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TUKTOYAKTUK GAS SUPPLY

SCOPING STUDY

FOR

INUVIALUIT PETROLEUM CORPORATION

AND

ESSO RESOURCES CANADA LIMITED

BY

RTM ENGINEERING LTD.
CALGARY, ALBERTA

JANUARY, 1986
C1513A

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3. DESIGN BASES

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1. INTRODUCTION

1.1 Terms of Reference

At the request of Mr. Pedro Van Meurs, consultant to the Inuvialuit Petroleum Corporation (IPC), RTM Engineering Ltd. (RTM) has undertaken a variety of special studies and prepared Design Bases for a system to provide natural gas to the community and industries of Tuktoyaktuk. Generally the scope of work to be carried out was spelled out in Appendix A, Study Scope of Work, as provided by Mr. Van Meurs.

The study commenced on December 30, 1985, and was originally scheduled to be complete in draft form by January 24, 1986. An added study to investigate gas supply to Inuvik and certain added drawings were added verbally, and the draft date changed to February 3.

RTM's proposal of December 23, 1985, applied except for the added work noted and the addition of several small internal studies considered necessary to more properly define pipeline and backup system.

Generally the terms of reference were interpreted to cover physical facilities from downstream of the wells and including the meters for the final customers. Wells, appliances and system administration facilities have generally been neglected herein.

The following Tuk gas demand cases have been considered:

- Base Case - Community demands slowly expanding and oil industry constant. Electricity generated locally. Esso demands are added only in a sub case.

- Low Case - Community demands slowly expanding but oil industry declining to zero in 7 years. Electricity generated locally.

- High Case - Base case plus sale of 2 MW of electricity to Inuvik.

- High High Case — Base case plus sale of all Inuvik electricity needs.

An Inuvik gas demand case has also been considered based on current demands, corrected for a DND demand decline to zero. Ms. S. Bogach has provided the various demand data (with peaks and lows estimated by RTM) in a separate report.

1.2 Report Outline

The report is presented in three sections:

1. Introduction — To set out the terms of reference and basic assumptions.

2. Special Studies — To present the various special studies carried out :

   - Dehydration and Chilling
   - Well Location Impact
   - Esso Supply
   - Tuk Electricity (Generation) Options
   - Inuvik Gas Supply
   - Backup (System Definition)

3. Design Bases — To set out criteria and parameters for the design of all facilities from downstream of the well(s) through to meters at customers.

   These are set out for the base demand case only - i.e. Tuk community and oil industry at current level of activity.

1.3 Ownership/Project/Operations Approaches

Generally the following assumptions have been made:

a) Ownership — Esso will own the wells and any facilities essential to their operation. The IPC (or a subsidiary) will own all other facilities. Certain facilities adjacent to the well required for system operation and/or safety - e.g. safety shelter and communications facilities - will be jointly funded although operation will divest to one party or the other.

b) Operation

All field facilities will be operated by one party Esso at the beginning and then IPC when its staff are trained. The IPC will operate all other facilities.

c) Project Approvals

A joint Esso/IPC application to COGLA for well(s), field facilities, and the pipeline will be made. However, herein the Design Bases start downstream of Esso's well and directly related facilities. The IPC is assumed to obtain any special distribution system approvals via the Government of the Northwest Territories Public Utilities Board or equal .

This report does not consider franchise application nor the obtaining of access to and/or easements, etc. required for the various facilities. It was assumed that a franchise would be granted and the IPC would obtain any and all rights-of-way required, including building access.

c) Electricity Generation

Existing ownership of various generating facilities was not considered as a constraint herein.

1.4 Data Bases

Ms. V. S. Bogach's report "Preliminary Market Study for Natural Gas in Tuktoyaktuk" as amended to February 3, 1986, has been used as the base for all market demands. Peak and minimum flows have been estimated from such demand estimates by applying appropriate factors to the summer and winter average demand figures.

Ms. Bogach's report also includes data on Inuvik demands. Published and verbal NCPC estimates relative to demands and other appropriate factors were used to arrive at peak and minimum rates.

Mr. Roger Gallant of Esso has provided appreciable preliminary data relative to the wells and production approaches. However, no data from the current well drilling program became available during the study period.

It should be noted that no reservoir pressure decline has been allowed over time due to assumed high reserve/demand ratios in all cases. Also no appreciable drop in well head pressure has been assumed at any peak rate required in the various demand cases. Also it has been assumed herein that one well will always be "free of charge".

Diesel and gas turbine vendors and related equipment suppliers have provided preliminary verbal cost and performance data for studies on generation. NCPC has generally provided data as requested, but only on a verbal basis. (More detailed responses appeared very likely to take more time than available, and to incur charges - $150 per man hour - by NCPC.) The quality of Tuk electrical demand data does not appear high due to lack of recording instruments in any case.

RTM, RTM Consultants, Canuck GEI and EBA have generally used file data to complete the study.

1.5 Approach

Approaches to the various sub-studies have been taken consistent with the available time. Generally the level of effort selected will provide data for major alternate selection and for design bases setting (including finalization of certain alternates).

Canuck GEI prepared pipeline design bases and also investigated the cost of supplying Esso's base with gas. RTM Consultants reviewed propane/air system concepts to arrive at a reasonably reliable system consistent with distribution pressures. EBA provided geotechnical advice. RTM co-ordinated the study and carried out all other studies and bases definition. Continuous interface was maintained with Ms. Bogach relative to demand related data.

1.6 Note

This study did not develop any overall cost estimates; those that were prepared were only as required to define the difference between various options in special studies.

Also it does not cover appliance strategy and selection, nor non-physical facility aspects of the gas system such as administration.

1.7 System Overview

1.7.1 Introduction

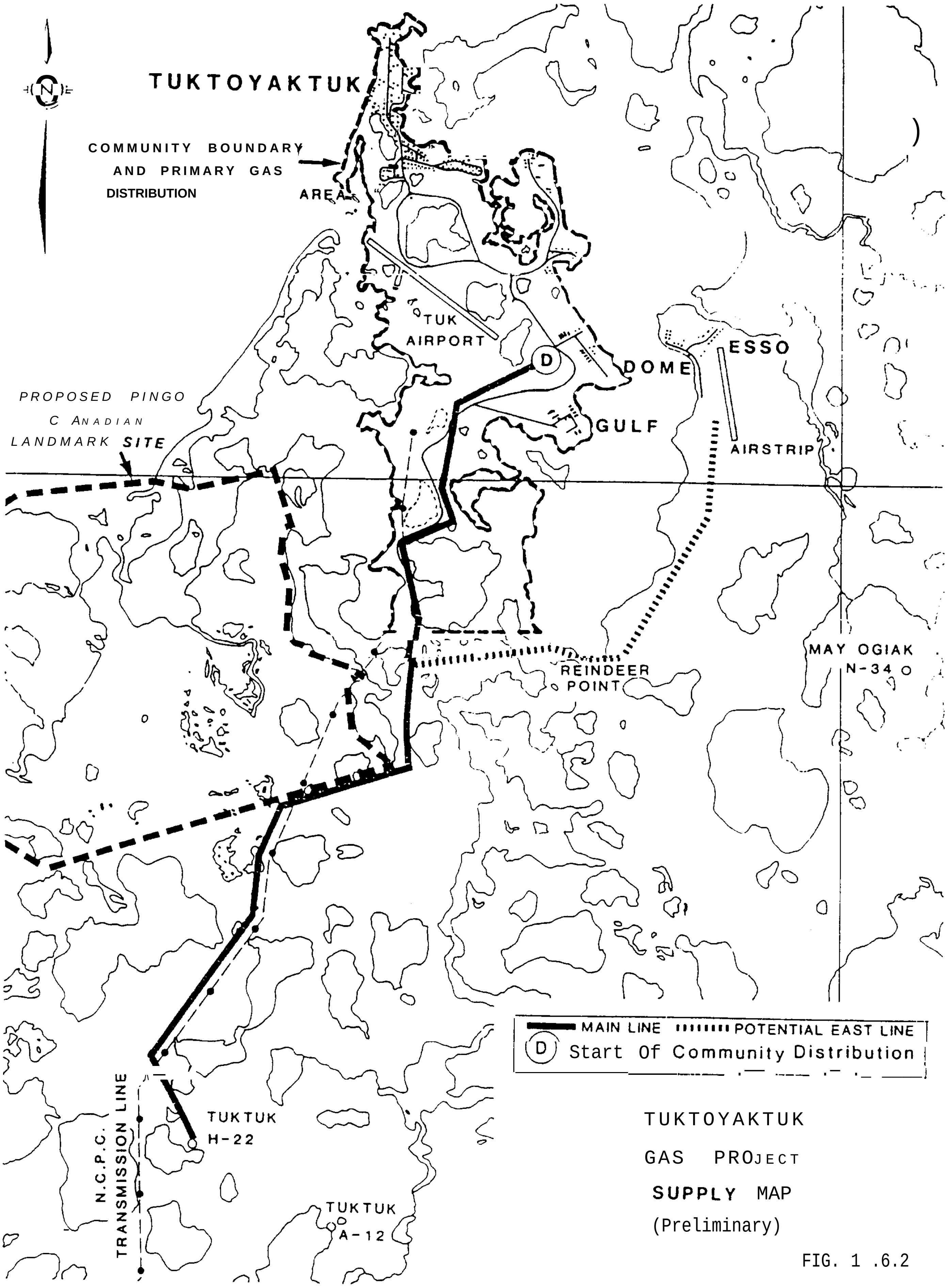
This section provides a brief overview of the Tuktoyaktuk Gas Project. Current drilling and testing will confirm gas reserves and define relevant wells. These efforts may change certain of the bases and assumptions noted below.

The gas system as described herein covers only supply for local needs - averaging about 32,000 m^3/d (1,130,000 scfd) in 1994/1995 projections. Some consideration is given export of electricity and gas to Inuvik in certain of the special studies, but is not assumed in this overview.

1.7.2 Source

Natural gas for local use will be produced from a relatively shallow gas rich formation in the Tuk gas/oil field. The field is assumed to contain appreciable reserves, enough to supply projected Tuktoyaktuk area needs for well over 50 years, if current tests prove successful. The gas is almost entirely methane - the lightest hydrocarbon - with no poisonous hydrogen sulphide or other impurity requiring removal, other than traces of water vapour. There are no heavier hydrocarbons present that might tend to separate out in pipelines and equipment.

The gas formations appear of high quality and able to be cycled to handle daily peaks and valleys, throughout the year. The gas lies below permafrost, and special techniques will be used to ensure that wells do not freeze up as the gas rises to the surface.



