATURE (exact)		
°F	Fahrenheit temperature	5/9 (after subtracting 32)	Celsius temperature	°C

*1 in = 2.54 (exactly). For other exact conversions and more detailed tables, see NBS Misc. Publ. 286, Units of Weights and Measures, Price $2.25, SD Catalog No. C13.10:286.

Approximate Conversions from Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
mm	millimeters	0.04	inches	in
cm	centimeters	0.4	inches	in
m	meters	3.3	feet	ft
m	meters	1.1	yards	yd
km	kilometers	0.6	miles	mi
		AREA		
cm^2	square centimeters	0.16	square inches	in^2
m^2	square meters	1.2	square yards	yd^2
km^2	square kilometers	0.4	square miles	mi^2
ha	hectares (10,000 m^2)	2.5	acres	
		MASS (weight)		
g	grams	0.035	ounces	oz
kg	kilograms	2.2	pounds	lb
t	tonnes (1000 kg)	1.1	short tons	
		VOLUME		
ml	milliliters	0.03	fluid ounces	fl oz
l	liters	2.1	pints	pt
l	liters	1.06	quarts	qt
l	liters	0.26	gallons	gal
m^3	cubic meters	35	cubic feet	ft^3
m^3	cubic meters	1.3	cubic yards	yd^3
		TEMPERATURE (exact)		
°C	Celsius temperature	9/5 (then add 32)	Fahrenheit temperature	°F



METRIC CONVERSION FACTORS

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APPENDIX D - CROSS-REFERENCE OF RESPONDENTS WITH PRACTICE AREAS

1.0 INTRODUCTION

1.1 BACKGROUND

The first of possibly several large-diameter, high-pressure pipelines has recently been constructed in the arctic environment of Alaska between Prudhoe Bay and Valdez. This 800-mile, 48-inch-diameter pipeline is designed for an ultimate throughput of two million barrels of crude oil per day and operates at a temperature of 100 to 145°F. Reserves of nearly ten billion barrels of oil are within the Prudhoe Bay production area, which also contains vast amounts of natural gas that will also be transported by pipeline.

The Northwest Alaskan Pipeline Company (formerly Alcan Pipeline Company) and associated pipeline operators were named in the President's 1977 Decision and Report to Congress on the Alaska Natural Gas Transportation System as the Federal government's choice to construct the gas pipeline system. This pipeline will parallel the Alaska oil pipeline from Prudhoe Bay to Delta Junction. At Delta Junction, the gas pipeline will diverge from the oil line and follow the Alaska Highway to the Alaska/Yukon Territory border. In Canada, the pipeline will proceed south across the Yukon Territory and British Columbia into Alberta generally parallel to the Alaska Highway. In southern Alberta, the transportation system splits into the western leg, which will extend to California, and the eastern leg, which will transport gas to Illinois. The natural gas transported through Alaskan and Canadian areas having continuous or discontinuous permafrost will be chilled below 28°F in order to prevent degradation of the frozen ground near the buried line. This is the first such construction of a high-pressure, long-distance, large-diameter, chilled gas pipeline in the United States or Canada.

Because of the cold environment, arctic pipelines will require special consideration in their design, construction, testing, operation, and maintenance. Special safety and environmental considerations will also be necessary, and specific regulations may need to be proposed. Most regulations or codes governing the safety aspects of pipelines in temperate zones can be applied to arctic pipelines.* However, in current regulations and codes, no explicit wording states that arctic pipelines may pose unique problems. The Federal gas pipeline safety regulations, 49-CFR Part 192, and the Federal liquid pipeline safety regulations, 49-CFR Part 195, do not provide specific requirements for arctic pipelines. The Gas Transmission and Distribution Piping Systems Code, ANSI B31.8, does not address arctic pipelines; however, the B31.8 Committee is discussing code requirements pertaining to arctic pipelines but has not produced any material. The Liquid Petroleum Transportation Piping Systems Code, ANSI B31.4, also does not address arctic pipelines, and the code committee is not considering adding any material on arctic pipelines at the present time. On the other hand, Chapter 1052 of the Canadian National Energy Board Act and its companion standards, CSA Z184-1979, were updated recently to include specific coverage of gas pipelines in the northern (arctic) regions.

The lack of safety information in existing U. S. regulations and codes specifically addressing arctic pipelines and the lack of procedures on which to base decisions resulted in a decision for a study of arctic practices, hazards, research, and design trends. Such a study could form the basis for effective regulatory efforts. For this purpose, the Materials Transportation Bureau (MTB) of the Department of Transportation commissioned this study.

1.2 OBJECTIVES OF THE STUDY

The purposes of this study are: 1) to provide a detailed assessment of current practices and procedures employed in the design, construction, testing, inspection, operation, and maintenance of arctic pipelines to provide for safety to the public and protection of the environment; 2) to recommend revisions to those sections of gas pipeline regulations that are applicable to

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*For the purpose of this study, arctic refers to any area containing continuous or discontinuous permafrost. Pipeline refers to all parts of a gas or liquid pipeline through which the commodity moves, including (but not limited to) pipe, valves, fittings, bends, compressors, pumps, measurement and regulating equipment and facilities, and any structure supporting equipment used to ensure pipeline structural integrity.

arctic pipelines; and 3) to recommend areas of further research for improving arctic pipeline safety.

1.3 SCOPE OF STUDY

The work performed during this investigation was divided into five tasks: 1) comprehensive survey of published information and of knowledgeable individuals active in various facets of the pipeline industry; 2) identification and evaluation of hazardous conditions inherent to pipeline construction and operation under arctic conditions; 3) review and critical comparison of gas pipeline regulations in force in Canada versus 49-CFR Parts 191 and 192; 4) identification of sections of 49-CFR Parts 191 and 192 where changes or additions would enhance arctic pipeline safety and recommendation for specific changes, where desirable; and 5) identification of and recommendation for research to improve the understanding of arctic pipeline problems and development of solutions.

Within Task 1, 13 areas of interest were selected for investigation of practices or trends that had developed or were developing. These areas of interest are:

- Materials of Construction
- Welding -- Joining of Materials
- Valves and Valve Spacing
- Corrosion Control
- Gas Compressor and Oil Pump Stations
- Pressure Testing
- Spacing between Oil and Gas Pipelines
- Soils
- River Crossings
- Construction Modes
- Construction Techniques
- Operation and Maintenance
- Operation of a Pipeline at Temperatures Below 32^{o}F

These areas of interest essentially cover all aspects of pipeline design, construction, and operation, as well as potential interaction between adjacent pipelines.

Draft descriptions of known practices in each of the areas of interest were prepared, based on project staff knowledge and preliminary review efforts. For each area of interest, survey forms or interview outlines were generated and a list of individuals was developed, drawing from the gas and liquid pipeline industry, the academic community, pipe and material manufacturers, and government agencies. Appropriate descriptions and surveys were sent to each individual requesting his assessment of existing practices, relevant hazards, present Federal regulations, and research efforts for solving problems posed by arctic pipelines in each of these interest areas. The individual responses were integrated with the knowledge of the project team members in executing each of the identified tasks.

1.4 ORGANIZATION OF REPORT

The results of this study are presented in the following sections. Section 2 provides a summary of the review efforts accomplished in surveying published information and canvassing knowledgeable individuals. A bibliography of selected references is provided in Appendix A, and the list of individuals who contributed in response to our inquiries is provided in Appendix B.

A summary of the state of the practice in arctic pipelines is given in Section 3. Major attention is given to problems that are unique to or accentuated by arctic conditions, and to the experience base that may exist to help in resolving these problems.

Section 4 contains a discussion of the identified public safety hazards that are inherent in arctic pipeline construction and operation, in contrast to those for pipelines in temperate climates.

Section 5 provides a detailed comparison of United States and Canadian gas pipeline regulations, with emphasis on similarities and differences pertinent to arctic conditions.

The conclusions and recommendations derived from this study are given in Section 6. Recommendations are made for modifications and/or additions to Federal gas pipeline safety regulations that are believed needed to incorporate provisions pertaining to unique arctic problems. Needed research into arctic pipeline exploration, design, and construction is also discussed.

1.5 PROJECT TEAM AND CONTRIBUTORS

The Project Director for this investigation was Dr. Ulrich Luscher, and the Project Manager was Mr. William T. Black. Other staff members of Woodward-Clyde Consultants who worked on various tasks included Dr. Douglas J. Nyman, Mr. Howard P. Thomas, and Dr. D. Michael Holloway. Messrs. Burt T. Mast and David L. Shall participated as consultants and contributed inputs to various facets of this study; however, the conclusions and recommendations are those of the project staff. The guidance and contributions of DOT personnel Melvin A. Judah and Paul J. Cory are gratefully acknowledged.

The individuals listed in Appendix B provided verbal comments during interviews or they provided written comments, opinions, or experiences to the staff that performed the study. They were asked to respond from their individual rather than corporate positions; their corporate affiliation is shown merely to indicate their association with the pipeline industry. The cooperation of these individuals is deeply appreciated.

2.0 SUMMARY OF REVIEW EFFORT

2.1 LITERATURE REVIEW

2.1.1 Approach

A comprehensive literature search was made to identify hazards and practices related to the safety of arctic pipelines. First, a search using appropriate key words was made of the Computerized Engineering Index (COMPENDEX) for titles, authors, and abstracts of nearly 300 articles. Upon review of the abstracts, approximately two-thirds of the articles were eliminated from further consideration because of obvious non-applicability to this study. Copies were obtained of the remaining 100 or more articles, and these were reviewed by one or more of the study team members.

Paralleling the efforts to review the COMPENDEX material, each key staff member was asked to identify articles of interest with which he was familiar because of his previous involvement with arctic pipelines. This effort, together with a systematic review of back issues of the ASCE Transportation Engineering Journal, Pipe Line Industry, Oil and Gas Journal, and relevant conference proceedings produced another 75 articles of value, all of which were reviewed by one or more staff members. As a result, a total of approximately 175 articles were reviewed for the study.

About 100 of the most relevant of these articles are listed in the Bibliography to this report (Appendix A). Most of the listed references readily apply to one or more of the 13 categories of practice. Many papers were found regarding soils, and a substantial number of papers addressed materials of construction, welding, corrosion, and construction techniques. Very few papers were found on valves and valve spacing, pressure testing of arctic pipelines, and spacing between oil and gas lines. The majority of papers reviewed related to design and planning of arctic pipelines. Only a few described actual performance, and most of these referred to the trans-Alaska oil pipeline, which has only been in operation for 4 years.

2.1.2 Principal Areas of Concern

2.1.2.1 Soils - In a number of papers, authors recognized and acknowledged that secondary stresses and resultant strains may be more significant in arctic pipelines than in temperate zone pipelines. Secondary stresses are usually associated with movement of the pipe during operation. In temperate zones, such movement is usually associated with river crossings and, in certain instances, with landslides. These problem areas can usually be identified and resolved. In the arctic, the sporadic presence of permafrost and/or thawed frost-susceptible soils constitutes a more severe problem, as identification requires extensive subsurface exploration, laboratory testing, and judgment. In addition, significant problems are posed by potential thaw settlement and instability of thawing permafrost and potential heave of freezing frost-susceptible soils, so that extensive analyses and complex design studies may be required to determine the best solution. The alternative to such a study is to design for the worst condition, which is costly and difficult. A strong desire is expressed in the literature for some simple, fast way to identify problem soils and to estimate the extent of the potential problems for each soil type. Various geophysical methods are considered most promising to achieve this aim. If this could be done, the subsurface exploration problems could be reduced to manageable proportions, an item of particular interest to the pipeline industry.

2.1.2.2 Materials and Welding - The literature search revealed a significant number of informative papers on materials and welding. Some authors feel that steel pipe manufacturing has improved to such a degree that pipe can be fabricated with toughness properties sufficient to minimize the occurrence of failures, including both shear and cleavage-type fractures, that have been experienced in gas transmission lines. Pipe steel properties have been enhanced through improvements in the manufacturing processes, such as lower carbon and sulfur contents, better control and finer grain size through metallurgical adjustments and controlled rolling techniques, and more sophisticated quality control through radiographic, ultrasonic, and other non-destructive examination techniques.

As deemed necessary for specific operating conditions, appropriate toughness properties can be achieved using these modern manufacturing methods to meet levels that are specified by the purchasers. Toughness levels may range upward from an average of 13 ft-lb Charpy V-notch at -50°F as required for ASTM A 333 Grade 6 pipe for low temperature service, to 50 ft-lb Charpy V-notch at +14°F as was required for the trans-Alaska oil pipeline system. A number of the papers were written by individuals associated with steel manufacturers involved in supplying plate materials for pipe manufacturing or in furnishing the finished pipe product. Other authors, such as Somerville and Slimmon (Canadian Arctic Gas Study Ltd. and Northern Engineering Services Co. Ltd.) in their paper "Property Requirements for Pipelines" and Eiber and Maxey (Battelle Columbus Laboratories) in their paper "CAGSL Crack Arrest Experiments 1 and 2" postulate the need for crack arrestors and specification of better quality steels.

All base material steels and weldments are subject to discontinuities of some kind and to varying degrees. A number of papers dealt quite thoroughly with welding, especially with regard to discontinuities, procedures, processes, operations, and other aspects of welding related to pipeline construction. Various test procedures are available for detecting discontinuities, but only empirical methods are available for assessing the seriousness of the discontinuities. Generally, the longitudinal pipe seam can be examined by both radiography and by ultrasonics. Girth welds are examined by radiography because ultrasonic machines currently available for examining field girth welds are not considered to be practical and acceptable by the industry.

Recent research in fracture mechanics is believed to provide a rational analytical method to evaluate the seriousness of weld discontinuities. In fact, industry officials (during construction of the trans-Alaska oil pipeline) felt that fracture mechanics technology could have materially reduced the cost of welding repairs on the line without sacrificing safety. The research indicates that the materials and procedures finally adopted for specific jobs would produce high-quality weld joints that exhibit good physical properties.

2.1.2.3 Corrosion - A number of papers on cathodic protection for arctic pipelines, particularly for the trans-Alaska oil pipeline, were reviewed. In general, the consensus of these papers is that corrosion control for warm and cold pipelines in permafrost requires a combination of protective coatings and cathodic protection similar to that used in temperate zones. In the case of the trans-Alaska oil pipeline, the 48-inch-diameter pipe was coated with a thin film epoxy coating prior to construction and was then coated with a heat-shrinkable tape coating during the construction phase. These two coatings resulted both in minimizing "holidays" in the protective layers and in assuring, insofar as possible, a permanent waterproof seal on the pipe. However, design details vary from job to job in order to accommodate the various soil conditions in the arctic environment. The sacrificial anode system selected for the trans-Alaska oil pipeline was in the form of twin zinc anode ribbons each weighing 0.6 pound per foot. The anodes were attached to the pipeline at regular intervals and were designed to last at least as long as the projected useful life of the pipeline--an estimated 30 years--while providing the level of protection required.

Telluric currents are mentioned as an effect that should not be ignored when planning a corrosion system, although no significant consequences have been reported. It is felt that a sacrificial anode system offers the best protection against such currents if they exist in significant magnitude. For the trans-Alaska oil pipeline, twin ribbon zinc anodes were used as a substitute discharge point, draining off induced potentials and relieving the pipeline of possible corrosion problems.

2.1.3 Summary of Literature Review

The literature review provided background information for many of the areas covered in the study. In many of the articles, the authors reviewed previous research or tests that have been conducted in areas that pertain to this study. Much of what was learned in this review was integrated into the descriptions of practice, preparation of the interview outlines, and development of the conclusions and recommendations. A cross-reference to identify the areas of pipeline construction practice covered by the references cited in the Bibliography to this report is provided in Appendix C.

2.2 SURVEY OF KNOWLEDGEABLE INDIVIDUALS

A list of professionals from the gas and liquid pipeline industry, the academic community, pipe and material manufacturers, and appropriate government agencies was established for each area of interest described in Section 1. Synopses and survey forms/interview outlines were developed for each of the 13 areas of interest, and respondent comments were solicited regarding the synopses and their assessment of relevant hazards, present Federal regulations, and research efforts that are needed to solve problems that may be associated with arctic pipelines. Some of the individuals responded to more than one questionnaire. Their individual responses to our inquiries were integrated with the knowledge of the project team members in executing each of the identified tasks.

In all, 132 inquiries were mailed to individuals or organizations covering the various categories of practice. Of these, 64 responses (48 percent) were received. A list of respondents to our inquiries is provided in Appendix B and a cross-reference to identify the areas of pipeline construction practice responded to by each individual is provided in Appendix D.

The format of the inquiries included a brief description of relevant arctic pipeline practice in the specific areas of interest and either a questionnaire or review outline to be used in summarizing the respondent's replies. Aspects related to each study task were to be discussed in terms of the individual's personal experience. Many valuable comments and opinions were obtained in this manner, and they formed a concensus of opinion/concern in many cases. These data were considered in preparing respective sections of this report.

