# PERFORMANCE OF THE TRANS-ALASKA PIPELINE SYSTEM FUEL GAS SUPPLY PIPELINE

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## Abstract

The Trans-Alaska Pipeline System includes a gas pipeline which supplies natural gas to the four northern-most pump stations. This gas pipeline extends south from Prudhoe Bay to Pump Station Four a distance of approximately 238 kilometers. The pipe grades from 25.4 cm to 20.3 cm in diameter and is buried in permafrost typically to a depth of one meter over the entire length. Polystyrene boardstock insulation was placed in the pipe ditch during construction approximately 0.3 m below the ground surface to prevent the formation of an extensive thaw bulb in the disturbed area of the pipe ditch.

The pipeline has now been in operation for over 13 years and several ongoing monitoring programs have provided data on its performance. These programs include periodic survey monitoring of pipe movements, thermistor monitoring of ground temperatures in the vicinity of the pipe, and magnetic pipe locator depth-of-cover surveys to identify areas of possible pipe movement. Performance of this gas pipeline has been excellent. No operational upsets have occurred from thaw settlement or frost heave. As a result of the monitoring program, one area of pipe settlement from thaw of ice-rich soils was identified and repaired without any loss of service. The pipe in the area of the repair was located on a gently sloping hillside where water flow along the pipe ditch caused thawing of ice rich foundation soils and subsequent settlement of the pipe. The repair included underpinning the pipe with piles and diversion of the water flow away from the pipe corridor. The details of this repair, initial design considerations, and the construction and operating history of the pipeline are discussed.

## Résumé

Le Réseau Trans-Alaska comprend un gazoduc qui approvisionne en gaz naturel les quatre stations de pompage les plus septentrionales. Ce gazoduc s'étend depuis la baie de Prudhoe au sud jusqu'à la quatrième station de pompage sur une distance d'environ 238 kilomètres. Il a un diamètre qui varie entre 25,4 et 20,3 cm et est enfoui dans le pergélisol, à un profondeur moyenne d'un mètre sur toute sa longueur. Des panneaux isolants de polystyrène ont été placés dans le fossé du gazoduc pendant la construction, à environ 0,3 m sous la surface du sol pour empêcher la formation d'un bulbe de dégel dans la zone perturbée du fossé. Le gazoduc est en service depuis 13 ans et plusieurs programmes de surveillance continue ont fourni des données sur son rendement. Ces programmes comprennent des relevés périodiques des mouvements du gazoduc, un suivi à l'aide de thermistances des températures du sol au voisinage du gazoduc et des relevés de la profondeur d'enfouissement à l'aide d'un détecteur magnétique de tuyau pour repérer les endroits de mouvement possible du gazoduc. Le rendement du gazoduc a été excellent. Son exploitation n'a jamais été interrompue par l'affaissement dû au dégel ou par le soulèvement dû au gel. Le programme de surveillance a permis de repérer une zone d'affaissement du gazoduc dû au dégel de sols riches en glace, et le gazoduc a été réparé sans interruption du service. Là où il a été réparé, le gazoduc était situé dans le flanc en pente douce d'une colline où l'écoulement de l'eau dans le fossé du gazoduc a entraîné le dégel des sols de fondation riches en glace, puis l'affaissement de la conduite. La réparation a consisté à asseoir la conduite sur des piliers et à dériver l'écoulement de l'eau hors du fossé du gazoduc. Les détails de cette réparation, les éléments initiaux de la conception et l'historique de la construction et de l'exploitation du gazoduc sont présentés.

## Introduction

The Trans-Alaska Pipeline System (TAPS) transports produced oil from the oil fields at and adjacent to Prudhoe Bay in northernmost Alaska to the ice-free port of Valdez where it is loaded onto tankers and shipped to the east and west coasts of the United States for refining. Of the eleven pump stations required to move the oil along the pipeline route, the four most northern pump stations utilize natural gas from the Prudhoe Bay fields as their primary source of power. This gas is supplied to the stations through a buried high pressure service line which closely parallels the oil pipeline from Prudhoe Bay to Pump Station Four, located just north of the Brooks Range ( Figure 1).