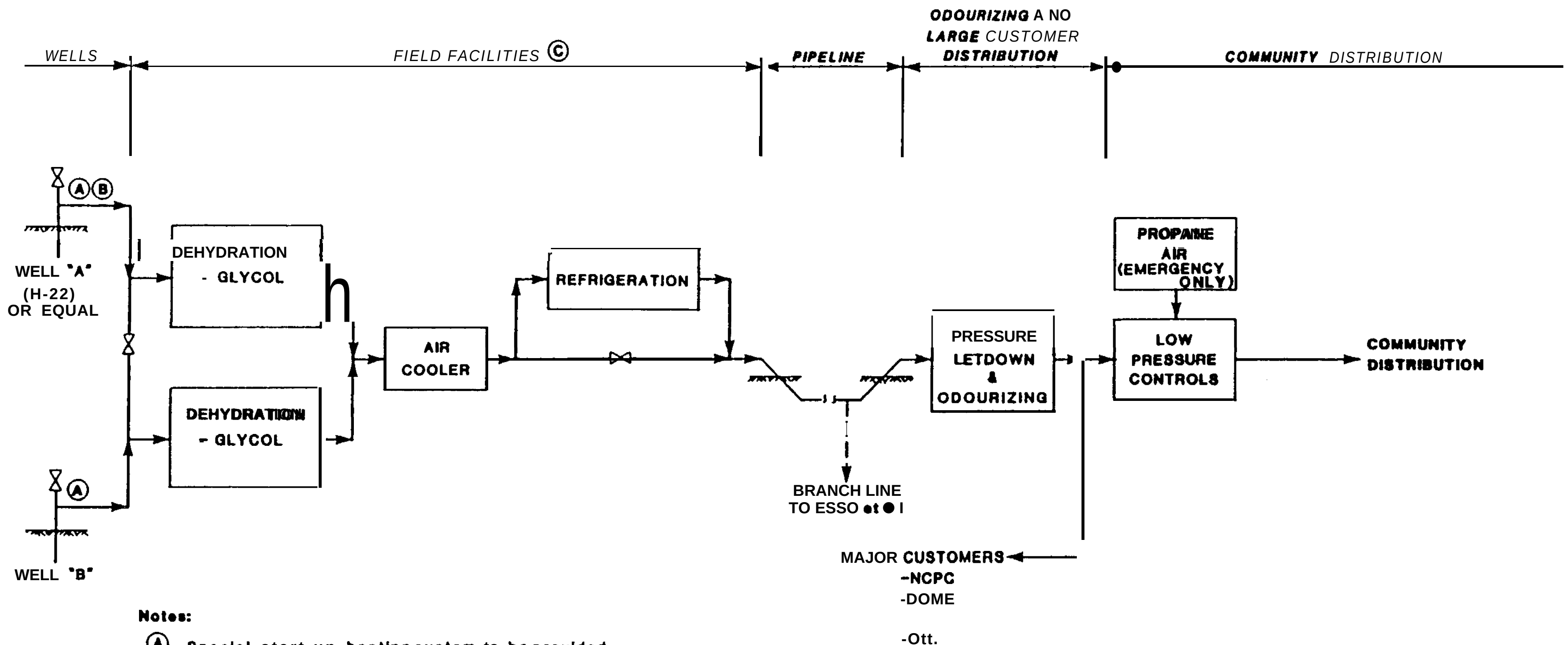
TUKTOYAKTUK

GAS PROJECT

SUPPLY MAP

(Preliminary)

FIG. 1 .6.2



Notes:

Ⓐ Special start-up heating system to be provided

Ⓑ Oil may ● Iso be produced via ● eperato lines

Ⓒ If well. ● re located over 0.5 km. ● part provide own dehydration and chilling ● yetem.

TUKTOYAKTUK GAS SYSTEM SCHEMATIC

FIG. 1.6.1

Gas will be produced in the H-22 or a nearby well, possibly in parallel with oil from deeper formations. A second well will also be used as a source, to ensure a high degree of reliability. The wells will normally be operated in prallel but each will be capable of O to 100% operation. The specific second well has not yet been identified, and may be a well drilled adjacent to the first well just for gas production.

The pressure of the gas in the formation is approximately 7500 kPa more than sufficient to move the gas through treating and pipeline facilities to town.

1.7.3 Field Facilities

Only removal of water is required in the field and this will be achieved in a highly-reliable, well proven glycol absorption process. There will also be a backup dehydration system, in case of maintenance or other outage of the main glycol system.

Before entering the pipeline to town, the gas must be chilled to approximately -5°C to prevent thawing of permafrost along the pipeline route. Normally air cooling will be used to achieve this cooling, but a refrigeration system will be provided for warm day use.

The well, treating and related facilities will be operated in a co-ordinated manner with automatic shutdown of individual well systems, in case of emergency. Certain equipment will be duplicated to provide very high reliability in all field facilities. But as both wells will normally be in operation, even when a well shuts down there will be no stoppage of gas flow and the remaining well's output will be increased to handle all demands until the other well is again on line.

Dual channel voice and automation communications will be provided between a town-located system control center and the field. Also a mobile radio system will be provided for communication with field personnel.

1.7.4 Pipeline

As the map shows, the pipeline to town will generally parallel the existing Inuvik-Tuktoyaktuk electricity supply line, except that it will skirt the eastern corner of the Pingo Canadian Landmark Site. The line will be buried in the permafrost layer, and as noted above, the gas will be chilled to ensure that no erosion occurs due to melting ice along the route.

The line will be designed to Canadian gas pipeline standards with special consideration to permafrost and other local considerations.

At this time a branch line to service the east side of the harbour, specifically Esso, is under study. If built, it will probably cross on or near the planned Reindeer Point bridge.

1.7.5 Service' Area

The proposed gas system will provide service to all potential users in the Tuktoyaktuk Community Site and, with the possible eastern line, to the east side of the harbour.

1.7.6 Distribution

At the town end of the main pipeline, the pressure will be let down to approximately 1000 kPa and odourant will be added.

The major customers such as NCPC, Dome and Gulf will receive their gas via buried pipeline at the 1000 kPa level, as certain large demand devices require such a pressure level. For heating devices, it is expected that large users will convert to dual fuel - gas plus P50 backup - burners, P50 being used only in the very rare event of shutdown of the gas supply system.

It is anticipated that virtually all electricity needed in the region will be generated through use of natural gas in lieu of the expensive present P50 fuel. However, P50 fueled generators will be kept available in the unlikely event that gas supply fails.

For commercial and residential customers, a buried low pressure distribution system will be provided. This system will be built up as loops wherever possible to allow short sections to be taken out of service for tying in new customers and for repairs, and to ensure maximum reliability. Each customer will have his own regulator and meter.

Unlike the large customers commercial and residential customers will not have backup alternate fuel systems. In order to provide the necessary reliability and surety of gas supply to such users a propane/air system will be installed to provide an artificial fuel gas compatible with natural gas equipment in the event of a loss of gas supply. Such systems are well proven and a simple, highly-reliable system is proposed. A one-month supply of propane will be kept on hand, which will cover all anticipated outages of the system.

1.7.7 Appliances

Commercial and residential customers will "replace existing oil burners and, in the extreme, oil fueled appliances with gas burners or appliances. These will be made available through the IDC, who will also provide service for such equipment, either directly or under contract.

1.7.8 Service

Aside from appliance service the gas utility operation will, in conjunction with local contractors, handle all normal new construction and all but the most major repairs. A customer relations program will introduce new customers to natural gas and keep all customers up to date on the optimum use of natural gas and new developments in the Tuk system.

1.7.9 System Design and Construction

COGLA regulations generally set out codes and standards for the portions of the system outside the urban area, referring to other federal and, in a few cases, Alberta codes and standards.

Generally federal (Canadian Standards Association) standards will be followed relative to the distribution systems, supplemented by provincial standards, and experience as necessary. Where the presence of permafrost requires modification, such changes will be reviewed with the Government of the Northwest Territories and/or federal officials as appropriate.

While winter construction is planned for the main pipelines, summer or winter construction may be used in town. The contractors of the Tuktoyaktuk region have developed appreciable experience in construction in the region, and it is planned that their capabilities will be used to the fullest, consistent with economics and time constraints.

2. SPECIAL STUDIES

2.1 Preamble

In this secton the various special studies are presented individually. The following basic case parameters have been assumed:

Two wells close together (by Esso), each capable of carrying the full system but normally operated in parallel,

Wellhead facilities to allow the startup or shutdown of either wells and parallel operation of both (by Esso),

- Lines from wellhead,

Dehydration and cooling facilities on each line, with cross over piping as appropriate,

Safety, communication and related facilities as required in the field, servicing both wells, and field processing facilities,

- 114.3 mm (4") pipeline from field to town, with an optional 60 mm line to Esso,

Distribution to NCPC, Dome, Gulf, ATL, NTCL and community (with Esso as an optional customer), and

Propane/Air system to provide community needs in the event of any loss of supply from the field, other users being backstopped by diesel fueled systems.

A base demand year of 1994/1995 has been assumed in all special studies as being reasonably representative of future needs. While this provides an adequate basis for specifying field and pipeline components - with review of the year 1999/2000 for certain components, such as the pipeline, that cannot easily be expanded - the distribution system will be expanded only on an as-needed basis.

In order to define the distribution system pressure, a quick study was undertaken of propane/air system alternates and reliability. Also a review was undertaken of the possible need for chilling the gas before it enters the pipeline(s). These are considered at the end of this section, and are the only special studies other than "Dehydration" whose recommendations appear in the Design Bases.

2.2 Dehydration and Chilling

2.2.1 Requirements

2.2.1.1 General

At the wellhead the raw gas must be dehydrated to a suitable water dew point to prevent any ice forming in the gas pipeline and distribution systems. Also, as noted in a later section, it appears necessary to chill the gas to no more than -5°C before it enters the pipeline. This special study examines dehydration and handling alternates.

2.2.1.2 Conditions

At this time the following conditions are assumed at the inlet to the dehydration facilities:

Temperature	25°C maximum
Pressure	7500 kPa maximum
Water Vapour	Saturated
Free Water	Trace on occasion, normally nil

The gas is almost all methane and there will be no condensation of hydrocarbons throughout the system under all forseeable conditions.

At the outlet of the dehydration and chilling system, the following quality criteria are desired:

Temperature	-5°C maximum, as developed in Section 2.2.1.3
Pressure	Maximum
Water Vapour	-25°C maximum dew point, as developed in Section 2.2.1.4 (with -50°C desirable) at 7000 kPa

The various anticipated throughputs are as follows for the year 1994/1995 including Esso:

	Average Rate ($10^3 m^3/d$)	Peak Rate (Winter) ($10^3 m^3/d$) (scfd)	Minimum Rate (Summer) $10^3 m^3/d$ (scfd)
Tuk Supply Cases			
Base with Esso	31.7	78.9 (2,780)	15.1 (530)
Low	14.9	50.2	5.1 (170)
Interm. Power (1.2 MW sales)*	46.6*	80.0*	10. 0* (350)
Maximum Power (Tuk plus Inuvik)	59.1	119.4 (4,040)	15.1 (530)
Tuk Plus Inuvik	Max. 102.3	247.1 (8,275)	5.1 (170)

* After 1990/1991 see Base Case

In this particular sub-study the base case with Esso is assumed except as noted.