3.0 STATE OF ARCTIC PIPELINE PRACTICE

3.1 MATERIALS OF CONSTRUCTION

The materials of construction for pipelines in temperate climates have been fairly well standarized over the years, and operations have generally achieved a high standard of reliability and safety. The quality of steel pipe, flanges, fittings, valves, etc., has been improved through innovations in the steel manufacturing processes, new and improved methods in the forging and casting industries, and through development of new and more sophisticated inspection methods and techniques. These innovations and improvements in material properties have generally kept pace with the changes in the pipeline industry due to the increased size, complexity, and throughput of contemporary pipelines.

Because of the harsh climatic conditions, difficulty in surveillance, remoteness, and difficulties in repair operations, arctic pipelines have been constructed from materials tailored to arctic service, rather than of those materials currently being used satisfactorily in temperate zones. Accordingly, the cold environment is a major consideration in material selection. The liquid or gas that will be transported in the line must be considered. The toughness required in the material for the intended service must be appropriate as demonstrated by tests such as Charpy V-notch, drop-weight tear tests, crack opening displacement tests, or other tests conducted in accordance with accepted national standards such as those of the American Society for Testing and Materials.

The basic industry specifications for line pipe are the American Petroleum Institute (API) pipe specifications 5LX AND 5LS. These specifications cover details such as manufacturing process, chemical composition ranges, physical properties, hydrostatic tests, tolerances, nondestructive testing, and workmanship. Other industry standards, such as those of the American Society for Testing and Materials (ASTM), are the basic industry standards for many other pipeline system components. Deviations or supplemental requirements to these basic industry standards are subject to negotiation between the purchaser and the manufacturer. Such deviations or supplemental requirements are generally based on purchaser design requirements and/or operating conditions such that they will not be directly applicable to another project. Therefore, it would be very difficult to select any one specification covering chemical composition ranges or physical property requirements that can be designated as "the best" for arctic pipelines. However, as an illustration, the basic chemical composition of the pipe used by Alyeska Pipeline Service Company in the trans-Alaska oil pipeline for pipe known to have good physical and welding properties is as follows:

<u>Pipe Specification -- Ladle Analysis</u>

Carbon: 0.18 maximum
Manganese: 0.80 to 1.40
Silicon: 0.35 maximum
Phosphorus: 0.025 maximum
Sulfur: 0.035 maximum

Nitrogen: 0.008 maximum
Aluminum: 0.04 maximum
Columbium & Vanadium: 0.12 maximum
Residual: 0.50 maximum
$C + \frac{Mn}{6} = 0.42$ for nom. wall = 0.5 inch
$C + \frac{Mn}{6} = 0.40$ for nom. wall   0.5 inch

In addition to the basic chemical composition specified, there was also a requirement that the steel would be fully kilned and fine-grained (ASTM Size 5 or finer) as well as modifications to accommodate variations in mill practices.

In addition to chemical compostion requirements, the purchaser may specify a particular steel-making process (e.g., open hearth, electric furnace, Kaldo oxygen) and/or the process for rolling pipe from steel plate. Physical properties or requirements such as acceptable grain size, minimum notch toughness values, maximum hardness values, and minimum test pressure may also be specified. Some steels that have been judged suitable for arctic use are manufactured to requirements such as the following:

1) Manufacture - Pipe shall be spiral or longitudinally welded by the submerged arc process with at least one pass made on the inside and at least one pass on the outside.

2) Yield strength - 65,000 to 75,000 psi maximum

3) Tensile strength - yield/tensile = 0.90 maximum

4) Notch toughness - 10 mm x 10 mm Charpy V-notch:

		Foot Pounds		Percent
	Test Temp	Average (3)	Minimum	Shear
Plate	14°F	50	35	50
Weld	32°F	30	20	--
Heat-affected zone	32°F	30	20	50

5) Hardness - Rockwell C24 or Vickers (HV_{30}-260)

6) Test pressure - 95 percent of specified minimum yield

7) Cold expansion - 1.5 percent maximum

8) Nondestructive testing - weld 100 percent x-ray or ultrasonic
- weld ends - 8-inch minimum x-ray
- bevel - wet magnetic particle

9) Tolerances - somewhat tighter than API 5LX or 5LS

10) Workmanship - somewhat tighter than API 5LX or 5LS

Other factors that should be taken into consideration and evaluated when designing and constructing a pipeline system include fracture propagation resistance and fracture initiation resistance.

The degree of fracture propagation resistance needed is a consideration in the procurement of line pipe for both oil and gas pipelines. A greater degree of resistance is generally needed for gas service due to the large amount of energy stored in the compressed gas. Greater toughness values for the pipe are widely accepted as a way to contribute to minimizing the fracture length for both cleavage and shear-type fractures. At this time, there is not sufficient agreement among users or manufacturers for specific levels of toughness to be included in any of the applicable codes and standards or in the generally used pipe specifications.

The usual steel-selection criterion for an oil line is fracture initiation resistance: the rapid pressure reduction when a break in the line occurs would not propagate the fracture because of the lesser amount of stored energy available in pressurized liquid than in compressed gas.

The effects of temperature on the materials exposed to the arctic environment typically are evaluated together with the effects of chemistry (percent carbon and alloy content on strength and ductility) and manufacturing procedures (controlled rolling, which can affect grain size and physical properties such as yield and tensile strength and toughness) to ensure structural integrity under the most severe operating conditions. These conditions include not only stresses due to operating pressure but also stresses imposed by other mechanical effects and environmental factors such as thaw settlement, frost heave, etc., that could cause pipe wrinkling and/or fracture initiation.

Techniques for arresting pipe fractures have been studied for gas lines in arctic and temperate climates. In the American Gas Association's NG-18 line-pipe research program, steel strength and toughness were investigated through laboratory fracture tests, full-scale experiments, and fracture mechanics analysis. The effects of manufacturing variables and fracture fundamentals were also investigated. Other topics addressed were the investigation of field failures, delayed hydrogen cracking in high-strength line pipe, cyclic stresses in rail shipment of pipe, and pipeline design, operation and safety.

Alyeska, in its purchase of line pipe for the trans-Alaska oil pipeline, had the pipe manufacturers conduct full-scale burst tests as a partial requirement in qualifying their manufacturing procedures. The Northwest Alaskan Pipeline Project Study Group has studied the stability of gas pipelines in permafrost and the effects of cold temperatures on gas pipelines. In addition, the Arctic Gas Consortium has done considerable research aimed at solving a number of specific problems associated with natural gas pipelines in the arctic.

Other studies and test programs are being conducted by oil companies, universities, and research laboratories. Some of these studies have been on pipe wrapped with wire, installation of heavy wall pipe into the line at intervals, installation of high-toughness pipe sections, and encircling bands on the lines.

Stringent quality control procedures have been applied to procurement of materials in order to assure an appropriate degree of toughness on a consistent basis and to cover all materials that will be exposed to arctic operating conditions where fracture initiation and propagation could occur. As noted previously, the quality of steel pipe, flanges, fittings, valves, etc. has improved to a considerable degree over the past years. One of the significant changes that has taken place is that pipe is now being purchased in accordance with API specifications, rather than to individual mill specifications. Such pipe purchased according to API 5L, 5LS, and 5LX specifications with supplemental provisions based on intended service conditions has proven to be satisfactory. Other pipeline materials, such as flanges, fittings, valves, etc., are also being manufactured to national standards, with supplemental provisions based on arctic service conditions where appropriate. These supplemental provisions generally relate to exposure to extremely low temperatures and to the selection of a minimum Charpy V-notch impact value or other toughness criterion that is considered to be adequate for the operating service condition.

Straight-seam pipe produced to API 5L or 5LX and spiral-weld pipe produced to API 5LS can be considered equal for arctic use as long as the specified properties of toughness are equal. Past selection has probably been dictated by mill production capacity in the country where the line is to be installed or by price, currency, or credit arrangements if purchased in a different country. There does not appear to be a provable difference in performance of pipe manufactured by the three different processes. Manufacturing tolerances for the API 5LX and 5LS grades vary slightly in some categories, but as far as has been determined, these minor variations have not presented any major problems in fit-up, welding, or performance in operation.

Steel pipe manufactured to API 5LX and 5LS specifications is governed by limits on chemical composition, physical properties (yield strength, tensile strength, and elongation) as well as other properties confirmed by tests, including fracture toughness when specified by the purchaser. Hydrostatic testing is also required by these specifications for each length of pipe. The specifications limit the steel-making processes employed to open hearth, electric furnace or basic oxygen processes. Other purchaser requirements, such as a micro-structure, grain size, transition temperature, unique fracture toughness properties, etc., are subject to negotiation with the pipe manufacturer. Thus, when the purchaser has determined the properties he desires in his line pipe, he may write supplementary requirements to the API specifications and negotiate with the manufacturer for the costs involved in meeting these supplementary requirements. This was the case with the trans-Alaska oil pipeline, where many supplementary requirements to API 5LX and 5LS were specified based on engineering studies of service conditions. Satisfactory performance of the line pipe over the past 4 years demonstrates the suitability of these pipe materials.

Other pipelines operating in cold climates similar to arctic conditions, such as the early Trans-Canada gas pipeline, early portions of the Alberta Gas Trunkline, West Coast Transmission Company gas pipeline, Kenai to Anchorage gas pipeline, and oil lines in the Cook Inlet vicinity, were purchased to specifications in effect at the time of construction. These specifications did not contain special toughness requirements or supplemental testing, but the lines have performed satisfactorily for many years.

3.2 WELDING--JOINING OF MATERIALS

The joining of materials in the oil and gas pipeline industry has progressed over the years through various stages, such as threaded and coupled joints, threaded and flanged joints, oxyacetylene welding, bare wire arc welding, and coated-wire arc welding. Today, the joining may be done satisfactorily by a number of processes. Welding is now the primary joining method for pipe, with shielded metal arc welding and submerged arc welding as the most widely used welding processes. However, relatively recent developments in automation have brought mechanization to pipeline welding, and the gas-shielded and flux core metal arc processes are being used with satisfactory results in some pipeline construction.

Submerged arc welding for double jointing of pipe has been used satisfactorily in arctic service as has shielded-metal arc welding of girth welds. Gas-shielded metal arc welding has been used for welding some lines in Canada. All of these processes have proven to be satisfactory when the welding has complied with procedures qualified in accordance with API Standard 1104 or ASME Boiler and Pressure Vessel Code Section IX, with supplemental requirements, to ensure that quality welding is achieved. These procedure qualifications take into account many welding variables such as the base materials, joint configuration, welding electrodes or wires, electrical characteristics, position and direction of welding, number of layers of weld metal, preheat, interpass temperatures, post-weld heat treatment, and methods of testing.

Since welding procedures developed for arctic service normally call for welding on a warm (usually 70 to 100^{o}F minimum) and dry surface, preheating to achieve these conditions is usually necessary. Preheating may be accomplished using gas torches, heaters, or other means.

Post-weld heat treatment normally is not required for pipe thicknesses of 1/4 to 3/4 inch, provided the procedure qualification test has demonstrated that satisfactory physical properties can be achieved (without post-weld heat treatment). Chemical composition, particularly with regard to carbon and alloy content, is a major factor in weldability testing and could be a controlling factor in determining whether post-weld heat treatment is required.

On the trans-Alaska oil pipeline, the submerged arc welding process was used for double jointing, and the manual shielded-metal arc welding process was the primary method used for field joint welding. A preheat of 70 to 300^{o}F was used with both of these processes, but post-weld heat treatment was not required. As welding processes have developed, so has the need for standardization and quality control to assure quality, reliability, and safety in operation. Within the pipeline industry, standards were developed to fulfill these needs. These industry standards were adopted by Federal regulations, such as 49-CFR Parts 192 and 195, that govern design, construction, and operation of gas pipelines and liquid pipelines, respectively. Basically, welding practices for arctic pipelines have followed regulations for temperate zone pipelines with variations in materials and practices deemed necessary to meet the more severe arctic climatic conditions. Base materials are selected to meet or exceed the minimum requirements of an acceptable standard specification and any supplemental requirements to ensure integrity of the pipeline. Welding is performed in accordance with established written welding procedures that have been qualified to produce sound ductile welds in accordance with an appropriate code. Stress relieving, if required, is made a part of the procedure qualification to assure that heat treatment of welding does not degrade the strength of the welded joint from that required. Welders must be qualified for each welding procedure to be used in accordance with the appropriate code. Welds are inspected according to the requirements of 49 CFR Part 192.241, 195.228, or 195.234 as follows:

- Visual inspection must be performed to ensure welding is done in accordance with the documented welding procedure;

- Visual inspection must be performed to determine quality and depth of undercutting, as required in the regulation;

- Nondestructive testing must be performed as required by the regulations, with 10 to 100 percent coverage, as detailed in 49 CFR Part

192.243 or Part 195.234. Requirements for nondestructive testing include:

(1) Testing must be done in accordance with written procedures.

(2) Testing must be done by persons who are trained and qualified in the established procedures and with the equipment employed in testing.

(3) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld.

(4) The number of welds tested must satisfy the percentage of each day's production specified in the regulations.

Unacceptable discontinuities must be removed from the weld, and the weld must be repaired or removed. The regulations give specific instructions as to what welds may be repaired and what welds must be removed from the line. Any additional stipulations required in a right-of-way grant must also be met.

In qualifying the welding procedures to API Standard 1104 or ASME Section IX, the degree of preheat needed to produce satisfactory welds, as demonstrated by the procedure qualification tests, must be established and followed in construction work. Supplemental specifications have been considered by the industry in addition to 49-CFR Parts 192 and 195. These requirements include testing to demonstrate adequate weld toughness, ductility, tensile/yield strength, and compatibility of weld and base materials as discussed below:

- Impact testing (such as Charpy V-notch, Izod, or drop-weight tear tests) has, on occasion, been made a part of the procedure qualification, if the intended service is such that there is a need for verifying the level of toughness. Generally, when impact tests are a part of welding procedure qualifications, such tests are made on the base material, on the heat-affected zone, and on the deposited weld metal, to demonstrate the suitability of the overall welded joint and to assure that none of the properties has been degraded by the heat of welding. The minimum values for impact testing of materials are generally those given in ASTM Standards, such as ASTM A333 for Seamless and Welded Steel Pipe for Low Temperature Service. The purchaser may specify other minimum values depending on the intended service condition.

- Fracture mechanics (or linear elastic fracture mechanics) techniques can be used to assess the susceptibility of high-strength steels to fracture through analysis and tests of local conditions at the tip of a crack in terms of applied loading and external geometry. These techniques have been proposed as another method for assessing material toughness and could be made a part of a welding procedure qualification test in a manner similar to that used in specifying Charpy V Notch impact testing. This procedure may be used more extensively in the future when the reliability of such techniques has been demonstrated and accepted by the industry and the regulatory agencies.

- Hardness tests, such as Brinell Hardness, Rockwell, or Vickers Hardness Tests, are sometimes made a part of the procedure qualification test. Hardness tests are generally made on a weld cross-section and are made to detect "hard spots" that may have developed from the of welding process. Hardness tests are used extensively by some companies as another welding control measure. Depending on the intended services and operating conditions, hardness values in the range of 200 Brinell are generally considered acceptable for carbon steel such as ASTM A106 in the "as welded" condition; hardness values in the range of 225 to 240 Brinell may be acceptable for low alloy material. The purchaser usually will specify the maximum permitted hardness values based on knowledge and previous experience.

- Yield and/or tensile strength requirements of the weld are a part of the procedure qualification requirements to demonstrate that the weld strength matches the specified minimum yield strength of the base material. Yield and tensile strength tests for welding procedure qualification tests are generally made using reduced section tension specimens such as those shown in QW-462.1 (b) of ASME Section IX or the standard specimen shown in API Standard 1104, Figure 2.

- Chemical analyses may be required by the procedure qualification to assure that the weld and base materials are compatible. Pipe complying with the specifications listed in 49 CFR Part 192 Appendix B--Qualification of Pipe, or in 49-CFR Part 195.112, should be welded using electrodes or wires that are of chemical composition similar to the pipe materials. The weld should have physical properties equal to or exceeding the properties of the base material.

Welders and operators are qualified to API Standard 1104 or ASME Section IX as appropriate per the regulations and codes. Basically, qualification to these requirements is the same for arctic construction as for construction in temperate zones.

Quality control of welding in accordance with API Standard 1104 or ASME Section IX and DOT Regulations 49 CFR Parts 192 and 195, when followed rigorously, is generally considered adequate. Some companies, however, choose to increase the level of radiographic inspection. Also, the regulatory agencies may require a higher percentage of radiographic examinations, as was done on the trans-Alaska oil pipeline, where stipulations by the Department of Interior required 100 percent radiographic examination of all mainline girth welds. When 100 percent radiographic examination is specified, inadvertent testing omissions or errors, such as placement of film, become a major problem. Generally, this may have no relation to weld quality but adds to record keeping and administrative workload. The industry feels that the 100 percent requirement is too severe and that the requirements of 49 CFR 192.243 and 195.234 are adequate when using API Standard 1104 as the acceptance standard, especially when visual examinations are done properly.

Stipulations for the Northwest Alaskan Pipeline Project require essentially 100 percent radiographic examination, with exceptions that permit no less than 90 percent coverage where it is impractical to obtain 100 percent examination. It is felt that requirements such as this will eliminate many controversies during construction without having any detrimental effect on welding or weld quality.

Also, some industry representatives feel that if a substantially greater percentage of radiographic examination of welds than required by 49 CFR 192.243 and 195.234 is mandated, an alternative method of acceptance, such as a fracture-mechanics-based approach, should be permitted.