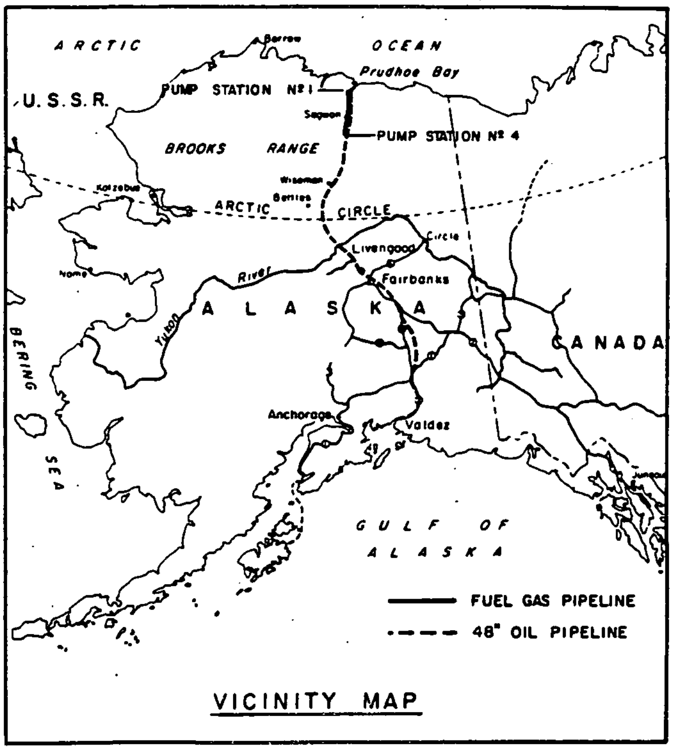


*Figure 1. Pipeline route map.*

The fuel gas supply pipeline was constructed during the winter from existing gravel pads and ice-pads to minimize disturbance to the sensitive tundra soils. The line has now been in operation for over twelve years and has performed well. During this period extensive monitoring of the line has been performed and only one segment of the line has been identified as requiring remedial work to maintain pipeline integrity. This segment of pipe, located near Pump Station Two, experienced significant settlement due to thawing of ice-rich supporting soils. The area was identified in 1985 and repaired that same year. This paper discusses the design considerations of the line, past performance, and summarizes the repair of the settled pipe segment.

## Design considerations

The purpose of the TAPS fuel gas pipeline is to serve the energy requirements of crude oil pump stations two through four located north of the Brooks Range. The decision to use gaseous fuel was based primarily upon economics. Permanent facilities near Prudhoe Bay can be provided with energy at far lower cost using natural gas from the Prudhoe Bay oil field than is the case with any other fuel. For pump station locations remote from Prudhoe Bay, gas pipeline construction costs mount, and use of liquid fuel derived from crude oil becomes more attractive. The economic break-even point between gaseous and liquid fuel lies between Pump Station Four and Pump Station Five, or approximately at the Brooks Range. The fuel gas pipeline was designed to supply sufficient gas to meet the peak energy needs of these stations as shown in Table 1.

The gas properties and operating conditions which to a large extent governed design of the pipeline are shown in Table 2.

The required gas flow volumes and pressure losses along the line dictated distribution of the pipe by diameter, grade and wall thickness. The pipeline was designed to meet the requirements of the following documents:

Part 192, Title 49, Code of Federal regulations, Transportation of Natural and Other Gas by Pipeline.

ASME Guide for Gas Transmission and Distribution Piping Systems,1973. (ANSI B 31.8)

For the fuel gas pipeline, (Type A Construction, Class 1 Location) these documents specify that the hoop stress shall not exceed 72 % of specified minimum yield strength (SMYS) line wide, and shall not exceed 60 % of SMYS at all uncased road crossings and elevated river crossings. To meet the criteria listed above, the pipeline design consists of 25.4 cm nominal diameter, 0.635 cm wall thickness pipe from Pump Station One for a distance of 54.7 kilometers where it transitions to a 20.3 cm nominal diameter, 0.635 cm wall thickness pipe for the remainder of its total length of 240 kilometers. Specified minimum yield strength is 358,530 $kN/m^2$. The majority of the length of the pipeline (approximately 242 kilometers) received an external coating and cathodic protection to inhibit corrosion. The line utilizes the oil pipeline for cathodic protection where practical and is electrically isolated from the pump stations by insulated flanges.

In addition to the above design considerations, the inlet temperature was required to remain (1) below -2 °C to protect and maintain the integrity of the ice-rich permafrost soils encountered throughout the length of the line and (2) above the water and hydrocarbon dew point temperatures of the gas to prevent accumulation of condensate. A series of hand thermal calculations in conjunction with a computer program to model gas thermodynamic properties determined that the gas would remain above the hydrocarbon dew point

**Table 1. Fuel gas pipeline transmission requirements.**

| Pump Station Requirements | MSCMD | Transmission Requirements | MSCMD |
|---|---|---|---|
| Pump Station 1 | 1954 | PS1 TO PS 2 | 1274 |
| Pump Station 2 | 425 | PS2 TO PS 3 | 850 |
| Pump Station 3 | 425 | PS3 TO PS 4 | 425 |
| Pump Station 4 | 425 | | |

**Table 2. Gas design properties.**

| Gas Property | Value |
|---|---|
| Design Pressure (kPa) | 9929 |
| Temperature (degrees C) | -23 to -2 |
| Hydrocarbon Dew Point (degrees C) | -40 at 5516 kPa |
| Water Dew Point (degrees C) | -51 at 5516 kPa |
| specific gravity (air = 1.0) | 0.685 |

temperature of -40 °C at a burial depth of one meter. Thermal calculations to model gas temperature and possible melting of permafrost are discussed below.

