FOREWORD

This Appendix contains Geotechnic evaluation of the Alaskan Arctic Gas Pipeline Company's Application for transporting natural gas from Prudhoe Bay across the northern slope of Alaska to the Canadian border. The Geotechnic evaluation was directed at the identification of those critical factors that affect the transportation system's integrity and thereby pose a threat to the environment and/or public safety. This evaluation was conducted by the Aerospace Corporation under Contract 08550-CT5-13 from the Bureau of Land Management, Department of Interior.

For easy reference, the material contained herein is presented in the order defined ~~by the DOI/FPC~~ Environmental Impact Statement Outline. Only those topics of the outline that were jointly identified by BLM and Aerospace Corporation as being pertinent to pipeline integrity were addressed. The Table of Contents for the Appendix identifies those subjects addressed by underlining the section, sub-section or words in the title of such section or sub-section which limit the scope of the input. Each of the outline items discussed was subdivided into: Applicant's Submission; Analysis of Submission; Conclusions, and Recommendations.

The material reviewed consisted of Applicant's Environmental Report, Application for Certificate of Public Convenience, Alignment Charts, and numerous answers to questions posed by DOI, which included reports prepared by other organizations in support of the Applicant's submission.

HIGHLIGHTS

The thrust of the Geotechnic Evaluation centered on the identification and assessment of pipeline integrity issues that may pose a threat to the environment or public safety. The scope was limited to the Alaskan portion of the pipeline. Well-head operations, gas compressor/chilling stations and related facilities located at Prudhoe Bay were excluded in accordance with BLM direction. The system configuration investigated included; 195 miles of pipe crossing coastal plain and approximately 22 rivers with block valves located 15 miles apart. Remote communications for command and control, three maintenance sites and large landing sites were also ~~included.~~

The Alaskan Arctic Gas Pipeline from Prudhoe Bay across the northern slope of Alaska to the Canadian border is an engineering project involving many challenging problems. The permafrost~~,~~ with the insulating organic cover, requires the use of special techniques during the construction phase to prevent permanent environmental damage and frequent pipeline failures. During pipeline operation the maintenance of the permafrost requires control of the gas temperature. Control of drainage, erosion, and pipeline integrity at river crossings, on slopes, and flood plains also requires careful consideration during all seasonal changes while the system is in both inactive and active states. All of these problems, while difficult, are well within the realm of engineering feasibility. However voids in the design data should be filled before construction approval is granted to insure that sound engineering practices are being used in resolving pipeline integrity issues.

The discussion of pipeline integrity in this report is arranged in a sequence consistent with the outline of The Environmental Impact Statement to insure proper cross referencing. Since certain issues may be of greater significance than others, an effort was made to select those critical technical issues requiring more immediate attention. The issues have been sifted from the extensive environmental material and limited design data submitted by the Applicant.

1. Pipe Safety Factor Marginal

The pipe is, at present, designed only for hoop stress (not including gas surge pressure) with the lowest safety factor (0.72) allowed by Federal Regulations. This approach tacitly assumes that any external loads imposed on the pipe by forces such as frost heave or mass wasting are insignificant. Such an assumption may not be warranted and requires verification under the predicted worst conditions both with the pipe in a nonpressurized and pressurized states.

There is also a specification question associated with the use of the API X 70 type steel. This steel is quite different from the steels normally used for pipeline construction which have a wide spread between yield strength and ultimate strength. The allowable stress for API X 70 steel may be substantially lower than the 72% of the yield stress used by the Applicant in order to be compatible with the intent of Title 49 of the Code of Federal Regulations.

A comparison of API X 70 steel versus ASTM A53-69a steel shows approximately 50% greater factor of safety for the A53-69a type steel based upon ultimate strength. (See Section 1.1.1.3.A.1)

2. Pipe Toughness is a Key Element Preventing Failures

The fracture toughness of the APIX-70 steel at the low operating temperatures requires further investigation. Performance data at low temperatures has not yet been fully developed by industry. Preliminary calculation employing characteristics of similar materials indicate that a flaw size of 1.2" long and 0.2" deep could cause an unzipping of the pipe over long distances when the system is fully pressurized. Stringent quality control will be required to prevent this type of failure. The toughness problem becomes more acute in welded portions of the pipe and the field welds in particular. Field procedures and equipment for flaw detection for all field welds should be defined. (See Section 1.1.1.3.A.)

3. Summer Repair & Maintenance Concept Viability Questioned

Summer repair and maintenance of the pipe is a major problem without a permanent road. The proposed solution is the use of aircraft and air cushion vehicles including the construction of landing or unloading pads before repair can begin. The availability of these machines, their lift capability, the time necessary for such repair, and their impact on the environment need further investigation. (See Section 1.1.1.1.7.C.3)

4. Frost Heave Effects

Since the gas will be chilled to prevent thawing of the permafrost throughout the regions traversed, the pipe tends to freeze any existing water in the active layer and any supercooled water in the permafrost. This frozen water may then induce localized stress on the pipe, which, in combination with pressure stress, may threaten pipeline integrity. Additional testing and analysis is called for to assuage these difficulties. The uncertainty involved in this additional stress may require a higher safety factor in the pipeline design or a decrease in the operating pressure.

Another factor involving frost heave is associated with the possible delay in the application of chilled gas in the pipeline for one summer after construction has been completed. Russian experience with unchilled buried pipelines in Siberia indicates that dislodgement of the unchilled pipe from the ground was frequently observed. The Applicant plans to flow chilled gas immediately after winter construction. However, a delay through a summer thaw due to delays in Canada might ensue, and analysis and test of the unchilled pipeline is called for. (See Sections 1.1.1.3.A.2, 1.1.1.1.B.2 & 2.1.1.3.C.4 E)

5. Effect of Mass Wasting on Pipeline Integrity

Although the Applicant has shown a sound understanding of the potential effects of mass wasting on the pipeline integrity, it is anticipated that this will remain a major design issue. The effects of mass wasting, particularly in case of undercut slopes which should be identified, on pipe external loads should be evaluated in detail for the case where the pipe may remain inactive and unchilled for one or two seasons, and with a chilled pipe. (See Section 2.1.1.3.C.2.g).

6. Protection of Pipe at River Crossings

River crossings should be examined in detail with regard to the anticipated scour depth and bank erosion. Standard Project Flood Plain data should be used for design of the negative buoyancy provisions and depth of pipe burial. During thaw periods ice dams may form in the river above the chilled pipeline. When the dam breaks the resulting channelling can significantly effect the scour depth and may expose the pipe. (See Section 2.1.1.1.5.B.2).

7. Leak Detection

The hostile environment and inaccessibility of the pipeline with normal methods makes small leak detection extremely difficult with current technology. A research program directed at remote leak detection systems should be undertaken. (See Sections 1.1.1.3.C.1 and 1.1.1.6.D.1).

8. Effect of Leaking Gas

Effect on the environment of the gas leak and gas loss in the case of pipe fracture, including fire hazard, should be investigated. Assuming the gas trapped between two sets of block valves 15 miles apart is released, approximately 180 million scf of gas will be discharged into the atmosphere. Means should be defined and precedures set for detecting gas leaks underground and under ice. (See Sections 3.1.1.6 and 7).

9. Corrosion Control

Corrosion control should be defined in more detail. Specification for external coating and internal coating, as well as details of the cathodic protection network, should be prepared. (See Section 1.1.1.7.B.1).

Gas composition should be defined with respect to the allowable level of contaminants (sulfides and CO_2) and particulates. While it is understood that the Prudhoe Bay compressors and scrubbers are not part of the Applicant's Environmental Report, nevertheless, detailed gas specification is required to evaluate corrosion hazards and valve operation. (See Sections 1.1.1.3.C.1., 1.1.1.7.A.2 and 1.1.1.7.C.4).

10. Danger of Condensates in Pipe

Condensates in the pipe may, at the operating temperatures and pressures, include some of the heavier hydrocarbons such as propane.

If that is the case, provision for collection of the condensates to prevent them entering the compressor should be specified. Ingestion of liquids by the compressors could cause failures. (See Section 1.1.1.7.C.4).

11. Hydrotesting Plan is Incomplete

Procedures should be defined for hydrotesting, including the water/methanol disposal, emergency repairs, and health and safety of the personnel. (See Section 1.1.1.6.D.1).

12. Seismic Monitoring is Needed

Seismic instrumentation should be provided along the pipeline route in the vicinity of Flaxman Island which has a history of seismic activity should be determined. (See Section 2.1.1.1.3.C.1.b.1).

13. Gas Chill Temperature

Temperature maintenance of the pipeline should be defined in such a manner that while the gas is always below the freezing point, the gas temperature at the Canadian border is not too low. Gas temperature near $0^{o}F$ reduces the fracture toughness of the steel and provides conditions for continuous frost bulb growth around the pipe. (See Sections 1.1.1.3.A.2 & 1.1.1.1.B.2).

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ARCTIC GAS PIPELINE PROJECT
ALASKA GAS PIPELINE

APPENDIX A
GEOTECHNIC EVALUATION

Prepared for
Bureau of Land Management
Department of the Interior

5 February 1975

Information and data presented in this document are preliminary and subject to change.

Prepared by

Energy and Resources Division
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El Segundo, California

INTRODUCTION

This Appendix contains Geotechnic evaluation of the Alaskan Arctic Gas Pipeline Company's Application for transporting natural gas from Prudhoe Bay across the northern slope of Alaska to the Canadian border. The Geotechnic evaluation was directed at the identification of those critical factors that affect the transportation system's integrity and thereby pose threat to the environment and/or public safety. This evaluation was conducted by the Aerospace Corporation under Contract 08550-CT5-13 from the Bureau of Land Management Department of Interior.

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1. DESCRIPTION OF THE PROPOSED ACTION

1.1 Arctic Gas Pipeline Project

1.1.1 Alaska Arctic Pipeline

1.1.1.1 Purpose

B. Function of Related Facilities

2) Temperature Maintenance

Applicant's Submission

The Applicant proposes a buried pipeline with the gas chilled to a temperature between 10° and 30°F to maintain the permafrost, and prevent frost heave. Field tests are being conducted in Canada to obtain data both on operating and non-operating installations of buried pipe.

The Applicant presented test results from Prudhoe research facility on the permafrost thermal balance associated with different pipe burial construction techniques (Battelle, 1974). Four separate pipeline temperature regimes were tested.

1. Dormant period. Prior to pipeline operation.
2. Proof test. Simulated proof testing with 41°F average temperature air.
3. Pipeline operation. Operation with average air temperature of 25° F.
4. Refrigeration system breakdown. Several day shutdown after continuous period of operation with chilled air.

The type of construction and pipe temperature operational regime are shown to alter the thermal behavior in the vicinity of the pipe (in a predictable manner), however, it is stated that this alteration has not effected the integrity of the pipeline soil system, as designed and installed.

In Applicant's answer to question 2 it is assumed that the pipe will be warmer than the soil in winter and cooler in summer resulting in ground water flow reversal to and from the pipe and thus reducing the hazard of frost bulb growth and frost heave.

Analysis of Submission

The Applicant's submission has addressed the effect of several anticipated pipeline temperature operating regimes on the permafrost thermal behavior. The test results have also reasonably verified the thermal predictive model, thus lending credence to their predictive technique.

The test program could not evaluate the effect of gas temperature reduction along the pipeline as a result of the system pressure drop. The temperature history along the pipeline is treated extensively in 1.1.1.3.A.2. This temperature drop could be on the order of 22.5°F for a chilled gas inlet temperature of 25°F. This lower gas temperature may result in a net yearly heat flux into the pipe from the surrounding permafrost rather than a net heat flux into the permafrost as exhibited in the Prudhoe tests. Though this may provide greater assurance of maintaining the permafrost in a frozen state, it could increase the impact of ground heave if the soil under the pipeline contained liquid water prior to the startup of system operation. There will be areas in the pipe route where the pipe will remain colder than the soil throughout the year and this condition may be the most critical one.

With ground temperatures of 20°F in summer and 28°F in winter at the pipe midpoint and the chilled gas at 0°F the possibility of induced frost heave cannot be discounted. The chilled gas also will aggravate the fracture sensitivity of the pipe (discussed in detail in 1.1.1.3.A.1). The aforementioned frost heave and fracture toughness concerns lead to questioning the Applicant level of gas chilling. The lower limit may have to be raised 5° to 10°F to reduce these hazards.

Conclusions

The Applicant's test program has considered most of the important pipeline temperature influences on the thermal behavior of the permafrost. An area not considered, however, is the ground heaving effect associated with initiation of chilled gas operation with an initial permafrost temperature above freezing around the pipeline. The possibility of brittle failure also increases with lower pipe temperature. The possible requirement to raise the lower limit of chilled gas should be investigated.

Recommendations

(a) The Applicant should conduct additional tests and/or analysis to evaluate the "worst case" high temperature of the active layer at pipeline startup combined with a "worst case" ground moisture content. The lowest anticipated gas temperature should be used once the test is started and maintained throughout the test to demonstrate the effect of frost heave induced on the pipeline by freezing of this active layer.

(b) The Applicant should evaluate the effect of low gas pipeline temperature on pipe material toughness and consider operating at higher inlet temperatures to reduce this effect. The results of these analyses along with the Applicant's recommendations should be presented to the DoI for review and approval.

Reference: Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)," Columbus, Ohio.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.3 Facilities

A. Pipeline Design

1) Length, Diameter, Thickness

Applicant's Submission

The Applicant states that "the design, construction, testing and operation of the proposed pipeline will be in accordance with the requirements of Part 192 Title 49 of the Code of Federal Regulations, 'Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standard' and such other Federal, State and local rules and regulations as may be applicable," and that the line pipe used in Alaska will be 48 in. diameter by 0.8 in. wall thickness grade X70 steel which will meet or exceed the requirements of: (1) the American Petroleum Institute Specification for High-Test Line Pipe (API Spec. 5LX), Nineteenth Edition and/or (2) the American Petroleum Institute Specification for Spiral-Weld Line Pipe (API Spec. 5LS), Seventh Edition. The nominal strengths of this pipe are yield strength $\geq$ 70,000 psi and ultimate strength $\geq$ the maximum of 82,000 psi, or yield strength +10,000 psi. Further metallurgical characteristics of the pipe are not contained in the report. The Applicant has submitted brief qualitative discussions of the effects of buoyancy, frost heave, differential settlement and seismicity upon the pipe. The discussion contained in the environmental report have been amplified by Volume III of the Battelle Lab Report (1973) which deals with the pipe stress and displacement phenomena observed in an instrumented test loop of pipe installed at the Prudhoe Bay research facility.

The data presented for the Prudhoe Bay test section show axial force, vertical and horizontal bending moments, and vertical displacements of each 800-foot-long test leg for a period covering approximately 15 months. The reported results indicate low pipe stresses as well as small pipe displacements. Exceptions to this are bending moments at pipe anchors which were over 20% of the yield moment.

Analysis of Submission

In order to be assured of an adequate factor of safety against pipe rupture it is necessary to evaluate the magnitude of stresses induced in the pipe from all sources, and to compare these stresses to stress levels at which the pipe will rupture and/or leak. The principal sources of pipeline stresses are:

1) internal pressure,
2) thermal expansion and contraction,
3) frost heave,
4) buoyancy,
5) differential settlement,
6) seismic events,
7) soil slippage (slope instability), and
8) initial stresses from construction operations.

The allowable stress level for steel pipe in an arctic environment must be the maximum stress level which provides an adequate safety factor against all possible failure modes. The allowable stress for X70 steel at sub-zero temperatures may be substantially lower than the nominal 72% of the material yield stress specified by Paragraph 192. 105 of Title 49.

In the following sections an evaluation of the applicant's submission is given for these various aspects of the pipeline design and safety determination.

1) Pressure Induced Stresses

Paragraph 192. 105 of Title 49 gives the design formula for steel pipe as

$$P = \frac{2St}{D} \times F \times E \times T.$$

This formula relates the design pressure (P) to the pipe diameter (D), the yield strength of the steel (S), the wall thickness (t), a temperature derating factor (T), a joint derating factor (E), and design factor based upon the human population density adjacent to the pipeline route (F). In the current case, with D = 48 in., t = 0.8 in., S = 70,000 psi, E = 1, T = 1, and F = .72 the resultant design pressure is 1680 psi; this is exactly equal to the design pressure proposed by the applicant. Paragraph 192.105, however, specifically states the wall thickness, t, used in the above equation may not include such additional thickness as is required for concurrently applied external loads from all sources other than internal pressure.

The requirement from Paragraph 192.105 may be restated more conventionally in the form: "The stresses induced in the pipe from all sources may not exceed an allowable stress, S_a, defined as

$$S_a = F \times E \times T \times S. \text{"}$$

In the present instance, with E = T = 1, the equation for S_a reduces to

$$S_a = F \times S = .72 \times 70,000 = 50,400 \text{ psi} \quad .$$

2) <u>Stresses from Sources Other Than Internal Pressure</u>

The Applicant's treatment of stresses other than pressure induced stresses is superficial - it consists primarily of the assertion that all these stresses are negligible but without quantitative analytical substantiation of the assertion.

In order to properly assess the maximum failure stress levels in the pipe it is necessary to determine stress levels in both the hoop and longitudinal directions. The following table shows estimates of the magnitude of the several types of stress states in the chosen pipe resulting from various causes.

Cause	Hoop Stress Direct	Hoop Stress Bending**	Longitudinal Stress**
Internal Pressure = 1680	+50,400 psi	0	Tension ≅ + 15120 psi
Temperature Excursions	0	0	$\pm$ 21000 psi/100°F change
Frost Pressure on Opposite sides of pipe	Negligible	$\pm$ 12500 psi/10 psi unpressurized, < 12500 psi/10 psi pressurized	~ 0
Buoyancy	0	Small	Beam Bending
Differential Settlement	0	0	Beam Bending
Siesmic*	0	12500 psi/10 psi nonuniform load	Beam Bending
Construction Initial Stress	Negligible	12500 psi/10 psi	~ 0
Cold Bend			$\sigma =$ S during bend $\sigma \approx \lambda$ S residual $\lambda \ll 1$

* Local effects at a fault line are not evaluated here

** Calculations of these stresses are shown in the Attachment (c)

From the foregoing table it may be seen that local crushing of the cross section is the only type of action which will produce stresses directly additive with the pressure induced hoop stresses. The most likely causes for this type of action are nonuniform frost action, nonuniform soil compaction during construction, action resulting at the fault line such as an earthquake, or action occurring during soil slippage. The longitudinal stresses are not directly additive to hoop stresses, but also can be the cause of failure if: 1) they are sufficiently large, or 2) they are moderate in magnitude, compressive, and occur simultaneously with the maximum hoop tension condition.

As stated previously, the Applicant has provided no quantitative assessment of stresses other than pressure induced stresses except for data obtained from the Prodhoe Bay test section. However, only small credence may be put in the vertical deflection measurements as presented by the Applicant since they were made with a transit rather than a level, were not obtained as part of a conventional, closed loop level circuit, and are admittedly not self-consistent.

The strain gage data show that stresses in the test loop were generally low during the 15 month period but, since the gages were not installed and/or calibrated until after the pipe was in the ditch, the installation stresses were not measured. Relatively high bending moments calculated by the Applicant at pipe anchor points are an indication that external loads cannot be neglected and require careful analysis.

A check of the cross section constants used in data reduction indicates that the data were for a 0.28-inch wall thickness pipe rather than the 0.8-inch wall pipe scheduled for use. No discussion of the correlation between the two pipe sizes is given.

3) Determination of Allowable Stress Levels

For a steel pipe of conventional low strength steel operating at normal temperatures the use of an allowable stress, S_a, based upon the material yield strength is appropriate. In the proposed arctic pipeline segment two aspects of the design are such that the S_a = 50,400 psi approach is not directly applicable:

a) The pipeline is to operate in an extremely cold environment and is to carry chilled gas, and
b) The relationship between the yield strength and ultimate strength for X70 is such that a factor of safety based on yield strength may not provide as large a factor of safety based on ultimate strength as would be normally anticipated.

A comparison of API X-70 steel vs. ASTM A53-69a steel shows approximately 50 percent greater factor of safety based upon ultimate strength for the A53-69A type steel. (See Appendix C of this section.)

The colder than usual operating temperature may substantially lower the steel's fracture toughness, and consequently increase its sensitivity to flaws in both the basic material and the weld joints. The result of this phenomenon, if it exists to a significant degree, is to cause the actual factor of safety against sudden fracture of the pipeline to be substantially lower than that specified by Paragraph 192.105. The Applicant has not addressed the problem attendant to the use of low carbon X70 steel at low temperatures; this clearly is a subject which requires a detailed investigation by the Applicant. A separate discussion of a fracture toughness is provided in the Appendix A to this section.

Until the recent development of high yield strength steels for pipeline use the steel characteristically had a substantial spread between its yield and ultimate strengths. The actual ultimate factor of safety against rupture was as much a function of the relatively high ultimate strength (assuming low temperature fracture toughness was not the critical failure mode) as it was of the yield strength. The loss of this additional degree of safety when using high yield strength steels with small separation between yield and ultimate strengths should not be totally ignored.

Conclusions

- The Applicant has not shown analytically that stresses arising from sources other than internal pressure are negligible. Unless this condition can be demonstrated to exist throughout the reach of the pipeline segment the pipe wall thickness must be adjusted to accommodate such additional stresses as may occur.

- The results of the Prudhoe Bay test loop cannot be readily extrapolated to show that the entire length of the pipeline segment will be free from significant additional loads and temperature induced displacements. Relative high bending loads at anchor support points are indicators of the need for external load analysis. It is a virtual certainty the soil and geologic conditions at some points along the route will be more unfavorable than at the test site, and the test loop did not include any segments with significant vertical curvature.

- The unmodified use of the design equation contained in paragraph 192.105 of Title 49 is not appropriate for a pipeline installed and operated under arctic conditions. The behavior of the basic pipeline steel can change dramatically at very cold temperatures; an altogether different type of failure mode can occur under arctic conditions, possibly at stresses substantially lower than the nominal design stress. Further, the failure type originating from a critical flow field may be one of brittle fracture extending a great distance along the pipeline length, rather than an isolated leak or blowout (see Appendix B).

Recommendations

(a) The Applicant should make a comprehensive analytical determination of the maximum stresses that can exist concurrently with pressure induced stresses during pipeline operation. These analyses should cover thermal stresses for the worst possible combination of installation and operation temperatures, stresses associated with worst case frost heave phenomena, the effects of buoyancy and the attendant weighting and/or anchoring, differential settlement for the worst anticipated soil conditions, earthquake induced strain effects, pipeline behavior in regions of soil slippage, and the additive effects of construction induced initial stresses. The results of these studies should be used in conjunction with appropriate allowable stresses and operation pressures to determine pipe wall thickness.

(b) A complete investigation of the material properties of X70 steel should be undertaken in order to arrive at a meaningful allowable operating stress. The allowable stress should be such that an adequate factor of safety is provided against <u>all</u> potential failure modes. In particular, the Applicant should determine by conservative and rational procedures the stress and temperature levels at which small flaws in either the basic material or in the welds will precipitate failure. As a result of these studies, specification criteria should be developed for minimum acceptable fracture toughness of the material, a consistent inspection criteria for welds should be established such that all flaws above the critical size are detected, and a proof test requirement should be developed which will specify the test medium temperature as well as its pressure and the duration of loading.

(c) The Applicant should run chilled gas studies per 1. 1. 1. 1. B. 2 recommendation (b) to minimize hazard of brittle failures.

(d) The properties of API X-70 steel should be reviewed against the intent of Title 49 of the Code of Federal Regulations to determine the revisions (if any) required to incorporate the use of API X-70 type steels.

Appendix A to Section 1.1.1.3.A.1

FRACTURE TOUGHNESS

Any time steel is used at low temperatures, the possibility of brittle fracture must be considered. In a gas pipeline where the decompression speed may be less than the speed of a running crack, there is the possibility of a very small flaw initiating a failure hundreds or thousands of feet long. Because of brittle fracture considerations, conventional safety factors based on operating loads and the static strength of the steel are generally insufficient for safe designs at low temperatures. There must be the additional requirement of some kind of notched strength or, as it is generally termed, toughness. There is a variety of test methods for toughness and a variety of ways of relating the values obtained to satisfactory service. Pipe steels go through a transition from being very ductile at temperatures near ambient (70°F) and very brittle as the temperature decreases. There are a number of methods for defining the minimum suitable temperature for safe operation.

The most common test to define the minimum operating temperature is the Charpy V notch impact test. A C_V impact energy of 15 ft-lb or more was used to define the lowest service temperature for steels. This approach appeared to be adequate until the strengths of steels were progressively increased until classic failures were observed.