The need for protection of the weld and welder from adverse weather conditions is greater in an arctic environment than in temperate zones. The quality of the welds and welder productivity can be affected by extreme cold, wind, and precipitation. Shelters, such as wind breaks, tents, and heated enclosures, can be of great benefit in achieving quality welding under extreme arctic conditions.

3.3 VALVES AND VALVE SPACING

Valve requirements and practices for arctic pipelines are quite similar to those for pipelines in temperate climates. They are governed by such criteria as operational constraints (especially weather and terrain), isolation of sensitive structures or areas, and sectioning of the line to reduce losses in the event of line failure.

The considerations for valve spacing for an oil pipeline include minimization of spill and loss of product in the event of line rupture, and accounting for the elevation profile of the alignment. For arctic oil pipelines, the remoteness of lines, difficulty of access, sensitivity of water and land to permanent damage, difficulty of cleanup, and high capacity of lines require that careful attention be paid to sectionalization.

For the trans-Alaska oil pipeline system, both Federal and State stipulations included the Special Standard 3.2.2.1.

> "The design shall provide for remotely controlled shutoff valves at each pump station; remotely controlled mainline block valves (intended to

control spills); and additional valves located with the best judgment regarding wildlife habitat, fish habitat, and potentially hazardous areas."

The regulations and stipulations resulted in the provision* of 151 valves along the line plus additional valves at the pump stations and the terminal site. Along the line, 62 valves are remotely operated from the pipeline control center in Valdez. Block valves in the system stop oil flow from either direction (manual or remotely controlled), while check valves prevent the reversal of flow on uphill slope (automatically). A comprehensive assessment of oil spill risks resulted in valve spacings designed to limit the spill in an average section to 15,000 barrels after valves were closed. Maximum static spills after valves were closed could be held to 50,000 barrels of oil (along less than half a percent of the alignment); at the Denali fault crossing, the same limit would be 5,000 barrels.

For arctic gas pipelines, the elevation profile does not play an important part in gas losses from a ruptured line. Rapid and reliable access to the valves nearest the leak is of critical concern. Additional remote manual valves contribute very little to minimizing gas losses, since they do not allow prompt response to a detected pipeline leak.

One aspect of valve spacing for arctic lines deserving study involves the reliability of valves in the more severe climate. It would appear that the valves in extreme climates could require more frequent and detailed maintenance or have a higher potential for malfunction, especially in the event of a prolonged shutdown of a system. Although information on arctic construction emphasizes the vulnerability of mechanical equipment in cold climates, apparently no special consideration has been given to providing backup or redundant valving capability in the arctic.

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*This information is provided in the pamphlet "Trans Alaska Pipeline System, September 1975," by Alyeska Pipeline Service Company.

3.4 CORROSION CONTROL

The corrosion of pipeline steels in an arctic environment is generally the same as in temperate climates, with the primary exception of the presence of telluric currents in the line. Corrosion control methods used in temperate climates are equally applicable in the arctic and generally consist of a corrosion-control coating on the line and cathodic protection applied to the line (whether obtained by sacrificial anodes or by impressed current). However, selection of materials and methods may vary significantly between arctic and temperate climates. For example, a material such as coal tar or hot-applied asphalt enamel could possibly require controlled heating and cooling of the pipe to obtain a satisfactory coating. Such controlled cooling may be difficult to achieve and, therefore, may preclude the use of such materials. Likewise, materials with pressure-sensitive adhesives may require a different adhesive for low-temperature service.

Oil and gas pipelines would have similar corrosion control requirements, with the difference in methods associated with the operating temperature of the line. Gas lines and some product lines, including liquefied petroleum gas (LPG) and non-paraffin-base crudes, can operate below 32^{o}F. Heavy paraffin-base crude oil lines must be operated warm. Corrosion is generally more active as temperatures increase and is less active at lower temperatures, becoming almost negligible below freezing. A pipeline operating below 32^{o}F in solid permafrost would remain in a frozen regime, and corrosion would be minimal. A properly designed and applied coating, in combination with supplemental cathodic protection, should suffice for corrosion control.

For the case of buried pipelines operating at temperatures above 32^{o}F, problems in economically providing cathodic protection current to the line will be encountered. As permafrost thaws, corrosive activity will be increased, and the difficulty of impressing a requisite amount of current from a distance through frozen permafrost or soil becomes a major problem. An effective solution exists in providing sacrificial anodes in the thaw bulb area, either in the form of individual anodes or as a continuous ribbon. If the pipeline is placed above ground on suitable supports, corrosion control requirements become minimal due to little atmospheric corrosion in the non-polluted arctic environment. Vertical support members for the above-ground segments of the trans-Alaskan oil pipeline do not have a protective coating or cathodic protection system, even though the supports are insulated electrically from the pipe by sliding plates and bearing pads.

Pipeline coatings must have good bonding properties for operation at temperatures below 32^{o}F and at the higher temperatures normally encountered in pipeline service. Moreover, it must remain sufficiently ductile to prevent cracking, crazing, or disbonding from the pipe due to the combination of soil or pipe stresses resulting from low temperatures. Field application of the coating generally is more difficult and expensive due to lower temperatures at the time of application.

Heating of pipe and coating materials may be required, which would have associated temperature-control difficulties. The cost of removal and repair will be high if the process is not properly controlled, thus placing more emphasis on providing effective quality control and assurance procedures.

Mill-applied coating of the steel can provide adequate coating integrity prior to transporting the pipe, but some additional damage to the coating may occur due to handling and storage in low-temperature environments. Patching damaged coatings and field coating of welded joints are more difficult at low temperatures. Also, it is exceedingly difficult to heat small localized areas of the pipe for patching and joining purposes. Coatings for warmer pipelines must be capable of resisting cold during the storage, installation, and pre-operational periods and must also be capable of maintaining their integrity at the maximum operating temperature of the pipeline.

Thermal insulation is generally required for above-ground portions of arctic oil pipelines for operational reasons. The above-ground portion of the trans-Alaskan oil pipeline is insulated by a fiberglass jacket encased by galvanized sheet metal. At support points and valves, a modular fiberglass and polyurethane foam shell is used to enclose the pipe and support assemblies. Thus, the insulating jacket tends to protect the pipe from moisture and appears to have a beneficial effect in retarding corrosion.

For buried pipelines, insulation jackets are generally not used, because such pipe configurations are normally used only for lines in thaw-stable permafrost or for lines operating below 32°F. Exceptions are special below-ground refrigerated and insulated sections of limited length; some corrosion problems have been experienced when ground water penetrated between the pipe and the insulation.

Magnetically induced, telluric currents in the pipeline can be expected in the arctic. Provisions may need to be made to drain these currents from the line, or perhaps, to isolate the line electrically at compressor or pump stations by installation of insulating flanges or fittings. However, in the lower 48 states, stations have not generally been insulated from the pipelines because of a long-term tendency of insulating flanges to short out and leak. Insulating fittings other than flanges have become available in the last few years and should be satisfactory for this service.

On the northern-most pipelines presently operating, telluric currents have not been a problem. Telluric currents would tend to be alternating with low frequency. As such, they would not be as corrosion-producing as direct current and would generally be non-uniform as to location, depending on variations in the magnetic field of the earth. If telluric currents are generated, they would tend to discharge at locations of non-frozen inclusions in the permafrost and could cause corrosion at the points of discharge. If provision is not initially made to drain telluric currents from the line, the pipeline should be monitored to determine if there is a problem.

3.5 GAS COMPRESSOR STATIONS AND OIL PUMPING STATIONS

Two types of prime movers are used in gas compressor stations: reciprocating engines driving reciprocating compressors, and gas turbines driving centrifugal compressors. Oil pumping stations commonly employ centrifugal pumps driven through gear trains by gas turbines, reciprocating engines, or electric motors. Although a few installations of electric motor drives, steam turbine drives, and reciprocating engines driving centrifugal compressors have been made, these types of installations were selected because of special economic conditions that normally do not exist.

The principal advantages of reciprocating engines are: low fuel consumption and high availability. General disadvantages are: high initial cost, pulsation and vibration problems, a need for onsite maintenance personnel to ensure high availabilty, and more stringent foundation requirements. Engines with fuel rates of approximately 6,200 BTU/HP-hours have been in service for over 25 years.

The advantages of gas turbines are: relatively low initial cost, light weight, freedom from pulsation and vibration, ease of automating and running stations by remote control, and lighter foundation requirements. The main disadvantage is higher fuel consumption. The best gas turbines in the higher ratings will have fuel consumption rates of 7,000 to 7,200 BTU/HP-hour; turbines of 10,000 horsepower size and smaller will have fuel rates of 7,500 BTU/HP-hour and higher. Some gas engines and some gas turbines will have an improved fuel rate at lower ambient temperatures.

All types of equipment are normally provided with control and shutdown devices for the protection of personnel and equipment when operations exceed pre-set limits.

There are no nationally recognized codes or specifications for the manufacture of prime movers, gas compressors, or liquid pumps for pipeline service. Such equipment is considered proprietary, with design and performance standards established by the manufacturer. The manufacturer generally recommends the equipment to satisfy a customer's specified performance requirements. Pipes, valves, fittings, and fabrication for gas or liquid petroleum station facilities are controlled by the same or similar standards and specifications as the pipeline, including the welding requirements.

Pressure vessels, such as scrubbers, are generally constructed in accordance with the ASME Boiler and Pressure Vessel Code and are readily available. Sensing, monitoring, control, and regulating equipment and instruments also are generally proprietary items and are not covered by nationally recognized standards or specifications. Electrical power, lighting, control and signal wiring are usually installed in accordance with the National Electric Code, insofar as equipment and materials are generally available.

Electric power generation equipment and switchgear are readily available in explosion-proof configurations. These items are normally installed in buildings separate from the gas or liquid petroleum handling areas of the station.

Some electrical items are not available in the explosion-proof form, such as spark plugs for engines, and some electrical instruments are too large to encase in explosion-proof housing. Generally, such instruments are installed in a remote or pressurized control room to satisfy safety needs, but items such as spark plugs must remain in areas subject to flammable vapors or gas. Good building ventilation, as required by 49 CFR 192.178, provides an acceptable solution to the problem.

Fire suppression equipment, such as Halon gas or water-foam, is often installed in the compressor or pump buildings; however, fire-fighting equipment stored in a separate building at the station may also be required if the station is at a remote location that is not served adequately by a community fire department (See 49 CFR 192.171.). Automatic or remote-control station emergency shutdown valves are also generally provided consistent with the requirements of 49 CFR 192.167, and may require protective housing to assure proper operation.

Fuel for the gas compressor station is generally the gas being transported in the pipeline. Fuel for operating pumping stations along liquid petroleum lines may come from the pipeline (if it is a products line), but special provisions must be made for crude lines because the available prime movers cannot burn crude oil directly. The choice of fuel or electric motor drive is dependent on local supply availability and cost. In certain cases, it may be cost-effective to construct topping plants along a pipeline in order to produce turbine fuel from crude oil. On the trans-Alaska oil pipeline, natural gas is used for fuel on the four northern stations from a parallel gas supply line, and topping plants are used to refine a fuel from crude oil on the balance of the line. Fuel is also available from a refinery located near Fairbanks, Alaska, in the vicinity of the pipeline.

Gas compressor equipment and oil pumping equipment have generally been housed in buildings to facilitate operation and maintenance. However, use of enclosed modules in remote-control or automatic installations has increased, particularly with gas turbine drives. Exists and fences are also addressed in 49 CFR 192.163.

Water supply and sewage disposal must be accommodated to the arctic (permafrost) conditions. Potable and process water is usually supplied by onsite wells or from lakes. Storage and treatment facilities are furnished in accordance with local needs and requirements. Sewage disposal generally is accommodated onsite by septic tanks and ground beds designed to local requirements; however, in some cases, sewage has been incinerated due to difficulties and expense with conventional septic facilities in the arctic.

The practices described above were developed for temperate zone pipelines but have been applied to arctic pipelines where the equipment operates in a controlled environment. One major difference in the arctic is the potential need for different foundations. The heated pump station buildings apply a thermal load to the foundation soils. If the soils are frozen but unstable when thawed, detrimental settlement of the station could occur. This condition has been overcome by founding the buildings and other structures on completely refrigerated foundation materials. The systems were designed to keep the foundation material frozen. Other foundation systems addressing the permafrost conditions are also possible.

Another difference is that under arctic conditions, it may not be possible to install windows or fixed louvers for ventilation. Therefore, forced ventilation may be required. Activation of the ventilation system by gas or vaporsensing devices may be desirable. Additional consideration must be given to icing of the air inlets for turbines, which will present problems in arctic conditions. Icing in turbine inlets is an operating problem affecting continuity of service but is not a safety problem or concern. Freezing of any moisture in gas control lines or the outside air vents could also make pressure regulators inoperative. The temperature of a chilled high-pressure gas could be reduced to $0^{o}F$ or below due to pressure reduction effects; therefore, provisions to heat or dry instrument gas must be considered.

In summary, special conditions that should be considered for compressor and pumping stations in arctic service include:

- Prime Movers

  1) Environmental and temperature conditions under which the prime movers will be operated, to see if special metallurgy for low-temperature service will be required or if the operating environment can be controlled by placing the equipment in buildings.

  2) Oil heating and/or cooling requirements, with reference to the operating conditions.

  3) Jacket water and other cooling circuits, in view of the operating and contingency conditions.

  4) Battery protection, to be sure such equipment will be operable when needed.

  5) Building heating and ventilation needs, to ensure proper environmental control.

  6) Foundation design, to assure stability during operation and to prevent disturbing the thermal balance of the supporting soil.

7) Air intake design, to include features that prevent freezing or obstruction, such as downward inlet air intake hoods.

8) Control and shut-down features, to ensure proper operation when needed under arctic conditions. These features should account for the possible accumulation of condensation and frost on piping, valves, etc.

9) Removal of heat of compression or pumping, if it would be detrimental under operating conditions.

- Other Equipment and Facilities

1) Heating and ventilating of buildings other than for operation of equipment.

2) Communications for operation, control, and maintenance, to assure that the arctic conditions will not result in interruptions. The need for redundancy depends, to a great extent, on whether the stations are staffed or not and on the importance of maintaining virtually uninterrupted throughput to achieve economic objectives. Microwave, company-owned or common carrier, satellite and ground wirelines are all proven pipeline communication systems. A wireline on poles is probably not practical in the arctic.

3) Housing and other protection for operating and maintenance personnel, in areas where arctic conditions are severe.

4) Separate enclosures for equipment, to isolate them individually in case of failure or fire. This may apply when multiple units are employed rather than a single large unit. Equipment enclosures can contribute to control of fire damage but increase maintenance problems. If maintenance is more poorly accomplished due to enclosures, then this measure could be self-defeating.

5) Electrical power service reliability for life support capability, particularly in remote areas where severe environmental conditions can prevail at certain times of the year. Emergency generators should be supplied with a fuel system and source that are completely independent of the normal station fuel supply system.

6) Sewage disposal facilities, particularly in permafrost areas.

7) Fire-suppression equipment and fire-fighting equipment, especially where the stations are located in remote areas and where arctic conditions could restrict access.

3.6 PRESSURE TESTING

For the overwhelming majority of pipelines and pipeline-related installations, pressure testing is performed according to applicable regulations. For gas pipelines and appurtenant facilities, the test requirements are outlined in U.S. Department of Transportation 49 CFR, Part 192, Subpart J--Test Requirements. The companion regulations for oil pipelines are given in 49 CFR Part 195, Subpart E--Hydrostatic Testing. For this testing, a length of pipeline is sectioned off and is pressurized with a liquid, air, or gas to a specified pressure. The pipeline is then checked for leaks by observing pressure drops and correlating with volume and temperature measurements in hydrostatic tests. Water is the conventional testing fluid for all liquid and most gas pipelines. Liquid petroleum has also been used for liquid pipelines under certain conditions. Testing with compressed air, inert gas, or natural gas is permitted for certain specified gas pipeline situations.

Testing with water has a number of advantages. Water is generally available in plentiful quantities and is easily disposable. Testing with water is safe because little energy is stored in the pressurized system; thus, any developing leak causes a rapid pressure drop and the failure stays localized. Water leaks generally have minimal adverse environmental effects.

Disadvantages of testing with water in arctic pipelining relate to the water's 32°F freezing point. First, the test fluid cannot be allowed to freeze during the test. Second, if the pipeline is designed to operate in a chilled mode (below 32°F) to maintain the permafrost in the vicinity, then any thaw caused by the water in the line must be limited to an acceptable extent. In the arctic, most testing with water is done in the summer months because fresh water is available and can be used without danger of freezing. Antifreeze additives may be used in water to permit pressure testing in cold weather or along chilled sections of arctic pipelines. The treatment of leaks or spills and disposal where additives are used will be more difficult because of potential for increased thawing in permafrost and adverse environmental effects. In spite of these drawbacks, it is expected that testing with water will continue to be the choice when applicable.

Liquid petroleum offers many of the same advantages as water. Moreover, it remains fluid over a broader range of temperatures such that it can be "prechilled" for use within sections of the pipeline designed to remain frozen. However, leaking test fluid may have serious environmental and/or safety consequences. Disposal of the fluid is by reuse or pumping to storage tanks.