The peak rate for refrigeration load purposes (only) is assumed equal to 125% of the average rate but with an air temperature of 10.6°C, the average for July. (Refrigeration can be shut down or be overloaded for short periods without major impact.)

The minimum ambient temperature is -50°C and strong winds peaking to 87 Km/hour and averaging about 17.5 Km/hour must be considered. (Calm periods are very infrequent.)

2.2.1.3 Reliability

The dehydration system must be very reliable as the entire community will be relying on it, with only an emergency propane/air system available as (short term) backup. And the word "emergency" relative to the propane/air system must be stressed as it is not planned other than as stop-gap whenever it is needed - losing revenues from all but the community itself and incurring propane costs relative to the community.

The feed to the dehydration system will be from one or two wells, by others, with appropriate pipeline systems to convey the gas a short distance to a single treatment facility.

2.2.1.4 Temperature to Pipeline

Earlier studies were based on the premise that gas could go hot from the dehydrator directly into the main pipeline. However, discussion with the geotechnical consultants and with persons experienced in Tuk area construction indicate that chilled gas will be highly preferable.

The main pipelines will all be buried 60 cm with only a few spots not below the active layer. With warm gas, a stream would develop wherever there is a slope, resulting in erosion and other environmental problems.

The 4" line to town has little pressure drop under all forseeable base case loads and, hence, friction heat is small and can be neglected.

Delivery of gas at or below -5°C is recommended. That temperature is believed to be below the freezing point of water solutions in the soils along the route. The average permafrost temperature is about -10"C.

It is recognized that this adds refrigeration facilities at the wells, but al ternates other than above ground pipelines are not available. During much of the year only air cooling is required. But during the May to October period mechanical refrigeration will be needed. Outages of up to a day are allowable as only a small amount of thawing will occur.

2.2.1.5 Dew Point

The water dew point required in the main pipeline system is set by:

a) Main pipeline ground temperature,

b) Field and town medium pressure distribution systems (ground and air), and

c) Community distribution system (ground and air).

In all cases minimum contact of piping with air will be planned, but some customer meters and distribution controls will be exposed. In the field all piping exposed to air can be insulated. Piping between the well(s) and treating will tie traced as well as insulated to keep the line above the hydrate point of about 12°C. All potentially exposed points will have methanol emergency injection points (as will be noted 1 ater).

The temperature of the ground along the pipeline is expected to average near -10″C with swings between -O and -20°C, depending on season and local topography and surficial soils. Thus, the design dew point from the dehydration scheme must be at most -25°C. This is at the 1000 PSIA (7000 kPa) or so pressure expected through treating and pipeline systems.

As the pressure drops, moisture will start to freeze at lower temperatures. The pressure level of the medium pressure systems has not yet been finalized, but will run in the order of 1000 kPa. With the exception of high to medium pressure let down systems themselves, the -30°C (-25°C maximum) high pressure dew point from glycol appears adequate with the note that all user systems should be carefully considered, as the actual dew point at 150 PSIG is only -50°C at that pressure.

In the distribution system the dew point will be -60°C or less so no problem is seen there, assuming the -25°C level is held at the field treating system.

Where pressure is reduced there is appreciable cooling and a heater before the 1000 to 1500 PSIG letdown is required to prevent temperatures dropping below -20°C (-5°C preferably) in the buried 150 PSIG and lower pressure systems.

2.2.2 Alternates

2.2.2.1 List

The following alternates have been considered:

	Inlet Liquids Removal	Dehydration	Refrigeration
Inlet Separator	X	--	--
Glycol Dehydration	--	X & E	--
$CaCl_2$	--	E	--
Dry Desiccants - Al/S.G.	--	X & E	--
- Mol Sieve	--	X	--
Air Cooling	--	--	P
Refrigeration	--	--	P
Glycol Injection to Chiller	--	X	X
Methanol	--	E!	--

E - Emergency Only
P - Part of year

Glycol injection to a refrigeration system chiller was discarded early on as it requires mechanical refrigeration all year and experience has shown that separation of dehydration and refrigeration provides lower water dew points and higher system reliability at essentially the same cost.

A combination of air cooling and mechanical refrigeration is the obvious choice for chilling the gas, with the refrigeration system only required through the warmer periods of the year.

The use of desiccants for emergency use is not recommended but is discussed later.

The use of methanol for emergency hydrate elimination is universal and assumed as a given regardless of the selected dehydration scheme.

Major points of difference between the various dehydration alternates are in water dew point of the product gas, and in their sensitivities to inlet temperature to the ultimate water dew point achievable.

2.2.2.2. Glycol Dehydration

Figure 2. 2-1 outlines a standard lean gas glycol system. With 8 trays in the glycol/gas contactor the dew point depression is about 60°C indicating an ultimate dew point of about -30°C as achievable with 25°C gas to treating. This has proved very successful in Alberta but, while fewer trays are often used, RTM has standardized in 8. However, a 10-tray system is recommended to provide added safety factor in the Tuk scenario. A 10-tray system will be unique only in the number of trays in the contactor.

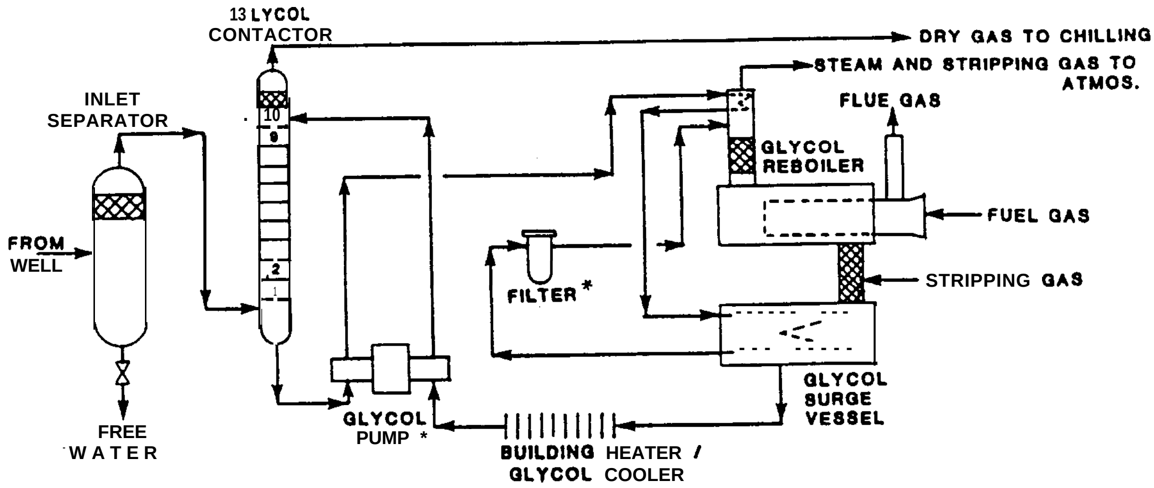
Also some means of cooling the raw gas to the 22 to 27°C range may be needed to minimize load on dehydration and to get as low as dew point as possible. (The raw gas hydrate temperature of about 12°C restricts the cooling possible as well as defining cooler design.) Thus the assumed 27°C maximum inlet temperature is very important.

Glycol systems have only one moving part - the glycol circulation pump - and have proven very reliable. Pumps are the main concern and a standby is always provided. Here a warehouse spare is also recommended. While a motor drive is preferred for reliability, it is recommended that at least the standby by a gas-driven model to ensure continuity in case of electrical failure.

Glycol systems can be turned down to below 10% of design, when well designed.

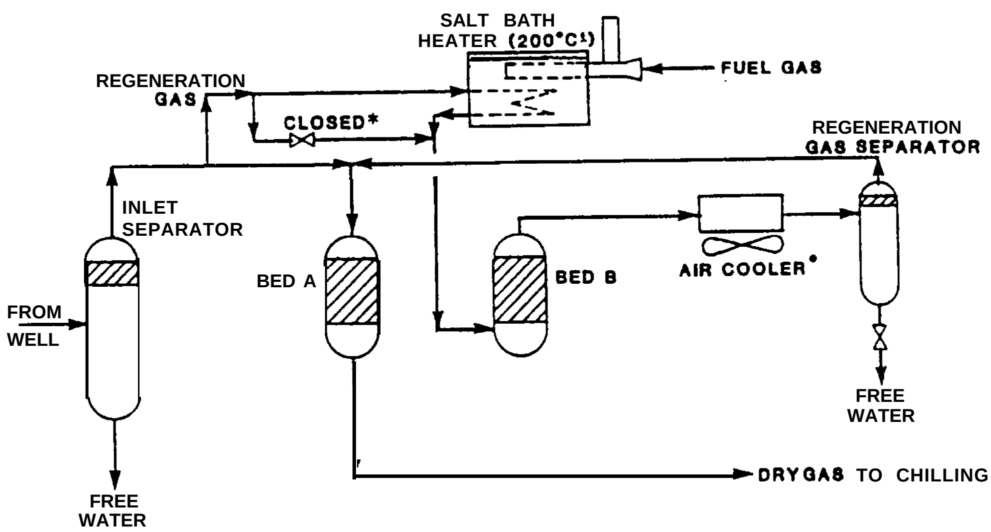
Glycol systems, while reliable, do require attention, especially to the pump and to glycol quality. A spared glycol filter is essential. Spare parts and replacements for all small components are readily available and can be air freighted to Tuk in 1 to 3 days.

Suitable glycol regenerators - the only hot portions of the system - can be found and delivered within 7 days, in virtually all circumstances. However, generally only instrument replacement is required, and some local stock will be recommended. Their frequency of replacement is in the order of every 3 to 5 years.



Notes:
- * Provide spare ● aulpmertt
- • Bubble cap trays for high turndown

TYPICAL GLYCOL SYSTEM
FIG. 2.2.1



Notes:
- • Special design to prevent freezing
- * Open when cooling bed B

Other cycling valving not shown. Approximately 6 valves open and shut to switch beds on ● nd off line ● nd hot and cold gas through bed being regenerated.
8 to 16 hour cycle time

TYPICAL DESSICANT SYSTEM
FIG.2.2.2

The 10 tray contactor will be unique but a standard 8 tray model can be found as quickly as the other components. But due to its size it will require special handling if shipped by air.

The cost of a 5,000,000 scfd skid-mounted and enclosed glycol system c/w inlet separator is currently about $105,000 FOB Alberta shop. There is not much scale factor at this size, but major oversizing is not recommended due to added heat loss when operating below design.