Route selection of the pipeline was based on a number of parameters including: accessibility, geotechnical considerations, road crossings permits, safety requirements, oil and fuel gas pipeline security, visual impact, environmental concerns, and project economics. Based on these parameters, a route which closely paralleled the oil pipeline or the Dalton Highway for the entire length of the line was chosen. Construction of the pipeline was conducted in the winter from either the oil pipeline workpad, Dalton Highway, or a snow work pad to minimize impacts to the tundra. The centerline of the fuel gas pipeline was generally located at least 1.2 meters from the toe of the oil pipeline workpad and 4.6 meters from the toe of the Dalton Highway (Figure 2).

Two separate computer programs were utilized to evaluate thermal effects of construction and operation of the fuel gas pipeline on the permafrost regime. One, a finite difference program which solves the steady state energy conservation equations for one-dimensional pipe flow was utilized to determine what the equilibrium temperature of the gas flow would be and how far from Pump Station One equilibrium would occur. High and low flow rate conditions (210 and 1200 MSCMD) during both summer and winter ambient temperature were analyzed. Results of the program indicated that for both low flow rate cases, the gas stream stabilized to within 0.5 °C of the surrounding soil temperature within 3.2 kilometers. For the high flow rate cases the gas temperature reached the surrounding temperature within 8 kilometers in the summer and 32 kilometers in the winter. This difference was caused by the large difference in soil temperature between the summer and winter. The study concluded that while there were expected to be areas where the active layer would extend below the pipeline the energy input to the gas would be small and would not cause significant thawing of the soils at other portions of the line.

The second computer program utilized to analyze thermal effects of the pipeline was a finite-element based program that modeled heat conduction with change of phase and a surface heat balance. The program did not address convective heat transfer due to ground water flow which can be important in some cases. The purpose of this analysis was to determine what protection was required for the permafrost beneath the fuel gas line to prevent thaw of the subsurface soils, and how construction timing affected the thermal regime. Results of the computer analysis with this program indicated that the proposed permafrost protection, eight cm of polystyrene insulation placed at a burial depth of 0.18 m below the ground surface, would prevent thaw from penetrating over one meter below the surface. This was anticipated to be completely sufficient to prevent melting of ice-rich subsurface soils providing that the tundra vegetation mat adjacent to the pipeline ditch was not disturbed.

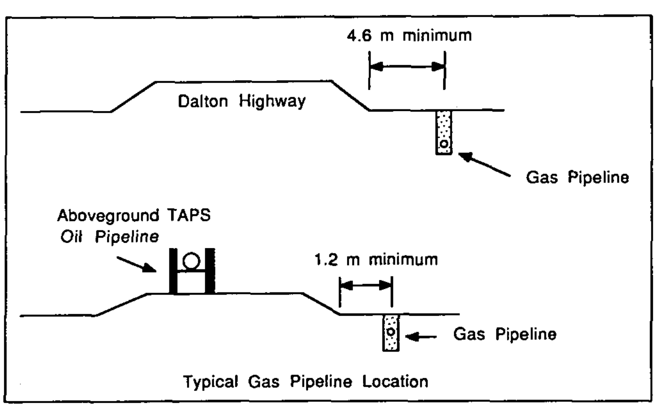


*Figure 2. Typical gas pipeline location.*

To ensure that the thermal regime was maintained as stable as possible, the construction plan called for no disturbance to the tundra mat except within the ditch lines. Valves and other pipeline appurtenances were placed on insulated pads, and any excavated or cleared material was to be removed to a permanent disposal site without damaging the tundra. Where any surface was disturbed during the construction process, the plan called for placement of insulation and revegetation.

## Soil conditions

The soil types encountered along the alignment of the fuel gas pipeline are extremely variable in both grain size and moisture content. Generally, the pipeline is buried within a surface layer of frozen non-thaw-stable fine grained material overlaying coarser, denser, frozen soils which in many areas are thaw stable.

The northern portion of the pipeline crosses the arctic coastal plain where the pipeline is buried predominantly within a non-thaw-stable low density silt. The silt material is mixed with organics and contains a significant amount of massive ice. Underlying the silt material is a sandy gravel which contains varying amounts of silt and occasional massive ice. The northern portions of the pipeline also contain areas with a variety of patterned ground formations and associated ice wedges. Within the ancient and active floodplains of the Sagavanirktok River and at minor stream crossings, the pipeline is buried within sands and gravels of alluvial origin. These floodplain deposits are essentially thaw stable and consist of gravels with some sand and little silt.