When liquids are used as the test fluid, an effective method must be used to dry the pipeline after testing. A number of runs of clean-out pigs may be used in combination with a drying agent (e.g., nitrogen or methanol) to remove the test fluid. Care must be used to assure that adequate clean-out and drying of the line are accomplished without introducing adverse effects on subsequent pipeline performance or on the quality of transported products.

Testing with gas or air encounters less serious temperature stability problems. However, the problem with the stored energy in the line and the potential for crack propagation means a small leak could develop into a major failure. For this reason, testing with gas or air is usually not used for strength testing of large-diameter pipelines. Pressure testing with gas has occasionally been used where water is not available and gas is available, as in looping a gas line in arid region. Testing with air has been also used beam in conjunction with hydrostatic testing to aid in locating small leaks.

3.7 SPACING BETWEEN OIL AND GAS PIPELINES

No major, closely spaced, parallel lines have been constructed in the arctic over great distances, so there is no precedent to guide the industry. Correspondence and conversations with knowledgeable personnel within the industry indicate that proponents are strongly divided between close spacing and complete separation. In the absence of any factual evidence, and with the difficulties involved in pre-testing to represent all possible hazards, the choice of employing or avoiding closely spaced parallel pipelines will be a sensitive issue and probably will require negotiated technical compromises. Even though present plans for the proposed gas line call for a minimum of 200 feet separation, in general, a number of crossings of the trans-Alaska oil line are included in the present (1981) alignment with the proposed gas line. Indeed, for future parallel pipelines, spacing closer than 200 feet may be desired.

The following discussion focuses on the issues currently being studied and debated.

If large quantities of oil and gas must be transported along parallel routes, the following arguments can be made that the lines should be close together in arctic or sub-arctic terrain:

1) One design advantage of such lines is the availability of information on subsurface conditions that will be encountered. To obtain such information for an alignment, the initial cost both in time and money is high; with close proximity, the information obtained for the first constructed pipeline can be used in design of the second pipeline.

2) The construction of a granular workpad is required to traverse most arctic soils because of the lack of support provided by surface soils during thawing. The mining, transportation, and placement of such materials are costly and subject to environmental impact problems. Significant cost benefits may be gained if the second line can be built from the same pad. This would be the case only for a spacing of

less than 100 feet. The cost savings must be weighed against the technical feasibility of close proximity along some sections, with careful consideration of any hazards involved.

3) Many support facilities, such as camps, access roads, or airstrips, may be effectively used for the construction of the second pipeline wherever it is located in close proximity to the first line.

Strong arguments can also be stated opposing close spacing. If the second line is to be constructed from the original workpad or with only a minor addition to the width, the new line must be constructed within 80 to 100 feet of the original line. Such proximity introduces potential design, construction, and operation safety problems that may offset the advantages of the close proximity. These objections are outlined below:

1) Construction of a buried pipeline in frozen arctic soils requires much more blasting than does a pipeline in temperate climates. The blasting patterns and procedures must be controlled to limit ground motion, and the use of mats to control flying rock will probably be required, especially where the original line is elevated. Construction equipment must be carefully operated within the narrow work space and/or a stable barrier must be constructed to prevent accidents to the existing line during construction. These hazards will be present during construction and can probably be controlled.

2) There is potential for long-term or possibly short-term operational problems. If the two lines are to operate at different temperatures, as most likely will be the case, there may be adverse interaction between the thermal regimes, which may result in drainage and/or stability problems. Also, any rupture or other accident to one line may increase the risk of damage to the other line. Scenarios can be developed to quantify the risk that a leak or rupture in one line would lead to damage to the other line. Maintenance and repair on one line would require the presence of operating personnel from the other line to ensure no damage to their line during the repairs.

3) Finally, a warm line and a cold line have different criteria for route selection. Thawing of permafrost can be a major problem for the warm line, so the route is selected to maximize the length in unfrozen or thaw-stable soil terrain. Conversely, initially unfrozen ground can be a major problem for a chilled line because of the potential for frost heave as the ground below the line is frozen. Thus, the route for the cold line is selected to avoid thawed ground and frost susceptible materials to the extent possible to minimize the potential for frost heave. Crossings of the pipelines over one another in the various construction modes may require special safety considerations.

3.8 SOILS

Subsurface conditions in arctic and subarctic regions are often highly variable, especially in permafrost, and the route of a linear pipeline compounds this problem by crossing many land forms. Structural load levels induced by necessarily large-diameter pipes and by large pipe temperature differences between tie-in and operating stages (for a warm oil pipeline) pose pipe-soil interaction and foundation support problems. Foundation soil response to thermal disturbance during construction and pipeline operation may involve thaw settlement or instability in ice-rich permafrost deposits and/or frost-heave (jacking) effects in previously thawed foundation soils. Frozen soils high in ice content may be subject to long-term creep effects under sustained loading conditions, unless appropriately low design stresses are utilized. These geotechnical design problems are unique to pipelines in the arctic and subarctic regions.

Permafrost is any kind of ground that stays frozen for more than a year. The term refers to the thermal condition rather than the composition of a material. Hence, permafrost can range from hard bedrock, to frozen silt, to pure ice, with a correspondingly wide range of mechanical properties. Permafrost forms whenever and wherever the climate is cold enough for a long enough period of time. It has been classified as "continuous," "discontinuous," and "sporadic." Except near large rivers and deep lakes, most permafrost north of the Arctic Circle is continuous and extends to depths as great as 1,800 feet. Discontinuous permafrost comprises most of the remainder of Alaska and much of northern Canada. Sporadic permafrost, which occurs along the southern boundary of the permafrost zone, is generally thin (frequently less than 50 feet thick) and is very fragile as its temperature is only slightly below freezing.

As a result of the difficulties inherent in characterizing in-situ properties of arctic soils and in anticipating their response to installation and operation of a pipeline, geotechnical engineering plays a major pipeline design role. Geotechnical engineering practice for the design, construction, and maintenance of pipelines in arctic and subarctic regions has been adapted from experience in temperate climates. The interpretation of subsurface exploration and laboratory test data for characterization of engineering properties of the materials is greatly complicated by the unique nature of the geologic materials and their thermal condition. More importantly, the primary design concern for arctic pipelines involves anticipation and accommodation of changes in the foundation support system caused by immediate and long-term disruption of the subsurface thermal regime; this evaluation too, is vastly complicated by the complexity of behavior and lack of long-term experience.

As a consequence of this difficulty in characterizing present and future foundation soil behavior, the practice has been to develop "envelope" design solutions that accommodate broad categories of expected subsurface and foundation performance conditions. For instance, a single pile adfreeze stress may be used for a broad range of soil types over a specified density range. Site-specific design for a pipeline is generally impractical, except when conditions are revealed during construction. Geotechnical design strategies on recent projects have involved extensive subsurface exploration, mostly by borings, field and laboratory testing, geologic interpretations, detailed mile-by-mile design, comprehensive field design modification programs during construction, and post-construction surveillance and monitoring to effectively mitigate or eliminate potential hazards.

Foundation engineering solutions for pipeline support and protection problems have required applications of more innovative techniques than usually applied in pipelining in temperate climates; the above-ground construction mode with thermal piles used for long sections of the trans-Alaska oil pipeline is an outstanding example. Design solutions are standardized based on pre-categorized site conditions. As perhaps the most important example, geotechnical conditions largely control where each construction mode can be utilized. On the trans-Alaska oil pipeline, conventionally buried line was generally employed only where the soil was either originally thawed or consisted of thaw-stable (i.e., clean) sand and gravel or of sound bedrock. Where these conditions did not apply, the pipeline was usually elevated. In the elevated mode, the choice of thermal over regular piles was usually dictated by the potential instability (liquefaction or slope instability) of the soil around the piles. Similarly, on the proposed Alaskan gas pipeline, the use of various frost-heave mitigating construction modes will be governed by the identified occurrence of thawed, frost-heave susceptible soil along the alignment.

In all cases, careful construction inspection and performance inspection and monitoring during pipeline operation are crucial in satisfying stringent environmental and safety requirements for arctic pipelines.

In general, pipeline design and construction in the arctic require much more soil data and geotechnical input than are needed for pipelines in a temperate climate.

3.9 RIVER CROSSINGS

Pipeline river crossings are normally made in the buried mode or are elevated on bridges. Just as in temperate zones, the buried mode is preferred, and most crossings are made in that manner. Because of the arctic climatic conditions, the presence of permafrost, and the changes in river regime from summer to winter conditions, several critical factors are considered for safe and environmentally sound crossings.

Depth of burial in arctic zones has been increased for crossings because of less predictable flow and scour conditions. Flow prediction is complicated by such things as glacier-dammed lake outbursts, ice jams, aufeis, lack of records, etc. Glacier-dammed lake outbursts are floods that result when a lake that has been dammed by a glacier suddenly releases all or part of its water as a result of rapid melting of a tunnel under or through the ice dam. Ice jams can develop in narrow places along a river, causing the water to back-up behind the ice jam; a sudden release of the ice jam causes a flood wave to move downstream. Aufeis is defined as seasonal formation of an ice sheet on the ground surface due to the freezing of a continuing or periodic overflow of water at the surface in winter. Scour depth is related to flow and is directly influenced by ice jams, aufeis, and thawing permafrost.)

For buried crossings, concrete weight coatings are applied to overcome the buoyancy of the empty pipe and in some cases to provide additional protection to the pipe. Heavier-walled pipe is commonly used to provide a greater margin of safety for secondary stress conditions but was not used for buried crossings on the large-diameter trans-Alaska oil pipeline . Because lateral migration of the river is frequently rapid due to large floods, thawing of permafrost in the banks, and undercutting of frozen surface soils that may result in block caving, the critical sagbend location may be located farther back from the arctic stream bank, as compared to temperate zone conditions. For aerial crossings, the same conditions require additional design effort to select location and type of support structures. Bank stabilization devices (such as rock revetments), groins, jetties, and other channel-directing structures may be used. Because these structures are costly and may cause unexpected problems, they are avoided if possible.

In the arctic, a change in the thermal regime of the river bed with a buried line is possible. If the line is warm, there may be thawing of permafrost soils beyond the previous river thaw bulb, which could cause channel changes and additional thaw. If the line is chilled, soil surrounding the pipe may freeze, blocking ground-water flow in the bed material and possibly causing aufeis conditions. Besides potential changes in channel location, either of these conditions can also cause direct loadings to the pipe. These characteristics must be given careful consideration when siting and/or designing arctic river crossings.

To overcome the problems with pipelines buried in a river just below the scour depth, alternate construction modes may be utilized. Aerial crossings on long spans (suspension bridges up to 1,600 feet long) and short spans (single-span girder bridges 180 feet long) have been used on the trans-Alaskan oil pipeline. Such crossings require thorough consideration of the arctic river regime to select the location, type, and design details of the supports. Pipeline crossings by directional boring have been constructed for pipelines that are up to 30 inches in diameter and are located in temperate climates; this method may be further developed to construct crossings of large-diameter lines below arctic rivers. A chilled gas pipeline might, in this way, be buried in the permafrost below the river thaw bulb.

Because of the potentially slow recovery of the natural terrain from damage, environmental conditions are major considerations in design and construction planning. The pipeline construction at river or lake crossings is scheduled to create minimum impact on fisheries and to reduce sedimentation potential. At most major crossings, work schedules have been limited to a few months per year.

3.10 CONSTRUCTION MODES

Design and construction of pipelines for arctic and subarctic conditions have required the development of several new construction modes. Formerly, all cross-country lines were buried with some consideration for ditch configuration and backfill requirements (buried mode). Because of the presence of permafrost and the adverse effects that permafrost thaw may have on stability of the soil, conventional burial can not be used for all soil conditions in the arctic. As a result, new construction modes have been introduced to accommodate those conditions.

The conventional buried mode is generally the safest, least expensive, and easiest construction mode for a pipeline. In this mode, the pipe is placed in a ditch, surrounded with select granular material, and covered with backfill over the crown. The pipe is essentially restrained from motion. Where the conventional buried mode is used in arctic pipelines, special design considerations may be needed due to the frequently high temperature differentials between initial tie-in and later operating temperatures, the large diameter of the pipe, and the special soil conditions prevalent in the arctic. Adequate pipe restraint must be provided in straight sections, in pipeline bends, and at transitions from buried to above-ground pipeline.

The most significant new construction mode involves elevating the pipe on pile-bent structures. This mode has been used for more than half of the trans-Alaska oil pipeline where conventional burial was not permitted by the stipulations because of potential thaw settlement or instability created by permafrost thaw. The pipe spans between bents. For large-diameter restrained pipe, large thrust forces develop from changes in the pipe temperature. To convert this thermal expansion into a controlled lateral movement, the elevated line is designed in a zig-zag or trapezoidal configuration and permitted to slide on the bent supports, except at selected anchor points. This configuration introduces important changes in behavior and requires more rigorous stress analyses. Foundation conditions must be investigated, and careful support design is required. On the trans-Alaska oil pipeline, the typical bents are supported by two 18-inch-diameter piles each, except for the anchors which have four piles. The piles have capabilities up to 100 kips and are designed for skin friction or end-bearing, with typical design skin friction stresses of 400 to 1,200 psf, depending on the soil and thermal conditions. A majority of the piles contain heat pipes designed to maintain the permafrost below the active layer. Earthquake effects may be severe for elevated pipelines and need to be considered. Different construction techniques are required for this construction mode (see Section 3.11 below).

An adaptation of the elevated line has been used for crossing a known active earthquake fault. Here the line is laid in a special zig-zig configuration and rests on wide steel crossbeams supported on a compacted gravel pad. This permits the line to move laterally as much as 20 feet in the event of fault movement.

An important mode for gas pipelines is the chilled mode. In this mode, the gas is chilled below freezing before discharge from the compressor stations along the line. The chilled gas prevents thaw of permafrost soils and, therefore, can be viewed as representing a suitable construction mode for permafrost soils. Chilled gas lines have been studied for several years as a means of overcoming permafrost problems and increasing gas through-put, but to-date, none has been constructed. Potential problems include: the effects of the dormant period between ditch excavation and operation where the pipeline crosses ice-rich permafrost areas, potential heave where the chilled pipeline crosses frost-heave-susceptible initially thawed soils, and changes in the ground-water flow regime in originally unfrozen areas (including river beds) by creation of a "freeze bulb." These potential problems must be mitigated by suitable construction modes. Use of insulation and/or overexcavation and backfilling with non-frost-susceptible materials are presently being considered.

A special construction mode that has been used for a few miles of the trans-Alaska oil pipeline to widen the range of applicability of below-ground construction is the buried and insulated mode ("special burial"). In this mode, the pipeline was insulated with 3 inches of polyurethane, and two refrigeration lines were placed in the trench--one below each side of the pipe. The thickness of insulation, brine-line diameter, and brine temperature were designed to prevent permafrost thaw below the pipe.

In addition to the modes discussed above, unique problems of buried lines have been solved with special designs. One of these was a heavily insulated section, with 21 inches of polystyrene board stock placed all around the pipe, forming a square box 96 inches to a side. The heavy insulation was designed to prevent thaw entirely in one northern location and to limit thaw at a more southern location. In other locations, thinner pipe insulation was combined with free-standing heat pipes, which extract heat out of the ground similar to the piles equipped with heat pipes, to create acceptable pipeline support conditions. This design was used only in short sections for road crossings or animal crossings.Performance observation of the "special burial" mode and the various special modes has indicated some potential problems related to convective heat flow associated with moving ground water and to long-term thermal performance of insulation systems.

Other modes have been studied. These have included: aerial cable suspension from widely spaced towers, burial in a gravel berm above the normal ground level, elevation on discrete gravel pad supports, construction in a cut-and-cover concrete tunnel, and others. None of these have been utilized to-date, presumably because the modes discussed earlier prevailed in comparisons. Because of the unique foundation and environmental conditions that occur in the arctic, it is quite likely that other construction modes will be developed and used in the future.

Because different modes must be considered, arctic pipelines require much more subsurface investigation, data analysis and engineering time than do pipelines in temperate climates. Arctic pipelines also require a larger quality control staff to validate modes and other design features during construction on a site-specific basis. Further, they require continuing surveillance and monitoring during operation.

3.11 CONSTRUCTION TECHNIQUES

Challenging aspects of arctic pipeline construction include remote locations, low temperatures, difficult logistics, and escalating costs. Because of the remoteness and lack of infrastructure, self-sufficient camp housing is needed in most areas for the construction workers. Because of the adverse effect that low temperatures have on worker productivity, construction is usually shut down during the cold, dark winter months.

The techniques used in arctic pipeline construction have been, and likely will continue to be, extensions of those techniques that have been successful in more temperate climates. Changes will be made where the climate, terrain, or worker safety dictate, but these changes probably will evolve slowly. It is quite likely that changes will be required in the cross-country pipeline construction activities rather than in construction of appurtenant works, such as compressor or pump stations. Therefore, this discussion concentrates on the cross-country pipeline work; stations, valves, and other appurtenances, as well as special construction situations such as river crossings, are discussed elsewhere in this report.