Another common measure of the suitability of steels for low temperature service is based on fracture appearance. The minimum operating temperature for successful service is considered to be the temperature at which the specimen fracture surfaces are predominately or entirely shear.

A third approach to define the minimum operating temperature is a drop weight test on a welded plate to define the nil ductility temperature (NDT) and then operate at a minimum service temperature which is 60°F above the NDT. The latter two approaches appear to give comparable results but correlation with a fixed C_V energy has been demonstrated to be totally erroneous. For low strength, non-heat-transferable grades of steel with similar NDTs, the C_V energy can vary from 13 to 44 ft-lb. For normalized grades with NDT similar, an order of magnitude variation in C_V energy has been observed, extending from 20 to 200 ft-lb.

A completely different and more quantitative approach to ensuring safe service is based on fracture mechanics. Here, a critical flaw size is determined with respect to operating stress or strain with stress intensity, K, or crack opening displacement, COD or δ, as a material parameter. Safe service is based on the probability of finding the critical flaw size, either during proof testing or during periodic inspections.

In examining the material requirements and designs to prevent brittle fracture, consideration must be given to two aspects involved in a catastrophic failure, each governed by different variables. The first is crack initiation. Here, flaw size, operating stress, residual stresses as well as the fracture toughness of the material determine the probability of fracture. Fracture toughness is dependent on the composition of the steel, the processing history, temperature, thickness, flaw orientation, and the presence or absence of a weld.

A key step in preventing crack initiation is the detection and repair of the manufacturing flaws that serve as stress concentrations and virtual cracks. While the bulk of the pipe may contain some flaws, the most common location is in the weld areas. The field welds are the most suspect since here weld quality depends on the skill and disposition of the individual welder. The longitudinal welds are factory welds using automatic equipment and very specialized and effective nondestructive testing methods so that undetected flaws are far less likely. The inspection of field welds is done under far less favorable conditions with a consequent loss in reliability.

With large pipe, there is the possibility of fatigue cracks being introduced during shipping because of very local stresses around support pieces and protrusions such as bolts in the shipping container or truck bed. Proper packing can prevent such flaws, but their detection could be difficult without a special effort to look for them.

Probably the most effective way of detecting failure initiating flaws is the proof test, but flaws found this way can lead to extensive damage to the pipe. A successful proof test does, however, give quantifiable confidence for the subsequent service of the pipe.

The second aspect of failure prevention is crack propagation. In this case, only the properties of the material that affect crack speed are important unless special designs for crack arrest are used. The crack speed must be appreciably less than the decompression speed in the gas to reduce the driving force to nearly zero in a short distance. From the standpoint of safety and environmental damage, crack propagation is probably more important than crack initiation since it determines the extent of any damage. From an operational standpoint, of course, any fracture is undesirable, but there is a more readily quantified relation between preventive costs and repair costs and any damage is confined to a local area.

In general, slow crack propagation rates are associated with shear type fractures while high rates exhibit brittle type fractures. However, shear cracks will run when the driving energy available is greater than the fracture energy. Therefore, it is desirable to use steels that exhibit shear fractures in notch tests at the service temperature with high energy absorption. For very low temperature service, obtaining such characteristics in steels requires alloying, heat treating, and very carefully controlled rolling procedures. Because such steels command premium prices, some form of crack stopping procedures may offer economic advantages. One possible approach is to incorporate sections of high toughness pipe at intervals along the line.

Appendix B to Section 1. 1. 1. 3. A. 1

CRITICAL FLAW SIZE

The procedures of fracture mechanics can be used to calculate the size of a flaw or defect that could initiate fracture. This critical flaw size depends on the fracture toughness of the steel and, depending on the analytical approach used, the applied stress or the local strain. Values of fracture toughness vary with the state of stress or strain and are single valued only for conditions when the local deformation can be considered plane strain. For ductile materials, this requirement translates into a case of very thick plate or very heavy wall pipe. Consequently, it is important for accurate analyses that the fracture toughness data be obtained on samples of the same thickness as the pipe to be used. For the 0.80-inch thick pipe considered here, no data were available; hence, it has been necessary to estimate the toughness from limited data on thinner pipe. It has also been necessary to estimate critical stress intensities from crack opening displacement (COD) data. Combined with the variations possible because of differences in processing during manufacture of the pipe, the resulting critical stress intensity values have a large potential for error. Nevertheless, the values obtained are useful to illustrate the sizes of flaws that could be detrimental to the integrity of the pipeline.

For this analysis, it is useful to use the concept of K_{IR}, reference stress intensity, where the critical stress intensity is referenced to the nil ductility temperature, NDT. On this basis, data for a number of constructional steels fall on a common curve so that K_{IC}, critical stress intensity, is known at any temperature if the NDT is measured. This approach has been used by the nuclear power industry and forms the basis for code requirements.

How well K_{IR} data apply to API X-70 steel is not known since the data were based on lower yield strength steels. One check is to see how existing data fit. There is one set of data on API X-70 steel where both NDT and COD data are available. In these tests, NDT was approximately -80°F and the COD at that temperature was 0.003-in. Using the relation

$$\left(\frac{K_{IC}}{\sigma y}\right)^2 \approx \frac{COD}{\epsilon y}$$

where K_{IC} = critical stress intensity

σy = yield strength (70 ksi)

ϵy = yield strain (0.005)

$$K_{IC} = 54 \text{ ksi } \sqrt{\text{in}}\ .$$

This is higher than the minimum value of 39 ksi $\sqrt{\text{in}}$ of the design curve, but falls nicely within the experimental data . Therefore, the use of K_{IR} seems appropriate.

The above API X-70 data were for pipe with a 0.46-inch wall. Experimental results from several studies suggest that increasing the thickness to 0.80-inch will raise the NDT about 40°F so that for the gas pipeline under consideration, the NDT is about -40°F. The minimum temperature of the pipeline will not be determined by the soil surrounding the pipe, but by the gas temperature. The gas temperature decreases along the pipe and toward the Canadian Border it could be close to 0°F, or even below 0°F. Consequently, assessment of critical flow size was made for 0°F.

For a surface flaw, the critical flaw depth, a, is given by

$$a = \frac{Q}{1.2\pi}\left(\frac{K_{IC}'}{\sigma}\right)^2$$

where Q is a shape factor and σ is the applied stress. Values of Q range from about 0.8 to 2.3, with a value of 1 representing a flaw length about six times the depth. Assuming a proof stress of $0.8\sigma y$ (= 56 ksi), the critical flaw depth is about 0.20-inch and about 1.2 inches long. A semicircular flaw would be about 0.47-inch deep.

For an operating temperature of 20°F (NDT + 60), K_{IR} would be 56 ksi $\sqrt{\text{in}}$ and the critical flaw depth would be 0.27-inch (for Q = 1). It should be pointed out that advocates of the NDT approach to specifying fracture toughness requirements consider NDT + 60°F as the temperature above which no unstable cleavage crack propagation can occur at stresses approaching the yield stress.

All of the above analysis has been directed at the base metal of the pipe. In general, welds have lower toughness than the base metal and in actual installations residual stresses are present. Both of these factors can reduce the critical flaw sizes from those calculated above.

Appendix C to Section 1. 1. 1. 3. A. 1

PIPE STRESS CALCULATIONS

1. Primary stresses caused by internal pressure and temperature.

For the case of plane stress (i. e., $\sigma_{zz} = \tau_{zx} = \tau_{yz} = 0$) the basic stress-strain relationship is

$$\begin{Bmatrix} \sigma_{xx} \\ \sigma_{yy} \\ \tau_{xy} \end{Bmatrix} = \frac{E}{1-\nu^2} \begin{bmatrix} 1 & \nu & \\ \nu & 1 & \\ & & \frac{1-\nu}{2} \end{bmatrix} \begin{Bmatrix} \epsilon_{xx} \\ \epsilon_{yy} \\ \gamma_{xy} \end{Bmatrix} - \frac{E\alpha\Delta T}{1-\nu} \begin{Bmatrix} 1 \\ 1 \\ 0 \end{Bmatrix} \tag{1}$$

For a buried pipeline which is restrained longitudinally (x) but not radially (z) by the surrounding soil $\sigma_{yy} = PR/t$ and $\epsilon_{xx} = \tau_{xy} = 0$. With these conditions equation (1) reduces to

$$\begin{Bmatrix} \sigma_{x} \\ \frac{PR}{t} \end{Bmatrix} = \frac{E}{1-\nu^2} \begin{Bmatrix} \nu \\ 1 \end{Bmatrix} \epsilon_{yy} - \frac{E\alpha\Delta T}{1-\nu} \begin{Bmatrix} 1 \\ 1 \end{Bmatrix} \tag{2}$$

Eliminating ϵ_{yy} results in

$$\begin{Bmatrix} \sigma_{xx} \\ \sigma_{yy} \end{Bmatrix} = \begin{bmatrix} \frac{\nu R}{t} & E\alpha \\ \frac{R}{t} & 0 \end{bmatrix} \begin{Bmatrix} P \\ \Delta T \end{Bmatrix} \tag{3}$$

For
$R = 24$ in.
$t = .8$ in.
$\alpha = 7. \times 10^{-6}$ in. /in. /°F
$E = 30 \times 10^6$ psi
$\nu = .3$

$$\begin{Bmatrix} \sigma_{xx} \\ \sigma_{yy} \end{Bmatrix} = \begin{bmatrix} 9 & -210 \\ 30 & 0 \end{bmatrix} \begin{Bmatrix} P \\ \Delta T \end{Bmatrix}$$

For P = 1680 psi and $\Delta T = 0$

$$\begin{Bmatrix} \sigma_{xx} \\ \sigma_{yy} \end{Bmatrix} = \begin{Bmatrix} 15,120 \\ 50,400 \end{Bmatrix}$$

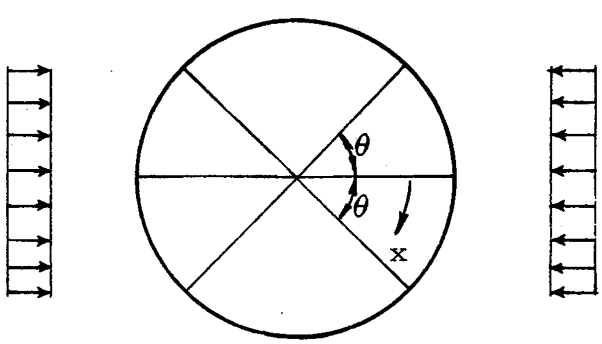
For P = 0 psi and $\Delta T = \pm 100^{\circ}F$

$$\begin{Bmatrix} \sigma_{xx} \\ \sigma_{yy} \end{Bmatrix} = \begin{Bmatrix} \mp 21,000 \\ 0 \end{Bmatrix} \text{, and}$$

For P = 1680 psi $\quad \Delta T = \pm 100^{\circ}F$

$$\begin{Bmatrix} \sigma_{xx} \\ \sigma_{yy} \end{Bmatrix} = \begin{Bmatrix} \substack{-5880 \\ +36,120} \\ 50,400 \end{Bmatrix}$$

2. Cross section bending stresses for crushing action on unpressurized pipe. (Ref.: Roark, "Formulas for Stess and Strain" 3rd Ed. McGraw Hill, 1954. Page 158, Case 11)



q psi

R = 23.6 in.

t = 0.8 in.

$\theta = \frac{\pi}{4}$

$$M = M_1 - q R^2 (\frac{1}{2} \sin^2 x); \qquad x = 0, \theta$$

$$M = M_1 - q R^2 (\sin\theta \sin x - \frac{1}{2} \sin^2\theta); \qquad x = \theta, \frac{\pi}{2}$$

where:

$$M_1 = q R^2 \left[.3183 (\frac{\theta}{2} + \theta \sin^2 \theta + \frac{3}{2} \sin\theta \cos\theta) - \frac{1}{2} \sin^2\theta \right]$$

For $\theta = \frac{\pi}{4}$, R = 23.6, t = .8

$$M_1 = 133 q$$
$$M = q (133-278 \sin^2 x) \qquad x = 0, \theta$$
$$M = q (272 - 394 \sin x) \qquad x = \theta, \frac{\pi}{2}$$
$$M_{max} = 133q \text{ at } x = 0$$
$$M_{min} = -122 q \text{ at } x = \frac{\pi}{2}$$

$$S_{max} = \frac{(133)(6) q}{(.8)^2} = \underline{1247 q \text{ psi}} \qquad x = 0$$

3. Factors of Safety Related to Ultimate Strength

	ASTM A53-69a*	API X70
S_y	35	70
S_u	60	82
$S_a = .72 S_y$	25.2	50.4
S_y/S_a	1.39	1.39
S_u/S_a	2.38	1.63
S_u/S_a	1.71	1.17

Note that the A53-69a steel has 1.71/1.17 = 1.46 times the safety factor of the X70 steel when the factors are based on ultimate strengths. Based on yield strength the safety factors are equal.

* ASTM A53-69a is one of the steels listed in Title 49.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.3 Facilities

A. Pipeline Description

2) Operating Pressure and Temperature

Applicant's Submission

In the Application for a Certificate of Public Convenience and Necessity, exhibit G-II, the Applicant presents the formulation and required data used to determine the normal operating temperatures and pressures of the flowing gas, as well as compressor and chilling station requirements. In exhibit G, the applicant presents flow diagrams which give the predicted pipeline pressure drops and compressor suction gas temperature for maximum daily capability for average summer and winter conditions. Flow diagrams are provided for each of the first five years of operation. No flow diagrams are provided for the peak design flow rate of 4.5 BCFD.

Analysis of Submission

The formulae used by the Applicant is the industry standard for for computation of natural gas pipeline transmission system pressures and temperatures. The critical physical quantity to be calculated is the gas pressure drop along the pipeline. This requires an adequate determination of the pipe friction factor (or transmission factor). The Applicant employs the method recommended by the IGT (Institute for Gas Technology) for determination of the transmission factor. This method requires the value of the effective pipe roughness. The Applicant, as stated in exhibit G-II, uses a value of .0003. This corresponds to values in general use for very smooth steel pipes, and is reasonable for gas pipelines which are internally coated with corrosion-resistant epoxy. An alternate method of obtaining the transmission factor is to use the empirically obtained "Panhandle B" transmission factor equation (which is based on actual pipeline data correlations) as was done in the Batelle Laboratories study performed for the Northwest Project Study Group. Under the flow conditions appropriate for the Alaska pipeline, the transmission factor predicted by the two methods are comparable. The pressure drops given in exhibit G (flow diagrams) thus appear reasonable. Aerospace Corporation checked the results by performing a calculation for the winter - operating year 3 case, which has a flow rate of 2.274 BCFD (standard). The Aerospace Corporation calculated pressure drop along the pipeline from pipeline entrance to station CA-05 (first compressor station across the Alaska-Canada border into Canada) is 383 psi. while the Applicant's is a comparable 375 psi. The difference in calculated values is not significant.

The gas temperature drop along the pipeline is a function of the pressure drop. With the gas being initially chilled to near the in-depth ground temperatures, the temperature drop along the line is mainly due to nonideal gas behavior. For the case of no heat transfer between the pipe and its surrounding soil, the total enthalpy of the gas would be constant. Since the gas flow Mach number is small, the static enthalpy of the gas is nearly the same as the total enthalpy and is approximately constant. If the gas were an ideal gas, its temperature would then be constant along the pipe. However, the gas is not ideal and has a nonzero positive Joule-Thompson coefficient $\left(\frac{\partial T}{\partial p}\Big|_h\right)$, so that the temperature drops as the pressure drops along the pipe. For the 2.274 BCFD throughput case mentioned above, the Joule-Thompson effect alone (neglecting heat transfer to the soil) would decrease the temperature by about 22.5°F. Heat transfer between the pipe and the surrounding soil would reduce this gas temperature drop, for an initial gas temperature of 25°F or less.

The Applicant uses acceptable standard methods (including heat transfer to the soil) for calculating the gas temperature profile along the pipe. Using these methods, calculations made by Aerospace Corporation indicate a gas temperature at entrance to compressor station CA-05 of 13°F, 8°, and 5°F for an initial gas temperature of 25°F and ground temperatures (at pipe center-line depth) of 28°F, 20°F, and 15°, respectively, with a 2.274 BCFD flow rate. For an initial gas temperature of 5°F at pipe inlet, the downstream temperatures are 5°F, O°F, -3°F for mean in-depth ground temperatures of 28°F, 20°F, and 15°F respectively. From exhibit G-II, the average summer in-depth ground temperature is 28°F, and the average winter is 19-20°F, with the minimum average monthly temperature being 15-17°F. For an inlet gas temperature of 25°F and average winter conditions, the Applicant calculates a compressor suction temperature of 9°F, which is comparable to the 8°F calculated by Aerospace Corporation.

The temperature results are based on the Applicant's tabulated values of the Joule-Thompson coefficient. These are obtained from calculations using natural gas compressibility factors determined according to AGA procedures, using the Prudhoe Bay gas composition. Batelle Laboratories, in its study, calculates temperature drops for specific cases. They use a gas enthalpy-pressure-temperature correlation in their calculations. Batelle's estimates for temperature drops, and hence their conclusions, appear to be too pessimistic and are not consistent with results obtained using the Applicant's tabulated values of the Joule-Thompson coefficient (which are reasonable) and mid-pipe depth soil temperatures. Part of the discrepancy arises due to Batelle using a soil temperature of 0°F. (For a ground temperature of 0°F, a flow rate of 2.25 BCFD, and a gas inlet temperature of 25°F, the downstream gas temperature at inlet to station CA-05 is calculated, by Aerospace Corp., to be -4°F.) The Applicant's temperature results appear reasonable.

The applicant does not provide any flow diagrams for the peak flow rate of 4.5 BCFD, as thus provides no indicated calculation of pressure drop. However, in the Applicant's reply to Question 24, he states that the compressor station discharge temperature (after chilling) will be 11°F, which results in a gas temperature of 0°F at arrival to the next station. Four additional compressor stations are contemplated, with an average distance between stations of approximately 45 miles. Aerospace Corp. calculations of pressure drop between these stations, showed a pressure drop of 292 psi. With a gas temperature of 11°F at each upstream segment of pipe, a downstream gas temperature of 2.5°F and -2°F was calculated for average summer and winter in-depth ground temperatures of 28°F and 20°F. For a ground temperature of 15°F, the downstream gas temperature at the end of a 45 mile long segment is -3°F. Thus the applicant's downstream temperature of 0°F is reasonable, although perhaps a trifle optimistic.

The Applicant does not present any considerations of gas overpressure due to valve closure. Therefore, gas surge calculations were performed by Aerospace Corp. for the maximum flow rate anticipated for the Artic gas pipeline, 4500 MMSCFD. A peak overpressure of 46 psi is predicted. (For a flow rate of 2.5 BCFD, a peak overpressure of 26 psi occurs.)

Rapid closure of a valve results in a compression (pressure) wave which propagates upstream away from the valve. An increase in pressure is created which stops the flow. For virtually instantaneous valve shut-off, the overpressure remains at its peak value until the pressure wave is reflected from an upstream obstacle (such as the pipe entrance or another closed valve) and propagates back to the valve. Placement of gas shut-off valves every 15 miles is contemplated. If the first valve downstream of the pipe entrance is rapidly closed, for instance, the reflected wave arrives back at the valve in 160 seconds, relieving the overpressure and causing the decrease in pressure. This condition lasts for another 160 seconds, until another wave has traveled upstream to the entrance, and back to the valve, when again an overpressure occurs which is less than the original peak value of 46 psi due to fluid friction and pipe losses.

The magnitude of the peak overpressure is independent of the location of the closed valve. The duration of the peak overpressure is approximately 10.8•(x) seconds, where (x) is the distance, in miles, from the valve to the nearest upstream obstacle, such as the pipeline entrance, a compressor station, or another closed valve. If the valve is closed slowly but closure is complete in a time less than 10. 8•(x) seconds after initiation of valve closing, the same peak overpressure occurs, but the duration is shorter. If complete valve closure takes longer than 10. 8•(x) seconds, the peak overpressure is decreased. The amount of the decrease depends on the time history of the closing process.

The Aerospace gas flow pressure and temperature, and surge overpressure calculations are shown in the Appendix to this section.

Conclusions

o The Applicant's methodology and required inputs for calculating the operating gas pressures and temperatures along the pipeline are complete and appropriate. The results for the first five years of operation indicated on their flow diagrams in exhibit G appear to be reasonable. However, no flow diagrams are presented for the 4. 5 BCFD throughput case. No results are presented, except the Applicant states in his response to Question 24 that the downstream compressor station inlet temperature will be $0^{\circ}F$ for an upstream station discharge gas temperature of $11^{\circ}F$. (Four compressor stations, approximately 45 miles apart, will be added to accommodate the higher throughput.) The Applicant's temperature drop result was checked by Aerospace and found to be correct.

o The Applicant does not present any considerations of gas surge overpressure due to valve closing, as during emergency shutdown procedures. Nevertheless, the peak overpressure that could occur, 46 psi, is not large relative to the initial gas pressure at the pipeline entrance. This overpressure, if included in determining the pipe design safety factor, reduces the stready-state operating pressure by only 2 1/2 percent. Alternatively, if the maximum operating pressure remains at 1680 psig, the safety factor is equivalently reduced or pipe thickness is proportionately increased. Minimization of gas loss and of gas leak safety hazards would appear to present a strong argument for closing the emergency valves as quickly as feasible rather than purposely slowing down valve closure time so as to reduce surge overpressure.

Recommendations

(a) The Applicant should provide flow diagrams for summer and winter operation for a nominal 4. 5 BCRD (standard) throughput.

(b) All upstream valves between the location of the emergency (leak, pipe fracture, etc.) and at least the nearest upstream compressor station be simultaneously closed as rapidly as possible during emergency shutdown. The Applicant should consider the loads induced by valve closure in the pipeline thickness determination under 1. 1. 1. 3. A. 1 recommendation (a).

(c) The Applicant should conduct a chilled gas effects study as per recommendations (a) and (b) of section 1. 1. 1. 1. B. 2 to reduce possible deleterious effects on frost heave and material properties.

Appendix to Section 1. 1. 1. 3. A. 2

(a) Operating Pressures and Temperatures

The equations and terminology used by the Applicant and given in exhibit G-II, which are the standard ones in the industry, were also employed by Aerospace Corporation.