The southern portion of the pipeline crosses the Arctic Foothills and the northern edge of the Brooks Range. The foundation soils found along this portion of the pipeline are predominately frozen glacial tills. These tills consist of poorly sorted material with particle sizes ranging from clays and silts through sands, gravels, cobbles and large boulders. The ice content of these till materials is generally high and ranges from 10 to 75 percent of the total volume of the material. A thin cover of organics and ice rich silt is generally found overlying the till material. The soil conditions encountered during the ditch excavation were not documented during construction of the pipeline, therefore detailed records of the foundation materials are not available.

The majority of the gas pipeline was constructed from a snow workpad which limited the pipeline construction timing to winter months (Bock,1979). Construction of the gas pipeline was completed during the winters of 1975-1976 and 1976-1977. Construction from a snowpad was considered by the State and Federal agencies as the best way to minimize the environmental disturbance. It was also considered to be less expensive than construction of a permanent gravel workpad. A 0.3 m minimum thickness of compacted snow was placed before heavy equipment was permitted on the pad. An adequate amount of drifting snow was naturally deposited in areas where the pipeline was located next to the gravel berm of the oil pipeline workpad or the Dalton Highway. This snow was then compacted and leveled to provide a working surface. In some areas snow was mined from large drifts and hauled to required locations. Maintenance of the snowpad, which included compaction and adding water, was accomplished on the night shift after each day of construction activity. Although the snow pad was utilized as a workpad from which to install the pipeline, equipment and materials were transported primarily on the Dalton Highway and access roads connected to the snow pad.

The pipe ditch for the gas pipeline was excavated with four Roc-Saws and one Barber-Green trenching machine. The Roc-Saw is a specially modified Caterpillar D-9 with a ditch excavator attached on the rear (Figure 3). The ditch excavator on the Roc-Saw machine is a 0.46 m wide chainsaw like cutter with carbide tipped teeth. These machines worked fairly well in frozen silts but the productivity was generally inversely proportional to the gravel content of the soils. Blasting and backhoe excavation were used in the frozen glacial till material where the trenching machines could not excavate the ditch at the desired rate.

The pipeline was backfilled with select material along with a hand placed 0.1 m layer of extruded polystyrene boardstock insulation. Backfilling of the ditch was

*Figure 3. Pipeline trenching machine.*

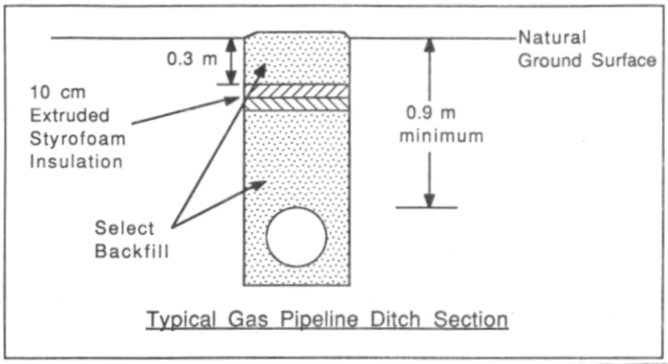


*Figure 4. Typical gas pipeline ditch section.*

accomplished in two stages to accommodate the placement of the boardstock insulation within the fill material at an elevation of 0.3 m below the ground surface (Figure 4). The first step in the backfill process was the placement of select material to a level of approximately 0.3 m below the ground surface. The insulation was hand placed and then backfilled with a second layer of select material up to the ground surface. After completion of this process, any backfill or excavation material which remained on the snow pad was removed to avoid contamination of the tundra. A conveyor type system was used to move backfill material from the Dalton Highway or oil pipeline gravel workpad into the gas pipeline ditch. This system minimized the contamination of the snow pad with backfill material. The backfill work was one of the more labor intensive and costly construction activities on the fuel gas pipeline project.

Hydrotesting was complicated by cold weather and permafrost conditions. The testing was accomplished sequentially in segments from north to south with a methanol-water mixture. Each segment averaged approximately 19 kilometers in length and required over 750 $m^3$ of fluid. The test fluid was moved forward through the segments and filtered between every other test. The cold weather and low soil temperatures caused several problems for the hydrotest procedure including four instances of ice blockage in the pipe. Ice blockage was the result of water, snow, or ice left in the pipe during construction, or inadequate protection of pipe ends. Severe ice blockages required excavation and replacement of the pipe at a number of locations.