One of the major differences between temperate and arctic pipeline construction is the heterogeneity of the arctic soil conditions that forces frequent changes in construction modes and field verification of designs. Design changes during arctic pipeline construction are frequent, and these changes disrupt the smooth flow of work and cause delays. They also dictate a well organized and executed plan of inspection, testing, record keeping, and deficiency reporting and repairing to ensure quality construction and to meet requirements of regulations and stipulations.

Pipeline work is usually contracted in sections; section lengths are governed by dollar volumes of the contract, time constraints on completion, terrain changes, or other aspects. Each contractor establishes his own work plan and marshalls the necessary manpower and equipment. Even though each contractor develops his own work plan, techniques, and equipment, all tend to come up with similar plans within the constraints imposed by regulation or stipulation because of precedent and the basic simplicity and continuity of pipeline work.

In sequence, construction progresses as follows:

- Preparation of the Alignment - This consists of clearing, grading as required, placing granular material (work pad) to cover soft spots or to reduce thawing of frozen ground, and arrangements for handling of water along or across the right-of-way. Conventional bulldozers and other earth-moving equipment are used for this work.

  Because of the presence of permafrost and indistinct surface drainage, much of the arctic lands are water-logged during the summer. Thus, construction must be done when the surface soils are frozen, or a gravel work pad must be constructed for equipment access. To reduce gravel use and to restrict the width of disturbance to the surface soil thermal regime, the work pad width is kept to a minimum. Board insulation within the pad has also been used. Excavation cuts are also kept to a minimum. No traffic is permitted off the workpad or haul road. The limited width and steeper grades require greater coordination and control of construction effort to avoid tie-ups and bottlenecks.

- Ditching or Installing Supports for Elevated Line - Ditching is done by either a special ditcher or a conventional backhoe. The use of a backhoe is more common because of its adaptability to either soft or hard ground. In competent rock and most frozen soils, drilling and blasting may be required prior to backhoe excavation. Blasting control may be more critical in frozen soils than in normal rock because of the heterogeneity and softer thawed layer beneath seasonal frost.

  Ditch excavation and following work are controlled so that the ditch remains open a minimum amount of time. Even with this control, a ditch excavated in ice-rich soils in the summer will slough and fill with water very rapidly as the soil thaws. Flowing water will increase the problem especially on a slope. It is desirable to consider scheduling ditch excavation during the "shoulder" months along sections of the alignment where slope thaw degradation or ditch flooding problems are anticipated. In the early spring, the ground is most solidly frozen and the air temperature is below freezing most of the time, such that the rate of exposed slope thawing is low. In the late fall, the surface-water runoff is minimal (less chance of ditch flooding) and the below-freezing temperature limits thaw of the trench sides most of the time.

  Installation of supports for above-ground cross-country pipeline is a new requirement for pipeline work. Several combinations of pile types and installation techniques have been tried. The most prevalent design calls for steel pipe piles installed in pre-drilled oversize holes. The annular space is backfilled with a sand-water slurry and permitted to freeze by natural conduction of heat to the surrounding permafrost. Natural freeze-back may be enhanced by artificial devices such as heat pipes. Once the piles are in and frozen, a steel superstructure on which the pipe will rest is installed. Such installations require heavy drilling equipment not used for a temperate zone pipeline. Surface construction modes are under consideration, including surface laying and coverage by a berm. Such modes will require development of modified installation techniques.

Certain ground or environmental conditions do not permit use of either normal burial or elevated line. For these special designs, the contractor must plan for and execute the construction to fit the design. (This process is similar to what is done at a major river crossing.) These special design sections tend to disrupt the normal flow of work to an exaggerated degree because each may require a unique solution unprecedented in pipeline work.

- Pipe Stringing - The pipe is transported by conventional trucks to the alignment in the longest pieces that can readily be handled (usually 80 feet, composed of two shop-welded sections). It is strung along the ditch level using side boom tractors. Prefabricated thermal insulation on the pipe has been considered for certain conditions that would require special pipe handling.

- Pipe Bending, Line-up, and Field Welding - Bending machines, handling equipment, and welding procedures are conventional, except that restrictions are usually placed on the lowest ambient temperatures at which the work can proceed.

- Coating, Wrapping, Lowering-in, Backfilling - Lowering-in is a conventional procedure using sideboom tractors for buried line; however, depending on the height of the supports, cranes may be required for "lifting-in" elevated line. Pipe-wrapping procedures, if used, are conventional, except that more pipe heating may be required at low ambient temperatures when using tapes that are normally applied without heating. For critical backfill zones, such as bedding and padding, clean non-frost-susceptible granular material may be required. Also, because of the presence of frozen soil that thaws upon exposure to warm ambient temperatures, keeping the ditch open and free from sloughing material or water has proven difficult. In the case of elevated line, the supporting collars and shoes have to be attached and adjusted to provide the proper support.

- Tie-in Welds - Restrictions are usually placed on temperatures at which tie-in welds are made, especially in a buried line, to reduce the stress effects of temperature changes in the pipe under operating conditions. Welding details are discussed in Section 3.2.

- Pressure Testing - Conventional equipment and techniques are used for pressure testing, with the possible addition of anti-freeze and provisions of suitable "test water" disposal (see Section 3.6).

- Additional Work - Several items of work have been introduced that are not conventional in cross-country pipeline work. An elevated warm line or a buried chilled line may require insulation to avoid unacceptable heat loss or gain. In addition, it may be necessary to readjust all supports for an elevated line to ensure that each is transmitting the proper load to the ground and to position the pipe laterally so that it will react as designed in response to temperature changes. It is expected that other new and major work items may be required as different modes are developed.

As discussed above, several changes in construction procedures and techniques have been developed to adapt temperate zone techniques to arctic conditions and designs. Most of these changes have been dictated by the design for arctic conditions (e.g., use of the elevated line), rather than as a result of the effect of arctic conditions on construction personnel and machinery. Some machines have been developed or modified to accommodate the arctic designs, such as the specialized drill rigs and pile installation machines developed for the trans-Alaska oil pipeline. Also, insulation applicators and other innovations have been introduced. Low-ground-pressure vehicles (such as the Rolligon) have been widely used for summer travel over the tundra without creating significant damage to vegetation. It appears to be the consensus that changes will continue to consist of modifications and adaptations of existing equipment and techniques that have proven successful.

3.12 OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) include all those activities necessary to ensure safe transportation of the products through the pipeline at the prescribed rate. The logistical and economic considerations result in long, large-diameter, high-throughput lines traversing arctic and subarctic regions. These regions have problems of remote access, harsh climate, and fragile environment that are more acute than typically encountered in pipelines in temperate climates. Geotechnical, hydraulic, and ice conditions peculiar to arctic and subarctic regions likewise impose more stringent surveillance and monitoring requirements. These considerations dictate that comprehensive O&M measures be tailored to meet the needs of the particular pipeline. Monitoring must be performed more frequently and must use more sophisticated techniques. Maintenance must be rigidly scheduled to take advantage of good weather or opportune seasonal conditions.

One of the most important aspects of O&M of any arctic pipeline is a well-designed plan for identifying and correcting field conditions that might cause damage to the line. Essential to this is the availability and use of clear and comprehensive manuals for surveillance and monitoring and for maintenance and repairs, as well as contingency plans for spills. Predesign of corrective measures is desirable to ensure that all equipment and materials are available as needed.

Buried pipelines in arctic regions introduce changes in the thermal regimes of the geologic materials. Warm oil lines may thaw permafrost soils and, thus, induce unstable support or slope conditions that threaten the integrity of the pipeline system. Chilled gas pipelines crossing thawed ground may produce ground-water flow obstructions, aufeis, or frost-jacking phenomena that may damage the pipeline system. In both cases, surveillance is hampered by the fact that potentially damaging conditions at pipeline depth may have little surface manifestation.

Much effort is expended in designing and constructing the pipeline systems to avoid or mitigate these hazards (see preceding sections); however, the existing technology cannot completely resolve them. The result is that surveillance and monitoring of the pipeline must be more detailed and extensive than for lines in temperate zones. Surveillance personnel must be trained to observe and evaluate surface condition changes in respect to what may be happening to the buried pipeline. This problem is made more difficult by the low visibility and snow cover in the winter months. Monitoring and maintenance of elevated portions of pipelines are not so critical because the performance of the line can be directly observed, even in inclement weather. Further, the elevated line is a more flexible structure than the buried line such that it can sustain more displacement without damage. For both buried and elevated pipeline, a detailed surveillance manual should be prepared to serve as a guide for personnel training and the actual surveillance.

The shortcomings of surveillance, especially for the buried line, may be supplemented by flow rate monitoring and leak detection systems, pipeline settlement surveys, in-line instrumented pigs, and other monitoring techniques. These methods involve more sophisticated technology and evaluation procedures to detect potential defects. Again, a detailed manual should guide training and actual monitoring. The instrumentation and procedures employed in the trans-Alaska oil pipeline system have generally proven successful, although improvements and innovations are certainly desirable for enhancing techniques of early detection of defective conditions. Recognizing the fact that large movements of the buried pipeline during operation may cause leaks and that surface surveillance is not highly effective, considerable effort has been invested in the development of an instrumented pipeline pig. The instruments would detect local strains and deformations in the pipe wall as well as beam-type bending. To date, these effects have not been completely successful.

Excessive cooling of a warm oil pipeline (e.g., during a prolonged shutdown) could cause blockage. Extensive effort may be needed to restart the flow, a problem which, though not unique to arctic conditions, could be much more severe. The above-ground insulation of the trans-Alaska oil pipeline was designed to prevent solidifying of the oil during a shutdown that lasts as long as two weeks; no shutdown has ever approached this duration during the four years of operation.

Because of the remoteness and isolation in arctic regions, it can be difficult to attract and keep competent operations and maintenance personnel. Operating pipeline companies have attacked this problem by offering attractive salary and fringe benefit packages and intensive training programs.

3.13 OPERATION OF A PIPELINE AT TEMPERATURES COLDER THAN 32°F

At present, there is no commercial cross-country pipeline operating at controlled temperatures at or below 32°F. Several gas pipeline investigations have considered depressed temperature levels as one possible design criterion. The primary advantages for a chilled gas pipeline include the increased throughput for a given pipe diameter and pressure, the relatively low energy costs involved in chilling the fluid, and the maintenance of the frozen state of surrounding permafrost along portions of the pipeline buried in these materials. Operation of oil pipeline at depressed temperatures would not be economical because the reduced temperature decreases throughput (increased viscosity), increases deposition of tars and gums (increased maintenance cost), and requires substantial expenditures of energy for chilling (increased operating costs).

Although a chilled pipeline essentially solves the problem of thawing during operation where the pipeline is buried in permafrost, it introduces a new problem to pipeline designers. Where the chilled pipeline crosses initially thawed soils, freezing below the pipeline will occur. Under certain soil and water conditions, ice lenses will form and tend to heave the pipe upward. The magnitude of the force exerted on the pipe is dependent on the capability of the pipe to restrain the heave which, in turn, depends on: 1) the weight of pipe, its contents, and the soil directly above the heaving area, and 2) the flexural characteristics of the pipe. The behavior also depends on the location and degree of movement restraint of the pipe at each end of the frost-heave area. Careful consideration of these factors during design and construction will minimize problems during operation. A change in the groundwater flow conditions caused by a frost bulb may produce operational difficulties due to aufeis and ice force effects on the facilities. Detailed surveillance and monitoring may be necessary during operation to ensure that 1) gas temperature is maintained below 32°F within permafrost deposits that would become unstable upon thawing; 2) the pipe is not endangered by frost heave;

and 3) the ground-water flow and thermal regime interactions do not create a hazard. More details on these potential hazards are given in Section 4.0 of this report.

4.0 HAZARDS FOR ARCTIC PIPELINES

4.1 GENERAL COMMENTS

Arctic pipelines are subject to more hazards than are pipelines in the temperate regions. In addition, hazards that are common to all pipelines may be made more severe by arctic conditions. Although most of the potentially hazardous events have not occurred, planners and designers who must anticipate the events have developed or must develop mitigative designs.

Most of the potentially hazardous conditions or events considered unique to arctic pipelines are caused by changes in restraints or loads in a pipeline. These restraints or loads, which result from ground movements caused by disturbance of the ground thermal regime, impose bending stresses in addition to the stresses that designs for pressure address. Such stresses can and have contributed to buckling, wrinkling, and even crack formation in operating pipelines. Other hazardous conditions are related to the special design measures taken to overcome the ground movement hazards and to the cold temperatures encountered in construction and operation of arctic pipelines.

These potentially hazardous conditions or events, which are discussed in the following sections, were distilled from this study's interviews and literature reviews, the 13 practice areas identified by DOT, and consideration of other arctic pipelines aspects.

4.2 LOSS OF PIPE SUPPORT AND RESTRAINT

A buried pipeline exerts little (if any) net bearing pressure (in excess of the overburden loads prior to ditch excavation) on the supporting soils. Thus, for conventional, initially thawed soils that consolidate only in response to an increase in overburden loads (effective stress), there is little potential for excessive settlement or loss of support. (Very soft or compressible soils such as muskeg may respond to very small stress changes.) However, loss of support is a significant hazard for buried pipelines in the arctic because of the presence of permafrost. When ice-rich permafrost thaws, large total and differential settlements and associated bending of a pipeline can occur. In addition, for segments of buried pipe subjected to large temperature change and pressure, the pipe could become overstressed at bends (sagbends, overbends, sidebends) due to loss of restraint.

If there is an abrupt transition from thawed to firm soil or rock at the end of a thaw-settlement zone, the pipe may be subjected to high localized bending stresses. These bending stresses, coupled with stress due to thermal and pressure effects, could exceed specified maximum stress limits, and local buckling (wrinkling) and possibly rupture could occur.

Due to the variability of subsurface conditions, a buried pipeline will experience differential settlement through a thaw-settlement zone. Pipe anchors or supports, bedrock outcroppings, cobbles or boulders, and stiffer soils all provide potential zones of intermittent support. The pipe will tend to "hang up" at such points as it settles, and buckling at the bottom of the pipe is a possibility.

4.3 FROST HEAVE

Frost heave or frost jacking can occur in any region where temperatures drop substantially below freezing for prolonged periods. Ice lenses form at a stationary freeze front as water is attracted to that front. The lenses continue to grow as long as there is a supply of water. The principal factors controlling the process are thermal gradient, soil suction (negative pore pressure) generated at the freeze front, and availability of water. Intermediate thermal gradients tend to cause most lensing: steep gradients advance the freeze front, and shallow gradients do not extract enough thermal energy to cause rapid freezing. The availability of water at the freeze front depends on the existence of a source of water and the hydraulic transmissivity of the soil: if water is present, the amount transported is proportional to the hydraulic gradient and the soil's permeability. The soil suction is insignificant for clean granular soils but increases with decreasing grain sizes. Silt is generally the most frost-heave-susceptible soil because it generates significant soil suction at the freeze front and has intermediate permeability. Although sand has high permeability, it has low to zero soil suction. Clay, with high soil suction, has low permeability.

Frost heave frequently occurs in arctic and subarctic regions because of deep frost penetration, the common occurrence of silty soils, and the abundance of moisture. In the case of a chilled gas line passing through initially thawed soil, lenses could develop beneath the pipeline and either heave the pipe upward or impose locally large loads, depending on the restraint that the pipeline is capable of providing. Confining pressures tend to reduce lens formation, but the prevailing view is that lens formation is not prevented until pressures equivalent to several tens of feet of overburden are attained. Research on this issue is in progress. Ice lens formation occurs non-uniformly, even in an apparently uniform soil. Thus, differential heave and/or jacking forces will be experienced by a chilled pipeline. Further, at transitions, such as from frozen to unfrozen soil, pipeline heaving on one side may be restricted by high restraint on the other side. This condition may overstress the pipe and lead to pipe ovalling or wrinkling.

4.4 LANDSLIDES

In hilly terrain, landslides or mass earth movements can cause damage to either an elevated or buried line. The potential for mass earth movements in permafrost usually is not great because of its high strength; however, thawing of the permafrost in hilly areas greatly increases the potential. Thawing may be caused by the burial of a warm oil pipeline or by a construction activity (such as grading or workpad construction on ice-rich slopes) that changes the thermal regime. The thawing can result in progressive failure, characterized by an active downslope movement that may be extensive. Movement lateral to a pipeline may tend to transport a buried line within the soil mass or may pile the soil mass up against the pipeline or supports of an elevated line. Movement parallel to the line can result from the sliding of a cylindrical plug of thawed material surrounding the pipeline, a situation identified by the term "thaw plug instability." Either type of movement can impose new restraint and loading conditions on the line and could cause wrinkling, buckling, or cracks.

Downslope movement of materials in the seasonal active zone is a common occurrence and is called "solifluction." These movements are generally shallow and slow moving and do not appear to pose a major hazard to a pipeline, but are a sign of thaw instability.

4.5 AVALANCHES

Snow slides and their associated pressure waves can move at high speed and with great force. These pose a particular hazard in areas of steep (30- to 60-degree) slopes and heavy snow accumulation and where forest cover is sparse or absent. In broad valleys, avalanches originating on the valley slopes have been observed to move as much as a mile out onto the valley floor. The hazard is significant only for an elevated pipeline and appurtenant facilities. Broadside impact of an avalanche on an elevated pipeline could push or lift the pipe off its supports or knock out supports.