(1) Pressure loss from pipe inlet to inlet to CA-05, for $Q_b = 2.274 \times 10^9$ (2.274 BCFD)

$$P_2^2 = P_1^2 - C_e - \left(\frac{Q_b P_b}{38.774\, d^{2.5} Z_b T_b F}\right)^2 G L T_{12} Z_{12}$$

Since N_R is greater than N_{R_t} ,

$$F = 4 \log_{10}\left(\frac{3.7d}{k}\right) = 4 \log_{10} \frac{3.7(46.4)}{.0003} = 23.2$$

$$C_e = .0375 \frac{G\, \Delta h\, P_{12}^2}{Z_{12} T_{12}} = \frac{(.0375)(.665)(100)}{(.67)\, 475} \frac{2}{3} \frac{1695^3 - 1320^3}{1695^2 - 1320^2}$$

$$= 3 \times 10^4$$

$$\therefore P_2^2 = 1695^2 - 3\times10^4 - \left(\frac{2.274 \times 10^9\ (14.73)}{38.774\, (46.4)^{2.5} (520)(23.2)}\right)^2 (.67)(224)(475)(.67)$$

$$P_2 = 1312 \text{ psia}\ , \quad P_1 - P_2 = 383 \text{ psi}$$

(2) Gas temperature at inlet to CA-05 for Q_b = 2.274 BCFD

Take K = 1, which is appropriate based on the range of frozen ground conductivities given in exhibit G-II.

$$T_2 = T_a + (T_1 - T_a)e^{-A}$$

$$T_a = T_g - \frac{(P_1 - P_2)J_{12}}{A} - \frac{\Delta h}{j A C_{P_{12}}}$$

$$A = 5280 \frac{2\pi}{\cosh^{-1}(2z/D)} \frac{KL}{m C_{P_{12}}} = \frac{5280(6.28)}{\cosh^{-1}[2(41/4)]} \frac{(1)(224)}{\left(\frac{(.051)2.274 \times 10^{9}}{24}\right)(1)}$$

$$= .93$$

$$(P_1 - P_2)J_{12} = (383)(.055) = 21$$

$$\frac{\Delta h}{j A C_{P_{12}}} = \frac{100}{(778)(.93)(1)} = .14$$

For $T_g = T_{ground}$ = 28°F, 20°F, 15°F, then

T_a = 5°F, -3°F, -8°F respectively

then for T_1 = 25°F,

T_2 = 13°F, 8°F, 5°F respectively

for T_1 = 5°F,

T_2 = 5°F, 0°F, -3°F respectively

(3) Q_b = 4.5 BCFD (L = 45)

P_2 : Since $P_1^2 - P_2^2 - C_e \propto Q_b^2 L$ and $C_e \ll P_1^2 - P_2^2$,

$$\frac{(P_1^2 - P_2^2)_{Q_b = 4.5}}{(P_1^2 - P_2^2)_{Q_b = 2.274}} = \left(\frac{4.5}{2.274}\right)^2 \frac{45}{224} = .79,$$

$$P_2^2 = 1695^2 - .79(1695^2 - 1320^2)$$

$\therefore P_2$ = 1403 psia, $P_1 - P_2$ = 292 psi

T_2 : $A \propto L/Q_b$

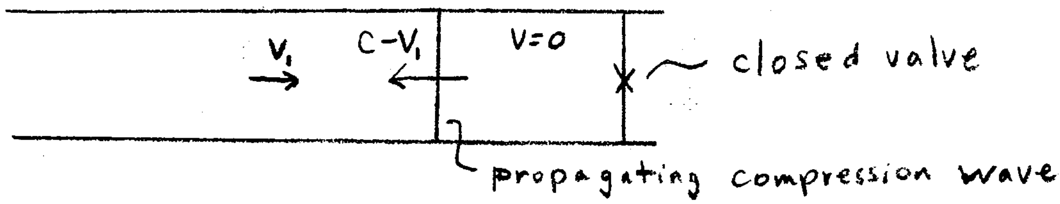
$$\therefore A = \frac{45}{224} \frac{2.274}{4.5}(.93) = .095$$

For T_g = 28°F, 20°F, 15°F, then,

with T_1 = 11°F,

T_2 = −2°F, −2.5°F, −3°F respectively

(b) Gas Surge Peak Overpressure (Q_b = 4.5 BCFD



Valve closure initiates a shock wave traveling at velocity C relative to the undisturbed gas. The overpressure due to valve closure is the pressure increase across this compression wave.

$$\Delta p = mC = \frac{P_b Q_b}{g R T_b z_b \frac{\pi}{4} d^2} C$$

$$C = \sqrt{\gamma_1 R T_1 z_1 g} = \left((1.29) \frac{1544}{19.25} (475)(.62)(32.2) \right)^{1/2}$$

$$= 985 \text{ ft/sec}$$

$$\therefore \quad \Delta p = \frac{(14.7)(4.5 \times 10^9)/(24)(3600)}{(32.2)\frac{1544}{19.25}(520)(1)\frac{3.14}{4}4} (985)$$

$$= 46 \text{ psi}$$

1.1.1.3 Facilities

C. Description and Operating Characteristics of Plants, Compressor Stations, and Related Facilities

1) Treatment, Measurement & Compression

Applicant's Submission

For the initial period covered by this submittal, building up to a flow of 2.24 BSCFD, there are no provisions for Compressor facilities in Alaska with exception of the Prudhoe Bay station.

Four maintenance station locations are identified as sites for future expansion into compressor stations if deliveries increase to 4.5 BSCFD. A gravel-padded area of approximately 15 acres each is planned for these maintenance sites so that required buildings and equipment to be added for such conversion could be accommodated. A separate environmental impact assessment would be made prior to such action.

The four future compressor stations would be similar in design and a typical station description was given. The submittal identified the additional buildings for housing operating equipment and ancillaries needing weather protection. At each site, it is proposed to install a single, nominal 27,500 or 30,000 HP gas turbine driver and centrifugal gas compressor to recompress the pipeline gas flow from suction pressure to 1680 psig. The suction side of each compressor would include gas scrubbers to protect against particulate ingestion such as condensed liquids or dirt. The compressors will be equipped with surge controls. The gas turbine drive units operating on air and natural gas bled from the pipeline will have an intake air anti-icing system in addition to filters and will be equipped with intake and exhaust silencers.

A gas-turbine-driven (17,000 HP) refrigeration system using propane as a refrigerant would be installed to cool the recompressed delivery gas to sub-freezing temperatures. This is done in order to maintain the permafrost temperature levels along the buried pipeline. The propane, contained in a closed loop, will extract the heat of (mainline gas) compression using surface heat exchangers referred to as "gas chillers" by the Applicant. The major equipment items are all housed, except for the air-cooled propane condensers (not to be confused with the above-mentioned chillers) and the propane receiver. The submission states that the stations will be operated by remote automatic control from the Gas Control Center. While all prime movers (turbines) are natural-gas-powered, the on-site turbine generators for electrical power can switch to standby liquid fuels in emergencies. All buildings housing equipment containing natural gas or propane will contain gas leakage detectors, flame detectors, alarm signal systems (at Gas Control Center), automatic shut-down) capability, and inert gas fire-fighting systems. During an emergency shutdown, 3750 MSCF of natural gas within the station block valving would be vented to atmosphere. Emergency venting of propane would be accomplished automatically upon detection of fire within the propane compressor building. However, the pressurized propane would not be vented to atmosphere; instead, it would go to a closed flare system.

Design equations, data on likely gas composition and properties, and related information dealing with compressor station equipment sizing analyses to support the information given were contained in Exhibit G.

Clarification of certain information contained in the submittal was provided in response to question (24). Basically, the Applicant stated that specifications are as yet preliminary. Analyses have been carried to the point of assessing and assuring availability of major equipment items using conventional state-of-the-art technology. Equipment selection, including possibly multiple units at a compressor station will be made on the basis of providing lowest cost service at the optimum volume. The stations will be designed to operate unattended.

Matters regarding operating safety in the question response provided some new information. Sensors are planned for protection of compressors from excessive vibration and bearing temperatures, also there are to be isolation valves for the pressurized propane in the refrigeration system, if a fire should occur. Emergency battery power is planned and manual operation of certain emergency valves has been considered.

There is one measurement station planned for Prudhoe Bay and another will be located in Canada. Multiple meter runs, including a spare will be provided. These will be housed in buildings. Gas composition measurements will be made. Decisions concerning equipment types are being deferred. Special equipment not normally used in pipeline measurement stations may be required to assure compliance with the dew-point specification. Gas water content and other contaminant levels will be kept within limits commensurate with good pipeline practice.

Analysis of Submission

The compressor station description is typical for gas pipeline transport systems except for the propane refrigeration system needed to protect the permafrost by chilling the pipeline flow.

All proposed compressor facilities should be designed, constructed, and operated in compliance with Part 192, Subpart D, Title 49, Code of Federal Regulations, "Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards". Facilities construction should also be in accord with OSHA requirements. This was not indicated.

The trend in modern pipeline systems is toward a single large gas-turbine-driven centrifugal unit. The use of single large compressors at each station may be defended from an economic standpoint. Process industry experience has shown that trouble-free operation of gas compressors is obtainable with the use of diagnostic monitors such as vibration, temperature, and proximity sensors to prevent damage by warning of changes in the condition of rotating machinery (Wett, 1973; Jackson, 1974). One paper noted, however, that it may not be desirable to depend entirely upon a single large piece of rotating equipment for each train. Expected downtime required for routine maintenance and availability of units during the first five operating years was given for the Prudhoe Bay compressor facilities. Descriptions of these facilities show eight compressors in the first stage train. If the expansion proceeded with installation of the four large compressors, it is not known how much the pipeline capacity would be reduced from 4.5 BSCFD with one of the compressor units down.

The basis used to establish compressor power requirements is conventional. A crosscheck of the Applicant's submission shows that a 30,000 GHP compressor (80% polytropic efficiency) is capable of handling 4.5 BSCFD of gas having the Prudhoe Bay composition (85.11 vol. % CH_4 - Exhibit GII) with a repressurization approaching 325 psi to an outlet of 1695 psia.

The fact that the Applicant stated the need for anti-icing equipment on turbine intake air is noteworthy. Problems with turbine operations in the North Slope region owing to the lack of proper attention to this detail have been reported (Stenson, 1972). The low temperatures have contributed to ice fog formation (especially in the vicinity of a water vapor source such as engine exhaust), and other weather difficulties. Turbine damage (air compressor), power losses, and frequent shutdowns, have resulted. It is not known how the anti-icing equipment will be sized, how much turbine exhaust-generated ice might be inducted, or how such induction shall be avoided.

Several questions appear with regard to operating safety of the refrigeration system. The Applicant's statements indicate how the propane will be handled in case of a fire. Propane venting to atmosphere must be avoided because the vapors are denser than air. It is not practical to prevent leakage altogether in normal operations and in the event of a fire, the risk of encountering a serious leakage situation within a building is greatly enhanced. The danger of a severe accident resulting is then also enhanced. It is understandable that the Applicant should consider propane as a likely refrigerant as it is probably the most economical readily available fluid. It is not known whether any other non-flammable media were considered as candidate refrigerants.

Conclusion

Considering the facts that no compressor stations are included in the initial request and extensive lead time is involved before expansion is anticipated, a satisfactory amount of general information has been supplied.

Recommendations

(a) Future design data submitted to DoI for approval of compressor status should include trade off data showing the total economic impact of compressor stations with single large compressor units versus compressor stations comprised of two or more units with standby capacity to maintain station capability during maintenance operations or during single compressor failures. This trade-off should consider the remote location of these compressor stations and the down time involved or flow capacity lost from compressor failure.

(b) Since proper operation of the pipeline and facilities depends upon the gas properties, it is necessary to control the composition and concentrations of water, corrosive elements and solid contaminants, etc. which will exist at pipeline entry. The Applicant shoulddevelop a specification stipulating the composition and properties of the gas which will be accepted for input into the pipeline with special emphasis on the types and amounts of contaminants.

(c) The Applicant should examine the safety aspects and industry experience involving the use of propane as a chilling fluid versus other nonflammable refrigerant alternates.

(d) A unique feature of buried natural gas pipeline transport systems in permafrost is represented by the need to chill compressed gas. Current Federal Standards dealing with Compressor station design and safety overlook such refrigeration facilities. The need for future revisions should be considered a subject for study.

1.1.1.3.C.1 (Cont.)

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1. DESCRIPTION OF PROPOSED ACTION

1.1.1.6 Construction Procedures

B. Unique Pipeline Construction Techniques

1. <u>Ditching & Snow Roads</u>

<u>Applicant's Submission</u>

The Applicant proposes to use conventional pipeline construction techniques whenever possible. The applicant indicates that 75% of the length will be excavated by a wheel-type ditching machine. The Applicant claims to have conducted a ditcher testing program in frozen silts during the winter of 1972-73, at Churchill, Manitoba on special heavy duty wheeled ditching equipment designed for arctic service and plans to conduct additional testing in the winter of 1973-74 on newly developed ditcher components. He substitutes a snow road over the right of way in lieu of the usual work bed.

<u>Analysis of Submission</u>

The arctic region with its sub-freezing temperatures requires methods which deviate from the more usual gas peipeline construction techniques, specifically --

(a) Ditching in large expanses of Permafrost

(b) Use of Snow Roads as a work bed

The Applicant does not state the degree of success or failure in his testing programs on ditching equipment,the degree of reliability and maintainability that ditching equipment experienced in the arctic environment tests.

Previous ditching tests performed in frozen gravel for the hot oil pipeline indicated that in the case of the frozen gravels, equipment wear was extreme and excavation rates were very low. Problems with maintaining a uniform ditch depth were also noted for the case of stratified deposits.

The Applicant admits that he does not now have an acceptable blasting method (Battelle 1974). The schedule requires that the Canadian leg will be constructed first, and there is no doubt that acceptable methods can be developed with reasonable study.

The Applicant plans to use snow roads for a work bed. Practices for the construction and use of snow roads are not well defined in the Applicant's basic submission. In answer to DOI questions 9, 25 and 41 substantial detail is provided on snow cover in the region. While a thick road will minimize the damage to vegetation in the active layers, it will remain longer in spring and delay spring growth which is necessary for erosion control. This coupled with the additional moisture from melted snow will aggravate drainage problems and increase the conditions for solifluction and skin-flows, etc. Establishment of adequate requirements for snow roads, such as minimum thickness, compaction and surface preparation is necessary to insure minimum effect on underlying vegetation. The Applicant does not address these requirements.

The question of snow supply adequacy is a serious one. The snow supply in any one year is uncertain. If the snow supply is at the minus 2 Sigma Level the project may be threatened. Means of increasing snow along the right of way are necessary to insure sufficient quantities in a timely manner. Experience indicates that snow work pads may not be constructed and operational until the first week or two in November. By mid-April, as temperatures warm, the snow work pad will start to deteriorate. Thus, the construction season based on the use of a snow work pad is about 5 months during which time all work requiring heavy wheel loads will have to be accomplished. Logistics problems that often develop in a project of this magnitude may cause a slip in schedule which could result in a full year being lost unless alternate work pad design concepts, adaptable to late spring and early fall conditions, are developed.

An additional 30 days of schedule may be gained by resorting to the development of an ice road structure, which requires 40,000 to 50,000 gallons of water per mile, less whatever snow could be accumulated in the early winter.

Conclusions

Additional development of ditching and blasting techniques is required. Snow road criteria must be provided. Snow logistics must be studied in detail.

Recommendations

(a) The Applicant should provide a detailed plan for developing ditching and blasting techniques appropriate for ditching in frozen gravels and other stubborn permafrost areas.

(b) The Applicant should provide snow road criteria, including requirements for thickness and density.

1.1.1.6.B.1 (cont.)

Recommendations

(c) The Applicant should provide a logistics and contingency plan for snow and/or ice roads in the event of a minus 2 Sigma snow fall.

(d) The Applicant should provide test data substantiating the feasibility of wheel type ditching equipment for use in permafrost.

Reference:

Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)", Columbus, Ohio

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.6 Construction Procedures

B. Unique Pipeline Construction Techniques

2) Backfill

Applicant's Submission

The Applicant indicates that where ragged rock or frozen fill is encountered, padding material or rockshield will be applied to protect the pipe.

The Applicant provides little information on backfill problems in his original application. Battelle conducted a test program on backfill and the reports are provided in response to Question #25.

Analysis of Submission

The Applicant recognizes the need for pipe protection for rough ditch conditions.

The Applicant does not state that he will comply with all of the Battelle recommendations to preclude subsidence and ponding when high ice content backfill materials are utilized. To remedy the subsidence and ponding use of problems the supplemental borrow, 50% overfill, and side overlap over the ditch are cited. The side overlap is required to prevent thaw depressions and to impede ambient thermal inputs into the ditch walls.

Conclusions

The results of the Applicant's backfill test program pointing to the need for supplemental borrow, 50% overfill and side overlap appear valid and should be instituted.

Recommendations

(a) The Applicant should provide for review and approval, criteria for backfill material, configuration and procedures for installation. These criteria and procedures should be substantiated by test data which shows that ponding, thaw depressions and ditch sidewall degradation are avoided when the criteria and procedures are adhered to.

Reference:

Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)", Columbus, Ohio.

1.1.1.6 Construction Procedures

C. Plants, Stations and Related Facilities Construction Techniques

2. Site and Building Construction

Applicant Submission

Compressor stations will not be built in the first five years of the pipeline operation and the construction of compressor stations will be the subject of a separate application. Permanent buildings will be placed on granular pads of sufficient thickness to prevent degradation of the permafrost.

Analysis of Submission

Possible approaches for maintenance of the permafrost are: (1) providing either ventilation space between the structure and the ground surface, (2) a ventilation duct system, or (3) a thick gravel pad. The Applicant has not provided any analysis to show that a gravel pad is an acceptable solution for a steady state heat input into the ground from the operation of heat generating equipment and the heated building itself. In making any analysis, the radiant heat collected by the exterior walls of the building and conducted to the ground must be added to any internally generated heat. It appears, however, that this proposal is incompatible with maintenance of the permafrost and methods such as air cooled or refrigerated pad; pile driven into permafrost with adfreeze provisions; or the thermopiles may be required.

The topography and geology of the sites are discussed in section 2 of the environmental report. Foundation systems for the building facilities, workpads, roads, airfield and communication will all require design for permafrost and soil conditions quite similar to those existing at Prudhoe Bay. While utilization of similar foundation concepts may be appropriate for these sites, the design analysis for specific foundation units should be based on appropriately selected parameters. Sufficient justification for selection of such design parameters, including detailed subsurface soils information, are required for each site.

In particular the location of the second compressor station CA-02 - MP 83.0 may not be optimum. The location is questionable since it is within the ice rich silt mantled deposit with the possibility of high termal sensitivity and potentially unstable massive ice. A single test hole, AG 546, has been placed adjacent to the proposed site and disclosed highly ice rich material to the full depth of the 20 foot boring. A second boring, AG 545, placed approximately one mile west of the site in a lower lying old outwash deposit, encountered 15 feet of well graded gravel. Problems associated with these foundation conditions range from high sensitivity to thermal erosion and degradation to unacceptable creep or strains for moderate loading on piles placed in the massive ice and ice rich soils. The potential for headward gulley advancement toward the proposed station site, particularly in view of the imposed construction activity, should be evaluated since any such erosion could extend into the site within a short period of time.

Based on the single test hole, (AG 546 results), it appears that the outwash deposit may provide significantly better foundation and site development conditions than those that exist at the presently proposed compressor station site.

1.1.1.6.C.2 (cont.)

The Applicant's proposed Compressor Station No. CA-03-M.P. 129.2 is located in the transition area between the Arctic Foothills Province and the Eastern Arctic Coastal Plain Province. The station site lies approximately one half mile west of the Jago River and is situated on a fossil flood plain generally containing up to several feet of silty sand overlying well graded sandy gravels.

The Applicant's test hole AG 567 was placed adjacent to the proposed site and encountered silty sand to a depth of 2.5 feet continuing through sandy gravel to the depth of the boring which was terminated at 17 feet below ground surface. The soil data indicated relatively high moisture contents for the frozen sandy gravel. Presence of thawed ground is not expected in this soil unit except possibly adjacent to shallow drainages or the river bluff.

Foundation conditions for this soil unit are expected to be good; however, the high moisture contents noted for the underlying frozen gravel indicate that thaw settlement strains must be considered if thermal degradation extends down to this material. The airfield is shown to be located in the thicker ice rich silt mantle terrain unit and, as such, will be placed on poorer foundation materials.

As for the other station sites, design detail containing specific information on related parameters must be provided in order to allow proper evaluation of the proposed site.

Compressor Station No. CA-04 is located in the Eastern Arctic Coastal Plain Province, approximately 3.5 miles east of the Kongakut River.

1.1.1.6.C.2 (cont.)

The site is situated on an alluvial fan deposit typically containing thin silt cover overlying silty to clean sand and gravel having relatively low ice contents. Permafrost is essentially continuous.

Topographic relief at this site is characterized by midly north sloping ground and numerous minor drainages. The Applicant's test hole AG 573 was placed at the compressor station site and tended to confirm the above generalized terrain unit description. The test hole indicated the presence of a poorly graded sand gravel to the depth of the boring which was terminated at 7.0 feet below ground surface. This boring depth is inadequate for defining the range of possible foundation soil conditions that may apply to the site ana further exploration information is needed in order to identify foundation requirements.

The location of facilities on specific terrain units is nearly identical to those for Compressor Station No. CA-03 and the general comments made for that station apply equally as well to this proposed site.

Conclusions

- o Insufficient subsurface soil information exists to determine adequacy of preliminary sites. Detailed site studies are lacking for the compressor stations and airfields. The variability of the soil requires deep bore hole data at the exact locations.
- o The particular location of CA-02-M.P. 83.0 is open to question because a bore hole 1 mile west of the proposed site indicates the presence of more stable soil.

1.1.1.6.C.2 (cont.)

Conclusions

- o The proposed construction of compressor site foundations is not clear. Placing the buildings directly on the gravel pad would lead to long term degradation of the permafrost.

Recommendations

(a) The Applicant should conduct a detailed site study for each compressor site and airfield along with possible alternates. Included therein should be all the appropriate parameters such as subsurface soils, and drainage properties.

(b) The Applicant should provide a detailed design analysis for his compressor station foundations to insure permafrost maintenance.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.6 Construction Procedures

D. Testing Procedure

1.) Hydrostatic Testing

Applicant's Submission

Field testing will consist of hydrostatic proof pressure testing. The procedures will be conducted according to detailed specifications which will be developed prior to start of the testing program in conformance with applicable codes. Proof pressure testing of a line segment would be conducted after construction and backfilling of a line segment. No gas testing or warm water testing (response to Question #39) is planned; instead, a solution of water containing methanol as a freeze depressant is currently being considered. The concentration of methanol has been indicated as 26%, consistent with a minimum expected subsurface temperature of $0^{\circ}F$.

Water sources and requirements were covered in response to Question (41). Details concerning withdrawal rates are being deferred pending the results of field surveys prior to construction. Methanol requirements have been estimated as 640,000 Imperial gallons.

Operations relating to filling the pipeline are covered in response to Question #40. In the relatively flat terrain, test section lengths of 3 miles are planned. The test fluid would be mixed before entering the first test section and moved from section to section as construction proceeds. Reserve fluid for about two miles of pipeline will be prepared. Approximately 55,600 barrels of solution is needed to fill 5 miles of 48-inch pipe.

In the event of an accidental spill of test media containing methanol, it will be allowed to pond. The suction pumps will then be used to recover as much of the spill as practicable, and it will be stored in bladder-type storage tanks.

After completion of a test and transfer of fluid to the next section, methanol will be used to dehydrate the pipeline.

1.1.1.6.D.1 (Cont.)

Analysis of Submission

Hydrostatic testing represents the usual method of proof testing a pipeline in the field. The main purpose is to prove that the components will withstand worst case internal static pressures without rupture or leakage. Conversely, an indirect purpose of such tests (before commitment to service) is to induce failure of structural material of insufficient strength due to previously undetected manufacturing flaws (such as cracks or occlusions), flaws occurring in transit, or fabrication faults (such as weak weld joints).

Consideration must be given to proper procedural details to assure success. This is measured in terms of ability to perform the test while in compliance with specific sections of cited safety regulations. Proper specification of test pressures, selection of appropriate test fluids, avoidance of overpressurization, ability to detect failures and make necessary repairs, handle spills and leaks, provide for appropriate safety precautions on the part of test personnel, assure satisfactory removal and waste disposal of test fluids, are examples of items requiring definition.

Federal standards and safety regulations pertaining to gas transportation pipeline systems hydrotesting include (1) Department of Transportation Regulations, 49 CFR, Part 192, "Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards". Compliance with these regulations was not indicated by the Applicant.

In the case of the Alaskan pipeline construction, a problem area involves selection of a satisfactory test fluid. The preferred hydrostatic test medium for pipelines is normally water, sometimes containing small amounts of nontoxic corrosion inhibitors and leak detectors in the form of odorants or dyes. In certain situations, the fluid which is to be pumped through the completed pipeline is used, or other substitutes are employed. The prevailing subfreezing weather conditions in the North Slope Alaska region necessitates selection of a test medium with a lower freezing point than water. DOT 49 CFR, Part 192 allows the use of air, natural gas, or inert gas testing but does not mention methanol solutions. DOT 49 CFR Part 195 "Transportation of Liquids by Pipeline" does indicate the use of methanol and other anti-freeze fluids where frost conditions prevail.

Operations relating to conducting the pressure tests for pressure proofing and leakage determination, and activities relating to safe operations involving the handling and use of methanol have not been discussed at all within the hydrotest section. Methanol in undiluted form is a flammable, toxic liquid. It is completely miscible with water so that handling and fire hazards diminish with water dilution. However, prior to dilution, methanol is known to produce blindness through ingestion or narcosis through inhalation. The threshold limit value for vapor inhalation by workers under repeated exposure is 200 ppm. The flash point of methanol is 52°F and the autoignition temperature is 878°F. Avoidance of the need for a worker to enter a vaporfilled line has been overlooked. Should such an eventuality occur, provisions for the use of proper breathing apparatus would be necessary.

The Applicant has not stated how the test pressure will be specified. It is usually the pressure required to stress the pipe to a level between 85 and 100 percent of minimum yield strength. This test pressure is above normal operating levels. The hold time, if any, was not stated. Methods such as use of dyes for detecting small leaks are also not covered by the Applicant.

The Applicant has not indicated what the allowable water concentration limit might be in the rinse liquid before deeming it unacceptable for reuse.

Conclusion

The use of methanol as a freezing point depressant in a water solution for hydrostatic testing appears reasonable provided proper handling procedures are followed. However, methods for detecting small leaks must be carefully considered.

Recommendations

(a) The Applicant should propose a detailed hydrotest procedure as per Recommendation (b) of Section (1.1.1.3.A.1).

(b) The Applicant should develop appropriate handling procedures and personnel safety practices taking into consideration the toxic nature of methanol vapors.