The gas pipeline was commissioned in June of 1977 and placed in operation for the start-up of the Trans-Alaska oil pipeline during the same month. Operation was normal during the first few months, but after cold weather arrived in September 1977, the downstream pressure diminished (Adams,1981). At times, these pressure drops nearly shut off an adequate supply of gas to Pump Station 4. The unusual pressure drops were thought to be the result of hydrate formation. Residual water remaining from the hydrotest can combine with natural gas to precipitate hydrates on the pipe wall at operating temperatures. A dewpoint survey conducted along the line confirmed the existence of free water. Methanol was pumped into the line in the problem areas to inhibit the formation of hydrates. The methanol treatment restored normal operation of the pipeline, but after a short time the downstream pressure started falling again. A pipeline maintenance tool referred to as a pig was then run through the pipeline to remove the residual water. A column of methanol was placed ahead of the pig to remove any hydrate obstacles. Several pig runs were required to remove the free water remaining in the line.

As the TAPS oil pipeline throughput increased in the early 1980's the pump stations required more fuel for operations. This included Pump Stations Two, Three, and Four, whose fuel requirements are supplied by the gas pipeline. At the same time, changes in the Prudhoe Bay field production techniques made it necessary to reduce the pressure and increase the temperature of the fuel gas supplied from the producers to Pump Station One. A gas compressor and chiller module was installed in 1984 at Pump Station One to provide an adequate fuel gas supply at a low enough temperature to minimize thawing of the gas pipeline foundation soils.

## Monitoring program

After several years of operation, visual surveillance of the pipeline identified many areas of water ponding, surface subsidence, hydraulic erosion, and exposed ditch insulation. The incoming pump station gas temperatures at Pump Stations 2, 3, and 4 were also found to exceed 0°C during the summer months with extreme temperatures ranging from 2.2-7.2°C. During the winter months, the gas temperatures observed at the pump stations cooled to well below 0°C. The temperatures of the incoming gas at the pump stations are indicative of the soil temperatures immediately upstream of the pump stations. The high summer gas temperatures indicated that the active layer was below the bottom of the pipe in these areas. These soils were also refreezing during the winter months.

As a result of the visual surveillance and high summer gas temperatures at the pump stations, a monitoring program was initiated to better understand the operating condition of the pipeline. This monitoring program included the installation of thermistor strings and monitoring rods. (Figure 5) These instruments were intended to determine the extent of the active layer at selected locations along the pipeline and the extent of any pipe movement associated with the seasonal thawing and refreezing of the surrounding soils. In addition, pipe depth of cover surveys were conducted along the pipeline to identify any gross pipe settlement or heave areas. A detailed ground surveillance program was implemented and the observations of the surface conditions were cataloged.

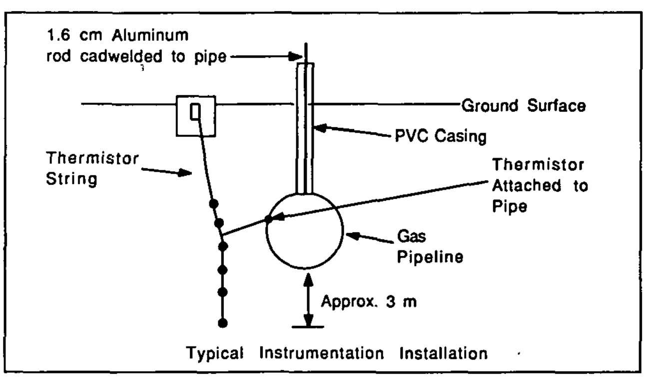


*Figure 5. Typical pipeline instrumentation installation.*

The thermistor strings and monitoring rods were installed during October and November of 1983. A total of 26 thermistor strings and 13 monitor rods were placed at various locations along the pipeline. At each of these locations the pipe was excavated and a thermistor sensor was attached to the pipe wall to monitor the approximate gas temperature at that location. A thermistor string was also installed adjacent to the pipeline in a borehole. These thermistor strings extend to a depth of 3 m below the pipe and were laterally offset a distance of approximately 15 cm from the edge of the pipe wall. The monitoring rod installation consists of a 1.6 cm aluminum rod cadwelded to the pipe and extending to the ground surface within a PVC casing. A series of control benchmarks were also installed in conjunction with the monitoring rod placement. Precise second order differential level surveys of the monitoring rods from the bench marks provide periodic indications of pipe movement. As-built pipe elevations were not documented during construction of the fuel gas pipeline, therefore a series of monitoring rod surveys over a period of several years were required to determine any pipe movement trends. Pipe depth of cover surveys were conducted along selected areas of the pipe during 1985-1988 (McDevitt and Cole, 1988). These surveys used pipe locators to determine the depth of cover over the pipe by electromagnetic induction. A variable frequency transmitter was directly attached to the pipe or the signal was induced in the pipe by a coil placed on the ground surface where direct attachment to the pipe was unavailable. The transmitter signal induces a symmetrical electromagnetic field around the pipe. A receiver unit was used to determine the location of the pipe centerline and by triangulation the depth of cover was determined. The elevation of the top of ground at the pipe centerline is determined by differential level surveys and, with the depth of cover determination, an elevation of the top of pipe was established. These measurements were taken every 7.6 m along the pipeline in selected areas, and a profile of the ground surface and pipe was developed. Although as-built elevation data was not documented along the pipeline, vertical bend as-built information is available. The profiles were reviewed and areas of suspected pipe movement were identified. A settlement area approximately 95 km south of Pump Station One which was repaired by underpinning was initially identified by the pipe locator surveys.