While the arctic areas do not have high precipitation, there is little snow melt during the winter season and there may be drifting, such that the total snow accumulation can be significant. During warm spring weather, the opportunities for avalanches are greatest. In general, areas subject to avalanches are readily identified and are avoided to the extent possible during the route selection process. Otherwise, the pipeline is placed underground.

4.6 THERMAL STRESSES ON PIPELINE

A warm arctic pipeline may experience large variations between tie-in and operating temperatures. As the pipeline warms up, it tries to expand longitudinally. This expansion trend produces high compressive stresses in a restrained, buried line. Below-ground bends (sidebends, overbends, sagbends) can be subjected to large transverse forces that tend to push the bend outward. For example, a large-diameter Russian gas line was reported to have thrusted out of the ground as a result of temperature increase of the pipe.

Prior to the advent of arctic pipelines, most U.S. lines were constructed in temperature zones offering stable geotechnical conditions and virtually full restraint conditions. In such cases, pipe stress criteria are based on internal pressure and are generally sufficient. However, for warm arctic pipelines, the large temperature differentials, coupled with marginal soil conditions or undetected zones of ice-rich soils, and internal pressures can lead to excessive axial and bending stresses. For the trans-Alaska oil pipeline, it was necessary to develop stress criteria for credible combinations of primary and secondary stresses. In the case of elevated lines, adequate transverse flexibility in the line must be provided to limit axial and bending stresses to acceptable levels.

In the case of a buried chilled pipeline, the temperature difference between installation and operation conditions will probably not be as great, perhaps only one-half that of a warm oil pipeline. In addition, because the line will be operated at a temperature that is less than that at which it was installed, the stresses imposed will be tensile. Hence, local buckling or wrinkling is not likely to be a major consideration. The major effect may be a tendency to lift off at sagbends or move inward at sidebends, which could damage insulation or corrosion protection.

4.7 EARTHQUAKES

Pipelines often must be located in areas of potentially strong seismic activity. Although buried pipe generally conforms to ground distortions without significant damage, it can be adversely affected by localized differential ground movements caused by faulting, liquefaction, slope instability, or general ground failure including ground squeeze, lurching effects, etc.

Pipelines supported above ground are affected by ground shaking in a similar manner as are building frames and other structures. In addition, seismic ground motions will vary along the length of a line, causing out-of-phase input motions to pipe supports, which may result in pipe distortion.

With regard to arctic pipelines, several types of earthquake hazards that are more-or-less unique are described below:

Dynamic Response of Elevated Pipelines - For warm pipelines, a portion of the pipe will be above ground and could be damaged by ground shaking and the effects of traveling waves.

Pipeline Fault Crossings - The effect of fault displacement on buried warm pipelines in arctic areas is essentially the same as for buried pipelines in temperate zones. However, for cold (less than $32^{o}F$) pipelines, the frozen soil surrounding the pipe will serve as a rigid encasement. Hence, because compliance of the pipe to ground distortions will be somewhat precluded and because of the pipe's inability to produce local soil failure, the pipe is vulnerable to relatively small fault movements. Particular attention is usually given to identifying active faults and to assessing the potential for movement. Above-ground pipe configurations may be the most suitable means for cold pipeline crossings of faults.

Nonuniform Ground Motion: Sporadically or incompletely frozen soil profiles pose a potential hazard because frozen soils are much stiffer than thawed soils. Because of the resulting variability in soil stiffness along the pipeline, seismic input motions will vary from point to point, possibly introducing additional distortions and stresses into the pipe. This problem also exists for pipelines in temperate areas, although the problem is attributed to discontinuous soil conditions rather than changes in thermal state of the soils. There is considerable research interest in this topic, but definitive mitigation procedures are not available at the present time.

Seismic Liquefaction: Seismic liquefaction is defined as the partial or complete loss of strength of a soil as a result of excess pore pressures generated by seismic ground shaking. Relatively loose granular soils are most susceptible to seismic liquefaction. In flat ground, this condition would have a similar effect as loss of support due to thaw settlement. In sloped ground, liquefaction may create instability and mass ground movement problems for the pipe. While liquefaction is also a concern for temperate zone soils, it is potentially more severe in the arctic areas because of the abundance of saturated, loose granular soil deposits.

4.8 GRADING, EROSION, AND AUFEIS

Several phenomena, which are initially environmental hazards but may escalate to jeopardize the integrity of a pipeline, are described below:

Grading - Although grading is not a hazard per se, it can have important effects on a nearby pipeline. More grading is done in the arctic because of the need to provide a substantial gravel overlay for summer traffic.

During construction, stripping of the vegetative mat or provision of an inadequate workpad thickness can lead to degradation of the permafrost with attendant settlement and instability. On a sloping site, the vegetative mat can become a potential sliding plane when loaded by a workpad. Moreover, because of the need to maintain a workpad for permanent access along the line and the potentially disruptive effects of thawing permafrost, additional grading may be required during operation of an arctic pipeline. The thermal changes initiated by grading may lead to soil settlement or instability problems described previously.

Thermal Erosion - In a similar manner, disturbance of the vegetative cover over permafrost soils can change the thermal regime sufficiently so that continuing thaw occurs. On flat ground in high ice-content soils, the thaw results in thermo-karstic terrain,* new waterways, or lakes. In sloping ground, the thaw may result in gullying that may impact the pipeline and the generation of large quantities of silt that eventually enter streams.

Sheet Erosion - Construction activities may also alter drainage patterns of runoff water and may remove vegetation that could bind and retain surface soils. Both practices tend to increase surface or sheet erosion. The eroded soils eventually enter streams and can change the stream characteristics.

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*Broken-up ground with fissures and cave-ins, created by thawing of massive ice, such as an ice wedge, or of ice-rich soil.

Sheet erosion can progress to gullying and the eventual exposure of the pipeline.

Aufeis - Aufeis is created by movement of water to the surface in winter, where it freezes. Large volumes of ice can result, and drainage patterns are disrupted. Aufeis can be caused by inclusion of a heat discontinuity, such as a chilled pipeline or thermal pipeline support, in initially thawed soils. The ice mass can cause new loads on a pipeline or new erosion patterns in streams that, in turn, can damage a pipeline. Aufeis formation across an access road or work pad may hinder access to a pipeline.

4.9 QUALITY OF WORKMANSHIP

Most management personnel believe that quality of workmanship decreases drastically when the worker is functioning with discomforts or encumbrances. Winter construction often is preferred in the arctic because of reduced impact on the environment and schedule requirements. As a result, the desire of a worker to provide high-quality work is weakened. He is either cold or is encumbered by clothes or temporary protection. His vision, dexterity, or judgment may be impaired. The darkness prevailing much of the day contributes to the difficulties. Such conditions not only make him vulnerable to accidents but also may jeopardize the quality of the work. As an example, threats to quality could result from placing pipe in a trench with snow covering rock outcrops or from failure to properly observe and interpret subsurface conditions that would require field design adjustments. For certain operations, such as welding, these problems can be minimized by providing a shelter (see Section 3.2), but this practice is not common for most construction activities. Construction in the "shoulder" months (fall and early spring) is frequently a viable alternative to winter construction. The cold is much less intense, and daylight hours are longer. Perhaps the main problem with this solution is the uncertainty introduced by variable weather conditions; solid freeze-up in fall may be delayed a month and prevent movement on the tundra, and break-up in spring may occur earlier than expected. Hence, critical scheduling must be conservative.

4.10 VANDALISM AND SABOTAGE

Direct action of man, including vandalism and/or sabotage, may be potential hazards. An elevated line presents a more vulnerable target for blast or military action. Alaska is big-game country, and many hunters with high-powered rifles are present during the season. A high-powered rifle would puncture the pipeline with a direct hit. This type of hazard is most apparent for warm pipelines where much of the pipe would be above ground. Since temperate-region pipelines are often exposed in areas such as river crossings, this hazard is not particularly unique to the arctic, except in degree of exposure; i.e., a much larger portion of the pipe is exposed. On the other hand, the population density in arctic regions is considerably less.

4.11 PARALLEL PIPELINES

If arctic conditions and constraints require use of parallel and closely spaced pipelines (such as now being studied for a proposed gas pipeline from Prudhoe Bay), interaction between the two lines may increase the hazards to either line. Blasting or traffic accidents are more likely. Damage to one line could have an adverse affect on the other line. The interaction effects of the combined thermal regime (buried warm oil pipeline next to a chilled gas pipeline) are unknown and difficult to study because of the complexity of the heat flow phenomena. Of these potential hazards, the effects of combined thermal regime are probably the technical problem most difficult to resolve; the other hazards can be minimized by careful supervision and management. These aspects are discussed in more detail in Section 3.7.

4.12 PIPE PERFORMANCE

Although line pipe and other materials of construction are purchased to exacting specifications, arctic conditions may increase certain inherent hazards. Because of the distances involved and the absence of well-established transportation systems, damage occurring while transporting and handling pipe may be more prevalent. Although welding procedures are essentially the same for both arctic and temperate climates, adverse climatic conditions make verification of weld quality more important.

All elements of a pipeline, except those housed in temperature-controlled buildings, operate in lower ambient temperatures than do corresponding elements in temperate climates. Some elements will be exposed to very low ambient air temperatures, and these low temperatures result in reduced ductility and increased expansion and contraction stresses. Thus, for chilled, high-pressure gas lines, resistance to fracture initiation and propagation is an important consideration. It is therefore necessary to select materials with appropriate ductility and toughness for the temperature extremes anticipated. These aspects are discussed in more detail in Section 3.1.

5.0 COMPARISON OF U.S. AND CANADIAN GAS PIPELINE SAFETY REGULATIONS

5.1 GENERAL COMMENTS

The U.S. Department of Transportation 49-CFR Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards" (DOT) applies to all pipelines transporting gas. However, these standards were written prior to development of the need for pipelines in the arctic areas of our country. As a result, there are no specific regulations for or even mention of gas pipelines in such areas. On the other hand, Chapter 1052 of the Canadian National Energy Board Act, "Gas Pipeline Regulations" (NEBA) was updated recently, and it specifically covers gas pipelines in the northern (arctic) regions. As a part of the study to identify and possibly initiate changes in DOT regulations to cover arctic pipelines, a comparison was made of the two documents. The discussion herein focuses on this comparison, primarily as the documents' contents pertain to arctic gas pipelines.

The thrust of the DOT regulations is aimed toward furnishing "hard" criteria for designing, building, operating, and maintaining gas pipelines. The intent is to furnish specific performance standards for all safety aspects, with minimal approval role between the government and the gas pipeline operator. The DOT regulations incorporate some 42 companion industry codes and regulations by specific reference.

The NEBA regulations have a lesser emphasis on stringent requirements; instead, these regulations furnish a guideline-oriented framework that the constructors and operators must follow. The emphasis is on safety responsibilities, with encouragement of constructor/operator interaction with the regulatory board in many instances. This document incorporates by reference only one companion standard, CSA Standard Z184-1979, which furnishes most of the "hard" criteria included in the DOT regulations. In most respects, these two "tiers" of Canadian regulations cover the same subject matter as the DOT regulations, with somewhat more comprehensive treatment given in the Canadian regulations. Complete comparison of all applicable tiers of regulations or standards has not been attempted; however, relevant comparison of the DOT regulations with the "equivalent" NEBA regulations necessitated consideration of the CSA Standard in a number of instances.

It should also be pointed out that NEBA has an approval review authority, and staff to implement such review, both of which DOT does not have.

5.2 SCOPE OF REGULATIONS

5.2.1 49-CFR Part 192

The Federal DOT gas pipeline regulations prescribe minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf. Regulations cover transmission, gathering, and distribution lines. The document is comprised of 13 subparts that delineate selected aspects of gas pipelines, and four appendices. The appendices describe (a) standards incorporated by reference, (b) qualifications of pipe, (c) qualification of welders for low-stress-level pipe, and (d) criteria for cathodic protection and determination of measurements.

In general, detailed regulations are prescribed for each subpart category, such as materials and pipe design. In subject areas having no definitive regulations, there is little discussion of the rationale or methodology that could be considered. Rationale for these regulations was described in the preamble to the original issue of these regulations, which was not included in later editions. As an example, the regulations frequently describe the minimum cover over a buried pipe in consideration of the buried mode; however, no discussion or guidelines are provided for the design to consider alternative construction modes.

The DOT regulations provide for a minimal interface between the government and operator. Formal reporting and record-keeping requirements are prescribed in detail, consistent with the concept of "minimum safety requirements." Cold weather (arctic) conditions, construction mode alternatives, and many geotechnical, environmental, and health hazard issues are either untreated or considered only indirectly. Recognition of this fact provided the incentive for this study.

There are no provisions or requirements that a company must obtain a permit, submit plans or specifications, or even notify DOT of intent to construct a pipeline. The regulations come into effect by provisions therein, such as "No person may operate a pipeline unless..." see 192.13 (a) and (b) .

5.2.2. NEBA Chapter 1052

The NEBA regulations deal essentially with gas transmission pipeline systems that cross province boundaries; intra-province pipelines are apparently excluded. In addition, compliance with CSA Standard Z184-1979 is required for all pipelines, including gathering and distribution systems, with the provision that the NEBA regulations apply in the event of conflict.

The NEBA regulations emphasize guidance and methodology to be applied in the design, construction, operation, and maintenance of gas transmission pipelines. Criteria are stated for performance of preliminary investigations of geotechnical, hydraulic, and environmental conditions "consistent with good engineering practice." Guidelines for selecting and implementing pipeline construction modes are provided with requirements to assess specific conditions, such as permafrost, frost heave, water/ice scour, and maintenance of the ground thermal regime. Significant attention is focussed throughout on consideration of construction conditions for arctic pipelines. Hardly any attempt is made to formulate "hard" criteria; however, the criteria incorporated by reference to the CSA Standard are on a par with those given in the DOT regulations.

The NEBA regulations are written with the intent of alerting pipeline designers/constructors/operators to the problems requiring attention. Unlike the DOT regulations, there is a clear emphasis on establishing an active interface between the regulatory Board and the participating project organizations, which is not a function of DOT.

NEBA regulations require submittal of detailed plans, specifications, etc., for approval prior to the start of construction, and they provide for an officer who is authorized to act on certain matters, if the Board appoints such an officer.

5.3 REGULATION COMPARISONS

5.3.1 General Comments

Although the subject matter of both documents is similar, the differences in style and format make direct comparison somewhat difficult. In order to compare, it is necessary to subdivide the subject matter of the documents to enable direct comparison regardless of the format. Four major categories that were utilized are: design, construction, pressure testing, and operations and maintenance. These four topics encompass the areas in which meaningful improvements in existing regulations may warrant consideration. Direct, detailed comparisons and cross-references between the two regulations for each of these topics are provided in Tables 1 through 4, and are summarized below in the text. In addition, general comparisons are made between the two sets of regulations in the areas of pressure testing, welding, and corrosion control.

5.3.2 Design

Design criteria relevant to arctic pipelining are not addressed as such in the DOT regulations. The only construction mode apparently considered is that of a buried pipeline, with the minimum cover and clearance requirements specified according to class locations; however, general requirements apply equally to any mode. Regulations that apply to above-ground modes pertain to supports and anchors (192.161) and protection from hazards (192.317).

Category and Topic	DOT Part 192 Title 49 Gas Pipeline Minimum Safety Standards Sub-part	¶	Comments	NEBA Chapter 1052 Gas Pipeline Regulations Part	¶	Comments
DESIGN						
Class Locations	A	.5	Unit - 220 yds either side of 1 mile length of pipeline - class designation depends on the type and number of buildings.	by reference*		CSA Standard Z184-M1979 requirements are identical to DOT regulations.
General Criteria	D	143	General all-inclusive paragraph, non-specific.	I	5	Identified general scope of engineering studies to determine ground conditions, river/lake bottom conditions, fish and wildlife impacts, and aggregate/borrow materials plans.
Construction Modes	G	319	Not considered explicitly; general requirements for pipeline installation in a ditch are summarized in the cited ¶. No reference is made to Arctic pipeline considerations.	I	6,7,8	Outlines performance criteria which must be considered for below grade, grade, and elevated modes of pipeline installation, including attention to thermal, surface water/ice, and groundwater regimes.
Buried Line Cover and Clearance	G	327, 325	Specific depths and backfill material cover requirements are identified according to class location, etc., underground clearance minimum in absence of protection is 12 inches.	by reference*		This document does not address these items directly at all. Reference* general conforms to DOT Part 192, Title 49.
Steel Pipe Design Pressure	C	105-115	The design pressure for steel pipe is determined as a function of the section geometry, yield strength, and factors adjusting for class location, longitudinal jointing, and temperature, with details concerning determination of the various parameters.	by reference*		This document does not address these items directly. The referenced document* is essentially identical in content to DOT Part 192, Title 49, with minor differences.
Valves, Spacing and Vaults	D	145 179, 181	Reference is made to pertinent standards Specific criteria are provided for spacing (in terms of class location), access, protection from hazards.	by reference*		This document does not address these items directly. The referenced document* provides the same basic criteria and guidance as contained in DOT Part 192, Title 49.
Stations	D	163-174	Outline given of explicit design and construction considerations, emergency shut down systems and requirements, pressure limiting devices, ventilation systems, and additional safety equipment.	I	9-19	Performance requirements are delineated with regard to suitable access, housing facilities, waste disposal (sewage, garbage and petroleum products), geotechnical considerations (support erosion, stabilization, etc.) and safety. Specific automatic shutdown criteria are cited, including refrigeration facilities where used to maintain stable ground. The reference* more thoroughly details items contained in the DOT Part 192, Title 49 sections.