(c) The Applicant should provide means for small leak detection during hydrotest.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.6. Construction Procedures

D. Testing Procedure

2) Water Quality

Applicant's Submission

Either dilution with water or distillation is mentioned. Residual solutions will not exceed 1% methanol concentration. The diluted solution will be disposed of by controlled spray dispersal onto snow surfaces or land so as to prevent undue flooding, erosion or siltation. Final selection of the disposal technique is stated to be dependent on an assessment of environmental considerations.

Preliminary studies have shown that high concentrations of methanol are not harmful to vegetation, and work in the laboratory has indicated that fry of Arctic char and grayling were not adversely affected by concentrations of less than 1% solution of methanol even with exposure of µp to a week.

Tests conducted near Inuvik, N. W. T., have shown that winter application of a water/methanol solution does not detectably effect shrub-tundra vegetation. The release of test fluids onto land is not anticipated to have any adverse effect on terrestrial or riparian vegetation.

Methanol recovered by distillation will either be reused or disposed of by burning.

Analysis of Submission

There is an inconsistency in statements because the Applicant has noted under Waste Disposal that distillation and dilution of the test solution to a concentration of 10 ppm methanol will be accomplished. Thereupon, the Applicant states that residual solutions to be discharged will not exceed 1% methanol. The nature of the studies and the laboratory efforts mentioned by the Applicant are not described in detail and are not known.

1.1.1.6.D.2 (Cont.)

Conclusions

Considering the fact that the methanol will be reused, the disposal question does not appear to present a serious problem.

The only fluid requiring disposal will be material recovered from leaks and spillage.

Distillation is considered to be an ineffective way of disposal from an energy standpoint. Dilution is preferable.

Recommendations

None.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.7 Operational, Maintenance and Emergency Procedures

A. Technical and Operational Feasibility

1) Valves, Controls and Pipeline

Applicant's Submission

The operations and maintenance planning of the Applicant is based on the use of automatic, unattended equipment at the measurement and maintenance stations, communication sites, and mainline block valves. A communication system extending along the entire length of the pipeline will provide voice services, data transmission for the supervisory control systems, and maintenance information related to equipment performance. Tentatively, a terrestrial microwave communication system has been selected, with five primary communication sites, located at Prudhoe Bay and near the four maintenance station sites, and four repeater communication sites located between each primary site. The system will tie together the Applicant's Field Operating Headquarters at Prudhoe Bay with the Gas Control Center located in southern Canada.

Mainline full-opening block valves will be placed at the beginning of the pipeline, at each maintenance station, and along the pipeline at approximately 15-mile intervals. They will have automatic controls to close the valve when a rate of change of pressure is sensed that indicates a break in the pipeline. Applicant also refers to manual operation of these valves and the inclusion of the necessary blowdown valves and stacks.

Scraper trap assemblies will be located at the maintenance sites. A description of components and operation is provided.

If compressor units are installed at the maintenance stations in the future, they too will be designed for automatic, unattended operation. Discharge pressure and temperature set points and unit start-stop will be controlled remotely or locally. Stations will be self-protecting, with safety devices to shut down the station under hazardous conditions. The initial pipeline design will allow the compressor stations to be connected and activated with no significant interruption of gas delivery.

Analysis of Submission

The Applicant has not mentioned any installation of pressure limiting or pressure relieving devices. The gas supplies should provide pressure relieving devices upstream of the delivery point to protect the pipeline. Future compressor stations should also provide for pressure relief protection of the pipeline. Such devices are an important feature in maintaining pipeline integrity and should be discussed.

There is no reference to odorizing gas service lines in the maintenance (and later compressor) stations. Since these sites will occasionally be occupied by personnel, it would seem prudent to odorize the gas despite provision of hazardous gas detection equipment.

Since design specifications for control equipment have not yet been prepared, it is impossible to comment on their adequacy. Of particular concern is the design of the automatic block valves to assure they will function properly during exposure to the low winter temperatures.

The scraper trap assemblies will be at ambient, relatively high temperatures during the summer months. The Applicant should present any test data or analysis available as to whether the heat flow back to the pipeline can cause local thawing of the permafrost. A similar question applies to the block valves and vents which also extend to the surface.

Conclusions

o The Applicant has presented a general overview and concept definition for the pipeline valving, control system and appurtenances. Yet to be prepared are the equipment design specifications, piping and electircal diagrams, and the operation and maintenance plan. Additional items also needing final resolution are covered under separate topics (see, for example, Corrosion Checks, Section 1. 1. 1. 7. B. 1). Consequently, it is difficult to critique technical features that are still in a very nebulous state.

o The many natural gas transmission lines in the lower 48 states that operate automatically, unattended, by remote control, with few major mishaps attest to the feasibility of the Applicant's operational concept. However, the North Slope environment is far more fragile than that heretofore experienced in the lower 48 states. It is incumbent, therefore, that design details be carefully scrutinized as they become available to insure that they are capable of meeting the environmental stresses imposed and that all foreseeable conditions have been considered.

Recommendations

(a) Plans should be defined for protection of the pipeline from overpressure, both in the initial stages and when the compressor stations are activated.

(b) Plans should be defined to odorize the gas in the service lines to the maintenance stations and, later, to the compressor stations.

(c) Data or analysis should be presented regarding heat soakback from exposed piping, such as from the scraper trap assemblies and mainline block valves.

(d) Design specifications should be prepared for the control and communication equipment, when available.

(e) An Operation and Maintenance Plan should be prepared.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.7 Operational, Maintenance and Emergency Procedures

A. Technical and Operational Feasibility

2. Process and Treatment Descriptions

Applicant's Submission

The pipeline system does not provde for any processing or treatment of the flowing gas. The product accepted at Prudhoe Bay for transportation through the pipeline will only be subjected to pressure and temperature changes resulting from frictional losses and heat transfer with the pipe wall. In the event that the flow rate is increased beyond the 2250 MMCFD value, additional compression/refrigeration equipment will be required along the pipeline. The Applicant has also discussed some of the compositional requirements of the gas acceptable for transmission in his pipeline.

Analysis of Submission

The Prudhoe Bay raw gas contains relatively high concentrations of carbon dioxide and sulfur which must be substantially reduced at the processing/compression station (not a part of the pipeline system) before delivery to the pipeline (see Section 1.1.1.3.C.(1)). The consequences of improper processing of the gas include the formation of liquid and solid phases in the pipeline and development of conditions conducive to internal corrosion.

Conclusions

No processing or treatment of the gas along the pipeline will be provided for, nor should it be necessary if the composition of the incoming gas is adequately controlled and if condensation of any of the constituents does not occur. Later addition of compression/refrigeration equipment will require some processing equipment, e.g., gas scrubbers to protect the compressor units.

Recommendations

The Applicant should develope a specification limiting contaminates as per recommendations (b) of Section 1.1.1.3.C.1.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.7

A. Technical and Operational Feasibility

3.) Testing and Startup

Applicant's Submission

The initial hydrotest procedure for the pipeline is described and evaluated in Section 1.1.1.6.D. This section is specific to the immediate steps proceding initiation of gas transmission.

The Applicant has provided a brief description of the startup sequence. The Measurement Station at Prudhoe Bay will be commissioned first; all facilities and instrumentation necessary to measure operating parameters will be tested for accuracy and performance after installation. Piping in the Measurement Station will be purged with nitrogen to eliminate all air.

The mainline purge will be accomplished in sections, using a pig to prevent mixing of the gas and air. The natural gas system for maintenance station facilities will be purged and activated. All station water handling facilities will be tested to assure correct chemical treatment and filtration. The emergency shutdown systems will be tested. The maintenance station facilities will initially be manned until the system has been approved for unmanned operation.

Analysis of Submission

The descirption of the startup procedure does not, of course, take the place of a detailed, step-by-step startup plan that will have to be prepared later. Consideration of the procedures involved indicate that, in general, they are similar to those used in commissioning natural gas lines in the lower 48 states. This also applies to the startup of future compressor stations. However, there are a few unique conditions on the North Slope that will require some additional care in executing the pipeline startup sequence.

Since the present plan is to commence operation of the pipeline in the summer months, it will be necessary to control the startup activity and associated traffic along the route to avoid damage to the terrain. Inasmuch as the activity involves personnel rather than heavy equipment, most of the transportation can probably be by air with minimum impact on the environment.

Another caution is that all purging of the mainline must be done using chilled gas. Whether the slug of nitrogen gas usually placed ahead of the purge pig needs to be cooled will depend upon its size and a thermal analysis of its effect on pipeline temperature.

Conclusion

Only a rudimentary description of the checkout and startup procedure has been supplied.

Recommendation

The Applicant should provide a detailed startup plan.

B. Maintenance Procedures

1.) Corrosion Checks

Applicant's Submission

Two methods will be used to control external corrosion of the pipeline: an external coating plus a cathodic protection system. Two basic coating systems are described, either of which may be used on different segments of the pipeline. One technique is to apply a continuous polyethylene tape over-the-ditch with an outerwrap of polyethylene rock shield. The alternative approach is to use pipe precoated with a fusion-bond epoxy and then field-cost the girth welds with either polyethylene tape, shrink sleeves, or direct application of epoxy material equivalent to the precoat. Full encirclement holiday detectors will be used to check the integrity of the coating.

The cathodic protection system will comprise an impressed DC current source and ground bed anodes at or near each maintenance station, test leads at approximately one mile intervals, and galvanic anodes where specially required. The type of ground bed construction to be used will depend upon the particular conditions at each site following detailed testing. Cable trenches will be 24 to 30 inches in depth and up to 2 feet in width. Energization will be accomplished as soon as practicable following construction of the pipeline section.

Internal corrosion will be controlled by limiting the water content of any gas accepted for transportation to an amount that will preclude the accumulation of water or a water solution on the steel surfaces. Routine monitoring of internal corrosion will be carried out using corrosion-rate monitoring probes at station inlet points.

Corrosion of pipe, fittings, valves, and vessels exposed to the atmosphere will be controlled by covering them with a suitable paint system.

Analysis of Submission

Corrosion was the major cause (78%) of all gas transmission line leaks in the United States in 1973 (Office of Pipeline Safety data). Major leaks were predominantly caused by damage from outside forces (58%) but corrosion still accounted for 13% of the failures. Thus, it is important that the corrosion control system be carefully designed.

The selection of polyethylene or epoxy coatings as generic classes appears to be satisfactory for this application, providing the specific materials are correctly specified and properly applied. As the Applicant indicates, some sections of the pipe may require a thicker coating than the average, for example, at river crossings and where concrete weighting is used. Applicant states in response to Question 24 that tests have been performed to determine the suitability of various external coating systems under simulated operating conditions, also that preliminary specifications have been prepared covering the application of various pipe external coating systems. Test results and the preliminary specifications should be requested from the Applicant.

The description of the cathodic protection system is too vague to make a technical assessment. Applicant states in Appendix A of his Environmental Report, and in response to Question 24 that tests have been performed to determine that buried structures can be successfully cathodically protected in permafrost; a description of the tests and the results should be supplied.

Adherence to the Federal Regulation (DOT FR, Part 192) covering cathodic protection systems will generally insure adequate pipeline protection. However, such regulations are minimum standards, emphasizing monitoring test requirements, and provide no design information. For example, it is permissible to go as long as 15 months between test lead potential measurements along the pipeline; an early failure in this period could go undetected for many months while the pipeline corroded. Thus, most gas transmission companies conduct surveys on a quarterly basis. As another extreme case, if the Applicant's design proves inadequate when installed, an extended period of modification may be needed before the regulations could be met. Therefore, it is recommended that the Applicant submit his design for the cathodic protection system for review by DOI.

With regard to internal corrosion, the Applicant's approach of controlling the water dewpoint of the incoming gas to prevent condensation in the line is adequate for any fuel gas of commercial grade. (A NSI B31. 8-AGO)

The Applicant's further criteria that contaminants will be kept within limits commensurate with good pipeline practice (response to Question 24) reinforces this conclusion; however, he has not specified what such limits would be. The subject of gas purity is discussed further in Section 1.1.1.3.C.1.

Conclusions

The Applicant's general approach to corrosion prevention is correct as far as it goes but additional information needs to be furnished for a detailed and complete assessment.

Recommendations

(a) Test description and results, as well as preliminary specifications for the external coating system should be provided.

(b) Test description and results showing the feasibility of cathodic protection in permafrost should be provided.

(c) A detailed description should be provided of the impressed current and sacrificial anode (if used) cathodic protection systems, including power supply, cabling and maintenance plan.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.7

B. Maintenance Procedures

2.) Corrosion Prevention

Applicant's Submission

Routine monitoring of internal corrosion of the line may be carried out using corrosion measurement probes at station inlet points. Inspection and painting of all above-ground painted surfaces, followed by reparis as required, will be part of the regular maintenance program. Ground patrols will include inspection of monitoring systems, which is interpreted to include cathodic protection test lead measurements.

Analysis of Submission

The Applicant has not specifically described his plan for surveillance of the cathodic protection system, including what measurements and inspections will be made, their frequency, who will make the measurements, and the reporting system. Although Federal Regulations set certain minimum requirements, the Applicant should provide his plan for implementation considering the special conditions of weather and terrain applying to this pipeline.

Conclusion

The Applicant has not provided sufficient information on this subject.

Recommendation

The Applicant should provide a test and surveillance plan for the cathodic protection system.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.7 Operational, Maintenance and Emergency Procedures

C. Emergency Features and Procedures Feasibility

(1) Design Features for Geological, Meteorological, and Man-Induced Hazards

Applicant's Submission

The construction approaches proposed by the Applicant to satisfy the more obvious geotechnic requirements, e.g., slope instability and seismicity, are evaluated in other sections of this report. This discussion covers several design measures that can mitigate the effects of abnormal or hazardous pipeline conditions.

Mainline block valves will have automatic controls to close them in the event of a pipeline break, thus limiting the amount og gas released to the atmosphere. Emergency shutdown and fire extinguishing systems will be installed in meter and maintenance facilities, and future compressor buildings. Major mechanical equipment will be self-protecting, with automatic shut down, and venting in the event of unsafe operating conditions, such as excessive vibration or high bearing temperature.

Passing reference is made to pipeline mileposts. Since the pipeline route is in an area of little human activity, other than by Applicant's employees, the need to warn the public of the existence of the pipeline is less critical than in more populated areas.

The corrosion prevention measures, viz., pipeline coating and cathodic protection, should essentially eliminate this source of pipeline failure. Likewise, control of the water dewpoint and corrosive contaminants should effectively prevent internal corrosion.

Analysis of Submission

There are a few additional design features not mentioned by the Applicant. One is lightning protection for buildings and other above-ground facilities. Pressure limiting or relief devices should be included in the pipeline system. All facilities, including mainline valves, should be fenced, more for protection against animal damage than from human activity.

1. 1. 1. 7. C. 1 (cont.)

Conclusion

Most of the necessary design features have been covered in at least a preliminary manner.

Recommendation

The Applicant should furnish measures to protect the pipeline from overpressure as per recommendation (a) of Section 1. 1. 1. 7. A. 1.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.7

C. Emergency Features and Procedures Feasibility

2.) Shutdown and Venting

Applicant's Submission

Emergency shutdown procedures will be developed later as a part of the operating procedures. During the initial period of pipeline operation, prior to installation of the compressors, shutdown will be limited to failure of the pipeline. In this situation, automatic controls on the mainline blockvalves will close the adjacent valves to isolate the break and limit the escape of gas. Shutdown of meter or maintenance (compressor) stations will be effected automatically upon the detection of fire or hazardous concentrations of gas, with all gas within the station vented to the atmosphere.

Analysis of Submission

An evaluation of both emergency and routine shutdown procedures cannot be accomplished until equipment and piping have been defined and an operating/maintenance manual written.

Conclusion

Applicant has furnished general design criteria for the shutdown equipment.

Recommendation

Applicant should furnish an operating/maintenance manual covering shutdown procedures.

1.0 DESCRIPTION OF PROPOSED ACTION

1.1.1.7 Operational, Maintenance and Emergency Procedures

C. Emergency Features and Procedures Feasibility

3) Emergency Contingency Procedures

Applicant's Proposal

Neither contingency plans nor emergency procedures have been prepared as yet, but general considerations and main courses of action are presented in the Environmental Report and in response to questions of the DOI-FPC Environmental Team. Contingency plans will be developed for each section of the pipeline containing the manpower, materials and equipment needed to effect major line repairs and the sequential steps for their utilization. As an example, there will be a Mainline Break Repair Plan, a part of the Operating Manual, which will consider the location, type of terrain and weather conditions which will be encountered. It will preplan methods of repair and include an estimate of time required for the operation. Other information in the plan will be the location of equipment storage areas and their contents; recommended methods of transportation and routing considering seasonal and environmental constraints; assignment of supervisory and repair personnel; notification and reporting requirements.

General considerations and sequence of events in repairing a line break are given in the Environmental Report, while specific procedures in the case of a break during the winter months are given in the response to Question #20 and, for the summer season, in the response to Question #5. Inasmuch as most environmental damage will result in transporting men, materials and equipment to the break site, the Applicant's description of repair activities focusses on the transportation vehicles available and how they might be employed.

There are, of course, emergency conditions other than those on the pipeline itself. For example, the response to Question #15 covers the case of personnel that become lost during the winter months while operating or maintaining the pipeline.

The best of contingency plans are of limited usefulness if personnel are unfamiliar with their contents and implementation. Thus, the Applicant states that operation and maintenance personnel will be kept familiar with contingency measures through scheduled training programs, and practice drills requiring response to simulated specific emergency situations.

Analysis of Submission

Although the difficulties attendant to pipeline repairs during the winter and summer months have been addressed, there may be periods during the spring or fall seasons that will pose even more severe maintenance problems. Many streams overflow their banks immediately following the thaw periods which usually begin in mid-May. The heaviest snows occur in the fall. However, probably the most important consideration is that the surface organic layer is particularly susceptible to damage when a thin ice layer covers the ground.

In describing the repair procedure during the summer period, the Applicant does not address the consequences of the excavation on subsequent soil conditions in the ditch affecting pipeline integrity. Questions regarding local thawing, flooding and subsequent refreezing should be addressed.

The movement of the heavy equipment for summer repairs is to be carried out by air cushion vehicles to be based either in Prudhoe Bay or in Canada. These vehicles are in the early use phase and experience on their operation in Arctic conditions is limited. They also require concrete or other hard pads for loading and unloading of equipment. Since pipe failure could occur at any place, a requirement for a number of these pads may be prohibitive.

The Applicant also places emphasis on the use of helicopters and STOL aircraft for both routine and emergency maintenance, but he does not indicate the number or type of such aircraft he intends to base at Prudhoe Bay. Two pilots and two flight engineers are assigned to Operations Headquarters, which may be indicative of the quantity of aircraft. Some discussion is needed of the number and size of aircraft; load capability; airborne ambulance facilities mentioned; and the availability of additional aircraft for charter in case of a major emergency.

The Applicant has not mentioned the possible use of the new line break detectors (acoustic principle) which can detect and locate gas leaks along the line. Considering the difficult weather and terrain condition in the area, such a system might be justified by quickly indicating the occurrence of a leak and its specific position.

An emergency condition that the Applicant has not mentioned is a sudden temperature rise in the incoming gas at Prudhoe Bay, due, for example, to a failure in the producer's refrigeration equipment. Presumably, the incoming gas would be shutoff if a specified temperature is exceeded but there is no discussion of this situation. Also, there is no coverage of compressor station repairs or the effect of loss of a unit.

Conclusion

Although the Applicant has covered many aspects of this subject in his several submittals, the discussions are generally incomplete and indefinite. Perhaps this is all that can be expected at this time, but certainly more information and definition will be required on this very important topic.

Recommendations

(a) The effect of summer pipeline excavation on subsequent local soil conditions and pipeline integrity should be analyzed.

(b) Additional precautions should be discussed that might be employed during periods in which the ground is covered by a thin ice layer or thin thawed layer.

(c) Air cushion vehicle operation and type and number of aircraft required for summer repairs should be presented in detail.

(d) Procedures to be used in the event of high incoming gas temperature should be described.

(e) An evaluation should be performed on line break detection equipment and on detection of small gas leaks.

(f) Repair procedures for compressor stations should be specific.

(g) A contingency plan and emergency procedures for the pipeline system, including the time required for repairs, should be prepared.

1. DESCRIPTION OF PROPOSED ACTION

1.1.1.7 Operational, Maintenance and Emergency Procedures

C. Emergency Features and Procedures Feasibility

4) Precipitates and Condensates

Applicant's Submission

In Question 24 (second series) in regard to gas composition, it is stated that thecriteria for acceptance of gas for transmission include: (1) a maximum water content such that water, water solutions, or hydrates will not accumulate on the pipe surfaces; (2) hydrocarbon liquids will not form in the gas to the extent that pipeline operations will be impaired; other contaminants (assumed to include particulates and sulfur compounds) within limits commensurate with good pipeline practices. To meet hydrocarbon dewpoint requirements, equipment nor normally used in pipeline measurement stations may be necessary.

In a preceding discussion of meter station design, Applicant states that drains and a liquid collector will be provided on the inlet header.

Analysis of Submission

The primary effect of water condesation is internal pipeline corrosion. Small quantities of carbon dioxide and hydrogen sulfide may normally be present in the pipeline gas; the transportation contract will specify the maximum allowable content of these components. In the presence of condensed water, acidic solutions can be formed which are corrosive to the steel pipe. The The primary method of internal corrosion control is therefore based on avoiding the possibility of water vapor condensation in the pipeline system by specifying a maximum water dewpoint.

Condensation of certain of the heavier hydrocarbon species in the natural gas is also possible at low temperatures. Concentration of such components is kept at a low level by specifying a hydrocarboe dew point, as mentioned by the Applicant. Liquid hydrocarbons do not present a corrosion problem but must be prevented from entering meters, compressors and turbines.

Preliminary, ideal gas calculations using the gas composition given by the Applicant indicated that approximately 14% of the propane would condense at 25°F. Although the Applicant has not specified an acceptable hydrocarbon dew point, it should probably be considerably less than 25° to account for the temperature drop through the pipeline. If condensation of propane does indeed occur, procedures for its collection and storage should be specified.

Conclusion

Applicant indicates an understanding of the condensate problem but some details of the gas specification have not been given as to allowable particulates, hydrogen sulfide, and total sulfur content. There is also a question as to theacceptability of his indicated hydrocarbon dew point and possibility of propane condensation.

Recommendation

(a) The Applicant should justify the acceptability of his gas composition as regards its hydrocarbon dew point.

(b) The Applicant should supply complete specifications for allowable contaminant levels and water dew point as per recommendation (b) of Section 1. 1. 1. 3. C. 1.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1 Arctic Gas Pipeline Project

2.1.1 Alaska Arctic Pipeline

2.1.1.2 Topography

D. Steepness and/or Angles of Slopes Traversed

Applicant's Submission

The Applicant states that over 90% of the slopes traversed by the pipeline are less than 3°, and that 56 slopes are between 3 and $9+^{\circ}$. He concludes that the slopes which are less than 3° can be regarded as stable. He states that the remaining slopes are steeper and require careful field and office studies to determine the potential instability and corrective action. In general, three categories of mass movement (landslides) generated on unstable slopes were recognized by McRoberts and Morgenstern (1972); solifluction; skin flows; and bimodal flows. These modes were discussed by the Applicant, as well as general methods used for slope stabilization. Extensive discussion on slope stability is presented in the report of Northern Engineering Service Company attached to the answer to Question #24.

The Applicant mentions soil creep as an insignificant factor within the lifetime of the pipeline, but also as a factor which may call for special design.

Analysis of Submission

The purpose of describing the terrain which the pipeline will traverse is to recognize any special problems which may exist due to the steepeness of the slopes and/or the direction of the pipeline relative to the slopes. Implications of stability of slopes less than 3° cannot be supported. Segments of the alignment have surficial deposits containing significant massive ice with little mineral soil. With disturbance and thermal degradation, these slopes may become unstable even though they are less than 3°. Solifluction and creep may also occur on very gentle slopes.

For those slopes exceeding 3°, the Applicant did not present an evaluation of the critical slopes in detail, nor did he present specific slope stabilizing methods for specific critical slopes, although a list of slopes with some indication of stability was presented in the above-mentioned report of Northern Engineering Services Company. The thaw consolidation model described by the Applicant to predict the range of slope instability requires specific characteristics of the soil and "typical" soil properties may not represent a specific case study. While there is a good general correspondence between the terrain units shown and the bore hole data, there are large gaps between a number of the bore holes. Between 130 and 175 Mileposts there are no holes at all. This represents a 45-mile segment or approximately 23% of the alignment in which no ground truthing has yet been attempted.

The Applicant proposed the trenching and burial of the pipeline in the 1978-79 winter with the gas flow starting in mid-1979. However, possible delays in the construction of the Canadian pipeline could result in the Alaskan pipeline being buried and inactive for a longer period of time.