## Monitoring results

Monitoring of the thermistors and monitoring rods has been conducted periodically since the time this instrumentation was installed. The thermistors were primarily monitored during the fall months when the active layer thaw was at the deepest levels. The thermal data shows that the active layer extends below the bottom of the pipe in a number of areas. The areas with the deeper active layer depths are generally located in the southern portions of the gas pipeline. Gas temperatures observed during the winter months indicate that the soils completely refreeze each winter at all of the monitoring locations.

The gas temperature, after leaving Pump Station One, quickly cools or warms to the surrounding soil temperature. For the majority of the pipeline length the gas temperature is essentially equal to the temperature of the surrounding soil. The heat capacity of the gas is very small compared to the soil. At the present flow rates, the gas temperature approaches the temperature of the surrounding soil within a distance of approximately 16-19 km south of Pump Station One. Figure 6 shows the correlation between soil and gas temperatures. This figure also illustrates the variability of the gas and soil temperatures along the pipeline. These temperature variations are small, usually only a few degrees. The minor changes in the soil and gas temperature along the pipeline are caused by many factors but the near surface soil conditions, the thickness of the vegetative mat, and water flow through the pipe backfill material are the primary factors. These factors determine the depth of the seasonal active layer and the temperature of the soils. As the pipeline passes from a warm soil into a cooler soil, the gas

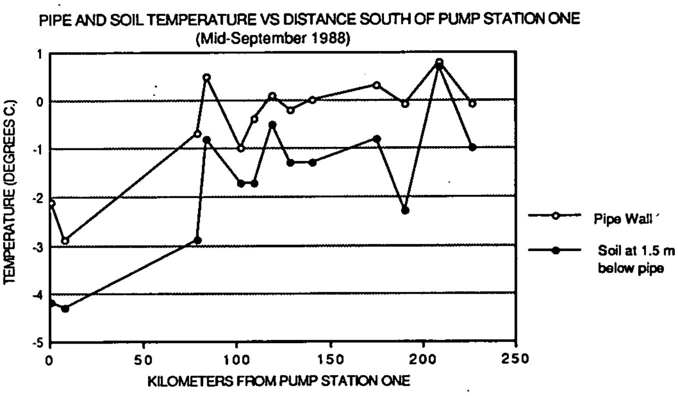


*Figure 6. Pipe and soil temperature vs distance south of PS 1.*

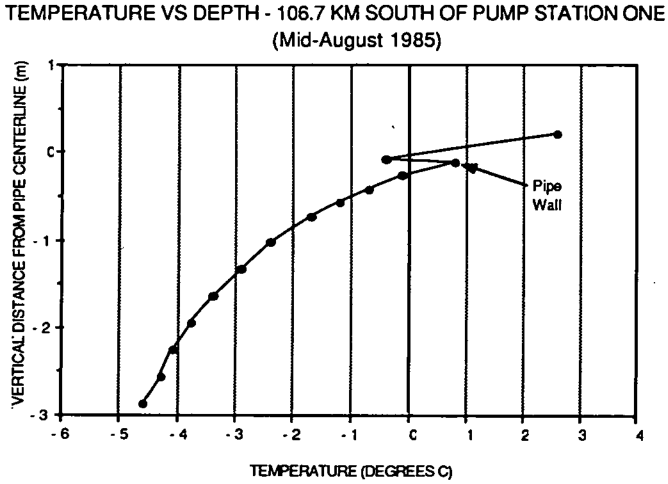


*Figure 7. Pipeline temperature vs depth.*

temperature remains above the surrounding soil temperature for a short distance. The gas is warmed by the soils with a deeper active layer and cooled as the gas passes into an area with a shallower active layer and cooler soils. Figure 7 illustrates this effect at a location 106 km south of Pump Station One during August where a 0.8 °C pipe wall temperature was recorded and the surrounding soil temperatures are approximately 0 °C.