2.2.2.3 <u>Calcium Chloride</u>

A calcium chloride dehydrator operates by the chemical reaction of chloride with water - first to form hydrated material and then as more water is added finally to a solution. The latter is drained off and more "briquets" of fresh chlorides added to the top of the bed. The more fresh, unreacted chloride the lower the dew point of the gas.

Of simple, no moving part dehydration systems, only calcium chloride units have proven successful. They do have occasional problems with dew point, generally overcome by keeping the bed topped up with calcium chloride.

When topped up a dew point depression of over 40°C can be achieved - this gives only a -15°C dew point with 25°C gas. Cooler raw gas will lower this figure. Hence, calcium chloride is not entirely suitable during the coldest parts of the year.

For the size range expected here, a single bed calcium chloride drier will cost about $50,000 FOB Alberta shop complete with initial charge and building.

2.2.2.4 <u>Dry Desiccants</u>

Silica gel adsorption can be used to achieve a dew point of about -30°C on a regular basis.

Figure 2.2-2 outlines a typical dry desiccant system. Two beds containing small desiccant beds are provided with one on line at a time, while the second bed is being regenerated.

The system can be built with no moving parts, except for fans and/or louvres on the air cooler. However, the regeneration cycle has several stages and this complicates the switching systems. Carryover of fine desiccant material complicates switching valve life as does the varying temperatures on either side in most services. Switching valves are often a major problem. Also the salt bath heater must be kept at 200°C or more and the bath can be corrosive.

In this setting freezing concerns arise due to the need for regeneration gas cooling with (often) very cold air. Turn down and variable flow rates will not normally be considered in controller settings in small units as here, increasing fuel consumption. Very low turndowns are a problem as the percentage of raw gas needed for regeneration increases and, hence, inlet temperatures rise and the water load comes largely from regeneration.

Alumina will provide a slightly lower dew point than silica gel while molecular sieve adsorbent will provide dew points down below -100°C if desired. With molecular sieves the salt bath temperatures must be raised another 60°C, further complicating that heater's life and also that of switching valves facing higher temperature differentials. Desiccant vessel insulation also can be of major concern due to cycling nature of the operation.

From a water dew point standpoint dry desiccant systems are ideal for this setting. However, from a mechanical standpoint they are far from ideal (compared, say, to glycol). Also the cost of a suitable system is estimated at roughly 3-1/2 times that of an equivalent glycol system.

For emergency use a single desiccant bed can be used. In this case it is regenerated by depressuring to near atmospheric pressure and then passing a small stream of dry gas through the bed. While it is practical to design such a system for one day outage, it will take up to a week to regenerate and a significant quantity of gas will be needed - in the order of 1 to 2% of sales over that time. Thus the bed is not available for reuse until regenerated and the emergency that can be handled is finite.

2.2.3 Air Cooling

Ambient air can provide much of the chilling needed to get the 25°C+ gas from dehydration down to the desired -5°C temperature for pipelining. Except for mid-summer days and a few hours at other times, air can provide all cooling needed.

This cooling stage sees only low dew point gas, but the dew point of such gas is above the lowest ambient temperature in all but May, June, July, August and September. Thus special attention will be needed to the design to recirculate air to keep the temperature above -25°C to prevent freezing. However, such a system offers little technical challenge. Small electrical or gas motor fan drives are anticipated.

2.2.4 Refrigeration

The refrigeration system will be a conventional ammonia or propane refrigerant system, except that the compressor will likely be gas engine driven to minimize electrical generation costs. The reliability of such a system will not be 100% - nearer 95 - but some outage aPPears allowable. Also the system will only be needed in May, June, July, August, September and part of October.

2.2.5 Methanol

The dehydration medium of last resort is methanol. Here, it is proposed that its injection be limited to cases of identified buildup of hydrates (as noted by pressure drop).

There will be some carryover of glycol and methanol that will carry through the piping system. Hence, a filter separator is essential on the town line of the line.

2.2.6 Summary

Glycol is strongly recommended as the primary desiccant. As calcium chloride is not completely suitable for emergency use (needing methanol injection in case of hydrate buildup), it's lower cost than a full spare glycol system is not of advantage. Use of a second glycol unit with gas driven pumps is recommended in a parallel system whenever two gas wells are located close enough for common operation.

However, the two glycol systems must be located in separate buildings at least 50 meters apart, so that one continues to operate in case of fire or other disaster in the other system.

2.3 Well Location Impacts

2.3.1 Introduction

While it may be possible to operate with only one well, generally it is felt that at least two wells should be incorporated into the gas supply system. The H-22 well has been assumed as the base gas supply well; possibly completed as an oil and gas well. The second gas supply well could be located adjacent to the H-22 well or at some distance - this special study is to determine the impacts of alternate locations.

2.3.2 One Well or Two

While quick "judgement" indicates the need for two wells for reliability purposes, a preliminary analysis was carried out to see if such an assumption is justified.

Well failure potential was broken into several points for a non-statistical analysis and the results from this very preliminary review follow:

Failure Point/Mode	Degree of Risk	Outage Duration	Remedial Action
Freeze off	High*	3 days	Heat and/or Methanol
	Low	<90 days	Tubular failure - replace kill well, fly in crew, etc.
Tubulars - Corrosion, mechanical etc. (other than freeze-up)	Low	<90 days	Swab? Pull, replace
Sand Invasion	V. Low	30 days	Pull & Pack - Can schedule
Fracturing Needs	Low	30+ days	Can schedule
Water coning	V. Low	90 days	Abandon or recomplete (deep pay zone should allow selective completion zone)
Pressure dec" ine	Low		Can schedule new well in different formation

* Especially at low rates (and higher with two wells on line).

Note that many geological and completion method assumptions have been made in above, which require further study.

The following table attempts to put some numbers on these assumptions:

TABLE 2.3.2.1
CAPITAL NEEDED
ASSUMING COMMON SITE
(In $\$10^6$)

	ONE WELL	TWO WELLS
Capital - Second Well	0	1.5
- Service Rig	0 (a)	0
- Propane Storage (peak days)	0.6 (90) (b)	0.2 (30) (c)
- C_3 + P50 Inventory (peak days)	0.9 (90)	0.3 (30)
TOTAL	1.5	2.0
Operating - Loss on backup fuel (d) Plus Revenue Loss - per average year		
- 1 month every 10* years	--	0.04
- 1 month every 5* years	0.08	--
- 8 months every 12* years	0.08	--
TOTAL	0.16/year	0.04/year
Discounted Value	0.8	0.2
TOTAL COST	2.3	2*2

NOTES :
* Validity needs confirmation!!
(a) Assume in area - $200,000 if new rig needed
(b) Maximum spring transport outage period. In practice need added time to rig up and work on well.
(c) Recommended minimum backup fuel storage.
(d) Assumes 1/3 loss on purchase and sale on backup fuel.

This very rough analysis indicates that two wells will probably be justified in a proper study. Hence, the preliminary judgement that two wells are needed appears very reasonable.

2.3.3 Facility Alternates

The dehydration and chilling systems as recommended in the previous special study have been assumed as applying:

	Wells Close Together	Wells over 1/2 Kilometer apart
Well piping	Manifolded	Separate
Dehydration	Parallel - 2 x 100% glycol systems	Single 100% glycol system at each well
Chilling	Single air cooler	Single air cooler at each well
	Single refrigeration system	Single refrigeration system at each well
Gas Line	Single 4" line to town	Branch 3" line from one well to main 4" line from other well to town
Controls	Local, monitored from town	Local, integrated between wells via town as essential

Wells will be planned and operated to allow each to supply O to 100% of gas demand, but with each normally producing 50% of demand.

Note that only a 3″ line is needed in the field, as no additional line pack need is indicated and a 3″ line will carry the base case plus Esso gas adequately over distances up to 5 kilometers.

2.3.4 Differential Costs

There are two main components of differential costs relative to location when the facility alternates of Section 2.3 are considered:

a) Differential facilities costs,
b) Added pipeline costs.

If the well is closer to Tuk than H-22 and spaced over 1 km from H-22, its 3″ product line will be routed to join the main 4″ line on the town side. If the second well is over 1 kilometer beyond H-22, a new line between the second well and H-22 will be needed.

Spacing between 0.5 and 1 kilometer will need special analysis to determine whether to integrate or not.

From a facility standpoint a remote well will:

- Duplicate chilling facilities adding approximately $500,000
- Increase communications complexity, $50,000, and
- Duplicate emergency facilities including emergency generator, etc., $100,000

Thus splitting wells will add very roughly $650,000 in facilities costs.

3″ pipeline will cost in the order of $100,000 per kilometer.

Operating costs will increase as well as spacing increases, but at the most only one added man can be foreseen - say $75,000 per year all in, say, $300,000 on a discounted basis.

Note that these costs are incremental to the cost of a second well and all its auxiliary facilities.

2.3.5 Conclusion

Assuming a new gas well costs $1,500,000 complete when drilled near enough to H-22 to integrate sites, this brief analysis would conclude that a well necessitating more than about 5.0 kilometers of connecting pipeline would not be economic for gas supply to Tuk. Note also that branch line size may have to be increased when over 5 km long.

Data used here are not precise and the yes/no distance is likely to be between 3 and 7 kilometers. Detailed study is recommended of any case where the distance is less than 7 kilometers, over that a second well appears justified.

2.4 Esso Supply

Two alternates have been considered by Canuck:

- Cross harbour line from Nailok Point to Sanktok Point, and Reindeer Point crossing and route up east side of harbour.

Their reports are being transmitted separately and are only summarized here.

In both cases a 2" (60.3 mm) line has been assumed. But while such a line is adequate for a peak Esso flow estimated at 7,100 m^3/d at a pressure of 700 kPa over the short Nailok Point crossing, the pressure will need to be kept at the field pressure of 7000 kPa if the eastern route is used to avoid a larger line size. However, at the higher pressure the line is more than adequate for Esso and supply to future industry on the east side of the harbour.

The Nailok Point alternate would use medium pressure odourized gas from the industrial distribution system. Running high pressure gas to the east side will require a line heater and depressuring system as well as a small odorizing system at Esso.

The Nailok Point route - on shore and marine - is estimated by Canuck at $1.1 million exclusive of engineering and related fees which will add another $150,000. The Reindeer Point route is estimated to cost about $600,000 including the depressuring and odorizing systems. This assumes a crossing under the proposed bridge structure - if a marine crossing is used the cost rises to about $750,000 (as tidal currents appear to keep a 6.5 meter depth at that point).*

Thus the southern route is recommended. Some consideration of a larger line at least to the eastern end of the bridge should be considered to handle major new potential gas users considering the east side of the harbour.

As the Tuk gas system evolves and local pipeline construction costs drop it appears likely that the cost of the Nailok Point crossing can be reduced. At that time a loop around the harbour would provide added surety of supply for all industrial customers.

* The bridge will be completed at the earliest in the winter of 1987, but any delay in the GONWT approval could delay it one year.