Conclusions

- o The Applicant has not provided adequate information along the pipeline route to determine the significance of the slopes encountered, nor specified design modifications or construction precautions required for slopes of less than maximum stability.
- o The Applicant has not considered the effect of pipeline inactivity or pipeline startup at different seasons on slope stability.

Recommendations

(a) The Applicant should develop for review and approval, allowable loads criteria for each landslide bench traversed by the proposed pipeline with supporting analysis.

(b) The Applicant should identify all slide areas along the pipeline route and avoid heavy blasting utilizing simultaneous detonation of many charges when traversing such areas.

(c) The Applicant should specify precautions to be taken to prevent reactivation of movement of all parts of the landslides identified along the pipeline route and specify their program for future monitoring to detect any ground movement.

(d) The Applicant should restore surface drainage along the pipeline route to pre-construction conditions except that wherever closed depressions existed on a bench, these depressions will be regraded to permit runoff of the surface water over the edge of the slope.

(e) Applicant should determine conditions created by possibility of the inactive pipeline buried for one or two seasons, as well as by pipeline flowing chilled gas, together with proposed stabilization methods.

(f) Applicant should make an estimate of actual displacements to be expected during the life of the pipeline due to the most severe conditions of solifluction and creep which may occur. If necessary, Applicant should measure solifluction and creep by field observation. Applicant should also describe in detail measures which will be taken to control such displacements.

2.1.1.2.D (cont.)

(g) The Applicant should estimate maximum differential settlement due to solifluction, creep, seismic activity or other factor and use this criteria in the determination of pipeline wall thickness in accordance with recommendations in Section 1.1.1.3.A.1.

Reference: McRoberts, E. C. and Morgenstern, N. R., "The Stability of Thawing Slopes," Department of Civil Engineering, University of Alberta, Edmonton, Canada, November 1973.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.2 Topography

E. General Drainage Characteristics

2. Geomorphic Description of Major River Channels, Flood Plain and Other Related Features

Applicant's Submission

General physiography of river crossings in Canada and some Alaskan crossings is extensively treated in two separate volumes (Northern Engineering Services, 1974) attached to the answer to Question #7. This report discusses river regimes, methods for computing scour depth, pipeline anchoring, bank erosion and stability, and related subjects. The crossing of the Sagavanirktok River in Alaska is described in some detail, and a measure of the erodibility of flood plains and river channels is provided in the alignment sheets.

Dimensions of watercourses are given for 12 Alaskan rivers, partial dimensions for an additional 10.

The response to Question #33 discusses qualitatively the depth of pipeline burial beneath active and dry meanders.

Analysis of Submission

As a general construction guide, the treatment of river regimes given in Northern Engineering Services (1974) is complete and adequate for its purpose. It is not clear to what extent it is applicable (except for the discussion of the Sagavanirktok River) to the North Slope river crossings in Alaska, nor to what extent the Applicant proposes to utilize it.

The most important question regarding the geomorphology of river crossings is that of bank erosion and bed scour. Lesser considerations involve siltation and effects of aufeis and borrow pits. These questions are discussed in general terms by the Applicant, but he had not addressed himself to specific instances of river crossing, deferring studies to the construction phase of the project.

Conclusions

o Applicant's statement is adequate in its compilation of background material, in his awareness of the environmental needs involved in river crossings, and of the technology required to meet them. It is deficient, however, in failing to present a thorough analysis of specific river crossings and specific measures applicable to individual crossings.

Recommendations

(a) Applicant should provide detailed information on each major river crossing in Alaska, noting bank profiles, slopes, soil erodibility, breaching of banks, if required, including extent and slope of breach, restoration of banks, and computation of scour depth vs. statement of depth of pipe burial.

Reference: Northern Engineering Services Co., Ltd. (October 1974), "Reference Book of Water Crossings, Vol. I, Hydrology, and Vol. II, River Crossing Design," Calgary.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Seismic Hazards

1. Seismicity

b) Historic Experience

(1) Severity

Applicant's Submission

In his discussion of seismic hazards, the Applicant draws considerably upon a report by Newmark (1974) which gives design criteria for two levels of earthquake magnitude (probable and maximum). Applicant proposes to use the Design Maximum Earthquake as his design criterion. Applicant adopts the magnitude 5.5 (M5.5) Richter Scale, proposed for this area by the USGS (Page, 1972) and provided maps of strain release and earthquake epicenters.

The response to Question #23, in remarking that no seismograph station is considered for this route, states that criteria for design of pipeline have taken into account the probable magnitude of any seismic event. The response to Question #25 states that special design features may be used for areas of seismic activity.

The Applicant notes that no active faults have been recognized in the Alaskan portion of the pipeline (primary route). If faults are encountered during construction, the Applicant proposes to minimize the risk of pipe breakage by suitable trenching methods.

Analysis of Submission

Recognizing that this section of pipeline lies in an area of low seismic risk, it appears that the Applicant's selection of source material is judicious and generally adequate. The only exception to this may be the area in the vicinity of Flaxman Island which has an historic record of seismic disturbance above the M5. The Applicant does not correlate the seismic accelerations and displacement with the stresses imposed on the pipe. Effect of seismic disturbance on the pipe safety should be evaluated, both in summer and winter conditions.

Conclusions

- The major deficiency in the Applicant's discussion of seismicity is his failure to provide a relation between seismic data presented and specifications for aseismic design, however limited the requirement may be.

- Applicant does not supply an historic record of seismic events in this area except for the statement of Newark (1974) that no M5 or greater earthquake has occurred in the interval 1899-1970 . In view of the meager information available, this is not considered a serious omission.

Recommendations

(a) The Applicant should develop loads criteria for the pipeline design per recommendation (a) of Section 1. 1. 1. 3. A. 1 to withstand earthquakes of M5. 5. Criteria should treat trench and backfill requirements, specifying a maximum acceleration in g and a duration above a minimum acceleration level such as 0.05 g. If data are available, an estimate should be made (see, for example, Howell, 1973) of the Average Regional Seismic Hazard Index.

(b) The Applicant shall install seismic instrumentation in the vicinity of Flaxman Island, considered the most likely center of seismic activity along the route.

(c) A detailed discussion should be presented of the special design features for areas of seismic activity mentioned in response to Question #25.

References: Howell, B. F., Jr., (1973), "Average Regional Seismic Hazard Index (ARSHI) in the United States," from: Geology, Seismicity, and Environmental Impact, D. E. Moran, S. E. Slosson, R. O. Stone and C. A. Yelverton, Eds., Association of Engineering Geologists, Spec. Pub. (October 1973), University Publishers, Los Angeles, California.

Newmark, N. (March, 1974), "Seismic Design Criteria for Canadian Arctic Gas Pipeline and Alaska Arctic Pipeline."

Page, R. A., Boore, D. M., Loyner, W. B., Coulter, H. W. (1972). "Ground Motion Values for Use in the Seismic Design of the Trans-Alaska Pipeline System, "Geol. Survey Circ. 672, USGS, US DoI, Washington, D. C.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Geologic Hazards

1. Seismicity

b) Historic Experience

(3) Areas Susceptible to Liquefaction

Applicant's Submission

The Applicant's review of the historic data available on Alaskan earthquakes notes that north of L 67°N no earthquakes greater than M5, Richter Scale, have been detected (Stevens, 1974). Since the only ground susceptible to liquefaction by seismic energy is that which consists of loose, fine, uniform sands, in conjunction with a high water table, only one short section of the pipeline route is appraised as a liquefaction hazard. In this section, additional pipe weighting is to be provided at a river crossing; elsewhere, the shallowness of thawing is said to limit the extent of soil liquefaction.

In discussing depth of pipe burial, Applicant states that where potentially buoyant areas are crossed, the minimum depth of cover may be increased to four feet, to reduce the effects of buoyancy.

Analysis of Submission

The success of the Applicant's determination of potential seismic liquefaction areas depends on the thoroughness of his soil sampling program and the uniformity of the ground along the route.

Ballasting the pipe to anchor it in thixotropic soil should be an adequate preventive measure.

Conclusion

o The assertion that seismic liquefaction conditions are limited to a single area is not well supported since gaps as large as 45 miles (between mileposts 130 and 175) exist between test bore holes. On the other hand, if the Applicant's claim can be demonstrated that liquefaction (apart from one river channel) is not a hazard to the pipeline, then further soil sampling to determine liquefaction potential is not justified nor required outside of river channels.

Recommendations

(a) The Applicant should give the location of the area considered subject to thixotropic liquefaction, with a description of soil texture and soil water content.

(b) The Applicant should provide an explanation of the relation between the pipeline, active layer, and permafrost surface which precludes pipe movement in case of seismic liquefaction.

(c) The Applicant should make a statement including potential liquefaction areas as in his treatment of potentially buoyant areas.

Reference: Stevens, A. E. and Milne, W. G. (1974). "A Study of Seismic Risk Near Pipeline Corridors in Northwestern Canada and Eastern Alaska," Can. J. Earth Sci., 11, p. 147.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Geologic Hazards

2. Mass Wasting

d) Possible Effects of Trenching and Machinery on Weak or Slide Prone Areas

Applicant's Submission

The Applicant discusses effects of trenching and machinery on slopes with emphasis on slope stabilization. It is asserted that all slopes to be cut will be carefully analyzed and slope stabilization schemes applied as necessary. A method of analysis by McRoberts (1974) is proposed. Some cuts can be allowed to slough and heal naturally. Five slope stabilization methods are cited, to be applied as local conditions dictate. In slope cuts filling techniques using snow or water will be used as much as possible. Access roads are subject to the same general considerations as trench and right-of-way, as far as slope effects are concerned.

Analysis of Submission

The Applicant's approach to evaluating slopes, slope stabilization, and protection of cuts appear to be adequate as far as they are developed, with two exceptions. It would seem that the Applicant's use of the technique said to be used in highway construction for steep-cutting of slopes, allowing the walls to erode naturally to a stable angle and the surficial organic layer to drape over the undercut portion, should be applied with great caution, if at all. Severe problems of erosion by gullying and of siltation may result if the technique is injudiciously applied.

The Applicant's use of snow or ice fill for slope cuts must be applied with due regard for possible erosion when these materials melt.

Conclusions

o The Applicant has not provided details of constraints on construction for gentle slopes subject to soil creep and solifluction, or steep slopes at river crossings. Such excavations could encounter ice-rich soils where thaw would result, accelerating mass wasting and stream siltation, with possible undermining of pipe.

Recommendations

(a) The Applicant should identify all potentially unstable slopes affected by construction with a determination of the factor of safety by the McRoberts Method.

(b) The Applicant should reevaluate the method of restoring slopes by natural sloughing processes, including an examination of slopes where this method has been applied, reporting any instances of excess erosion or degradation of cover.

(c) The Applicant should make a similar reevaluation of the use of snow or ice fill, reporting on damage incurred by the melting of such fill.

References: McRoberts, E. C. and Morganstern, N. R. (1973), "The Stability of Thawing Slopes", Department of Civil Engineering, University of Alberta, Edmonton.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Geologic Hazards

2. Mass Wasting

g. Possible Effects on Pipeline

Applicant's Submission

The Applicant discusses various forms of mass movement which may occur in saturated, thawing soils. These are solifluction, creep in the thawed active zone, and large or small scale slumping, particularly in the ice wedge polygon terrain.

Solifluction, which is a slow gravitational downslope movement of saturated unfrozed soil over a surface of frozen materials, is widespread along the pipe route. Areas of intense solifluction have been avoided by appropriate route location.

Creep of unfrozen or thawing slopes is considered to be insignificant in the lifetime of the pipeline and detailed analysis is not required. On the other hand, creep of frozen slopes and deep-seated failures are possible types of pipeline failure and as far as possible the route selection has avoided areas where failures of this type may occur.

The mass movements along the slopes with ice-rich soils are subject to thaw consolidation, which the Applicant discusses in the section on soil solifluction or liquefaction. The thaw consolidation analysis is performed in the answer to Question #3. This phenomenon was manifested in a shallow skin flow at the proposed pipe crossing of the Katakturuk River, as described in the answer to Question #27. As a result of this landslide, the Applicant decided to change the location of the crossing originally proposed to one a few hundred feet downstream where gravel outcrops along the bank. A detailed discussion of mass wasting phenomena with suggested analytical treatment of skin flows was also identified in that answer. Means of soil stabilization were discussed.

Another form of mass wasting is ground differential settlement which may be caused by thermal regression of permafrost along the right-of-way, by loss of ground support due to erosion, and by compression of the supporting soil under the weight of the pipe and backfill. The latter will be most pronounced during hydrostatic test of the pipe and settlement up to 12 inches was estimated. In general, the Applicant does not consider the differential settlement to be a problem, as stated in answer to Question #3, since the depth of burial of the pipe will be such that thaw will generally not penetrate below the top of the pipe.

Analysis of Submission

The Applicant reviewed extensively but qualitatively the problem of mass wasting and stabilization methods. It is obviously an area of concern particularly in view of the lack of experience with large diameter pipes buried in permafrost. The fact is recognized that removal of the organic mat in the right-of-way will upset the delicate heat balance in the permafrost. The removal of this insulating layer will increase the depth of thawing and in ice-rich, fine grain clay-type soils with low permeability and poor drainage will increase the water pore pressure, releasing an excess of water in the trench. Thus, conditions conducive to solifluction and skin flows will be created. The landslide which occurred at Katakturuk River at the crossing site originally selected by the Applicant indicates a need for a detailed review of the prime route in order to identify other potential problems areas which could result in pipe failure.

At present, the pipe is sized for hoop stress only, with the assumption that any external loads which may be superimposed will produce stresses which will be small compared to the principal stress. Such an assumption is of primary importance to the pipeline integrity and should be verified analytically, at least in the near-worst locations where pipe movement caused by mass wasting may be expected. For instance, the Applicant stated that during the hydrotest a settlement of 12 inches is possible, but that this settlement will be relatively uniform. What happens if the settlement is not uniform in a given location and a section of the pipe is displaced by this amount is not stated. No assessment of the degree of nonuniformity which is safe from a pipe integrity standpoint is made.

Another problem which should be considered is the thermal conditions associated with inactive versus active phase of buried pipeline. The Applicant has stated the "During the inactive period (after construction and prior to operation) differential settlement within the chilled gas portion of the pipeline may result". Presumably, if the pipe remains inactive over longer periods than planned for reasons beyond the Applicant's control, there will be no chilled gas flowing through it and the active layer will then extend to a greater depth. The effect on mass wasting and pipeline external loads has not been assessed.

The depth of burial of the pipe with respect to the expected 32° F isotherm is important with regard to solifluction and mass wasting and it should be above the pipe at all conditions. The depth of the undisturbed active layer varies, according to the Applicant's data, from 1 to 3 feet along the route. Removal of the organic mat will increase the depth of the active layer across the right-of-way, with the exception of the layer in the vicinity of the pipe, when it is chilled with the flowing gas. The minimum depth of cover specified by the Applicant (from the top of the pipe to the original ground surface) will be 2.5 feet. The top of the pipe will be an average of 4 feet below the original ground surface according to the answers to Questions #4 and #6. The depth of the active layer above the chilled pipe and over the right-of-way was also calculated by the Applicant in answer to Question #4, at certain assumed pipe and ground temperatures. The calculation shows an active layer of 1.8 feet over the right-of-way and 0.4 feet over the pipe. Presumably, the calculations considered only a conductive heat transfer between the pipe and the soil, and surface and soil. The Applicant did not address the problem of how a slow groundwater flow would affect these calculations when a convective heat transfer term is added. One would expect that over the right-of-way denuded of the organic mat the thickness of the active layer would be greater than that of the undisturbed ground. Consequently, calculations should be performed in which the active layer is close to the 3 feet quoted and to compare it then with the proposed pipe burial depth. The depth of burial should be quantitatively specified for a few near-worst locations rather than to be quoted in terms of "minimum" or "average".

One of the locations which should be looked at in detail is in the Arctic coastal plain between Mileposts 4 and 7 and is representive of typical conditions within this province. Here the line crosses terrain units containing approximately 1.8 miles of Arctic Coastal Plain sediments and 0.9 miles of Former Oriented Lake sediments and closely skirts 0.3 miles of an oriented thaw lake shore. The Arctic Coastal Plain sediments commonly contain 10 to 15 feet of ice-rich silty sands which overlie sandy gravels, some of which are silty and have varying ice content. Ice wedges are characteristic, as are small ponds and swamps. The moisture content of the soils is generally high.

The closest drill hole locations to this site are at approximately 1.5 and 7.85 miles. In order to assess the soil characteristics, it is necessary to extrapolate the drill hole data presented. This appears to be satisfactory for a broad overview, but the variability of the soils make specific judgments somewhat tenuous. In addition, thaw bulbs exist under some of the lakes and without more detailed information it is difficult to assess the significance of this undrozen condition on the proposed pipeline. Surface water is present in almost all areas. This water will be ponded or intercepted by the pipe ditch or diverted by the berm above the ditch. Diversion of drainage will be feasible in a few areas but ponds will develop in others. These ponds tend to accelerate melting even if flow is prevented.

Several phenomena occurring in such an environment could affect pipeline integrity. The thaw areas exist in soil which would be conducive to formation of a frost bulb and frost heave with a chilled pipe. Poor drainage of the soil may lead to local ponding, which would aggravate the condition, and an unchilled pipe could lead to backfill erosion and pipe buoyancy.

The backfill material will be ice-rich and thawing will cause subsidence, changing the pattern of surface water flow and increasing the possibility of erosion in the pipe right-of-way.

Conclusions

- The Applicant has displayed a good understanding of the mass wasting problems and presented an extensive qualitative description of the various aspects of this phenomenon, analytical methods available, and stabilization methods known.

2.1.1.3.C.2.g (cont.)

Conclusions

o A detailed review of the route is needed to identify potential mass wasting areas. For those areas, quantitative analyses are needed to determine: the depth of pipe burial, location of 32^{o} isotherm, drainage requirements, mass wasting hazards and their effect on pipe integrity and appropriate stabilization methods.

Recommendations

(a) The Applicant should identify potential mass waste areas along the prime route and a detailed analysis perform of mass wasting hazards and their effect on pipe integrity.

(b) The Applicant should determine external loads imparted by mass wasting on the pipeline for all areas considered to be a potential hazard and incorporate in pipe thickness determination per 1.1.1.3.A.1 recommendation (a).

(c) The Applicant should determine the depth of pipe burial as a function of active layer depth with chilled and unchilled pipe and cover the contingency of delayed pipe operation after burial.

2.1.1.3 Geology

C. Geologic Hazard

4. Permafrost

d. Physical Characteristics (shear strength, density, etc.)

Applicant's Submission

A substantial amount of data is provided on the thermal and physical properties of permafrost. Most of the data are presented in the Northern Engineering Service Co., Ltd., (1974) attachment to the answer to Question #24. The data includes values of coefficient of consolidation; permeability of various soils and thawed backfill; and frozen and thawed soil conductivities.

Analysis of Submission

The properties of permafrost have to be known in order to assess the behavior of the buried pipe. Specifically: permeability; consolidation coefficient; density; sheer strength; and conductivity of both thawed and frozen soils along the pipeline route are required.

Permeability defines the ability of soils to drain off water and low permeability is indicative of poor drainage and easy accumulation of excess water. For silty sands, the permeability is on the order of 1×10^{-3} cm/sec to 1×10^{-5} cm/sec, while for silts and clays it varies between 1×10^{-5} to 1×10^{-7} cm/sec. Kachadoorian and Ferrians (1973) predict a possibility of mass movement on slopes with high water content and permeability of less than 1×10^{-5} cm/sec.

The coefficient of thaw consolidation defines the rate by which water may be squeezed out of the thawing surface overlying the advancing thaw interface. The smaller the coefficient and the higher the rate of thaw, the greater the tendency of the soil to move toward a semi-liquid slurry condition. This is of particular importance on slopes where a drastic reduction in soil shear strength associated high liquefaction could initiate mass movement. The Northern Engineering Service Company (1974) report mentioned above quotes the coefficient of consolidation data for silty sands a 1×10^{-1} to 1×10^{-2} cm/sec, and for clays as 1×10^{-2} and 1×10^{-3} cm/sec.

The densities of permafrost vary as a function of soil composition, compaction and moisture content. Penner et al (1973) quotes densities of various soils and various moisture content, and the values lay between 90 and 140 lb/ft^3. Slurries with high water content and high densities produce high buoyance on immersed pipe. For instance, in a slurry with density of 110 lb/ft the net buoyancy of the pipe would be approximately 900 lb per foot of pipe length. Such situations would require a careful assessment of the negative buoyancy provisions.

Data on thaw interface shear strength of permafrost soils are limited and none are provided by the Applicant although means of increasing shear strength are discussed. Some laboratory data on fine inorganic silt soil obtained by Thomson and Lobacz (1973) with varying overburden indicate values of 0.4 to 0.8 kg/cm^2. Interestingly enough, a change in natural stress (overburden) had a relatively small effect on the shear strength. However, any increase in moisture content beyond the saturation point caused a substantial reduction in the shear strength. This is of particular importance in the slope stability assessment.

The soils identified by the Applicant's bore hole records covered nearly the full range of possible classification and water content, and hence a range of physical properties. However, the number of bore holes is limited and a substantial length of pipe route (up to 40 miles) has no bore hole data given. There is a need for such data, particularly for soils on slopes, at river approaches under rivers and at proposed compressor station sites.

Conclusions

- The Applicant provided a substantial amount of data on permafrost physical properties, except for the shear strength of unfrozen soils and on frozen-unfrozen soil interface.
- There is insufficient bore hole data along the pipeline route and this information should be added for proper assessment of pipeline integrity.

2.1.1.3.C.4.d (cont.)

Recommendations

(a) The Applicant should provide shear strength data on unfrozen soils and soil interfaces for assessment of mass wasting hazard and external loads on the pipe to be used in analysis of recommendations (a) and (b) of Section 2.1.1.3.C.2.g.

(b) The Applicant should provide comprehensive bore hole data along the pipeline route, particularly for slopes, river approaches, under rivers, and at compressor stations.

References

Kachadoorian, R. and Ferrians, O. (1973) "Permafrost-Related Engineering Geology Problems Posed by the TransAlaskan Pipeline", National Academy of Science, 2nd Permafrost Conference.

Northern Engineering Services Co., Ltd., (Dec 1974) "Interim Report - Slope Stability in Permafrost Terrain", Prepared for Alaskan Arctic Gas Co., Ltd., and Canadian Arctic Gas Co., Ltd., Calgary.

Penner, E., Johnson, G.H. and Goodrich, L. E. (1973), "Thermal Conductivity Laboratory Studies of Some MacKenzie Highway Soils", National Research Council of Canada.

Thomson, S. and Labacz, E. F., (1973), " Shear Strength at a Thaw Interface", National Academy of Science, 2nd Permafrost Conference, 1973

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Geologic Hazards

4) Permafrost

e) Frost Heave

Applicant's Submission

Frost heave is caused by volume differential between frozen and unfrozen water. The potential for frost heave arises when three conditions are satisfied: freezing temperatures; frost-susceptible soils; and source of water. With a chilled pipe there will be a tendency for the pore water to migrate toward the advancing freezing front to form an ice lens.

The frost heave problem, in answers to Questions #2 and #6, was categorized as follows: heaving in the active layer across the right-of-way; heaving caused by freezing of unfrozen groundwater in permafrost soils; and heaving in unfrozen ground, such as under water bodies that do not naturally freeze each year.

Frost heaving in the active layer should not occur because the maximum depth of the active layer along the north slope is 3 feet, and the top of the pipe will be an average of 4 feet below the original surface, that is, below the active layer. Consequently, the chilled pipeline will not dominate the freezing in the active layer and the conclusion presented in the answer to Question #4 is that pipe integrity will not be affected by heaving in the active layer.

The problem of heaving caused by unfrozen groundwater in the permafrost was discussed in the answer to Question #1. Since the pipe is colder than the surrounding medium in summer and warmer in winter, the unfrozen water will tend to migrate toward the pipe in summer and away from it for the rest of the year. This will mitigate against significant ice buildup around the pipe. Also, the rate at which water will migrate through permafrost along the route is extremely low because of very low permeability of frozen soil (ranging from 10^{-9} to 10^{-15} cm/sec). It is, therefore, considered that ice heave in these conditions does not constitute a problem.

The problem of heaving in unfrozen ground under rivers was discussed in answers to Questions #2 and #26. The formation of a frost bulb around the pipe was estimated with no groundwater flow and low rate of water flow in terms of erosion potential caused by interruption of subsurface flow. The conclusion was reached that if the restriction of subsurface or surface water flow represents a real problem, remedial steps will be taken such as insulating the pipe or burying it deeper to minimize the effects. Also, any drained lakes with a potential of pingo formation will be avoided.