The gas would also cool the soils as it passed from a shallow active layer area with cooler soils into an area with warmer soils. The soil temperatures are only slightly affected by these minor gas temperature changes and are controlled mainly by water flow along the alignment and heat transfer at the ground surface. Within the monitoring period 1984-1988 the soil and gas temperatures have remained relatively stable (Figure 8). The minor changes in the yearly soil and gas temperatures are thought to be caused by annual climatic variations. This figure also shows the general yearly cooling of the gas 1.6 km south of Pump Station One associated with the installation of the gas chiller at that pump station.

The maximum depth of thaw below the top of pipe at each of the thermistor installations is shown in Table 3. These thaw depths indicate that an equilibrium has been established and that progressively deeper thaw is not occurring each year. The initial deeper thaw depths recorded in 1984 are likely associated with the disturbance caused by the installation of the instrumentation. The settlement associated with the thawing has been fairly minimal with a maximum settlement of approximately 0.13 m at a location 203 km south of Pump Station One. The monitoring rods have also shown a minor upward pipe movement during freezeback of the foundation soils. The upward movement is associated with frost heave which does not accumulate from year to year. The maximum upward pipe movement observed in one year was approximately 2.5 cm. The pipe typically returns to its pre-frost heave position after the soil thaws and reconsolidates in the summer.

The ground surveillance conducted along the alignment of the gas pipeline identified several areas of thermal and hydraulic erosion (Figure 9). These areas were generally investigated and repaired. The findings of the surveillance were cataloged for future reference. Pipe locator depth of cover surveys indicate that many of the areas which have

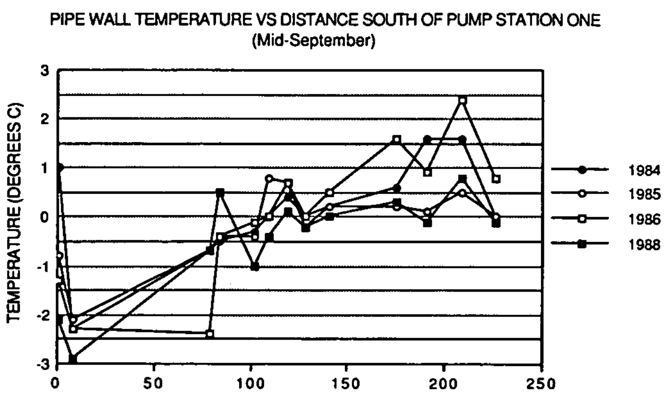


*Figure 8. Pipe wall temperature vs distance south of PS 1.*

Table 3. **Maximum thaw depths and pipe settlements.**

| Distance south of Pump Station One (Kilometers) | Maximum Thaw Depths Below Top Of Pipe (Meters) 1984 | 1985 | 1986 | 1987 | 1988 | Pipe Movement (cm) 1984-1988 |
|---|---|---|---|---|---|---|
| 0.88 | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | -1.1 |
| 8.38 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 |
| 88.06 | 2.7 | 0.3 | 0.5 | 0.0 | 0.0 | -0.1 |
| 96.91 | 0.2 | 0.3 | 0.3 | 0.0 | 0.0 | -2.1 |
| 106.66 | 0.3 | 0.0 | 0.3 | 0.3 | 0.3 | |
| 119.15 | 0.8 | 0.6 | 0.8 | 0.8 | 0.8 | |
| 127.64 | 0.6 | 0.6 | 0.6 | 0.8 | 0.6 | |
| 175.22 | 1.1 | 1.1 | 1.4 | 1.4 | 1.1 | -3.5 |
| 180.09 | 0.9 | 0.5 | 1.5 | 1.1 | 0.6 | -1.7 |
| 190.31 | 0.8 | 0.8 | 1.1 | 1.1 | | 0.4 |
| 195.33 | 0.8 | 0.3 | 0.8 | 0.8 | 0.8 | -3.0 |
| 201.74 | 2.7 | 0.8 | 0.9 | 1.1 | | -0.9 |
| 204.47 | 2.9 | 0.9 | 0.8 | | | -13.0 |
| 209.30 | 2.4 | 2.1 | 3.0 | 3.4 | 3.0 | -2.1 |
| 211.18 | 3.0 | 0.8 | 0.9 | 1.1 | | -3.5 |
| 213.87 | 0.9 | 1.1 | 0.5 | 0.5 | 0.5 | -1.0 |
| 226.35 | 1.2 | 0.6 | 0.6 | 0.9 | | -1.0 |

surface thaw settlement features do not have associated pipe settlement. An area of exposed pipe was observed where the pipe crossed an ice wedge which had thawed around the pipe. A depth of cover survey over this area did not indicate any associated pipe settlement. The pipe was backfilled and the area was regraded. Water movement along the gas pipeline ditch in areas of sloping terrain has caused some hydraulic and thermal erosion. These areas are generally repaired by the placement of water diversion structures to divert the water flow away from the pipeline ditch. At one location approximately 95 km south of Pump Station One the water flow along the pipe ditch had caused thawing of the foundation soils and significant pipe settlement.