2.5 Tuk Electricity Options

2.5.1 Current NCPC Situation

NCPC

Currently Tuktoyaktuk normally receives its electricity from Inuvik via a 69 KV line, with a peak capacity of approximately 2.3 MW. During line outages, 3 local trailer mounted P-50 fueled diesel generators [Caterpillar 399(2) and 398(1) models] are used. (These units have al 1 been relocated from other NCPC plants and are older than local Dome and Gulf units.) The average load in 1984/1985, allowing 10% for distribution losses, was 0.755 MW with a peak demand of 1.800 MW.

A contract operator is employed to start the NCPC engines whenever required. Normally they are on line within 15 minutes. Problem with the transmission line is the normal reason for starting them up. The NCPC Tuk generation system is planned only as a standby. No new major loads are accepted at this time - even 75 KW. However, during crises in Inuvik the Tuk power plant has been used to provide some electricity for Inuvik in addition to local needs.

Local generating capacity at 2.1 MW gross does not meet utility standards which are based on:

Generating Capacity Required = Peak Demand plus largest unit plus 15%* of peak

By this formulae only 1.03 MW of net generating capacity is "available".

The poor quality of the existing power line has been discussed in Ms. Bogach's report - she assumes that it will go out of service in 1991. At such time NCPC will be obligated to add additional generating capacity in Tuk. The formula indicates a shortfall of one 800 KW machine even in 1984/1985. NCPC's own forecasts indicate peak loads equal to 61 KV line capacity in 1987/1988. Thus an early decision is needed on added Tuk generating capacity in any case.

* In Inuvik 10%. The 15% should drop to 10% with larger units and larger systems.

Dome and Gulf: Each have 3 - 800 KW Caterpillar model 399 diesel generators. While Dome notes an average generation of 1.2 MW (summer?) with a normal peak of 1.8, the average here has been assumed as 1.0 MW (all year). During certain periods Dome's peak can rise to 2.1 MW; however, it is assumed herein that such peak can be scheduled off peak from other community and oil industry demands. Gulf's generating pattern is assumed the same as Dome's normal operation. However, Gulf use part of the diesel waste heat for heating (with regular furnaces providing added heat an average of three hours a day). Gulf note some (unidentified) problems in always getting full rating from their engines; hence, they presumably have occasionable trouble meeting peak needs.

P-50 is now used as fuel by both Dome and Gulf.

Esso: Esso's electrical needs are not considered herein other than as a potential gas sale. However, Esso has 3 - 400 KW diesel generators, with waste heat providing part of facility/camp heating needs.

2.5.2 Tuk Demand Projections

Ms. Bogach's report assumes an average NCPC system load of 1.230 MW in 1994/1995. A peak demand of 2.9 MW in 1994/1995 as projected by NCPC is assumed. The average rises to 1.42 MW in 2000/ 2001, with a peak of 3.46 MW. No variation in NCPC load is projected for any of the alternate demand cases.

Minimum rate data were not available for any system and have been assumed as 0.6 min/avg for NCPC and 0.25 min/avg for the oil companies.

Dome and Gulf loads are expected to stay constant in the base case, but to drop to O by the year 1994/1995 in the Low Case.

This table assumes peaks coincide, which is unlikely; hence, the peak demand figures need to be treated with caution and considered maxima.

There is a loss of approximately 12% of Tuk demand in the transmission line, that is not included in the Table but must be considered if supply from Inuvik is considered.

TABLE 2.5.1 1994/1995 LOAD SUMMARY (2000/2001) ELECTRICAL						
	BASE CASE			LOW CASE		
	AVERAGE	PEAK	MIN'M	AVERAGE	PEAK	MIN'M
NC PC	1.23(1.42)	2.9(3.5)	0.7(0.8)	1.23(1.42)	2.9(3.5)	0.7(0.8)
Dome	1.0 (1.0)	1.8(1.8)	0.3(0.3)	0	0	0
Gulf	1.0 (1.0)	1.8(1.8)	0.2(0.2)	0	0	0
TOTAL	3.23(3.42)	6.5(7.1)	1.2(1.3)	1.23(1.42)	2.9(3.5)	0.7(0.8)

* Short term higher peaks assumed scheduled at other than NCPC peaks.

In this study no work downstream of generation is considered relative to added demands. It is assumed that such additions will be carried out in any case and do not influence the conclusion of this study.

2.5.3 No Integration Cases

2.5.3.1 Introduction

This section considers reaction to gas availability assuming the three Tuk electrical systems west of the harbour are not integrated.

2.5.3.2 NCPC on Own

NCPC will require 2-1600 KW generators by 1994/1995, in any case to meet peaks in its system. (Addition of only one large machine does not meet the reliability requirement - peak less largest unit.) The two units will preferably be dual fuel - gas/diesel - units, either the continuous sYstem of diesel type engines or switchable design for gas turbines.

NCPC would also appear to need a proper control center for a permanent Tuk station. Housing for key employees will also be needed.

It appears likely that diesel type engines will prove more efficient and less expensive overall than gas turbines at the required size. However, there is a great spread in efficiencies between competitive generators and in capital and operating costs. A capital cost of $3 to $4,000,000 appears indicated with 80 to 95% of electricity generated by gas - the rest by P50 pilot fuel in case of diesels and emergency fuel in case of gas turbines. Operating costs will run in the order of $600,000 exclusive of fuel and financing costs.

Note that NCPC will require such expenditures even if gas does not become available.

2.5.3.3 **Companies on Own**

The oil companies can schedule their own operations to avoid overloading the existing generators. However, Dome's concerns appear to indicate that at least they may consider adding another generator to meet peak needs. Only Dome and Gulf are considered here.

As Gulf is currently using diesel waste heat Dome may be able to do the same. However, as Gulf requires supplemental heat for several hours a day a gas turbine also appears likely to fit.

Added gas only 1200 rpm internal combustion engines matching existing diesel engines appear the cheapest alternate at about $900,000 for 1,300 KW (2 x 650) - above the average needs. At this level about 55% of electricity will be gas generated. A third engine at $450,000 would increase this level to 95%. But note that this would provide parallel gas and diesel systems, with 6 generators at each site.

Two dual fuel diesel type 1000 KW engines would cost roughly $1,600,000 and generate 90%+ of electricity by gas.

In the above alternates supplementary gas will be needed as at Gulf, as waste heat availability will not increase.

Small gas turbines are only half as energy efficient as equivalent sized diesel type engines. Hence, they are unlikely to be fully competitive except for average or less duty where the bulk of their waste heat can be used. A single 1200 KW unit complete with waste heat has a capital cost of about $1,200,000, but will provide only 50% of electricity from gas (but should eliminate supplemental heating fuel at both Oome and Gulf).

A peak sized (1800 KW) gas turbine is likely to have the low efficiency (about 20%) of the typical small gas turbines (compared to 26 to 30% of the 3000 to 5000 KW machines). Gas turndown is not as good as for i.e. machines.

In summary, appreciably more study is needed to optmize individual oil company response to avail abil ity of gas. While likely not optimum, for now we'd recommend use of the conservative two new 1200 KW i .c. (dual fuel) machines at each site generating 90% of electricity from gas. This is equivalent to an overall conversion of 93% to gas from P50, at a capital cost for each company of $1,600,000.

2.5.3.4 <u>Inuvik Supply</u>

In the no integration cases only NCPC can be expected to provide electricity to Inuvik at any time.

Without any special generation additions other than those discussed in Section 2. 5.3.2 above, NCPC should be able to feed about 0.8 MW of gas generated electricity to Inuvik via the existing 69 KV line. However, to provide all Inuvik electrical demands will require much more generating capacity at Tuk - in the order of 6 MW, as well as a new $16 million dollar, 115 KV supply line. That added generated capacity would be integrated with that needed for Tuk demands. Larger gas turbines have efficiencies (before any use of exhaust heat to reduce fuel) approaching diesels (30% vs. 33% for small diesels and 39% for slow speed marine types); hence, must be considered in detailed study.

Existing Inuvik capacity will be available for that end and standby needs at Tuk need only correspond with Tuk needs. One large gas turbine - e.g. 8840 KW Solar Mars at 33% efficiency at capacity - could handle all loads and require only a new 1200 KW machine additionally for Tuk emergency needs. Alternately two 4000 KW gas turbines could be used - with dual fuel option - at lower efficiency. The latter will cost about $4,300,000 and the former nearer $5,000,000. In both cases operating costs will be roughly $800,000 and 95+% of electricity will be gas generated.

2.5.4 Integration Cases

2.5.4.1 Integration

In the past two years, two systems have grown to three west of the harbour as Dome has gone on its own. However, an integrated approach allows the potential for minimizing/optimizing new equipment needs and providing more reliable supply to all users than the current system.

This study does not address the ownership of generators, or purchase/ sale price of electricity. But it must be noted that current NCPC rates - even more so than their lack of capacity - make internal generation economic when the demand is over roughly 100 KW.

An integrated system will be based on one of three scenarios:

a) Dispersed generating with central control,
b) Partially dispersed with central control, and
c) Central generation and control.

The first leaves existing generators where they are now, but allows added capacity at just site, if that is optimum. The second allows the relocation of existing - e.g. NCPC trailer mounted - generators to another site, and the last assumes all generation at one site.

Gulf's use of diesel waste heat has been kept in mind with the possibility that Dome could use a similar approach. Both companies are expected to be able to use hot water (or equal) produced by waste heat from gas turbine exhaust.

2.5.4.2 Dispersed System Scenarios

Introduction

In this case Dome generation will be connected to the NCPC grid and that grid extended and expanded, as appropriate, to connect up Gulf's distribution and generators. A central manned control center will be required, from which all 9 existing and any new generators will be controlled. The cost of the control center, necessary switch gear and transformers is estimated at $500,000. Cost of housing, etc. for employees coming in from the south has not been considered.

Diesel/Minimal Cost

The following summarizes new capacity needs in 1994/1995 with a dispersed system:

System Peak	6,500 KW	
Gross Capacity - NCPC	2,100	
- Dome	2,400	
- Gulf	2,400	6,900

Net Capacity = 6,900 - 800 - 1,000 = 5,100 KW
Required new capacity (minimum) = 1,400 (in two units of no more than 800 KW)

A single large new unit does not fit in as its capacity is deducted in the calculations of net capacity.

Thus, if all diesel system is maintained, two more small diesels would likely be added at a cost in the order of $800,000 ($1,300,000 including system interconnects). Note that this is far less than the $3,000,000 cost estimated for NCPC if they continue on their own. Operating costs are unlikely to be any higher with the integrated system than with NCPC on its own, as the same number of new staff will be needed.

Integration appears fully justifiable (as long as ownership and transfer rate concerns can be resolved)!

But note that the minimum cost solution does NOT use any gas as the net capacity must be available, regardless of fuel being used and the smaller units are only available in all diesel and all gas versions.