Analytical methods will be used to predict heaving pressures due to ice segregation. It was found that heaving of the pipeline can be prevented by applying surcharge pressures greater than computed maximum heaving pressure. The analyses will consider the geothermal aspect of the 32° isotherm advance, soil properties of the frost-susceptible soils with high water content, and stress analysis of the pipe from differential heaving in adjacent sections.

Experimental data obtained from Prudhoe Bay of four buried sections of 48" pipe over a period of 1-1/2 years will be used in the analysis, where applicable.

Analysis of Submission

The Applicant has expressed proper concern for the potential detrimental effect of frost heave on the proposed buried pipeline. However, statements identifying procedures to be utilized in assessing and mitigating frost heave effects are presented only in terms of general concepts. The full consequences and required design conservatism have not yet been defined.

Examples of specific points where frost heave could occur along the proposed pipeline route should include all thaw lakes, beaded drainages and possible taliks. Under these conditions, the pipeline will be uniformly buried with native backfill placed back over the pipe. In passing through a thawed section, the pipe would be constrained at both frozen end sections but would be subjected to frost heave effects along the thawed length when refrigeration by gas throughput begins. The development of the 32-degree isotherm and consequent frost heave forces could induce significant pipe stress changes and deformation. This condition is considered to be quite critical in terms of demonstrating the design adequacy of the frozen bury mode.

The test results from Prudhoe Bay presented by the Applicant in Battelle Labs (1973), show bending moments amount to 20% of the yield moment at pipe anchors caused by frost heave. These moments are not insignificant and they probably do not represent the worst condition.

Information provided by the Applicant does not yet identify either the range or tolerance in allowable pipe stresses relating to deformation. Those stresses associated with frost heave effects must be included in the evaluation of pipe stresses. While the potential reduction in frost heave due to minimizing ice segregation by surcharging procedures would obviously be beneficial, detailed information on the feasibility and justification of this consideration is required. The effect of buoyancy and the fact that all natural backfill material will be disturbed should also be considered, particularly if granular bedding and padding materials are not utilized.

The frost heaving in the active layer may not pose a problem if the pipe is buried below the active layer. However, it should be kept in mind that in the right-of-way the depth of the active layer will be greater than that of the undisturbed ground and this should be considered when defining the burial depth.

The freezing of the unfrozen water in the permafrost may not be mitigated by the water flow reversal, as explained by the Applicant. The mean winter ground temperature of pipe centerline is approximately 20°F and the mean summer temperature 28°F (Applicant's data). Since the pipe temperature drops 15 to 20°F along the length of the pipeline, there will be a length of pipe where the pipe will be cooler than the ground, both in summer and winter, or where the mitigating effect of groundwater flow reversal will not take place. Examination of the soil conditions at this pipe section is necessary for re-assessment of frost heave problems.

The effect of increasing surcharge pressure on the heave magnitude is dramatic, according to the Applicant. So would be the reverse effect when the surcharge pressure is removed, for instance, by river erosion. This hazard merits an evaluation.

Conclusions

The Applicant is well aware of frost heave problems and means at his disposal of mitigating them. However, the Applicant tends to minimize the effect of frost heave on pipe integrity by qualitative general statements. A detailed review of specific near worst but realistic conditions of the soil and pipe is required to verify this view and to calculate the additional stresses in the pipeline.

Recommendations

(a) The Applicant should evaluate the ground temperature profile for all conditions of flow and for all seasons of operation/non-operation to determine the optimum pipe burial depth to minimize effects of the active layer.

(b) The Applicant should assume worst case ground moisture conditions and determine the external frost heave loads imposed on the pipe first for inclusion in the pipeline thickness determination per recommendation (a) of Section 1. 1. 1. 3. A. 1, and second, in the chilled gas effects study per recommendation (b) of Section 1. 1. 1. 1. B. 2.

Reference: Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)," Columbus, Ohio.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.5 Water Resources

B. Surface Waters

2. Principal Streams in Basins - River Crossings

Applicant Submission

The pipeline will cross 120 streams of which 22 are rivers of reasonable size. The list of the streams is given, as well as the depth and flow data (where available) of the major rivers. Further characteristics of larger rivers, such as active flood plains and major channel width, depth, and summer and winter flow rates (most are riverbed frozen during the winter) are quoted in answer to Question #8. Data on major riverbed slopes are presented in answer to Question #5. The streams can be divided into single channel, (which are mostly stable except when excessive meandering may lead to channel shift), split channel, and braided sub-channels, the latter two being unstable and subject to lateral migration. The hazard of lateral migration of a sub-channel stream lies in the difficulty in predicting rates of bank erosion when the river shifts and/or in defining location of pipeline sag points outside of possible shift areas. The most troublesome season in which damage to the pipeline crossing could occur would be during the spring breakup when intense flooding and heavy frontal rainfall can occur. The floods will dissipate themselves quickly in steep rough channels and may be more destructive than any other flow event. Such flows sometimes reach alluvial fans in the Canning River region Northern Engineering Services (1974) (Appendix A). This problem is recognized and need for further assessment is indicated in the answer to Question #30.

The proposed approach to river crossing is to bring the pipe below the anticipated potential scour depth. No above-ground crossings are being planned. The crossings will be made perpendicular to the principal flow direction between the foothills and where the distributing channels fall out.

The effect of chilled pipeline crossing unfrozen ground below a river was examined in answers to Questions #2 and #5. Cases were examined for the growth of frost bulbs around the pipe in rivers with small winter flow and in rivers frozen to the riverbed. The conclusion was reached, that in either case there will be no adverse effect on the river flow, on riverbed stability, or on the pipeline integrity.

The river crossing presents a hazard to the pipeline by the possibility of exposing it to hydraulic and abrasive forces of the stream flow due to deep, local scour, general bed degradation, erosion of a riverbank beyond the sag point, and erosion in the flood plain area. The protection of the pipe against this hazard is by deep burial beyond the scour depth, location of the sag point outside of the flood plain and provision of negative buoyancy on river crossing pipe segments. In some cases, the potential for scour, erosion or channel relocation will be so large that deeper burial is prohibitive from economical or environmental considerations and pipe protection must be provided by means of bank armoring and/or river training.

The provisions for negative pipe buoyancy in certain delineated areas are quoted in the Applicant's report and the various design means to achieve this buoyancy are discussed in Northern Engineering Services (1974) Appendix B.

Analysis of Submission

The problems associated with pipeline river crossing can affect both the pipeline and the environment. General criteria for river engineering considering the various factors were presented by Blench and Associates (1973). The goal of the pipeline construction is to maintain it buried at the approach to and under the river at all foreseeable conditions. In this, river scouring, channeling, bank erosion, flood plain erosion have to be considered. The environment may be affected by the pipeline construction precipitating mass wasting on some of the slopes, riverbed degradation, and formation of ice bulbs around the chilled pipe in the unfrozen ground below the riverbed.

These problems were addressed by the Applicant in a qualitative way with the exception of frost bulb growth, which was calculated for a given set of conditions. However, the vertically asymmetrical growth of the frost bulbs around the pipe could result in an upward shifting of the pipe from its original position. This problem should be examined for specific stream crossings where the frost bulb growth rate is greater (that is, pipe temperature is lower) and determine the additional stresses in the pipe resulting from it.

There is also a question regarding the calculation of the frost bulb. The text in Question #2 and #5 quotes water flow velocity as 0.945ft/hr, while the figures show 0.00945 ft/hr. Presumably, the lower figure was used in the calculations. The soil water content is not specified, nor is the method of calculation of the convective heat flux which is presumably much higher than the conductive one.

Statements were made about the pipe burial depth below streams being greater to avoid the scour problem, but no data are given. Interpretation of figures attached to the answer to Question #2 leads to a burial depth of 5 feet (between the original riverbed level and the top of the pipe). This may not be sufficient since calculations performed in Norther Engineering Services (1974) Appendix B show, for a typical braided river, scour depth of 12 feet, and for a single channel river scour depth of 13 feet. This scour depth was calculated from Blench's (1969) equations. In a survey of the areas, Taylor (1972) considered the possibility of scour depth resulting from local summer channeling of 20-30 feet below the normal stream bed elevation. More detailed review of the scour depth and pipe burial depth under streams with potential scour hazard is necessary. It is possible as it was pointed out in Northern Engineering Services (1974) Appendix B, that in some cases the burial depth would be prohibitive and, in those cases, the pipe may need protection by bank armoring and/or river training.

The flood plain criteria were not specified although these are important in determination of the negative buoyancy provisions. The criteria to be used, according to DoI instructions, are: Standard Flood Project if no permanent roads along the pipeline route are provided, and 100-year flood data if permanent roads are provided.

The negative buoyancy provisions, while discussed are not quantitatively defined and it can only be inferred that they will be between 5 and 20%. A more detailed review is required of the magnitude of negative buoyancy provided as a function of the terrain crossed.

To obtain a better understanding of the local problems at stream crossings, it would be necessary to examine data from a few critical river crossings.

The crossing of the Canning River is one such example. The pipeline prime route crosses the river normal to its flow just at the beginning of a large, braided flood plane. Bore holes A6 518 and A6 538 indicate sparse ground covering with 1 - 1.5 feet active layer with sand or silty gravels and high moisture content (at the 2-foot depth) of 70%. The west bank of the river at the location of bore hole A6 518 is abrupt, 8 feet high, and the whole area is a fossil flood plain with an ice-rich silty to fine sand topstratum crisscrossed with large polygonal features 30-70 feet in diameter. These features suggest the presence of highly frost-susceptible soils with large quantities of segregated ice (Taylor, 1972) and, 15 feet of highly frost-susceptible silt.

The pipeline integrity may be affected in this area by extensive scouring, bank flood erosion, and solifluction.

The Canning River flow in the summer months is maintained by a high precipitation in the Franklin Mountains, and a mean runoff of 2 cf/sec, square mile with a peak of 50 cf/sec, square mile, resulting in large flood areas.

These conditions indicate the need for careful analysis of pipe burial depth and of the negative buoyancy provision to prevent vertical and/or lateral displacement of the pipe in case of channeling or flood erosion.

A second example is the Sadlerochit River which is fed, similar to the Canning River, with heavy mountain precipitation and a summer runoff. It is a heavily braided river with the pipeline crossing normal to the river. Bore holes A6 560 and A6 561 in the river vicinity indicate light peat cover, 1-foot active layer, underlain with gravelly sands or organic silty clays of low plasticity containing up to 21% moisture. The fossil flood plain is ice-rich silty to clean sand and gravel. Surficial indicators suggest the presence of highly frost-susceptible soils with significant quantities of ice, both massive and interstitial (Taylor, 1972).

Since the pipe will cross the braided section of the river, the summer hazard of large inundated areas is even more pronounced than in the previous case and, therefore, the length of the weighted pipe for negative buoyancy and the depth of burial to avoid pipe exposure under the most adverse conditions require substantiation under "worse case" assumptions.

A crossing of an unfrozen stream, such as Sadlerochit Spring or others, should also require detailed review because of the possibility of frost bulbs forming around the buried, chilled pipeline in the undrozen ground below the stream bed. A growth of this frost bulb caused by the water migration toward the cold zone was presented by the Applicant in answer to one of the questions posed by DOI. Calculations performed at $5^{o}F$ temperature differential between the pipe and the surrounding permafrost indicate that the maximum rate of freeze and thaw could be approximately 0.015 in/hr or an average frost bulb could grow at 4 ft/yr. The Applicant shows that some obstruction of the stream flow occurs after a period of 36 months and this obstruction can be further increased by growing buoyancy of the bulbs and/or frost heaving. An increase in the convective cooling above that calculated by the Applicant is also possible. Lachenbruch (1970) quotes convective heat flows as being 1000 times greater than conductive. The hazard to the pipe would lie in the possibility of heavy riverbed erosion and aufies formation.

<u>Conclusions</u>

- o The Applicant presented an adequate review of problems associated with river crossings. However, more details should be given regarding the depth of pipe burial under braided and channeled rivers to avoid the scour problem. If bank armoring or river training is required in some of these crossings, the proposed method of control and location should be identified. Flood plain criteria should be stated and compatibility of the pipeline with the criteria adopted should be shown.
- o Possible pipe displacement caused by asymmetrical frost bulb growth under the rivers merits examination and assessment of external stresses imposed on the pipe.
- o Details on the negative buoyancy provisions of the pipe when crossing critical terrains are needed.

2.1.1.5.B.2 (cont.)

Recommendations

(a) The Applicant should provide for review and approval detail design at all river crossings with supporting analysis to show that depth of burial and negative buoyancy provisions are compatible with worse case assumptions.

(b) The Applicant should provide for review and approval, flood plain criteria and show that the pipeline design is in conformance with this criteria. Details of pipe negative buoyancy provisions as a function of the terrain crossed should be provided and substantiated by analysis.

References

Blench, T., "Mobile-Bed Fluviology. A Regime Treatment of Canals and Rivers for Engineers and Hydrologists", University of Alberta Press, Edmonton, Canada, 1969.

Blench, T. and Associates, Ltd., "Criteria for River Engineering Aspects of the Design, Construction and Maintenance of Buried Pipeline Crossing", March 1973.

Lachenbruch, A. H., "Periodic Heat Flow in a Stratified Medium with Application to Permafrost Problems", Geological Survey Bulletin 1083-A, 1959.

Taylor, R. S., "Engineering Geological Reconnaissance of Three Potential Routes for a Gas Pipeline from Prudhoe Bay to the Canadian/U. S. Border", 1972.

Northern Engineering Services Co., Ltd., (Dec 1974), "Interim Report - Slope Stability in Permafrost Terrain", prepared for Alaskan Arctic Gas Co., Ltd., and Canadian Arctic Gas Co., Ltd., Calgary.

2. DESCRIPTION OF EXISTING ENVIRONMENT

2.1.1.10 Sociological Factors

D. Environmental Noise Level

Applicant s Proposal

The Applicant has not described the existing noise level along the pipeline route.

Analysis of Submission

The pipeline traverses mainly open land where the noise level is that associated primarily with nature. For the most part the noise level can be characterized as low.

Conclusions

The existing environment poses no special problems to pipeline construction.

Recommendations

None.

3. ENVIRONMENTAL IMPACTS OF THE PROPOSED PROJECTS

3.1 Arctic Gas Pipeline Project

3.1.1 Alaska Arctic Pipeline

3.1.1.1 Climate

A. Air Quality Change

Applicant's Submission

The existing air quality on the northern slope of Alaska is not well known; however, the lack of human activity suggests a clear environment. In the short term, during the construction phase, equipment exhaust emissions will be high locally. During the first five years there will be no compressor stations. In the future, and subject to another application, a complete impact statement will be required. The Applicant provides expected levels of nitrogen oxides, carbon monoxide, sulfur dioxide and unburned hydrocarbons.

Analysis of Submission

During the operation and maintenance phases no problem is expected in meeting the federal air quality standards with the planned natural gas burning compressor turbines. Nitrogen dioxide is the most significant contaminant and the federal limit of .05 ppm annual arithmetic mean should not be violated. The Applicant's emissions estimates are reasonable.

The most significant problem relative to pipeline integrity is that associated with ice fog. The compressor turbines emit large amounts of water vapor. At sub-freezing temperatures this water vapor may transform into ice fog. The same compressor turbines require large amounts of air for combustion. Injestion of ice fog by the compressor turbine may cause turbine blade failure with attendant loss of gas delivery unless preventative measures are taken. Although the Applicant indicates an anti-icing system on his future compressors (see Section 1.1.1.3.C.1), no details are given.

Conclusions

The only air quality change related to pipeline integrity is the possible creation of ice fog at the compressor stations. Positive means of precluding damage to compressor turbine blades through ingestion of ice fog is required. The Applicant appears to recognize the problem and his final design should be checked for these provisions.

Recommendations

(a) The Applicant should provide the design measures necessary to preclude ice fog ingestion into compressor turbines during all phases of remote, unattended operation. The Applicant should support his proposed design with test data which verifies the design feasibility during operation under continuous ice fog conditions.

3.1.1.2 Topography

A. Development of Erosion Hazard

1) Pipeline Right-of-Way

Applicant's Submission

The Applicant presents 7 factors controlling water erosion, and discusses countermeasures. The overall plan is to minimize interference with natural drainage patterns until revegetation is effective. The Applicant discusses the case of control measures such as mound breaks, with suitable diversion dikes and ditches, plugs on downslope sides; riprap to control gullying; ditch plugs; and grading of slope cuts with breakers, crossberms, terraces, and diversion ditches as required.

Other topics discussed are the stability of frozen slopes, in terms of creep and deep-seated failure, and differential settlement in terms of thaw, erosion, and compaction.

Considerable material on erosion is presented by Applicant's alignment sheets, photomosaic strip maps giving such information as the preferred type of control measure (based on soil type and slope) and spacings of mound breaks.

Analysis of Submission

Applicant's treatment of erosion hazards and controls is extensive; however, since no specific criteria is presented, there are many opportunities for error.

The Applicant claims that control measures will be designed to minimize disturbance to the "existing hydrological regime." It is assured, in view of the orientation of the pipeline with respect to the numerous drainages of this section, that significant modifications of the "existing hydrological regime" could occur, regardless of the construction method or season of construction. Countless opportunities exist for cross-drainages to be diverted parallel to the pipeline and for thaw degradation ponding situations to develop.

The Applicant discusses the effects of the interruption of water flow in the active layer on side slopes due to intrusion of the ice ball around the pipe into the active layer and the tendency of water to be impounded on the upslope side of the pipe. Mitigating measures are discussed, however, no criteria are presented for maintaining runoff velocities below erosive velocities.

Permafrost over the pipeline will be 1-1/2 ft. higher over the pipe than over the rest of the adjoining slope. During spring thaw and fall freeze, there will be a time, therefore, when the permafrost along the pipeline intersects the surface while the up-slope and down-slope contiguous area has thawed to a depth of one to 1-1/2 ft. During spring the quantity of moisture in the soil and above ground will be high. Although mound breaks are provided they may be blocked by localized aufeis and heavy drifted snow which may precipitate erosive velocities and channelization outside the mound breaks. The improper handling of this problem can clearly modify surface drainage, induce local mass wasting adjacent to and downslope of the pipeline. Severe erosion downslope of the pipeline would be progressive and could threaten pipeline integrity if a landslide were induced.

The main emphasis of erosion control measures must be directed towards the control of surface runoff. Revegetation measures will only be successful in areas of stable terrain where the cycle of hydraulic and thermal erosion has either been prevented or arrested to a large degree.

Conclusions

The Applicant discusses all of the applicable erosion control methods adequately, however, success in utilizing these methods depends upon the criteria used for the selection of control methods for each case.

Recommendations

(a) The Applicant should develop criteria for submittal to the DoI for review and approval which will allow areas with a high potential for accelerated erosion, to be defined on a detailed basis and in a manner suitable for portrayal on construction drawings. These criteria should provide methods for the calculation of required quantities of backfill, mound breaks, culverts, ditch plugs, borrow and other control and restoration measures. Criteria should consider soil type, including thermal state and moisture content, topography, climate, hydrology, construction mode and grading geometry.

The various specific control measures should be formalized to the point of standardization such that they can be specified to apply, with appropriate modifications for local conditions, to any section of the pipeline. GOOD

The Applicant should provide specific criteria to restore river banks where these have been breached for crossing, and to protect them from excessive erosion.

(b) The Applicant should take care to insure that surplus spoil is not disposed indiscriminately on right-of-way with an undisturbed vegetative cover required as an erosion control.

(c) The Applicant should provide more information on creep and deep-seated failure in frozen soil, where he states that substantial field investigation is called for. Specifically, a survey should be made in the field of potential sites of each type of failure, the soil creep measured, and the deep-seated failure potential evaluated by the methods described in Applicant's submittal.

3. ENVIRONMENTAL IMPACTS OF THE PROPOSED PROJECTS

3.1.1.2 Topography

A. Development of Erosion Hazard

2. Borrow Areas

Applicant's Submission

The Applicant proposes to obtain borrow materials from pits in river flood plains shown on the alignment sheets. Where flood plains are not available other areas will be used. Restoration of borrow pits will be done by grading, contouring, reseeding, and application of fertilizer.

Analysis of Submission

Some of the borrow pits, as shown on Applicant's alignment charts, are placed near or in the river beds a short distance upstream of the pipeline. There is no discussion of the criteria to be used for these borrow sites. Removal of material from streams and river beds may result in changes in scour depth and changes in river bed location. Because these some borrow areas are upstream of the pipeline, the pipeline integrity rests to some degree on the success of the Applicant's measures to control erosion.

Conclusions

The borrow pits do not appear to be in an optimum location from a pipeline integrity standpoint.

Recommendations

(a) The Applicant should review the location of the borrow pits and show that erosion resulting from them will not threaten pipeline integrity.

3.1.1.2 Topography

B. Inducement of Landslides and Rockfalls During Construction by Blasting and Trenching

Applicant's Submission

As discussed in Section 2.1.1.2.D, 90% of the slopes traversed are less than 3^{o} and most of the remainder are between 3 and 9 degrees. The Applicant proposes to use special ditching equipment for trenching in frozen soil during the Alaskan winter construction period.

Analysis of Submission

If the development of suitable ditching equipment is successful (see Section 1.1.1.6.B) there should be no inducement of landslides or rockfalls during the construction period in the frozen materials.

Even if blasting is required, the relatively mild slopes and the nature of the frozen soils make it extremely unlikely that landslides will be induced. Blasting could, however, result in slumping, soil fall, or snow avalanches along steep slopes and steep river banks. Battelle (1964) (Volume 1) states that blasting techniques investigated to date have been found unsuitable for ditching in Permafrost.

Conclusions

- The key to the feasibility of the Applicant's submission rests on the successful development of suitable ditching equipment.

- Unique techniques and precautions may be required for blasting in Permafrost.

3.1.1.2.B (cont.)

Recommendations

(a) Recommendations (a) and (d) of section 1.1.1.6.B.1 should be implemented.

(b) The Applicant should identify areas along the pipeline route which, when subjected to blasting groundshocks, may be susceptible to slumping or soil fall and slopes which may be susceptible to avalanches. The Applicant should specify the special precautions to be taken when blasting is required in these areas.

Reference: Battelle Columbus Laboratories (June 1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region." Final Report - Volume I.

3. ENVIRONMENTAL IMPACTS OF THE PROPOSED PROJECT

3.1.1.3 Geology

B. Destruction of Permafrost in the Applicable Areas

Applicant's Submission

The Applicant proposed to operate the pipeline at temperatures below freezing to maintain the pipeline and the soil contiguous thereto in a permafrost condition. The Applicant has conducted tests on lengths of pipe, buried as he proposed, and data obtained for the non-operating and emergency shutdown modes.

Analysis of Submission

No detail is presented of the conditions as they exist when the pipe is installed in the ditch through startup and stabilization of the pipeline temperature. The thermal path from the surface through the ditch containing the pipeline will be considerably altered from the conditions that prevailed prior to laying the pipe.

The Applicant has not stated the degree of success obtained during the tests, nor is it clear that the conditions of the tests were sufficiently varied to form an adequate basis for the many problems likely to be encountered in the actual installation.

In any case, while the operating condition appears to offer a means of maintaining the integrity of the permafrost once the pipeline has been operating, it is not clear that the transition from construction to operation has been adequately studied to develop the necessary criteria, procedures, controls, and instrumentation to assure no destruction of permafrost and accompanying subsidence of the pipeline and contiguous areas.

The proposed winter snow roads do not preclude damage or destruction of the underlying vegetation. This damage will produce changes in the permafrost. Methods of assessing damage and criteria for repair of the terrain should be developed.

Conclusions

The Applicant has not provided sufficient information to evaluate the effects of his pipeline on the permafrost layer during all phases of operation.

Recommendations

(a) The Applicant should provide thermal analyses for all operating conditions of the pipeline and for worst case assumptions in startup conditions such as backfill water content and show that the permafrost will be maintained.

3.1.1.3 Geology

C. Effects on Slope Stability

Applicant's Submission

In general, slopes less than 3^{o} were considered stable and no special measures are anticipated to control mass movement on such slopes. In answer to Question #3, it was stated that ice-rich native soil will be used as backfill since any consolidation of backfill will not affect the pipe which will be secured in the permafrost.

Slopes greater than 3^{o} may be subject to instability but less than 10% of the slopes traversed are in that category. The table attached to the answer to Question #3 lists 56 such slopes. The steepest slopes are over 9^{o}.