*CSA Standard Z184-M1979

TABLE 1 - COMPARISON OF DESIGN ASPECTS OF DOT AND NEBA REGULATIONS

Category and Topic	DOT Part 192 Title 49 Gas Pipeline Minimum Safety Standards: Sub-Part	¶	Comments	NEBA Chapter 1052 Gas Pipeline Regulations: Part	¶	Comments
CONSTRUCTION						
Application	None designated		Scopes of Subparts E (Welding) and G (General Construction Requirements for Transmission Lines and Mains) encompass relevant items, including repair of steel pipe.	II	21	Part II applies to all work items involved in construction of pipeline, including surface travel, campsites, and excavation and grading.
Ground Disturbances	Not covered			II	23-25	Performance guidelines and requirements to stipulate avoidance of unnecessary disturbance of ground and vegetation, with protective measures (snow or stable insulated pad) for frozen ground to minimize adverse thermal and drainage effects. Restoration of natural state and protective/ stabilized schemes are required "where practicable."
Conservation Measures	Not covered			II	26-31	Guidelines are stated for protection of flora and fauna, waste management, aesthetics, and archeolgic site preservation.
Protection from Hazards	G	317	Protection from geotechnical and hydraulic hazards, and vehicular accidents is required by blanket statement.	I	5-8	Geotechnical hazards are addressed in terms of construction mode aspects and under Ground Disturbances (II-¶23 to 25). The remaining hazards are not explicitly considered, but are included by reference.*
Welding	E	221-245	Subpart E concerns all aspects of joining steel pipeline sections by welding, including qualification of procedures, qualification of welders, nondestructive testing, and repair or removal of defects. Detailed requirements are stipulated regarding testing to be done. Qualification of welders for low stress level pipe is included in Appendix C.	II	38-40	Only general requirements are stated in this document, with non-destructive testing of field welds to be "carried out ... at such frequencies as the Board may approve." The referenced document* contains thorough guidelines and specifications for pipeline welding. The detail is comparable to that referenced in DOT Part 192, Title 49, see text.
Inspection	G	305-307	General ¶'s without specific requirements/ guidelines, which appear to carry an indeterminate degree of importance. The position of such an inspector (regarding his employer) is not clear.	II	41-46	Broad guidelines are, likewise, given in this Regulation; however, the requirements are more clearly stated. Procedures are described whereby the pipeline company may appeal to the Board in the event that the company is dissatisfied with binding decisions of an inspection officer (who may be appointed by the Board).

*CSA Standard Z184-M1979

TABLE 2 - COMPARISON OF CONSTRUCTION ASPECTS OF DOT AND NEBA REGULATIONS

Category and Topic	DOT Part 192 Title 49 Gas Pipeline Minimum Safety Standards Sub-Part	¶	Comments	NEBA Chapter 1052 Gas Pipeline Regulations Part	§	Comments
PRESSURE TESTING						
Leak and Strength Test Criteria	J K	503-513 551-557	Test requirements are segregated in terms of class location, operating pressures, and system components tested. Strength test requires 8 hrs. duration sustained at specified pressure. Natural gas (@ 30% SMYS) is permitted as test fluid in Class 3 and 4 locations; Air/inert gas @ 50% and 40% SMYS, respectively. For Class 1 or 2 locations with occupied building within 300 ft. hydrostatic tests to 1.25 x maximum operating pressure are required. Pre-installation tests of components may be accepted under specific conditions. Subpart K presents regulations for uprating pipeline pressures which include documentation stipulations for prior history of the pipeline system.	III		Criteria are prescribed for permissible test substance, minimum/maximum test pressures, and maximum allowable operating pressures, according to class location. Unless otherwise authorized by the Board, the pipeline must be tested in place under all existing operating conditions. This document disallows use of air or gas in Class 3 or 4 locations. Separate criteria and procedures are outlined for leak testing versus strength testing, and detailed requirements for instrumentation qualifications are stated. Test duration is specified as 24 hours, and tolerable variations are identified. The relationship between test pressures and maximum operating pressures is discussed under the category Operation and Maintenance herein. Uprating of an existing pipeline is not treated separately. Referenced standard* contains more detailed requirements.
Test Records	J	517	Minimum data provisions are outlined as specific items.	III	61	General requirements stated, including those in DOT Part 192, Title 49.
Safety and Environmental Protection	J	515	Discusses general requirements/responsibilities for safety and disposal of test substance.	III	64	General statements which are enhanced by reference.*

*CSA Standard Z184-M1979

TABLE 3 - COMPARISON OF PRESSURE TESTING ASPECTS OF DOT AND NEBA REGULATIONS

Category and Topic	DOT Part 192 Title 49 Gas Pipeline Minimum Safety Standards		Comments	NEBA Chapter 1052 Gas Pipeline Regulations		Comments
OPERATIONS AND MAINTENANCE	Sub-Part	¶		Part	¶	
General Remarks			This document separates Operations (Subpart L) and Maintenance (Subpart M), with comprehensive coverage of the various topics.			Part IV treats Operation, Maintenance, Repair and Abandonment in terms of general statements by topic, with extensive reference to the CSA Standard* for details.
O&M Plan	L	605	This ¶ outlines general guidelines for essential items to be incorporated in the operator's plan, with broad interpretation available.	IV	65	Similar guidelines (with respect to DOT Part 192, Title 49) with explicit mention of reference standard.*
Operating Pressures and Class Locations	L	607-611	Details for initial determination and changes in class locations are set forth, with companion qualifications of respective maximum allowable stresses - Criteria exist whereby maximum operating pressure may be established without field testing. In terms of SMYS the allowable fractions for hoop stress are 0.6, 0.5, 0.4 for class locations 2, 3, and 4 respectively (see 192.11). Higher factors (0.72, 0.6, 0.5) may apply if previously tested to 90 percent SMYS and there is a change in class location.	III	51	Class locations are treated in the referenced standard.* Unless otherwise authorized, the allowable pipeline pressures are established by in-place testing. The maximum allowable operating pressures are 0.8, 0.72, 0.56 and 0.44 of SMYS, or 0.8, 0.8, 0.714, 0.714 of the test pressure, whichever is less, for class locations 1 through 4, respectively. The fractions of SMYS are somewhat more conservative for class 3 and 4 locations.
Surveillance, Inspection, Monitoring and Record Keeping	L M	613 705, 706, 809, 721, 723, 731, 739	General statements of operator responsibilities, patrolling, leak surveys, etc., for the various pipeline components.	IV	71, 76, 77	In addition to general statements of responsibilities, requirements are listed with respect to displacement measurements in potentially unstable soil locations (¶71 (b) (1)).

*CSA Standard Z184-M1979

TABLE 4 - COMPARISON OF OPERATION AND MAINTENANCE ASPECTS OF DOT AND NEBA REGULATIONS

Category and Topic	DOT Part 192 Title 49 Gas Pipeline Minimum Safety Standards		Comments	NEBA Chapter 1052 Gas Pipeline Regulations		Comments
OPERATIONS AND MAINTENANCE	Sub-Part	¶		Part	¶	
Repair Procedures and Testing	M	711-719	Immediate temporary measures and permanent field repair procedures are outlined in general terms, with acceptable options cited, with non-destructive testing providing the primary verification methods for welded repairs.	IV	79-80	General requirements similar to DOT Part 192, Title 49, with extensive reference to the CSA Standard.* The guidelines are subjective in nature, leaving the specific plans and procedures to the discretion of the operator. Special maintenance procedures are mentioned for "northern areas or offshore construction." The referenced standard* provides criteria complete and very similar to those presented in DOT Part 192, Title 49, with somewhat more detailed guidance.
Pressure Limiting and Regulating Stations; Inspection and Testing	M	739	General requirements set forth, with maximum 1 year interval between inspections/tests.	IV	68	Essentially identical in concept to DOT Part 192, Title 49.
Record Keeping and Accident Reporting	M	709	Inspection and repair records must be kept by the operator, with little detail of the inspection documentation required. Accident reporting details and procedures are specified in Part 191.	V	85, 86	Basically similar to those contained in Part 191, Title 49.
Corrosion Control	I		This subject is covered in considerable detail within this part, including comprehensive treatment of requirements, exceptions, and qualifications. Detailed criteria for cathodic protection are provided in Appendix D.	IV	78	Not covered explicitly, but rather it refers to CSA Standard Z184-1979 which itself is guideline oriented. "Hard criteria" are apparently incorporated in a companion tier of regulations/standards, see text.

*CSA Standard Z184-M1979

TABLE 4 - COMPARISON OF OPERATION AND MAINTENANCE ASPECTS OF DOT AND NEBA REGULATIONS (Continued)

The overall DOT criteria and requirements for gas pipelines are essentially covered in comparable detail in Canadian regulations by joint reference to the NEBA regulations and the companion CSA standards. In addition, the NEBA regulations prescribe the general scope of design investigations needed to establish criteria relative to subsurface geotechnical conditions, river/lake bottom conditions, the impacts of the project on fish and wildlife, and the planning required for developing borrow sites along the pipeline. There are performance criteria to be considered in selecting and applying specific installation modes (buried, on grade, and elevated pipelines) including attention to thermal, surface water/ice, and ground-water regimes that may impact safety in arctic regions. Performance requirements for maintenance of frozen ground conditions, including refrigeration, are outlined in general terms.

The NEBA regulations require application of "good engineering practice" in design, with ample interaction between the government and the designer. The DOT regulations apply only to the gas pipeline operator. Neither set of regulations directly considers mitigation of earthquake hazards.

5.3.3 Construction

The DOT regulations related to construction apply to safety in all climates in general but do not address the special problems of the arctic. Requirements for protection from hazards (geotechnical, thermal, hydraulic, and vehicular accident) are briefly stated in general terms, although 192.303 requires compliance with comprehensive written specifications or standards that are consistent with the general intent of the regulations.

The NEBA regulations apply explicity to all areas of construction activities, including surface travel, campsites, excavation, and grading. Performance guidelines stipulate avoidance of "unnecessary" ground/vegetation disturbance, employment of positive protective measures for frozen ground to minimize thermal/drainage disturbance, and restoration "where practicable." Construction mode considerations of geotechnical hazards within the NEBA regulations include consideration of ground disturbance effects, with more detailed requirements provided in the companion CSA standards. Conservation measures are expressed as relevant guidelines that include flora and fauna, waste management, aesthetics, and archeologic site preservation.

Construction inspection is treated in general terms within the DOT regulations, with uncertain requirements for inspector assignments (i.e., government versus owner employee, relevant authority, etc.) The NEBA regulations are somewhat more direct, with clear procedures for pipeline company appeal of inspector decisions to the regulatory Board.

5.3.4 Pressure Testing

The requirements for pressure testing both in NEBA and DOT regulations do not contain refinements in terms of arctic conditions. The major aspects of the two sets of regulations are as follows:

(1) The DOT regulations prescribe which lines must be tested, which test is to be made, which test medium may be used, and what duration is required (8 hours). In addition, the maximum allowable operating pressure is established using the test pressure as one parameter (192.607 and 192.619). The DOT regulations permit pre-installation tests of components under certain conditions.

(2) NEBA regulations prohibit use of air or gas testing in class locations 3 or 4, while DOT regulations permit lower test pressures with respect to the specified minimum yield stress (SMYS) in these categories when air or gas is used. Also, unless otherwise authorized, NEBA regulations require the pipeline to be tested "in place under all existing operating conditions."

In addition to covering the same points as DOT, NEBA regulations also provide:

(48) For submittal of detailed test program plan to the Board before testing starts. The test plan must contain line profile details and identify locations where pressure is to be recorded on each section;

(49) For Board notification seven days before test;

(52) Specifications for kind, type, and location of instrumentation;

(53) Details on filling a line with water;

(54) Required communications during test;

(57) Details on obtaining a "yield-plot";

(58, 60, 63 and 64) Additional testing details;

(59) Required test hold period to be 24 hours. The Board can authorize other periods.

CSA Standard Z184-1979 covers many of the same points as the DOT regulations and in about the same detail. Paragraph 11.5 includes amplification of concerns in testing "Pipelines in Northern Regions," including considerations of unstable soil effects in anticipating excessive stress conditions and the controlling of the test medium temperature "to prevent detrimental melting of the permafrost and instability of the soil surrounding the pipeline."

5.3.5 Operation and Maintenance

As in the case of pressure testing, those portions of the respective regulations dealing with operation and maintenance generally do not include special considerations for the arctic region. The only exception is the NEBA stipulation for monitoring pipeline displacements in areas of potentially unstable soils, which implicitly include thaw-instability and frost-heave conditions.

The major differences noted in comparing the two sets of regulations include: operating pressures allowed in class locations 3 and 4 as a fraction of SMYS (respectively 0.5 and 0.4 for DOT versus 0.56 and 0.44 for NEBA); and, more active communications and reporting of all test results to the regulatory Board in the case of NEBA regulations, compared with mandatory record-keeping requirements in the DOT regulations. Part 191 of the DOT regulations does describe reporting procedures related to accidental leaks and test failures. As with the other categories, a more active interface between the operator and the government is encouraged in the NEBA regulations.

5.3.6 Welding

DOT regulations exercise complete control over the welding process by requiring procedures to be established under API-1104 or the ASME Boiler and Pressure Vessel Code; by requiring welders to be qualified under the same codes or standards; by establishing limitations on welders; and by establishing standards for the preparation for welding, preheating, stress relieving, inspection and non-destructive testing of welds, and removal or repair of defects.

NEBA regulations have very little direct reference to welding, with Section 38 dealing with procedures in general and Section 39 providing for non-destructive testing of welds at a frequency to be approved by the Board. Sections 80 to 83 provide for welding repairs. CSA Standard Z184-1979, incorporated by reference, deals with all of the various faults of welding in great detail in Section 4 (4.1 through 4.13.15.2). This material is essentially the same as that covered by API-1104 and the ASME Boiler and Pressure Vessel Code.

5.3.7 Corrosion Control

DOT regulations require application of protective coatings and installation of cathodic protection systems on virtually all new steel pipelines. They also require care, inspection, and repair of coating defects during installation of the line. Provisions are included regarding lines in service when the regulations were adopted. The DOT regulations cover aluminum and copper lines, internal and atmospheric corrosion, electrical insulation, installation of test leads, monitoring and record keeping. Standards are provided for remedial measures when corrosion is found to exist in a line.

The NEBA regulations only require the company to establish procedures to detect and control corrosion; however, CSA Standard Z184-1979 covers application of coatings, installation of cathodic protection, inspection and repair of coating defects prior to installation, protection of the coating during installation and backfill, installation of test stations, and monitoring of the cathodic protection system. Atmospheric and internal corrosion-control requirements are specified, but not in detail. Aluminum and copper (lines) are not covered in the regulations, and although remedial action is required if corrosion is found, the remedial action or repairs are not specified.

6.0 CONCLUSIONS AND RECOMMENDATIONS

6.1 COMMENTS AND CONCLUSIONS

The pipeline industry is in a state of flux concerning arctic pipelines. On the one major pipeline that has been constructed, there appears to be a feeling that the higher than expected costs resulted in some degree from over-regulation. On the other hand, there is a feeling that substandard work was performed in certain areas having to do both with pipeline performance and environmental forces. On the second major pipeline now in the design phase there is cautious optimism that the regulatory process can be controlled and applied so that a safe and environmentally sound pipeline is obtained without major cost upsets. The conclusion of this study is that massive changes in the regulations are not warranted but that changes should be made cautiously to existing regulations and to other agency stipulations used to guide owners and operators where hazards are known to exist.

A systematic review has been made of the state of arctic pipeline construction practice in 13 identified practice areas. The methodology of the review is discussed in Section 2, and the results are presented in Section 3. On the basis of the presentations of the practice areas, hazards peculiar to arctic pipelines have been highlighted in Section 4. In the entire study, it was assumed that the existing regulations are suitable for pipelines in the lower-48 states, which extend from the tropical conditions of the Gulf Coast to the near subarctic conditions of the Central-Northern tier states. It has been concluded that the small relative climatic differences between the weather extremes of the northern tier states and Alaska are not sufficient by themselves to require major different treatment; rather, the different treatment for arctic pipelines is required by: (1) the presence of permafrost and its response to different thermal regimes; (2) the construction modes utilized to accommodate the resulting problems; and (3) the resulting pipe stress conditions.

The project team reached the conclusion that there is major concern over the influence of geotechnical conditions in arctic pipeline design and construction. To differentiate reliably between permafrost conditions and thawed conditions, it is necessary to perform soil borings, which are especially costly in the arctic. Further, the distance between borings, usually 1/4 to 2 miles, requires major interpolation. There are no criteria, tests or procedures that permit dependable determinations of whether thawing permafrost soils will be stable under a warm pipeline or whether frost heave will occur in initially thawed soils traversed by a chilled pipeline. Since major cost and safety issues are involved with the decisions reached, the reasons for concern are readily apparent, whether approached from operator or regulator viewpoint.