50% Gas Usage

A 3000 KW (nominal) rated generator will allow the generation of 50% of Tuktoyaktuk's electrical demands (ex Esso) by gas. It would require a second new engine, but that only need be a 600 to 800 KW machine, assuming the large new unit can also use diesel.

As noted before, a gas turbine starts to become energy-competitive with diesel types over 3000 KW and offers less maintenance and better reliability. Here we assume:

System Revision	$ 500,000
Solar Centaur T-4500 c/w waste heat recovery and dual fuel	$ 2,000,000
Cat Diesel 398	$ 300,000
Total	$ 2,800,000

The gas turbine will itself provide more heat (and at a higher level) than Gulf needs. Hence, Dome (and other) hot water sales would be solicited.

95% Gas Usage

100% gas usage is unlike y to develop as some diesel will be needed just to test standby machines and gas turbine diesel (standby) systems occasionally. Two gas turbines such as noted above will meet such a criteria. With two large units each capable of using P50 the amount of backup diesel required will drop and only 5-800 KW diesel units will be needed in reserve, allowing the sale of 2-800 and 1-500 KW generators - e.g. all existing NCPC units.

Thus only two sites will be used with Dome and Gulf kept and one serving as the focal point for new generation.

Capital cost will be in the order of $4,500,000 (with no credit for sale of surplus equipment). Operating costs will remain constant at about the $800,000 level.

Inuvik Sales

With the 95% Gas Usage alternate roughly 1.6 MW of gas generated electricity will be exportable to Inuvik as long as the 69 KV line stays in use.

Another two gas turbines or more likely 2-6000 KW gas turbine generators would be needed to supply both Tuk and Inuvik. Gas turbine generating efficiencies will improve with the larger units - but still be less than diesel/i.c. types if waste heat is not recovered. At that size we expect that exhaust waste heat will be partially used in an enhanced gas turbine system to increase efficiency to the level of good diesels.

The two large gas turbine systems are likely to cost in the order of $7,000,000 with waste heat use and dual fuel capability. The power line will cost in the order of $16,000,000. Operating costs - other than fuel - are not likely to increase beyond $1,000,000.

Note re Generator Types

While this study has assumed certain types in various settings, such selection is for illustration and preliminary costing only. A detailed study is required of specific scenarios to properly select the correct.

2.5.4.3 **Partially Dispersed**

The NCPC trailer-mounted generators can be relocated at another generating site for, say, $150,000 with system integration costs again in the order of $500,000. Such a move in itself will save only marginally on operating costs, but the system will have a higher reliability. (There is major advantage in dispersed arrangements as the Inuvik NCPC fire of 1983 showed.)

It will be noted that the 95% gas usage case for dispersed systems actually eliminated the need for the NCPC generators - in effect creating a partially-dispersed scenario. The discussion of that case and related Inuvik supply should be consulted.

2.5.4.4 Central

From the above it would appear that relocating just Dome units to Gulf or vice versa would be required with the 95% case to provide a central system. However, in practice a new site near both Dome and Gulf would be selected and any existing generators needed in the new scheme relocated. Assuming all six are relocated the capital costs will be about $100,000 above the dispersed cases when controls, etc. are considered - i.e. system costs before new generating costs will be in the order of $600,000.

New generating capacity needs and preliminary selections will be as in the dispersed cases discussed above.

In practice a central site with appropriate spacing of gas turbines and diesels appears the best overall answer.

2.5.5 Conclusions

a) Full study is needed of any scenario to properly define system details and new generator type. In particular the use of gas turbines must be compared to internal combustion engines.

b) NCPC should spend appreciable money to provide a proper system, even at this time and certainly by the time local peaks exceed the capacity of the 69 KV tie line in 1987/1988. As that line may go out of service at any time, the need for action appears urgent.

c) here is appreciable economic advantage in integrating the three existing generating systems relating handling both current and future loads - at least for NCPC.

d) Gulf's use of diesel waste heat must be kept in mind (and possible sale of waste heat to others should be considered).

e) As long as the 69 KV Inuvik to Tuktoyaktuk line is in place and appropriate (for Tuk) new generating capacity added about 1.6 MW can be fed to Inuvik backing out residual fuel (and to supply at non-peak demands).

f) Supply of all but emergency - e.g. tie line outage - demands in **Inuvik** will cost about $18,500,000 incremental to **Tuk's own** system needs, largely due to the need for a new 115 KV voltage line to replace the 69 KV.

g) While data are presented for a 50% gas use in electrical generation, a higher use is likely to prove best overall and data are provided for a **95%** case. In that case, an allowance of 5% P50 use has been made for upsets in gas supply and test use of diesel standby capacity.

h) Combining the integrated generation at one or at the most two sites is recamnended, especially as **NCPC's** 3 generators become redundant in likely new generating capacity scenarios.

i) The brief review has not considered corporate constraints or even approaches to integrated operation, nor housing, etc. for the new southern staff needed for a full local generating system.

2.6 Inuvik Gas Supply

2.6.1 Preamble

Moving electricity from Tuk to Inuvik is expensive due to major generating capacity needed at Tuk and a new power line to Inuvik. While the reliability of a new 115 KV power line will be much better than that of the existing 69 KV line, it will still be necessary to provide full generating capacity at Inuvik in the event of any line outage. Also a Tuk to Inuvik power supply will not reach more than a very minor portion of Inuvik heating needs. Thus a gas line option has been considered.

As in other study areas, 1994/1995 has been considered a base year for facility sizing.

2.6.2 Demands

Ms. Bogach has estimated demands for Inuvik based on NCPC data, town heating fuel needs in 1979/1980, and analysis of future population changes and government activity. The preliminary nature of the forecast should be noted.

In 1994/1995 (and 2000/2001) she indicates:

	1994/1995		2000/2001	
NCPC Power Generation	9,282,000 m^3	(36%)	10,089,000	(36%)
NCPC Heating System	11,409,000 m^3	(45%)	12,401,000	(45%)
Private Heating	4,801,000 m^3	(19%)	5,219,000	(19%)
TOTAL	25,492,000 m^3	(100%)	27,209,000	(100%)

Thus NCPC represents by far the largest portion - and is a single site gas delivery, compared to several hundred potential private heating customers spread on either side of NCPC's central heating system.

Load factors have been estimated from NCPC data and our own estimates, but again are preliminary:

TABLE 2.6.2.1
MAXIMUM TUKTOYAKTUK GAS DEMAND FORECAST
1994/1995

Load	Daily Average	Peak	Minimum	Factors Peak/Avg Min/Avg
NCPC Power	25,430 m^3/d	40",100	12,700	1.64/0.5
NCPC Heating	31,260 m^3/d	78,100	4,700	2.5/0.15
Private Heating	13,150 m^3/d	50,000	1,300	3.8/0.1
TOTAL	69,840 (2,464,000 scfd)	168,200* (5,939,000:	18,700 (660,000)	2.41/0.27

* 247,100 m^3/d when Tuk total (with Esso) (8,725,000 scfd) added

The large swing in private heating demands is to be noted.

Electrical generation has been estimated as follows:

1994/1995 MW			2000/2001 MW		
Average	Peak	Minimum	Average	Peak	Minimum
3.36	5.51	1.7	3.65	6.0	1.8

The lower electrical peak to average factor, compared to that at Tuk, is apparently due to larger and more stable population and significantly more commercial and government facilities. The average for Tuk and Inuvik as calculated in NCPC'S forecast has been used for Inuvik alone, to compensate for expected slightly greater Inuvik load swings after the DND pull out.

2.6.3 Gas System Elements

Tuk Gas Field Supply

It is assumed herein that the gas comes from the same system supplying Tuk, with only increasing the size of components. In practice the capital cost would be prorated based on the Inuvik share of the total system demand - about 68% in 1994/1995.

Incremental capital costs in the field are estimated at about $500,000 including added communications systems - assuming no added wells are needed.

Incremental operating costs should not increase by more than $50,000.

New Line from Tuk Field

A 6" line is needed to meet the above peak demands, assuming no intermediate compressor station. Such a line will deliver up to 280,000 m^3/d (10,000,000 scfd) at a pressure of 5600 kPa assuming a start of 7000 kPa.

Canuck have estimated a cost of $29,000,000 for the line from the field to the Inuvik NCPC plant, based on comparison with other gas line estimates for the same area.

NCPC Changes

These are discussed in the next section.

Private Distribution

Due to layout of Inuvik and the NCPC central heating system, other residences and businesses will likely be fed via two separate systems - northwest and southeast. Each is expected to have a high pressure delivery system, low pressure distribution loops, and a standby propane air system. A very preliminary estimate of the total distribution system capital costs is $2,500,000 with overall annual operating costs of roughly $800,000.

2.6.4 NCPC Gas Use

Basics

In the NCPC station existing hot water boilers can be expected to be converted to dual fuel - resid and gas without much problem other than relative to flammable gas passing through the building. Currently an average of about 40 million BTU per hour of fuel is put into water heating, from 15 in summer to 80 in winter. Continuity of enough diesel generating capacity to supply Inuvik is assumed here, even with the availability of Tuk gas. The capacity of the existing Inuvik electrical generating facility is estimated as follows:

Peak Demand in 1994/1995 (ex Tuk)		= 5.5 MW
Existing Capacity		
- GM Diesels (P40)	- 2.500	
	- 2.500	
	- 2.850	
- Mirrlees Diesels (resid)	- 2.080	
	- 5.180	
TOTAL	15.110 MW	
Net Available = 15.110 - 5.100 - 0.550		= 9.38 MW

Hence, even by the year 2000 there is ample capacity in the existing plant. As Tuk's project peak demand is about 2.3 MW in 1994/1995 there is significant surplus above the total of Inuvik and Tuk needs, but not enough to eliminate any existing machine.

Existing Unit Conversion

The GMD's do not appear amenable to conversion to gas in a dual fuel (diesel/gas) configuration, but the Mirrlees units can be converted to a dual fuel mode - see Appendix D - with only a loss of capacity of 1 to 9%. Given the size of the Mirrlees units and the peak demands, if both are converted they could handle all loads themselves. However, the NCPC operators prefer to operate the GMD's, especially for peaking needs, and it is not clear that the Mirrlees will be accepted for only emergency service.

In a dual fuel mode, the Mirrlees engines require 5 to 11% of total fuel as diesel as a minimum. Thus, even if the Mirrlees are converted, diesel and residual fuel will still run 15 to 20% of total fuel (when Mirrlees shut down periods are considered).

The costs of converting both Mirrlees units to dual fuel mode are estimated at roughly $2,500,000. Operating costs, except for fuel, are unlikely to change. Gas usage for electrical generation will be about 80% of that indicated in Table 2.6.2.1 above at best.

The conversion of the Mirrlees engines will take roughly four months during which period P40 diesel will become the predominant fuel for generation. (This can only be done after Tuk is self-sufficient in generating capacity.) The incremental cost of such fuel must be considered in the final analysis.