### PIPELINE SETTLEMENT REPAIR (KM 95)

As a result of the monitoring program initiated in 1983, one pipe segment approximately 95 km south of Pump Station One was thought to be over stressed due to large thaw induced settlements. Pipe locator depth surveys conducted in this area indicated the pipe had settled on the order of 1 m over a span length of approximately 30 m. This settlement was verified by a level survey when the pipe was excavated for repair. The cause of the settlement was

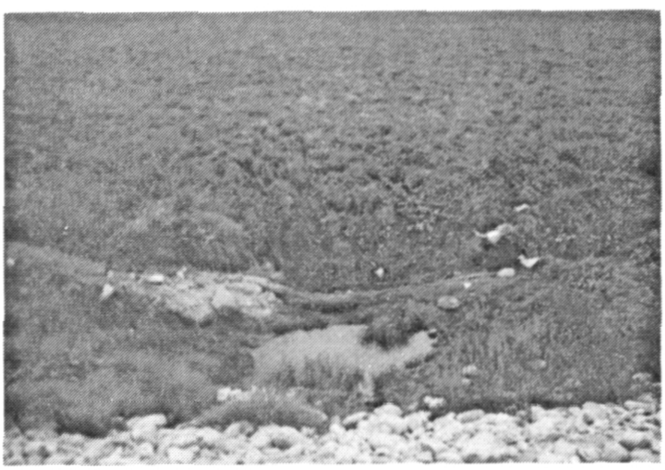

*Figure 9. Typical thermal and hydraulic erosion.*

determined to be thawing of ice-rich foundation soils by convective heat transfer from the large amounts of near surface ground water flow present in this area. The gas pipeline at this location is buried adjacent to the Dalton Highway. The natural thermal regime in soils near the road has been changed by the construction and presence of the road. Depth of the active layer at this location is greater than the surrounding tundra and the topography creates a natural channel for ground water flow down the pipe corridor. Soil borings near this area indicate that massive ice bodies are present at varying depths throughout this pipe section. Near surface ice bodies are subject to melting from active layer water flows such as those present at this location.

Since an accurate profile of the pipe could not be determined until after the pipe was excavated in the field, a definitive assessment of the pipe stresses due to the settlement could not be determined. Approximate hand calculations indicated that combined pipe stresses through the settlement area were approaching but still within allowable levels. Several repair alternatives for this pipe segment were considered, including releveling the pipe back up to the assumed as-built profile, drainage structures to divert active layer water flows away from the pipe corridor, and pile supports placed beneath the pipeline to support it if melting of the ice-rich soils continued. The last option of underpinning the pipe was chosen because it provided the most positive and permanent solution.

The repair design consisted of three supporting bents spaced 3.7 m apart and centered on the point of maximum pipe settlement. The bents consisted of two 20 cm nominal diameter standard weight pipe piles, placed in 35 cm diameter holes and slurried in place. Pile tip elevations were approximately 4.6 m below the bottom of the pipe which provided enough adfreeze bond strength to support the pipe section and prevent frost jacking of the piles. The two piles were spaced 1.8 m apart and a 30 cm X 30 cm timber beam was placed across the piles to support the pipe. The beam was notched to provide a uniform surface for the pipe and was lined with a elastomeric pad. Piles were initially set from the existing ground surface. The pipe was then excavated for placement of support beams which was followed by backfill and revegetation efforts. Construction time was approximately one week. The repair took place in the fall of 1986 and to date no further settlement has been detected.

## Summary

Current plans are to continue the gas pipeline monitoring program with instrumentation readings, ground surveillance, and depth of cover pipe locator surveys. An instrumented pig evaluation is planned for 1990 to identify any pipe corrosion. Although the depth of thaw beneath the fuel gas pipeline has exceeded design assumptions along a portion of the line, performance has been satisfactory. Minor problems associated with the increased thaw depths have been identified and repaired. Based on the available monitoring data the thermal regime along the pipeline corridor has reached equilibrium. However, minor remedial efforts may be required in isolated areas.

The experience gained from the the operation of this fuel gas pipeline has identified two specific areas in which additional research could enhance future projects of this nature: (1) Inclusion of convective heat transfer due to groundwater flows in thermal models used for the evaluation of buried pipelines could help to optimize designs and identify locations along proposed routes where seasonal water movement could affect pipeline stability. (2) New methods to identify and monitor pipeline movements could greatly reduce the cost over the current practice of attaching rods to the pipeline for periodic surveys and increase the operators confidence in the integrity of the pipeline with respect to settlement/jacking damage. In addition, the inclusion of pigging traps in pipeline design would allow the operator to be in a position to take advantage of new pigging technology as it is developed.

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