Besides the behavior of soils under thawing and freezing conditions, the use of different construction modes to mitigate or accommodate various subsurface conditions has probably been the most drastic change in pipelining for arctic regions. Mode concepts are still developing, and it is probable that the most effective solutions have not been reached. It would appear to be a mistake to adopt regulations that seriously restrict the choices to the extent that the efforts to develop better solutions would decline. Performance regulations appear suitable. Further, a realistic look at the various hazards that have been discussed herein and elsewhere is warranted in order to evaluate which hazards pose real and/or major threats to pipeline safety versus those in which the threat is more apparent than real. Hence, more tradeoffs in mode selection could be made, resulting in more effective mode selections.

As a corollary to the arctic problems posed by permafrost and different construction modes, it is apparent that pipe performance must be evaluated in detail. Pipe stresses, other than the circumferential stress due to internal pressures, must be evaluated. Design criteria considering other stresses and reasonable combinations of stresses must be established. These include, in particular, longitudinal and bending stresses due to differential pipe movements (from settlement and heave), thermal conditions, and earthquake effects. Further, to enhance the safety and serviceability of gas pipelines, especially those operated in a chilled mode, criteria assessing crack propagation and its mitigation would also be helpful.

Just as in any industry or operation where regulations are employed, there are many aspects of pipeline construction that do not lend themselves to specific regulation. This is evident by the many elements that are not covered or are covered indirectly under existing regulations. As an example, the quality and placement of backfill around a pipeline may have an important role in the satisfactory performance of large-diameter pipelines; the present code requirements for backfill are very general and pertain to support under the pipe, damage prevention to any pipe coating, and maintenance of design cover depth without mention of quality or placement. Further, several hazards identified in Section 4 of this report fall into this category. The project team did not find a need to depart from the philosophy that certain aspects do not warrant stringent regulations even in arctic climates.

6.2 RECOMMENDATIONS FOR GAS PIPELINE REGULATION CHANGES

As a result of the reasoning process presented in Section 6.1 above, it is recommended that the following changes be made in 49-CFR Part 192 to accommodate arctic pipelines:

- Unique artic pipeline hazards and attendant pipe stress conditions are summarized in Section 4.0 of this report. Such conditions are addressed only in a general manner in 49 CFR 192.103 and 192.159. Accordingly, these sections should be revised to clearly require consideration of all stresses, including hoop, longitudinal and potential bending moment stresses and reasonable combinations of expected stresses.

- Pursuant to the above recommendation for combined stresses, 49 CFR 192.317 should be revised to include consideration of potential ground movements, i.e., loss of support, frost heave, and landslides as discussed in Section 4.2 - 4.4 of this report, and of earthquake effects including liquefaction as discussed in Section 4.7. The revision should point out that sufficient seismic, geologic, and geotechnical investigations must be made to define and evaluate all natural hazards. These investigations must consider all potential changes in soil thermal regime and the resulting changes in support and load conditions (e.g., thaw settlement and frost heave) that might vary with time. Construction modes must be selected and designed that best accommodate or prevent the potential changes.

- At the appropriate place (possibly Section 192.103 or 192.55), a statement should be included to require that potential crack propagation, as discussed in Section 3.1 of this report, be considered in the design of chilled gas pipelines.

- As a general, less important comment, the oil and gas pipeline regulations were found to be not totally consistent. For example, Sections 192.221 to 192.245 (Subpart E, "Welding of Steel in Pipelines") should be compared to Sections 195.214 through 195.234 and the two made more consistent.

6.3 RECENT ARCTIC PIPELINE-RELATED RESEARCH

Limited information was obtained on several research study efforts pertinent to arctic pipeline construction that have been completed or are underway. The researchers and their areas of investigation are:

University of Alberta, Edmonton, Alberta

- Properties of permafrost
- Support piles in permafrost
- Frost-heave mechanics and testing
- Slope stability in permafrost regions

Northwest Alaskan Pipeline Company, Salt Lake City, Utah, with participation in some projects by Foothills Pipe Lines, Calgary, Alberta

- Field frost-heave test - Fairbanks
- Frost-heave test - Calgary

- Frost-heave tests at seven satellite sites in Alaska
- Frost-heave laboratory modelling
- Field test for aufeis on slope
- Effects of blasting in frozen ground
- Blasting tests near prototype structures
- Pipeline burst tests

EBA Engineering Consultants Ltd., Edmonton, Alberta

- Rail grade stabilization with heat pipes
- Thermal design and performance of buried utility lines
- Frost-heave testing and design procedures
- Soil/pipe interaction in frozen and thawing ground

ARCO Transportation Division, Los Angeles, California

- Support pipe piles driven in undersize pilot holes thawed with warm water (on Kuparuk Pipeline)
- Pipeline buried within a berm

University of Alaska, Fairbanks, Alaska

- Theoretical studies of aufeis-scour interaction and effects of chilled gas on ice blockage formation

Marks Research Consultants, Calgary, Alberta

- Pressure testing of arctic pipelines--state-of-the-art paper

Alyeska Pipeline Service Company, Anchorage, Alaska

- Partial development of instrumented pig to measure changes in pipe wall configurations
- Use of caliper pig to give information on pipe curvature

Mechanics Research Inc., Los Angeles, California

- State of the art evaluation of systems and equipment for rapid shutdown performed for the Department of Transportation (NTIS Report PB241324)

6.4 RECOMMENDATIONS FOR FURTHER RESEARCH

The industry representatives expressed concerns in several broad areas that affect both gas and liquid pipelines in the arctic. Research is needed in each of these areas to better define problems and develop alternative solutions. These areas are:

- Pipe Stress Criteria - Currently, 49-CFR Parts 192 and 195 specify that pipelines will be designed to satisfy stress criteria based on internal pressure. In arctic regions, it has been concluded that other components of pipe stress should be considered due to the presence of marginal or poor soil conditions. Therefore, it is recommended that criteria be developed for cases of combined stress or strain conditions. These criteria should account for credible combinations of stresses due to internal pressure, temperature changes, ground distortions, and external long-term and transient loading.

- Pipe Load Test - Due to the increased potential for severe loading conditions on arctic pipelines (e.g., due to large ground movements), there is a need for experimental data on pipe behavior under external loading. Other than a series of tests on the trans-Alaska oil pipeline's 48 inch-pipe and recent bending tests on small-diameter pipe, very little information of this type is available in the open literature.

  The purpose of the suggested testing would be to assess pipe performance for cases of large strains (elastic and inelastic) and various loading conditions of tension, compression, shear flexure and internal pressure. Load tests on a series of prototype large-diameter pipe would be of the most immediate interest.

- In-depth investigation is needed of the techniques used and the criteria applied in establishing weld quality. If the fracture mechanics research programs currently underway provide standard techniques for defining and measuring defects, the regulations should allow the techniques to be used as an alternative to API 1104.

- There is a need for a more direct, rapid method of exploration and evaluation of subsurface geotechnical and thermal conditions. Major problems will continue as long as dependence must be placed on widely spaced borings and the interpolation of these borings to locate permafrost, soils subject to frost-heave or thaw settlement, bedrock, and other conditions vital to arctic pipeline design and construction. Many types of exploration techniques (such as borings, seismic, and impulse radar) have been tried by various investigators. These efforts need to be inventoried and listed as to purpose, results, details of the techniques and costs. It may be that such a compilation would indicate further research efforts needed to develop a system that could provide a continuous profile along the alignment such as is obtained with marine geophysical surveys using boomer or sparker equipment.

- No accepted index tests are available that define the degree of thaw settlement or frost-heave to be expected for a given soil type. Development of such tests would be of significant assistance to the design of arctic pipelines.

- Continued development of automated techniques for monitoring pipeline condition (displacements, curvature, and cross-sectional dimensions) is needed. Most promising (despite the earlier failure) are various types of instrumented pigs.

APPENDIX A

BIBLIOGRAPHY

APPENDIX A

BIBLIOGRAPHY

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APPENDIX B

SURVEY AND INTERVIEW RESPONDENTS

APPENDIX B

SURVEY AND INTERVIEW RESPONDENTS

E.W. Brooker
EBA Engineering Consultants Ltd.

R.F. Carlson
University of Alaska

J.M. Childers
U.S. Geological Survey

T. Clarke
Northwest Alaskan Pipeline Co.

F.E. Crory
Cold Regions Research and Engineering Laboratory

N.C. Donovan
Dames & Moore

K.E. Eliason
K-Alaska, Inc.

T. Hayden
Northwest Alaskan Pipeline Co.

L. Heverly
U.S. Department of Transportation

R.B. Higgins
SOHIO Construction Co.

W.A. Hutchinson
ARCO Pipeline Co.

R. Isaacs
Northwest Alaskan Pipeline Co.

Z. Jan
Northwest Alaskan Pipeline Co.

D. Keyes
U.S. Department of the Interior

K. Klebba
Northwest Alaskan Pipeline Co.

J. Leonard
Morrison-Knudsen, Co., Inc.

G.B. Lipsett
Foothills Pipeline Ltd.

J.A. Maple
Exxon Company, USA

J.F. McPhail
Alyeska Pipeline Service Co.

G. Mocharko
U.S. Department of Transportation

N. Morgenstern
University of Alberta

V. Peterson
Northwest Alaskan Pipeline Co.

C.D. Richards
Alberta Gas Trunkline Ltd.

W.D. Roggensack
EBA Engineering Consultants Ltd.

A.A. Stramler
ARCO Transportation Division

T. Smith
Northwest Alaskan Pipeline Co.

L. Ulrich
U.S. Department of Transportation

E.L. Von Rosenberg
Exxon Production Research Co.

APPENDIX C

CROSS-REFERENCE OF LITERATURE WITH PRACTICE AREAS

CROSS-REFERENCE OF LITERATURE WITH PRACTICE AREAS

REFERENCES	1 Materials of Construction	2 Welding--Joining of Materials	3 Valves, Spacing, etc.	4 Corrosion Control	5 Compressor/Pumping Stations	6 Pressure Testing	7 Spacing between two Pipelines	8 Soils	9 River Crossings	10 Construction Modes	11 Construction Techniques	12 Operations and Maintenance	13 Operations below 32°F
Alyeska Pipeline Service Co. (1976)	X	X											
Andersland and Anderson (1978)								X					
Anderson (1979)												X	
Anderson and Hyman (1977)								X				X	
(Anon.) Pipe Line Industry (1970)												X	
(Anon.) Pipe Line Industry (1977)												X	
(Anon.) Engineering News Record (1979)												X	
(Anon.) Newsline (1979)								X					
Bangs (1975)	X	X											
Bock (1979)					X						X		
Bouwkamp and Steven (1973)	X											X	
Carlson (1977)									X				X
Childer (1978)									X				
Cold Regions Engineering Design Manual (1967)													
Connare (1973)	X		X										
Corkill (1977)													
Cotton amd Macanlay (1976)	X	X											
Curtis (1977)													
Dacy and Mayer (1973)					X								
Daniels (1978)						X							
Dauty, et al	X	X											
Davison, et al (1979)								X					X
DeLeon (1979)	X	X											
Donovan and Krzewinski								X					

CROSS-REFERENCE OF LITERATURE WITH PRACTICE AREAS

REFERENCES	1 Materials of Construction	2 Welding--Joining of Materials	3 Valves, Spacing, etc.	4 Corrosion Control	5 Compressor/Pumping Stations	6 Pressure Testing	7 Spacing between two Pipelines	8 Soils	9 River Crossings	10 Construction Modes	11 Construction Techniques	12 Operations and Maintenance	13 Operations below 32°F
Eiber (1979)	X	X											
Eliason (1978)											X		
Even (1979)	X	X											
Ewing (1976a,b)	X	X	X	X	X								
Ferrians (1966)								X					
Ferrians, et al								X					
Graham (1979)									X				
Hall, et al (1972)								X					
Hall and Newmark (1977)								X					
Hardy and Morrison (1972)								X					
Haugan	X	X											
Hood (1977)	X												
Howland (1972)													
Huck (1979)											X		
Hurd (1972)													
Hwang (1977)								X					
Hwang and Yip (1977)								X					
Ivanstov (1978a, b)											X		
Jahns, et al (1973)								X					
Johnston (1976)												X	
Kachadoorian and Ferrians (1973)								X					

CROSS-REFERENCE OF LITERATURE WITH PRACTICE AREAS

REFERENCES	1 Materials of Construction	2 Welding--Joining of Materials	3 Valves, Spacing, etc.	4 Corrosion Control	5 Compressor/Pumping Stations	6 Pressure Testing	7 Spacing between two Pipelines	8 Soils	9 River Crossings	10 Construction Modes	11 Construction Techniques	12 Operations and Maintenance	13 Operations below 32°F
Kennedy, Chow, and Williamson (1977)								X					
King (1977)													X
Knight (1971)								X					
Kreig (1977)								X					
Lachenbruch (1970)								X					
Luscher and Thomas (1979)								X					
Luscher, Black, and Nair (1975)								X		X			
Luscher, Thomas, Maple (1979)								X					
Luscher (1981)								X		X		X	
McGhee (1972)												X	
Merrett (1979)													
Morgenstern and Nixon (1975)								X					
Miyoshi	X												
Nakazawa (1978)	X	X											
O'Connell (1977)				X									
O'Connor (1971)		X											
O'Donnell, J. P. (1976)													X
O'Donnell, H. W. (1978)									X				X
Oriard and Tart (1979)											X		
Palmer (1972)								X					
Patton (1977)		X											
Peabody, (1979a,b)				X									
Pearm (1970)										X	X		
Pearson (1977)								X		X			

CROSS-REFERENCE OF LITERATURE WITH PRACTICE AREAS

REFERENCES	1 Materials of Construction	2 Welding--Joining of Materials	3 Valves, Spacing, etc.	4 Corrosion Control	5 Compressor/Pumping Stations	6 Pressure Testing	7 Spacing between two Pipelines	8 Soils	9 River Crossings	10 Construction Modes	11 Construction Techniques	12 Operations and Maintenance	13 Operations below 32°F
Pendarvis (1979)											X		
Perkins (1971)												X	
Phukan (1979)								X					
Powell and Mondkar (1977)								X					
Price (1978)	X	X											
Rowely, Watson, Wilson and Auld (1973)								X					
Rowland (1978)								X					
Seager and Havers (1970)											X		
Sloan, Zenone, and Mayo (1976)									X				
Slusarchuck, Clarke, Nixon, Morgenstern and Gaskin (1978)								X					
Smith (1976)											X		
Somerville and Slimmon (1976)	X	X											
Speer, Watson and Rowley (1973)								X					
Spiridonov (1972)								X					
Townsend and Farley (1973)									X				
Turner (1978)	X	X							X				
Van Rosenberg (2 papers)	X	X											
Wakefield (1971)	X												
Waldon (1972)	X												
Walker, Schulz and Theriault (1978)								X					
Wallbridge (1977)	X												
Watson, Rowley and Slusarchuk (1973)								X					
Williams (1970)	X	X		X		X							
Williams and Thomas (1979)								X					
Williams (1978)												X	
Wilson (1975)					X							X	
Witten (1979)												X	
Wormell (1973)		X											

APPENDIX D

CROSS-REFERENCE OF RESPONDENTS WITH PRACTICE AREAS

CROSS-REFERENCE OF RESPONDENTS WITH PRACTICE AREAS

RESPONDENTS	1 Materials of Construction	2 Welding--Joining of Materials	3 Valves, Spacing, etc.	4 Corrosion Control	5 Compressor/Pumping Stations	6 Pressure Testing	7 Spacing between two Pipelines	8 Soils	9 River Crossings	10 Construction Modes	11 Construction Techniques	12 Operations and Maintenance	13 Operations below 32°F
E. W. Brooker								X					
R. F. Carlson									X				
J. M. Childers									X				
T. Clarke	X	X											
F. E. Crory						X	X	X					
N. C. Donovan								X					
K. E. Eliason							X	X	X		X		
T. Hayden										X	X		
L. Heverly				X									
R. B. Higgins					X			X				X	
W. A. Hutchinson				X									
R. Isaacs								X	X				
Z. Jan			X			X	X						
D. Keyes										X			
K. Klebba								X					
J. Leonard						X					X		
G. B. Lipsett													
J. A. Maple	X	X		X				X		X	X	X	
J. F. McPhail							X			X			
G. Mocharko				X									

CROSS-REFERENCE OF RESPONDENTS WITH PRACTICE AREAS

RESPONDENTS	1 Materials of Construction	2 Welding--Joining of Materials	3 Valves, Spacing, etc.	4 Corrosion Control	5 Compressor/Pumping Stations	6 Pressure Testing	7 Spacing between two Pipelines	8 Soils	9 River Crossings	10 Construction Modes	11 Construction Techniques	12 Operations and Maintenance	13 Operations below 32°F
N. Morgenstern								X					
V. Peterson				X	X							X	X
C. D. Richards	X	X	X	X									
W. D. Roggensack													
A. A. Stramler								X		X			
T. Smith										X			
L. Ulrich		X		X									
E. L. VonRosenberg	X	X											