Gas Turbine Use

For analysis purposes a Solar Centaur 3130 KW turbine generator set has been used as a reference point with an average air temperature of -10°C. Data were readily at hand for this model which appears reasonably representative of turbines of that size. Compared to the Mirrlees engines, overall efficiencies are roughly as follows:

% Capacity	output 'W	Generation Effic. %	Overall Eff. with Waste Heat Recovery*	Waste Heat Recovered 10^6 BTU/hr	Mirrlees Effic %°
100	3414	26	76	15.8	37
75	2546	24	51	9.7	37
50	1707	20	37	4.8	36

NOTES:

* With exhaust heat above 400°F recovered to the town hot water system.
° Without heat recovery to other than station heating.

The efect of low ambient temperature is quite apparent in the 9% uprating of capacity. Also the effect of waste heat recovery on overall energy efficiency is to be noted.

As the amount of waste heat recovered at even 100% loads appears less than the minimum hot water system needs, it appears safe to say that the overall efficiency of gas turbines will be better than that of dual fuel I.C. machines in the Inuvik setting.

If such a gas turbine were selected (with diesel alternate fuel option), on its own it would generate roughly 50% of Inuvik's electricity needs at a capital cost of $2,300,000 including waste heat boiler. If the smaller of the Mirrlees were to be converted over 85% of Inuvik electricity could be gas generated. This combination would cost roughly $3,300,000 in capital costs.

A second identical gas turbine could be installed for a total of $4,200,000. In this case 95% of electricity will be gas generated - only occasional diesel use occurring during gas turbine maintenance.

The gas turbines should prove much lower in maintenance costs than the existing Mirrlees units which have provided major challenges to NCPC staff over the years.

<u>NCPC System Conclusions</u>

a) Added generators will not be required at Inuvik if gas does not come available.

b) Approximate capital costs and gas usage for various alternates are as follows:

- Convert Mirrlees engines to dual fuel :
  $2,500,000
  80% of electricity gas fueled

- Add one 3100 KW gas turbine:
  $ 2,300,000
  50% of electricity gas fueled

- Add gas turbine plus convert one Mirrlees:
  $3,300,000
  85% of electricity gas fueled

- Add two gas turbines:
  $4,200,000
  95% of electricity gas fueled

c) Gas turbine efficiency will be better than diesel type engines when waste heat recovery to town heating is considered (applicable only on gas turbines).

d) Maintenance costs should drop as Mirrlees machines are phased to standby or eliminated in the all-gas turbine alternate.

e) Use of gas turbines will allow the sale of two of the existing diesels.

2.6.5 Summary - Full System

Capital and operating costs are estimated as follows for the Inuvik supply system:

	Capital		Operating (excluding fuel)	
Field (prorated)	$ 300,000*		$ 50,000	
Pipeline	29,000,000		1,000,000	
NCPC	4,200,000	(max°)	- 50,000	(?)*
Distribution	2,500,000		800,000	No appliances allowed
TOTAL	$ 35,500,000		$ 1,800,000	

NOTES:
* Differential
° Corresponds to 2 gas turbines generating 95% of electricity from gas.

Gas sales with such costs will be approximately (1994/1995 base):

NCPC, Power and Heat	18,000,000	m^3/y
Private Heating	4,800,000	m^3/y
	22,800,000	(2.1×10^6 scfd average)

after rough corrections for enhanced efficiency due to use of waste heat recovery systems on the gas turbines and some (5%) allowance for use of diesel for electrical generation on occasion.

Both gas turbines and conversion of existing slow speed diesel units should be studied further to optimize NCPC capital and operating costs.

2.6.6 Minimum Line Cost Case

Due to the high cost of the Tuk to Inuvik pipeline, consideration was given a case with a 4" line rather than the 6" used above. A 4" line can supply just over 4,000,000 scfd (113,000 m^3/d equivalent to about 37×10^6 m^3/year). Such a line will not meet peak demands as shown in Table 2.6.2.1 for 1994/1995 but will be able to provide in the order of 80% of potential gas sales. In practice the 4" line appears likely to be able to satisfy NCPC demands at that time. Deletion of the private systems greatly improves load factors and lowers system operating costs.

In later years an intermediate compressor station would be used to match increasing NCPC needs and to add private users to the system, but such is not considered here, nor recanmended.

Costs are estimated as follows:

	Capital	Operating	
Field (prorated)	$ 400,000	$ 50,000	
Pipeline	20,000,000*	800,000	
NCPC	3,200,000 (rein")	0	(net)
Distribution	0	0	
TOTAL	$ 23,600,000	$ 850,000	

NOTES :
* Prorated off 6" - small line construction techniques may reduce figure slightly.
° Add one gas turbine and convert one Mirrlees

In this case sales will be about 18,700,000 m^3/year to NCPC in Inuvik, after allowing for efficiency and some diesel fuel use. Most residual fuel will be backed out - only a' small amount will be used as emergency fuel for the town heating system. NCPC P50 use will be equivalent to about 40% of the current level - for emergency and for 10% or so of Mirrlees engine use.

Two gas turbines could be added raising total capital cost to $24,600,000 and using about the same amount of gas but only about 15% of current NCPC P50 use for emergency use only.

2.6.7 Oversized Gas Line

In order to provide some perspective on export of gas via a Polar Gas or equal system plus Inuvik supply, Canuck also provided an estimate for the cost of a 10" line in the order of $50,000,000, from Tuk to Inuvik.

2.7 Backup

A propane/air system is proposed as the standby for the community heating as portions of the system. The parameters of such a system have been reviewed to determine optimum pressure in the distribution system and the appropriate configuration of equipment.

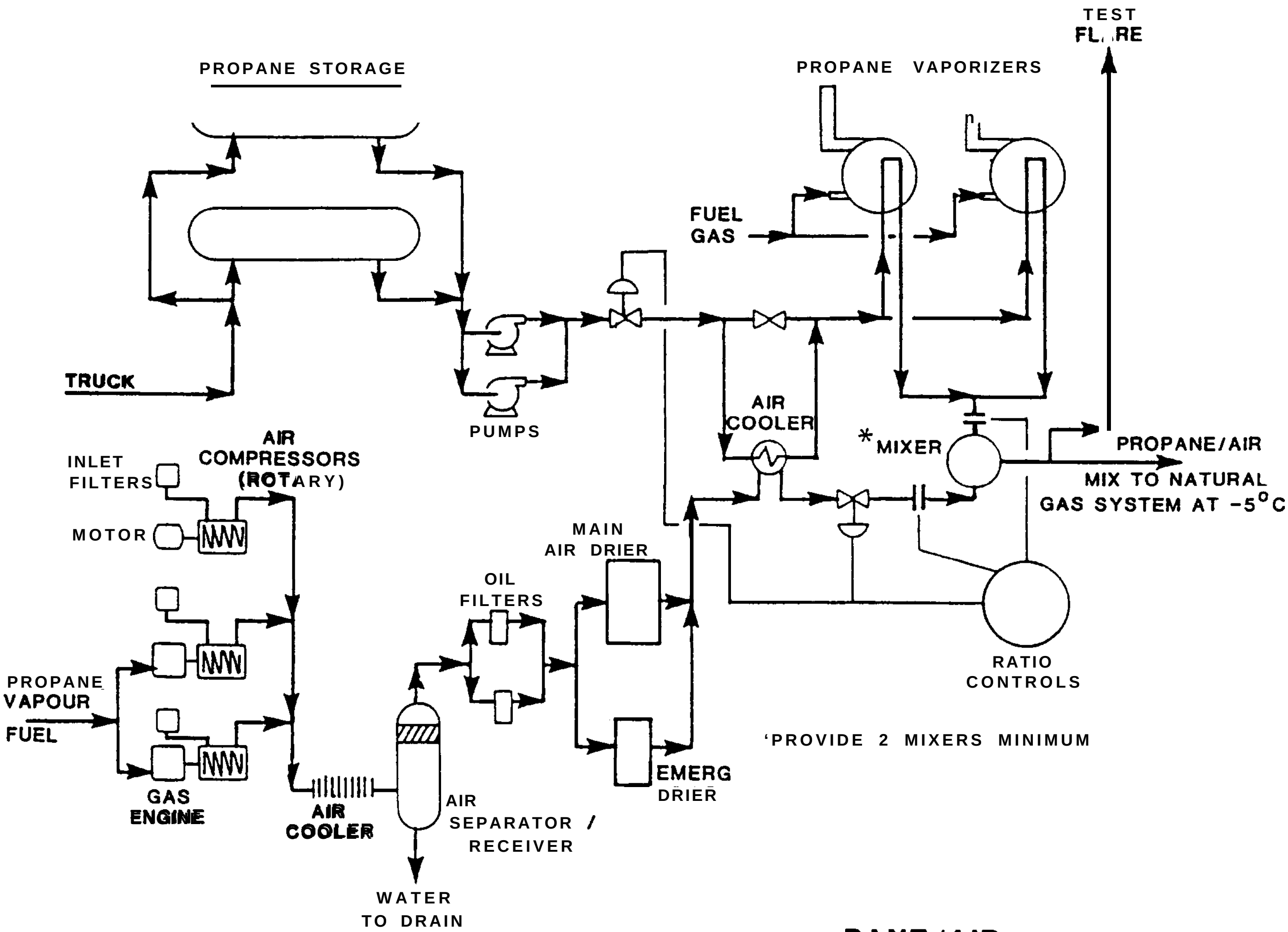
Alternates such as a mini-LNG system (as was used for Squamish, B.C. gas supply for many years) and oil gas were discarded early as not being appropriate to the site, given its remoteness from service facilities and as being more expensive than propane/air. In time development of a second gas field and a second high pressure pipeline system could make the propane/air system redundant.

In Section 2.2 above certain of the needs for propane storage were discussed. A minimum of one month supply of propane is considered essential to protect against any emergencies that necessitate the shutdown of the gas supply system. Experience with such systems shows very little use - normally only the regular monthly test - indicating a very high reliability of gas systems generally. Here, virtually all problems necessitating system shutdown should be fixed within less than 3 days. However, to protect against several such emergencies happening during periods when propane cannot be trucked ot trucked and barged in, at least 30 days' storage relative to peak demand periods is very strongly recommended.

Such propane must be stored in at least storage tanks separated sufficiently to preclude an accident to one affecting the other. Likewise other components should be suitably segregated as to provide a high degree of reliability.

It must be noted that this propane storage must not be used for propane sales, although separate storage at the same site could well be used.

Both high and low pressure systems were considered. While a low pressure system using high pressure propane eductor to draw in air to the system is by far the simplest system - only moving part is the propane pump - no simple means of suitably drying the air (in summer) appear available. Also a low pressure system will operate only up to



PRO PANE/AIR SYSTEM
SCHEMATIC

FIG. 2.7.2-1

about 150 kPa (5 PSIG) necessitating larger than normal low pressure distribution piping.