The slope failures may be shallow or deep-seated. The shallow slope failures, associated with the mass movement in the active layer, are not considered a hazard to the pipe integrity. The deep-seated slope failures involving soil movement at a depth greater than 8 to 10 feet would present the greatest threat to pipe integrity. An analytical method to predict where such failures could occur is not available; consequently, a close inspection of aerial photographs and site inspection is required to assess the general slope and ground condition. Similarity between the slopes which displayed instability and the other slopes inspected by the Applicant will be regarded as one of the criteria for identifying potentially unstable terrain.

An analytical method is presented for assessment of mass movement caused by thaw consolidation in the thawing active layer. This method is described in the Applicant's report and in more detail in the Appendix attached to the answer to Question #24 "Slope Stability in Permafrost Terrain" by Northern Engineering Service Co., Ltd. (1974). The analysis is based on the one-dimensional model of Morgenstern and Nixon (1971) in which two important parameters are the thaw consolidation ration (R), and the coefficient of consolidation (C_V). Where the values of R are low in a thawing soil, no excess water pore pressures are generated and the slope will be generally stable. If the values of R are high, the effective shear stress level of the soil approaches zero and mass movement on the slope is likely to occur. Although this method is conservative in that it neglects the two-dimensional stability effect of the soil, a comparison table shown in Northern Services (1974) indicates instances in which slopes failed at lower angles than those predicted by theory.

The removal of vegetation on the slopes has two negative effects: it increases the rate and depth of thaw which may lead to instability and, secondly, the mass balance is effected such that stable slopes could become unstable due to changes in evapo-transpiration rate along (see answer to Question #23).

The various means of slope stabilization are discussed in the answer to Question #24. In answer to Question #15, sketches are presented showing the means of protection of slopes undercut by pipeline construction.

Analysis of Submission

Slope instability is one of two major hazards of the buried pipeline which merits a careful evaluation and this was recognized by the Applicant. The problems connected with steeper slopes in permafrost, the means of slope stabilization, the effect of construction, and the analytical tools available is quite extensively discussed by the Applicant. However, the descriptive material is of general nature and is not applied to specific slopes along the pipeline route.

The generalized statement that slopes less than 3^{o} are stable; may not be true. Such slopes, when composed of liquifiable solids, would be susceptible to skin flow within the thawed active layer in the event of liquification. Slope failure can also be induced by stream or gully erosion resulting in undercutting and localized oversteepening of the adjacent flatter slopes. All slopes exceeding 3^{o} are subject to the same hazard, and in addition they can be subject to static instability discussed by the Applicant.

Flow intercepted by ditch plugs should be properly diverted so as to avoid creating erosion or icing problems. As stated by the Applicant the pipe ditch can be expected to intercept groundwater flowing in the active zone. On slopes where permeable bedding and padding material is used in the pipe ditch, the intercepted groundwater could, before initial throughput and subsequent ground freezing, readily flow through the ditch padding and bedding. Before initial throughput, this groundwater flow would tend to thaw the natural permafrost surrounding the bedding and padding. As the permafrost thawed it could be progressively eroded, creating voids around the bottom and sides of the pipe which could cause differential pipe settlement or movement. Once initiated, the progressive erosion may continue, after pipeline operation, despite the cold pipe. On the other hand, if the natural permafrost was not erodible after thawing, the intercepted, flowing ground water could create a thaw bulb around the pipe. The thaw bulb may freeze back after throughput begins, however, it could continue to grow even after permafrost was established. Because the pipe is not necessarily buried in thaw-stable material, the developing thaw bulb could lead to slope instability. Both possibilities could be avoided by eliminating the flow of intercepted groundwater through the padding and bedding where thaw unstable materials lie below the pipe.

The use of trench drains to control drainage along the right-of-way slopes in thaw-unstable permafrost could prove unsuccessful. Aggravated thermal degradation, due to both the occurrence of the trench drains themselves and the flow of drainage water within them, would tend to render the drains inoperative through the effects of thaw settlement on the trench drains; the drains could completely sink into the thawing permafrost. In general, wherever drainage facilities constructed on thaw-unstable permafrost can cause thermal degradation, the resulting disturbance can lead to ineffective operation of the drainage facilities.

In the analysis of shallow or deep-seated slope failures, criteria should be developed as to the degree of slope movement which is critical to pipe integrity. In that analysis, the angle between the pipeline and the slope is important. Pipeline running perpendicular to the slope (or undercutting the slope) would be more damaging to the slope stability with higher external loads imposed on the pipe than at other relative angles. To provide more detailed data, all slopes should be categorized with respect to the mass wasting hazard, relative angle to the pipeline, and external loads imposed on the pipe in chilled or non-chilled condition. Representative slopes of each category should be analyzed and method of slope stabilization, if necessary, described.

Three specific examples of slopes with various angles between the pipeline and the slope are discussed below.

– In the foothill area one of the steeper slopes reviewed (4.5-5^{o}) is situated approximately 4 miles east of the Katakturuk River. The pipeline runs parallel to the slope. It crosses ice-rich silty and organic soils probably overlying old morainal deposits of till. Thawing of these soils will result in a great loss of volume and the generation of large quantities of water. If this water is allowed to form ponds it will tend to accelerate melting; if it is allowed to flow, precautions will have to be taken to prevent the rapid erosion which would otherwise take place. Additionally, due to the interception of water from the active layer and from the numerous small streams, care must be taken to avoid concentration of flow and consequent thermal degradation and erosion of the soil and the formation of icings in the winter. The slope is located in smoothly rounded silt-manteled sloping regions composed of thick (up to 50 feet) eolian (silt) and colluvial (organic silt) deposits with many inclusions of ice. The moisture content for samples recovered below the active layer varies from 40 to 90%. Due to sample unreliability the actual moisture content experienced in construction may be significantly greater.

The removal of the organic mat for pipe burial will, as mentioned above, upset the heat equilibrium of the slope. With unchilled pipe, the thaw depth will increase and excess pore pressure may be generated during the thaw of fine-grained soils. The excess pore pressure occurs if water is released at a rate exceeding the discharge capacity of the soil. As a result of this, the effective shear strength of the soil is reduced with probable initiation of skin flows. The skin flow, which may be below pipe level, will cause a vertical movement of the pipe and, depending on the magnitude of the mass movement, pipe stresses may be substantially increased. This vertical movement of the pipe will be further aggravated by reduction of the negative buoyancy of the pipe because of water excess in the pipe trench. The slope flow may vary from inches/year to feet/year, depending on the soil condition and the disturbance introduced by pipeline construction. A more detailed assessment should be made by the Applicant from analyses of this data.

- Another slope in the foothill zone, which was selected for review, lies approximately 4 miles west of the Egaksrak River. It is a low angle slope ($1/3^{o}$ to 2^{o}) and was selected because the pipeline direction is 45^{o} to the slope. The slope is a part of an alluvial fan underlain by deep silting to clean sands and gravel sands. The bottom of the slope merges with the fossil flood plain with less than 5 feet of ice-rich silting to fine sand topstratum. Mass movement which could occur for the reasons mentioned before would cause vertical and lateral displacement of the pipe, although the lower angle of the slope would mitigate this movement.

- The third type of slope which merits examinations is the slope running perpendicularly to the pipeline in the alluvial fan. The sample is situated approximately 4 miles east of the Turner River near the Canadian Border. This zone is characterized by gently rolling terrain cut by broad, very gently sloping flood plains and alluvial fans which become the predominate features east of the Aichilik River at mile 150. The soils in the floodplains and alluvial fans are composed primarily of gravels although the drill hole data indicate the presence of isolated pockets of ice-rich fine grained soil. Silty surficial deposits generally less than 5 feet thick are commonly associated with the alluvial fans and the "fossil" floodplains.

Permafrost is essentially continuous. A thin active layer consists of inorganic silts and clayey silts with low plasticity. Moisture content (from bore hole data) varied from low in grained soils to 200% in fine grained soil. The general characteristics of the terrain are similar to the previous slope (alluvial fans with low gradients, $1/3^{o}$ to 2^{o}). Erosion is not expected to be a problem in these gravels except at river crossings or where subjected to flooding. Thawing can, however, initiate problems. Because of a lower specific heat and a greater thermal conductivity, gravels will thaw faster and to greater depths than will fine grained soils under similar circumstances. Settlement can be large enough to be a problem and the loss of fines through piping could accentuate problems or cause siltation. While no massive ice was observed in the drill holes it is good to remember that massive ice (wedges) has been observed in gravels in the Arctic.

A skin flow initiated by the surface disturbance associated with the right-of-way and trench would cause lateral pipe displacement which would be particularly hazardous if the displacement involves several sections of pipe length and is of a magnitude resulting in unsafe pipe bend curvature. The probable failure will be in the weld area with possible pipe deformation.

Conclusions

- o The Applicant presented a comprehensive description of slope stability problems including analytical models which could be used to assess active layer mass wasting and means of slope stabilization.

- o The description is general and does not address specific slopes in the prime route (except for providing a list of steeper slopes) nor does it categorize the clopes as to their mass wasting hazard. Such information is required for finalization of design and assessment of pipeline integrity. Such assessment cannot be based on conceptual design but only on detailed geotechnical data.

- o The statement that all slopes below 3^{o} are stable and that shallow failures will not affect pipe integrity should be re-examined and supported by more data on slopes crossed and external pipe loads expected from mass wasting.
- o It would be necessary also to examine the problem of slope stability for chilled as well as non-chilled pipeline in case the pipe remains inactive after construction for one or two years.

Recommendations

(a) All slopes should be categorized with respect to their potential instability, relative angle with respect to the pipeline, and mass wasting hazard. Slope stability analysis should cover the case of chilled and non-chilled gas.

(b) Typical slopes from each of the categories should be selected for detailed review. External loads on the pipe resulting from mass wasting should be established and slope stabilization method (if required) should be defined.

(c) The Applicant should determine the degree of slope movement which can be expected and establish criteria for including loads resulting from this factor into the pipeline thickness determination in accordance with recommendations in Section 1.1.1.3.A.1.

References: Morgenstern and Nixon (1971), "One Dimensional Consolidation of Thawing Soils", C Geot. Journal 10, pages 558 - 565.

Northern Engineering Services Co., Ltd. (December 1974), "Interim Report - Slope Stability in Permafrost Terrian", prepared for Alaskan Arctic Gas Co., Ltd., and Canadian Arctic Gas Co., Ltd., Calgary.

3.1.1.6 & 3.1.1.7 Effects of Leaks on Vegetation and Wildlife

Applicant's Submission

Pipeline rupture could cause temporary adverse localized impacts on vegetation; water and air quality; wildlife and aesthetic attributes. The Applicant states that repair and maintenance programs would alleviate the major long-term impacts associated with this type of accident.

Accidental leakage of gas undèr stream crossings would be of no significance to fish in the vicinity of or downstream of any leak. Escaping methane would diffuse into the atmosphere because it is not highly soluble in water. The only exception to this would be if escaping methane were trapped under ice. The Applicant concluded that the chances of this occurring in such locations as to represent a hazard to fish population are remote.

Pipeline emergencies requiring heavy construction vehicle access could cause vegetative mat compaction and localized surface damage. However, some Battelle tests have not shown significant tundra mat surface changes. Implementation of revegetation programs and practices was indicated to be under consideration.

The secondary effects of pipeline failure were studied through consideration of the potential for fires and the effects of fires. Generally, tundra fires remove all of the litter and some of the peat, but only char the cottongrass tussocks where this community type is dominant. Some woody species and lichens are consumed while most mosses are scorched and killed. The effects of tundra fires in the Inuvik area, N. W. T. were reported by Wein and Bliss (1973). Due to the lower standing biomass and cold frequently very wet soils, fires in tundra areas are considered much less damaging and usually are of much less extent than in forested areas farther south.

Recovery from fires in tundra areas is rapid, except for lichens, complete recovery generally requiring two to three years. Cottongrass (eriophorum sp.) and Labrador tea (Ledum palustre sp. decubens) show the most regrowth in the first year. Liverwort (Marchantia polymorpha) is often an important soil solonizer in some localized wet areas. Fire often stimulates the growth of the cottongrass (Eriophorum sp.) and bluejoint grass (Calamagrostis canadensis).

Analysis of Submission

The impacts of leaks on vegetation and wildlife are of two types, non-persistent damage, which results only in temporary effects which can be rectified, and persistent damage, which is manifested by an irreversible ecological change in either vegetation, or wildlife population, habits, or habitat.

These effects may be due to accidental low level or undetected gas leakage during operation which, by virtue of gradual diffusion of gas components along the pipeline right-of-way, can cause a significant alteration of the atmospheric oxygen balance.

The Applicant in examining the effects of normal operation and maintenance of the pipeline did not consider the fact that natural gas composition is not entirely methane but includes also some species with higher molecular weight than air. Differential diffusion of underground (permafrost) leakage could cause local temporary oxygen starvation, but persistent damage would not be expected if the leakage is detected and the necessary repairs effected quickly. A matter which becomes pertinent to accidental leakage loss effects upon the environment is rapid detection so as to prevent the possibility of persistent damage. The Applicant did not discuss methods for detecting losses due to leaks.

Environmental Protection Agency studies have indicated that an important source of damage to wildlife and vegetation from hydrocarbons is attributable to the presence of ethylene. This was not discussed by the Applicant. Whereas the Applicant discussed the effects of leakage under stream crossings on fish, no mention is made of leakage effects on terrestrial wildlife.

ethylene causes loss of leaves, early maturation of fruit, etc.

3. 1. 1. 6 &(cont.)
3. 1. 1. 7

The most catastrophic problem would be pipe rupture. The effect of pipeline rupture on wildlife and vegetation were not discussed by the Applicant other than the general statement that pipeline rupture could cause temporary adverse localized impacts on vegetation, water and air quality, wildlife, and aesthetic attributes. No mitigating measures other than prompt maintenance and repair was offered. The Applicant did not specify the probability of such a catastrophic event.

The Applicant did note the secondary effects of pipeline failure as presented above. Control would presumably be accomplished by isolation of the line section and allowing gas to vent to the atmosphere. In such an instance, depending upon the reaction time, system average pressure and temperature, and assuming a 15 mile distance between the isolation valves, approximately 4500 tons of gas could be released.

Conclusion

The Applicant has discussed effects of leaks on vegetation and wildlife in a gualitative manner but has not determined the magnitude of leakage required for specific types of damage or conversely, the threshold level below which damage would be negligible.

Recommendations

(a) The Applicant should establish a threshold level of leakage (if any) which would not cause damage to vegetation and wildlife.

(b) The Applicant should show that his leakage detection method(s) are capable of locating leaks of the magnitude defined by the Applicant in recommendation (a) above.

3.1.1.10 Sociological Factors (Construction and Operation)

C. Environmental Noise Levels

Applicant's Submission

The noise level from the compressor stations which will be built in the future and are not part of the Applicant's Environmental Report is estimated in dbA units as a function of distance up to 2000 feet from the station (dbA scale indicates sound pressure level against the sensitivity of the human ear and it de-rates low pitch sounds). The noise from the compressor station will be from three main sources: the main gas turbine; the refrigeration compressor turbine; and the electrical generation turbine(s).

Compressor noise simulation tests were performed at a sound level which was higher than the anticipated noise of future compressors equipped with silencers. The objective of these tests was to determine the effect of future compressor stations on arctic wildlife. Disturbance to some of the species was noted.

Comparing the estimated noise levels with criteria for non-aircraft noise sources measured outdoors they could be classified at distances greater than 1000 feet from the station as "normally acceptable" for daytime residential areas.

The noise connected with construction activities on the pipeline will be insignificant from an environmental point of view.

Analysis of Submission

The noise generated from compressor stations can be attenuated by the use of silencing equipment. Various levels of noise control were defined by NEMA (National Electrical Manufacturers Association).

The various sound pressure levels specified depend on environmental requirements and means of selective silencing are provided by manufacturers to meet the limits required. New noise standards are under preparation under the authorization of the Noise Control Act of 1972.

Equally important from a sociological point of view will be construction noise during at least three seasons, and pipeline blowdown noise during pipeline operation. This noise will be intermittent, sometimes of high level, and, therefore, more disturbing to the environment.

The construction noise and its effect on the environment is probably underestimated by the Applicant. Construction will take place in an environment with a very low background noise during the consecutive winters. It will involve movement of people, heavy equipment, trenching, blasting. It is not clear at all that the effect of all this noise on the environment will be insignificant and more detailed studies of construction noise and its effect should be made. Construction noise will not, however, effect pipeline integrity.

There will also be a noise from occasional pipe blowdown as a routine checkout or in an emergency. This noise will be of high level, but it is not mentioned by the Applicant. Assessment of this noise level and its frequency should be made.

Operational noise may effect pipeline integrity. This would be indirect in that the vibrations associated with it and with the rotating machinery may effect adfreeze strength of the piles supporting the buildings and equipment. This should be studied since even small displacement of the pump-turbine assembly will effect its long-term reliability.

Conclusions

- The Applicant did not assess adequately the construction noise or its effect on environment.

- Criteria for the noise level of future compressors and blowdown stacks needs definition in terms of sound pressure level and frequencies considering low background noise of the environment.

- There is a possibility that long-term noise and vibration may adversely effect the adfreeze strength of piles supporting the buildings and equipment.

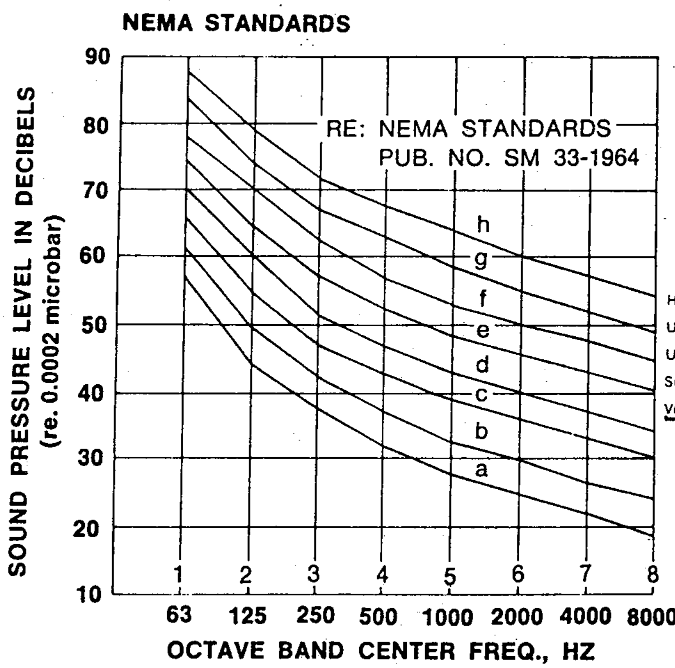
3.1.1.10.C (cont.)

Recommendations

(a) Evaluation should be made to establish any adverse effect of vibration and noise on the adfreeze strength of piles supporting the buildings and equipment. If control measures are required, these should be defined.

(b) Construction noise level and its effect on the environment should be analyzed.

(c) Criteria should be developed for the maximum noise level at various frequencies acceptable from the compressor stations and blowdown stacks.



TYPE OF AREA	PEAKING Daytime Only	PEAKING Nighttime Only	CONTINUOUS Daytime Only	CONTINUOUS Day and Night
Heavy Industry	h	f	g	e
Urban — Nearby Industry	g	e	f	d
Urban — Residential	f	d	e	c
Suburban — Residential	e	c	d	b
Very Quiet — Suburban or Rural Residential	d	b	c	a

Figure 1. NEMA noise standards for industrial and residential centers.

4. MITIGATING MEASURES IN THE PROPOSED ACTION

4.1 Arctic Gas Pipeline Project

4.1.1 Alaska Arctic Pipeline

4.1.1.3 Safety and Emergency Measures to be Implemented

Applicant's Submission

Strict adherence of the Applicant to requirements and guidelines of DoT and other regulations, with inspection and enforcement by government agencies, will go far toward ensuring the safety of personnel during construction, operation, and maintenance of the pipeline system. An important aspect of safety, particularly in the arctic, is the availability of a reliable communications system for coordination, supervision, information exchanged, reporting of accidents, and obtaining aid. The Applicant's proposed dedicated system, i.e., a system with communication channels assigned exclusively to one service, should provide the necessary communication services. Tentatively, a terrestrial microwave system is proposed for long-distance transmission of voice, and a mobile radio system would be used for short-range communications between crews working and moving along the right-of-way.

One of the first and fundamental approaches toward achieving a good safety record is the implementation of a training program for personnel. During construction, workers will receive training regarding safe procedures when working in arctic conditions. Arctic survival techniques will be presented, with emphasis on the minimum requirements under the most severe conditions. Safety training of operating personnel will be initiated at the time of their employment and continue throughout their services with the company. With coordination by a Safety Supervisor, the training program would cover such topics as survival and first aid, gas handling and on-the-job safety, personal safety equipment, station equipment and controls, and fire fighting.

Provisions for fire protection are important because of the presence of combustible natural gas, as well as auxiliary liquid fuel supplies. Again, the basis of the fire protection program is the training of construction, operations, and maintenance personnel in fire prevention and fire fighting. Protection against possible natural gas fires will be accomplished by the use of emergency, automatic shutdown equipment and automatic fire extinguishing systems. Along the pipeline, maintenance crews will always be provided with portable fire extinguishing equipment. At all airstrips and helipads, wheeled dry chemical fire extinguishers will be provided.

Propane is required during construction for pipeline heating and for applying insulating tape over the pipe. No propane will be required after construction until the future compressors are installed, at which time a propane refrigeration system will be needed for compressed gas chilling. Propane is carried in transportable cylinders which will be stored at stockpile sites and hauled by sled along the construction line. The requirements of the National Fire Protection Association will be adhered to, and employees handling propane cylinders will receive practical instruction by experts on the subject.

Several liquid fuels will also be required during pipeline construction and operation, viz., diesel oil, motor gasoline, and aviation gasoline. During construction, a dedicated diked area will be provided at each stockpile site. Diked compounds will also be constructed around permanent fuel storage tanks.

Acids and explosives will be stored in compliance with applicable federal, state and local codes. Explosives will be stored and guarded to avoid inadvertent detonation or misappropriation, and will be used only by qualified personnel.

To minimize the consequences of lost vehicles and aircraft during the winter season, they will carry automatic radio locator equipment in addition to normal mobile radio links to the pipeline communication system. Landing aids will be provided for aircraft to facilitate safe landing under adverse conditions.

Analysis of Submission

One aspect of safety that should have been included is the use of pressure limiting and relief devices to prevent over pressure in the line. Another detail relates to the design of the gas alarm system, particularly when compressor units are installed. It will be important to examine the gas sampling points in the system; fires and explosions have occurred because local gas accumulations built up without detection by the gas alarm unit.

Particular attention should be paid to the unique conditions in the pipeline area and how they impact emergency provisions. For example, outdoor equipment must be capable of operation with gloved hands. Emergency lights, particularly the portable type, should be readily available because of the long periods of darkness. Transportation equipment must receive careful maintenance with particular emphasis on winterizing provisions to assure reliable operation at low temperatures. Items such as mainline block valves must be capable of operation in the winter environment of snow and cold and they must be marked for easy location after a heavy snowfall.

Conclusions

Safety measures for this project are principally directed toward personnel associated with the pipeline because of the absence of other human habitation in the area. While this fact might appear to alleviate the safety problem, the inhospitable environment is more than counterbalancing, requiring constant vigilance, planning and training to safeguard employee and contractor personnel. The Applicant has covered many aspects in a general, preliminary fashion but much detail is lacking and remains to be defined before the project is initiated.

4.1.1.3 (cont.)

Recommendations

(a) The Applicant should provide a detailed health and safety plan, including a description of the safety training program and safety equipment for buildings, sites, vehicles, aircraft, and personnel.

4. MITIGATING MEASURES IN THE PROPOSED ACTION

4.1.1.5 Recommendations

The discussion of each recommendation shown below appears in the sections noted at the end of each recommendation.

1. The Applicant should conduct additional tests and/or analysis to evaluate the "worst case" high temperature of the active layer at pipeline startup combined with a "worst case" ground moisture content. The lowest anticipated gas temperature should be used once the test is started and maintained throughout the test to demonstrate the effect of frost heave induced on the pipeline by freezing of this active layer. (1.1.1.1.B.2, 1.1.1.3.A.2, 2.1.1.3.C.4.e)

2. All upstream valves between the location of the emergency (leak, pipe fracture, etc.) and at least the nearest upstream compressor station be simultaneously closed as rapidly as possible during emergency shutdown. The Applicant should consider the loads induced by valve closure in the pipeline thickness determination under 1.1.1.3.A.1 recommendation (a). (1.1.1.3.A.2)

3. The Applicant should provide flow diagrams for summer and winter operation for a nominal 4.5 BCRD (standard) throughput. (1.1.1.3.A.2)

4. Since proper operation of the pipeline and facilities depends upon the gas properties, it is necessary to control the composition and concentrations of water, corrosive elements and solid contaminants, etc., which will exist at pipeline entry. The Applicant should develop a specification stipulating the composition and properties of the gas which will be accepted for input into the pipeline with special emphasis on the types and amounts of contaminants. (1.1.1.3.C.1, 1.1.1.7.C.4, 1.1.1.7.A.2)

5. The Applicant should provide for review and approval, criteria for backfill material, configuration and procedures for installation. These criteria and procedures should be substantiated by test data which shows that ponding, thaw depressions and ditch sidewall degradation is avoided when the criteria and procedures are adhered to. (1.1.1.6.B.2)

4.1.1.5 (cont.)

6. The Applicant should provide a detailed plan for developing ditching and blasting techniques appropriate for ditching in frozen gravels and other stubborn permafrost areas. (1.1.1.6.B.1)

7. The Applicant should provide snow road criteria, including requirements for thickness and density. (1.1.1.6.B.1)

8. The Applicant should provide a logistics and contingency plan for snow and/or ice roads in the event of a -2 sigma snow fall. (1.1.1.6.B.1)

9. The Applicant should provide test data substantiating the feasibility of wheel type ditching equipment for use in permafrost. (1.1.1.6.B.1)

10. The Applicant should develop appropriate handling procedures and personnel safety practices taking into consideration the toxic nature of methanol vapors. (1.1.1.6.D.1)

11. The Applicant should provide means employed for small leak detection of the liquid in case of minor pipe defects during hydrotest. (1.1.1.6.D.1)

12. Plans should be defined for protection of the pipeline from overpressure, both in the initial stages and when the compressor stations are activated. (1.1.1.7.A.1, 1.1.1.7.C.1)

13. Plans should be defined to odorize the gas in the service lines to the maintenance stations and, later, to the compressor stations. (1.1.1.7.A.1)

14. Data or analysis should be presented regarding heat soak-back from exposed piping, such as from the scraper trap assemblies and mainline block valves. (1.1.1.7.A.1)

15. Design specifications should be prepared for the control and communication equipment, when available. (1.1.1.7.A.1)

16. An Operation and Maintenance Plan should be prepared. (1.1.1.7.A.1)

17. The Applicant should provide a detailed startup plan. (1.1.1.7.A.3)

18. Test description and results, as well as preliminary specifications for the external coating system should be provided. (1.1.1.7.B.1)

19. Test description and results showing the feasibility of cathodic protection in permafrost should be provided. (1.1.1.7.B.1)

20. A detailed description should be provided of the impressed current and sacrificial anode (if used) cathodic protection systems, including power supply, cabling and maintenance plan. (1. 1. 1. 7. B. 1)

21. Applicant should furnish an operating/maintenance manual covering shutdown procedures. (1. 1. 1. 7. C. 2)

22. The Applicant should provide a test and surveillance plan for the cathodic protection system. (1. 1. 1. 7. B. 2)

23. Additional precautions should be instituted that might be employed during periods in which the ground is covered by a thin ice layer or thin thawed layer. (1. 1. 1. 7. C. 3)

24. Air cushion vehicle operation and type and number of aircraft required for summer repairs should be presented in detail. (1. 1. 1. 7. C. 3)

25. Procedures to be used in the event of high incoming gas temperature should be described. (1. 1. 1. 7. C. 3)

26. An evaluation should be performed on line break detection equipment and on detection of small gas leaks in the operating line. (1. 1. 1. 7. C. 3)

27. Repair procedures for compressor stations should be specified. (1. 1. 1. 7. C. 3)

28. A contingency plan and emergency procedures for the pipeline system, including the time required for repairs, should be prepared. (1. 1. 1. 7. C. 3)

29. The Applicant should justify the acceptability of his gas composition as regards its hydrocarbon dew point. (1. 1. 1. 7. C. 4)

30. The Applicant should develop for review and approval, allowable loads criteria for each landslide bench traversed by the proposed pipeline with supporting analysis. (2. 1. 1. 2. D)

31. The Applicant should identify all slide areas along the pipeline route and avoid heavy blasting utilizing simultaneous detonation of many charges when traversing such areas. (2. 1. 1. 2. D)

32. The Applicant should specify precautions to be taken to prevent reactivation of movement of all parts of the landslides identified along the pipeline route and specify their program for future monitoring to detect any ground movement. (2.1.1.2.D)

33. The Applicant should restore surface drainage along the pipeline route to pre-construction conditions except that wherever closed depressions existed on a bench, these depressions will be regarded to permit runoff of the surface water over the edge of the slope.(2.1.1.2.D)

34. Applicant should determine conditions created by possibility of the inactive pipeline buried for one or two seasons, as well as by pipeline flowing chilled gas, together with proposed stabilization methods. (2.1.1.2.D)

35. Applicant should make an estimate of actual displacements to be expected during the life of the pipeline due to the most severe conditions of solifluction and creep which may occur. If necessary, Applicant should measure solifluction and creep by field observation. Applicant should also describe in detail measures which will be taken to control such displacements. (2.1.1.2.D)

36. Applicant should provide detailed information on each major river crossing in Alaska, noting bank profiles, slopes, soil erodibility, breaching of banks, if required, extent and slope of breach, restoration of banks, computation of scour depth vs. statement of depth of pipe burial. (2.1.1.2.E.2)

37. The Applicant should develop loads criteria for the pipeline design per recommendation (a) of 1.1.1.3.A.1 to withstand earthquakes of M5.5. Criteria should treat trench and backfill requirements specifying a maximum acceleration in g and a duration above a minimum acceleration level such as 0.05 g. If data are available, an estimate should be made (see, for example, Howell, 1973) of the Average Regional Seismic Hazard Index (ARSHI). (2.1.1.3.C.1.b.1)

38. The Applicant should install seismic instrumentation in the vicinity of Flaxman Island, considered the most likely center of seismic activity along the route. (2.1.1.3.C.1.b.1)

39. A detailed discussion should be presented of the special design features for areas of seismic activity mentioned in response to Question #25. (2. 1. 1. 3. C. 1. b. 1)

40. The Applicant should give the location of the area considered subject to thixotropic liquefaction, with a description of soil texture and soil water content. (2. 1. 1. 3. C. 1. b. 3)

41. The Applicant should provide an explanation of the relation between the pipeline, active layer, and permafrost surface which precludes pipe movement in case of seismic liquefaction. (2. 1. 1. 3. C. 1. b. 3)

42. The Applicant should make a statement including potential liquefaction areas as in his treatment of potentially buoyant areas. (2. 1. 1. 3. C. 1. b. 3)

43. The Applicant should identify all potentially unstable slopes effected by construction with a determination of the factor of safety by the McRoberts Method. (2. 1. 1. 3. C. 2. d)

44. The Applicant should reevaluate the method of restoring slopes by natural sloughing processes, including an examination of slopes where this method has been applied, reporting any instances of excess erosion or degradation of cover. (2. 1. 1. 3. C. 2. d)

45. The Applicant should make a similar reevaluation of the use of snow or ice fill, reporting on damage incurred by the melting of such fill. (2. 1. 1. 3. C. 2. d)

46. The Applicant should identify potential mass waste areas along the prime route and perform a detailed analysis of mass wasting hazards and their effect on pipe integrity. (2. 1. 1. 3. C. 2. g)

47. The Applicant should determine external loads imparted by mass wasting on the pipeline for all areas considered to be a potential hazard and incorporate in pipe thickness determination of 1. 1. 1. 3. A. 1. (2. 1. 1. 3. C. 2. g)

48. The determination of depth of pipe burial as a function of active layer depth should be calculated with chilled and unchilled pipe and cover the contingency of delayed pipe operation after burial. (2. 1. 1. 3. C. g)

49. The Applicant should provide bore hole data, particularly for slopes, river approaches, under rivers, and at compressor stations. (2. 1. 1. 3. C. 4. d)

50. The Applicant should provide for review and approval detail design at all river crossings with supporting analysis to show that depth of burial and negative buoyancy provisions are compatible with worst case assumptions. (2.1.1.5.B.2)

51. The Applicant should provide for reivew and approval, flood plain criteria and show the pipeline design is in conformance with this criteria. Details of pipe negative buoyancy provisions as a function of terrain crossed should be provided and substantiated by analysis. (2.1.1.5.B.2)

52. The Applicant should provide the design measures necessary to preclude ice fog ingestion into compressor turbines during all phases of remote, unattended operation. The Applicant should support his proposed design with test data which verifies the design feasibility during operation under continuous ice fog conditions. (3.1.1.1.A)

53. The Applicant should develop criteria for submittal to the DoI for review and approval which will allow areas with a high potential for "accelerated erosion," to be defined on a detailed basis and in a manner suitable for portrayal on construction drawings. These criteria should provide methods for the calculation of required quantities of backfill, mound breaks, culverts, ditch plugs, borrow and other control and restoration measures. Criteria should consider soil type, including thermal state and moisture content, topography, climate, hydrology, construction mode and grading geometry.

The various specific control measures should be formalized to the point of standardization such that they can be specified to apply, with appropriate modofications for local conditions, to any section of the pipeline.

The Applicant should provide specific criteria to restore river banks where these have been breached for crossing and to protect them from excessive erosion. (3.1.1.2.A.1)

54. The Applicant should take care to insure that surplus spoil is not disposed indiscriminately on right-of-way with an undisturbed vegetative cover required as an erosion control. (3.1.1.2.A.1)

55. The Applicant should provide more information on creep and deep-seated failure in frozen soil, where he states that substantial field investigation is called for. Specifically, a survey should be made in the field of potential sites of each type of failure, the soil creep measured, and the deep-seated failure potential evaluated by the methods described in Applicant's submittal. (3. 1. 1. 2. A. 1)

56. The Applicant should review the location of the borrow pits and show that erosion resulting from them will not threaten pipeline integrity. (3. 1. 1. 2. A. 2)

57. The Applicant should identify areas along the pipeline route which, when subjected to blasting groundshocks, may be susceptible to slumping or soil fall and slopes which may be susceptible to avalanches. The Applicant should specify the special precautions to be taken when blasting is required in these areas. (3. 1. 1. 2. B)

58. All slopes should be categorized with respect to their potential instability,relative angle with respect to the pipeline, and mass wasting hazard. Slope stability analysis should cover the case of chilled and non-chilled gas. (3. 1. 1. 3. C)

59. Typical slopes from each of the categories should be selected for detailed review. External loads on the pipe resulting from mass wasting should be established and slope stabilization method (if required) should be defined. (3. 1. 1. 3. C)

60. The Applicant should establish a threashold level of leakage (if any) which would not cause damage to vegetation and wildlife. (3. 1. 1. 6)

61. The Applicant should show that his leakage detection method(s) are capable of locating leaks of the magnitude defined by the Applicant in recommendation (a) of section 3.1.1.6. (3. 1. 1. 6)

62. Evaluation should be made to establish any adverse effect of vibration and noise on the adfreeze strength of piles supporting the buildings and equipment. If control measures are required, these should be defined. (3. 1. 1. 10. C)

4.1.1.5 (cont.)

63. Criteria should be developed for the maximum noise level at various frequencies acceptable from the compressor stations and blowdown stacks. (3.1.1.10.C)

64. The Applicant should provide a detailed health and safety plan, including a description of the safety training program and safety equipment for buildings, sites, vehicles, aircraft, and personnel. (4.1.1.3)

4. MITIGATING MEASURES IN THEPROPOSED ACTION

4.1.1.6 Research and Monitoring

Recommended needed studies are shown below. The discussion of each recommendation shown below appears in the section noted at the end of each recommendation.

1. The Applicant should make a comprehensive analytical determination of the maximum stresses that can exist concurrently with pressure induced stresses during pipeline operation. These analyses should cover thermal stresses for the worst possible combination of installation and operation temperatures, stresses associated with worst case frost heave phenomena, the effects of buoyancy and the attendant weighting and/or anchoring, differential settlement for the worst anticipated soil conditions, earthquake induced strain effects, pipeline behavior in regions of soil slippage, and the additive effects of construction induced initial stresses. The results of these studies should be used in conjunction with appropriate allowable stresses and operation pressures to determine pipe wall thickness. (1.1.1.3.A.1)

2. A complete investigation of the material properties of X70 steel should be undertaken in order to arrive at a meaningful allowable operating stress. The allowable stress should be such that an adequate factor of safety is provided against <u>all</u> potential failure modes. In particular, the Applicant should determine by conservative and rational procedures the stress and temperature levels at which small flaws in either the basic material or in the welds will precipitate failure. As a result of these studies, specification criteria should be developed for minimum acceptable fracture toughness of the material, a consistent inspection criteria for welds should be established such that all flaws above the critical size are detected, and a proof test requirement should be developed which will specify the test medium temperature as well as its pressure and the duration of loading. (.1.1.1.3.A.1, 1.1.1.6.D.1)

3. The Applicant should evaluate the effect of low gas pipeline temperature on pipe material toughness and consider operating at higher inlet temperatures to reduce this effect. The results of these analyses along with the Applicant s recommendations should be presented to the DoI for review and approval. (1.1.1.1.B.2, 1.1.1.3.A.1, 2.1.1.3.C.4.e)

4.1.1.6 (cont.)

4. The properties of API X70 steel should be reviewed against the intent of Title 49 of the Code of Federal Regulations to determine the revisions (if any) required to incorporate the use of API X70 type steels.

5. Future design data submitted to DoI for approval of compressor status should include trade-off data showing the total economic impact of compressor stations with single large compressor units versus compressor stations comprised of two or more units with standby capacity to maintain station capability during maintenance operations or during single compressor failures. This trade-off should consider the remote location of these compressor stations and the down time involved or flow capacity lost from compressor failure. (1.1.1.3.C.1)

6. The Applicant should examine the safety aspects and industry experience involving the use of propane as a chilling fluid versus other non-flammable refrigerant alternates. (1.1.1.3.C.1)

7. A unique feature of buried natural gas pipeline transport systems in permafrost is represented by the need to chill compressed gas. Current Federal Standards dealing with compressor station design and safety overlook such refrigeration facilities. The need for future revisions should be considered a subject for study. (1.1.1.3.C.1)

8. The effect of summer pipeline excavation on subsequent local soil conditions and pipeline integrity should be analyzed. (1.1.1.7.C.3)

9. Construction noise level and its effect on the environment should be analyzed. (3.1.1.10.C)

5. ADVERSE EFFECTS WHICH CANNOT BE AVOIDED SHOULD THE PROPOSAL BE IMPLEMENTED

5.1 Arctic Gas Pipeline Project

5.1.1 Alaska Arctic Pipeline

5.1.1.3 Discuss Impact in Relation to Pipeline Integrity

Applicant's Submission

The possibility of pipeline rupture is small but finite.

Analysis of Submission

The pipeline is a buried high pressure vessel containing a flammable gas. Because of the high gas pressure, any pipeline rupture will provide explosive force even in the absence of fire. Regulatory agencies may impose requirements and engineers may attempt to provide for pipeline integrity under every conceivable combination of worse case events; however, while the risk may be made small it can never be made to equal zero. The Applicant has proposed to implement safety and emergency procedures to reduce the hazard from a rupture of the pipeline. The pipeline design incorporates automatic features and block valves at 15 mile intervals to limit the volume of gas which would escape should the pipeline rupture.

The bulk of the pipeline is along an uninhabited or low population density route. The probability of rupture is small from normal natural causes since these can be foreseen and provided for in the design. Additional safety factors are imposed where the population density is higher. Any gas vented due to pipeline rutpure is much lighter than air (at all temperatures of gas and air that will exist on this proposed project) and, therefore, the gas will rise rapidly and will not produce a cloud near the ground that is hazardous to life.

Conclusions

Because there are unknowns and unpredictable events, there remains a small but finite probability that the pipeline will rupture. To reduce the probability of this element to the smallest possible value, the Applicant should implement a program of pipeline marking, surveillance, and public education.

5.1.1.3 (cont.)

Recommendations

(a) The pipeline design should attempt to consider all possible forces which could damage the pipeline and provide sufficient strength to withstand the combined effect of these forces per recommendations in Section 1.1.1.3.A.1.

6. RELATIONSHIP BETWEEN LOCAL SHORT-TERM USE OF THE ENVIRONMENT AND MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

6.1 Arctic Gas Pipeline Project

6.1.1 Alaska Arctic Pipeline

6.1.1.1 Risks to Health and Safety

Applicant's Submission

Inasmuch as there is no indigenous population along the Applicant's proposed route, and very few people in the entire area, health and safety risks apply principally to people associated with the construction and operation of the pipeline.

The principal federal guides to health and safety are: Code of Federal Regulations, Title 29, Chapter XVII Part 1910 (Occupational Safety and Health Standards), and Part 1926 (Safety and Health Regulations for Construction). These documents cover such pertinent topics as personal protective equipment; general environmental controls, including sanitation and temporary labor camps; medical and first aid; hazardous materials; materials handling and storage; machinery and machine guarding.

Prevention is the most desirable way of mitigating the health and safety problem. The Applicant has indicated the important features of such a prevention program, including physical and psychological screening of potential workers, a safety training program, provision of personal and station safety equipment, etc. In addition to preventive measures, first-aid/medical facilities and personnel will be provided in the event of sickness or injury at Prudhoe Bay.

The Applicant has presented published data for the entire construction industry to estimate the number of disabling injuries that would be expected during the construction period of the pipeline. He also included 1972 American Gas Association safety data from natural gas transmission companies to arrive at the probability of fatal and disabling injuries during the operational period of the pipeline.

Analysis of Submission

Some additional injury data are available from the American Gas Association report used by the Applicant. The gas utility industry as a whole ranked 19th in frequency rate of disabling injuries among 41 major industries in 1972 and 16th in the severity rate. Transmission companies ranked below the gas industry average in the frequency rate (5.88 vs. 8.38 disabling injuries per 1,000,000 man-hours) but above in the severity rate (762.3 vs. 534.9 days lost per 1,000,000 man-hours).* According to 1973 data**, there were a total of two employee and 33 non-employee fatalities for the gas utility industry, of which one employee fatality and one non-employee fatality was attributed to the transmission sector.

The transmission industry safety record given above and in the Applicant's proposal pertains to activities primarily in the contiguous United States. The harsh natural environment and construction working conditions impose unusual stresses and hazards which must be considered. For example, extended periods of construction work in subzero weather and darkness, in relative isolation, would be expected to increase the incidence of injuries and psychological illnesses compared to more benign conditions encountered in the lower 48 states.

It is convenient to divide the problem into the (relatively) short-term construction phase and the much longer operations and maintenance period. The former comprises three stages from preconstruction, small group activities, through construction of logistical sites, to actual laying of the pipeline. Manpower will increase correspondingly with three groups or spreads involved in the final pipe emplacement operations, each spread consisting of about 800 men who will work 12 hours per day, seven days a week. By contrast, normal operation and maintenance of the completed pipeline will require about 40 people, operating out of Prudhoe Bay on a five-day work week.

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* "The Gas Industry - 1972 Disabling Injury Experience," American Gas Association, Catalog No. J00443, 1973.

** "Sixth Annual Report of the Secretary of Transportation on the Administration of the Natural Gas Pipeline Safety Act of 1968 - Calendar Year 1973," United States Department of Transportation, 1974.

Apart from the sheer differences in numbers of men involved in the two phases, there are other factors which will tend to make the construction period more depanding on health service facilities. Many of the workers will be new to the arctic region and the unique hazards that such an environment imposes, as, for example, frostbite. Long hours of work will tend to increase the incidence of accidental injuries, as will the use of new types of construction equipment and techniques. Conversely, communicable diseases may be less of a problem than in the normal population, since workers will undergo a pre-employment physical and a routine immunization program.

The operations and maintenance phase of pipeline operation should, in general, be more conducive to the health and safety of the employees. Personnel will probably be more experienced in arctic operations, work on a less strenuous schedule, and perform more routine tasks. An exception would be the case of emergency repairs, when seldom-used equipment and procedures would be exercised under, possibly, extreme environmental conditions in the presence of fire or explosive hazards.

A particular concern is how health and safety measures will be supervised, coordinated, and controlled during the construction phase inasmuch as Applicant has indicated that much of the responsibility will be placed upon the individual contractors. As with other aspects of the project, government approval and inspection is mandatory prior to, and during, the construction and operation of the pipeline.

Conclusions

It is reasonable to expect that the frequency rate of injuries would be higher for the proposed pipeline than previous industry statistics indicate, due to the isolated location and climatic extremes. However, the very fact that both the Applicant and government officials are aware of the problem and will institute extraordinary precautions should tend to mitigate the problem. Further, by the time construction gets underway, there may be an available supply of personnel who have had considerable arctic experience working on other Alaskan projects.

6.1.1.1 (cont.)

Recommendations

(a) The Applicant should furnish a comprehensive health and safety plan for both the construction and operations phases to the DoI for review and approval.

7. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF RESOURCES IF THE PROPOSED ACTION SHOULD BE IMPLEMENTED

7.1 Arctic Gas Pipeline Project

7.1.1 Alaska Arctic Pipeline

7.1.1.1 Damages from Natural Catastrophy or Man-Caused Accidents

Applicant's Submission

There are several potential modes of environmental damage that could result from natural or man-caused incidents. Probably the major concern is the consequence of pipeline rupture. Design and protective measures will be employed in order to minimize fatigue and failure potential. A most important measure taken against the possibility of a major pipeline accident is the prevention of warm gas transmission. This is designed to prevent permafrost degradation and subsequent stresses which might be imposed in the pipeline due to excessive movement.

Pipeline failures have occurred because of corrosion or a material failure. The test and inspection program carried out during construction of the pipeline, and the application of cathodic protection, makes a failure from these causes unlikely. Thorough training of personnel, constant monitoring of pipeline performance parameters, and routine route surveillance should minimize the possibility of a man-caused accident, especially since there will be little, if any, other human activity along the route.

In the event that pipeline rupture were to occur, natural gas would be released to the atmosphere. Most of this gas would quickly rise and dissipate, as the main constituents are lighter than air even at extreme temperature differentials. Minor quantities of the heavier components would settle along the ground. Automatic activation of the mainline block valves with loss in pressure will isolate the break area. Nevertheless, there will be a sudden release of a large quantity of high pressure gas. Ignition of the gas is remote but possible. There could also be an upheaval of a limited segment of pipeline and crown.

Such a failure could elicit temporary adverse localized impacts on vegetation (physical destruction and/or fire) water and air quality (combustion products), wildlife (noise, fire) and aesthetic attributes. Localized heating of the permafrost is likely.

The possibility of tundra fires, either as a result of pipeline failure, aircraft or vehicle accidents, or other man-caused incidents, has been considered. Generally, tundra fires remove all of the litter and some of the peat but only char the cottongrass tussocks where this community type is dominant. Due to the lower standing biomass and the cold and frequently very wet soils, fires in tundra areas are considered much less damaging, and usually of much less extent, than in forested areas further south. Recovery from fires in tundra areas is rapid, except for lichens, complete recovery generally requiring two to three years.

In the event of a major pipeline emergency, the need for rapid access to the pipeline would require controlled vehicular passage over unprepared surfaces to move heavy equipment to the location. Localized effects of a single vehicular passage on tundra would be related to sub-surface ice conditions, vegetation type, and amount of surface peat accumulation. Any passage, however, could be expected to compact the vegetative mat, which in turn might influence subsurface permafrost characteristics. This could be expected to incur isolated instances of seasonal thaw zones, subsidence, and ponding. Passage of vehicles over unprepared show surfaces in the winter season would not result in significant changes in the physical characteristics of the tundra surface but subtle changes in the flora and total biomass are possible.

Another area of concern is the consequences of a fuel spill. Two potentials for accidental spills exist: (1) leaks during unloading and stock-piling along the coast, and (2) spills on land during construction, and to a lesser degree during operation of the pipeline. In the case of the gas pipeline, any leaks or spills would be in the range of a few barrels or less. Prevention and cleanup are the two measures to mitigate any harmful environmental effects. All operating personnel will be oriented, trained, and motivated to prevent accidental leakage.

7.1.1.1 (cont.)

Analysis of Submission

The occurrence of a pipeline rupture is reduced by the absence of other human activity in the area. This should also minimize the chance of fire if gas is released. The primary source of environmental damage will probably result from the activities associated with control and repair of the failure, especially if not carried out with care and expertise. Because of the delicate balance of natural conditions in the area any environmental damage can be potentially serious.

Conclusions

The Applicant demonstrates an awareness of the consequences of pipeline failure on the environment. One can only fault the measures he intends to take in order to prevent failure or effect repairs. These subjects are addressed in detail throughout other sections of this report.

Recommendations

No recommendations are made specific to this section. Technical questions and recommendations related to prevention of environmental damage are given elsewhere in this report.