A high pressure (up to 50 PSIG - 450 kPa) system using air compression and drying was finally selected, as shown in Figure 2.7.1. Such systems are relatively common as better adapted to existing gas systems than low pressure systems. Also the hydrate (dew) point of the resulting propane air system is much better (below -60°C).

Delivery at 250 kPa is proposed, representing the minimum design pressure (for line pack and availability) of the low pressure gas distribution system. Normal pressure with natural gas will be in the order of 280 to 350 kPa.

The propane/air system, while complex equipment-wise, will use only proven components and shelf spare parts will be available. As much as possible will be housed - air compression and drying in one building and vapourizer/mixer systems in two.

As propane/air is heavier than air and natural gas is lighter, special attention will be warranted through the entire community gas system to provide appropriate venting of any low enclosed spaces.

Further analysis is needed in the detailed design stage relative to ensuring positive pressure in the propane storage tanks at all times. If required, simple electrical heaters that strap to the tanks can be provided or some warm vapour may be recycled to the top of the tanks.

At this time one propane pump is assumed electric driven, and the other compressed air driven. In the event of a power failure most community users will also lose their heating system as forced draft air furnaces are the norm. However, there too more study is needed. Two gas driven compressors are proposed with one motor driven one on standby, to provide capacity in case NCPC does not expand its system.

The air drier will be of the highly-proven pressure swing adsorption type with a single bed unit of 12 hour summer peak capacity on standby (allowing any maintenance needed on the main drier). The latter can be regenerated in a few hours with a small stream of dry air. However, in winter air drying capacity needs will be much less than in summer.

The proposed system can be easily expanded by adding another propane pump, compressors, vaporizers, and revising the controls accordingly. Thus capacity is not of major concern as long as piping is of sufficient size.

Further analysis may show certain large community users able to convert to dual fuel systems, reducing the propane/air system capacity. However, the incremental cost of capacity in the propane/air system is not large other than as added storage becomes involved. Some users, now scheduled for P50 backup , may prefer to use propane/air instead.

3. DESIGN BASES

3.1 Introduction

3.1.1 General

These design bases are intended to provide instructions to the engineers and designers for the various portions of the system downstream of the wells. Certain facilities relative to the wells will be added to the scope of coverage when their needs are known and concepts have been developed. End using devices, appliance and related piping, wiring and controls are not covered herein.

The bases herein are based on the system generally described above in Section 1.6. Certain portions of field pipeline, and distribution are discussed in Secti_on 2 and in Canuck reports. The basic system is planned to provide gas to industrial, electrical utility and comunity - residential , commercial and government - users on the west side of the harbour. However, the same principles will apply to a supply system to Esso and others on the east side.

At this time the actual wells to supply the gas have not been defined and H-22 is used only as a nominal reference point. A second well adjacent to H-22 is assumed.

Inuvik gas or electrical supply are reflected only insofar as excess generating capacity may be available for feeding some electricity to Inuvik during off-peak hours. No impact on gas system sizing or criteria is assumed.

The people and industries of Tuktoyaktuk require a very reliable gas distribution system sufficiently economic to back out virtually all liquid fuels. While most major alternates have been defined in the studies to date, alternate approaches that will improve reliability and decrease the delivered cost of gas will be considered.

3.1.2 Timinq

The various portions of the project are not in themselves large, and only an 18-month period is allowed for design and construction assuming a March 1986 start on design. No major delays are envisaged in the regulatory process.

Construction and transportation windows must be considered throughout - generally construction will take place November through April and June through September. Land/marine transport outages of up to ninety days in the spring (mid April to Mid July) and sixty days in the fall (October to December) must be noted.

The design of field, pipeline, town "terminal" and distribution systems will proceed in parallel with continuing support assistance such as geotechnical. Each section's work will be planned to complete construction and commissioning before the middle of September, 1986.

3.1.3 Local Conditions

Climatic data are available as required for specific design considerations from Environment Canada. RTM has put together a package of applicable data, but further data may be required. The low temperatures generally, and high winds - especially in January - are to be noted.

Parallel with detailed engineering, design and construction activities, a geotechnical consultant will provide data from files or via tests, as required for design and construction. Also a survey consultant will provide topographic and legal survey data as required.

It will be essential for representatives of each selected engineering company to visit the site of their work, to fully understand local conditions and concerns and to develop rapport with geotechnical and survey consultants.

3.1.4 Regulatory Bases

Esso and IPC will take a co-ordinated approach relative to all aspects dealing with regulatory agencies. Generally major permits will be obtained by Esso and/or IPC with the engineering consultants only providing assistance as requested.

Esso and IPC will handle all major permit applications, but the engineering consultants must be familiar with the requirements under each.

Access to land, easements, etc. will also be negotiated by the IPC with the Inuvialuit Land Administration, the federal government and/or the Northern Canada Power Corporation as appropriate. Such negotiations will be carried out under advice from the respective consultants regarding land needs and locations.

The federal Canadian Oil and Gas Lands Administration will provide:

Drilling Licenses
Development Plant Approval
Pipeline Construction Approval
Production Operations Approval
Certificate of Fitness (Wellhead and Process)
Pipeline Operations Approval

all under the latest draft or formal issue of:

Canada Oil and Gas Act
Oil and Gas Conservation Act
Canada Oil and Gas Production and Conservation Regulations
Canada Oil and Gas Production Installations Regulations
Oil and Gas Pipelne Regulations

Surface development plans are subject to Inuvialuit Land Administration approval. Environmental approvals may be required of Environmental Impact Screening Committee and the Environmental Impact Review Board.

Generally the regulations relative to the design of physical facilities from the well to town come under COGLA and the three referenced regulations must be strictly adhered to.

The distribution system design will be set by C.S.A. Standards CSA Z184 and B149 and regulations if/as issued by Government of the Northwest Territories agencies, particularly the Public Utility Board, The Inuvialuit Land Administration and the hamlet by-laws will also govern many aspects of rhe distribution system.

Generally federal C. S.A. standards apply with Alberta regulations to be used where no federal standard applies - if appropriate to the particular setting.

3.1.5 Operating Philosophy

As noted, a very high degree of reliability is required in the system. Generally the entire system will run unattended, except for routine maintenance and emergencies.

The system must be designed to operate in such a manner with the automatic callout in the event of certain abnormal events, e.g.:

- Fire in any field facility
- Emergency shutdown of any portion of the system
- Low pressure - at the entrance to the pipeline
  - at the town end of the pipeline
  - in the medium pressure system
  - in the low pressure system
- Operation of the propane/air system.

The automatic callout of personnel shall not, in itself, override normal and/or planned abnormal operation of any part of the system.

The presence of low pressure in the main pipeline will be alarmed to users of medium pressure gas, to have them convert to alternate fuel prior to an automatic cutoff of medium pressure gas delivery.

At least daily surveillance of all but the pipeline can be assumed. The pipeline route will be covered at least once a week when site conditions permit. But any such checks shall be for inspection only and equipment adjustment other than normal maintenance should not be required.

Equipment and systems used shall be completely suitable for the climate and a community remote from suppliers and accessible only by air for up to five months a year. While spare parts will be kept on hand, it is not the intent to keep more than a minimal amount; hence, small parts used should be readily available elsewhere. Insofar as possible maintenance and repair work should be such that it can be carried out with a small staff using locally available facilities and/or equipment.

While initially specialists will be used to oversee the operation of various portions of the system, it is the intent that such specialists will train local personnel to take over most, if not all, functions within a reasonable time.

3.2 Field Facilities

3.2.1 Preamble

This section covers the portions of the overall system from the well head to the point where the main pipeline first goes underground, except for surface facilities required for well operation. The latter will, in any event, be fully integrated into other field surface facilities, and such integration may require some revision in certain of the systems defined herein.

All field facilities come under COGLA regulations previously noted. Where COGLA regulations do not fully define code requirements, reference shall be made to Alberta standards. However, the latter may require some revision to be more appropriate to the site. Certain facilities will overlap with Esso's responsibilities and Esso may require that the latest issue of their Engineering Specifications be used where applicable. The engineering consultant(s) for the field facilities will be advised of any such coverage.

The latest edition of ASME Boiler and Pressure Vessel Codes, ANSZ/ASME B31.1 Chemical Plant and Petroleum Refinery Piping, Canadian Building Code, Canadian Electrical Code and National Board of Fire Underwriters Bulletin 294 shall apply. The design pressure of the process side of all field facilities shall be 8,280 kPa at 66°F.

The site will be cold with high winds at the coldest periods. All systems must be capable of starting, stopping and operating continuously with a temperature of -50°C with a wind of 87 km/hour and with no sunlight. Generally process equipment shall be housed in heated buildings with lighting.

Field facilities will not be attended, other than for daily overview and routine maintenance.

Buildings will be separated from each other by at least 50 meters and from the well heads by 100 meters for safety reasons. However, all buildings will be located on a common pad.

3.2.2 Hell Surface Piping

The well fluid line to the inlet separator will be suitably insulated (with aluminum jacketing) and traced to ensure that the well head temperature of the gas is maintained with less than a 5°C decrease or increase in flowing gas temperature under all flowing and climatic conditions.

Tracing alternates to be considered will be electric, hot glycol from dehydration, glycol/water heated by hot glycol, and hot oil heated by hot glycol. Heating of the well piping will be integrated with well antifreeze systems, to be specified by Esso.

A corrosion allowance of at least 0.3 mm shall be used due to the possible presence of wet $C0_2$.

The lines from each well will be manifolded to allow either to be routed to either inlet separator.

3.2.3 Inlet Separators

Each inlet separator shall be housed with its respective glycol system. Separators shall be vertical and not integral with glycol equipment and complete with demister to remove 99% of entering free water at a maximum rate of 0.001 m^3/m^3 of raw gas over the range from 5 to 100% of the total design flow to the sales gas pipeline.

The inlet separator shall also be considered in wet $C0_2$ service. Provisions to hold at least 1 m^3 of water will be required. Other requirements are discussed below.

3.2.4 Glycol Systems

Each glycol system shall be capable of processing from 5 to 100% of total design sales flow achieving a dew point depression of at least 65°C assuming an inlet gas temperature of 20 to 25°C and a water saturated gas feed.

The glycol system shall consist of:

Contactor with at least 10 bubble cap trays (or equal), and at least a 152 mm thick stainless steel demister,

Insulated and aluminum clad reboiler complete with packed column, packaged gas stripping zone, removal fire tube, surge vessel complete with glycol to glycol exchanger,

Glycol cooler as applicable,

Two 100% circulation pumps rich glycol powered,

Two glycol filter and charcoal filters, each 100% capacity.

Each inlet separator and glycol system shall be complete with all necessary controls to operate without electricity and in an unattended manner. Attention should be needed only for startup and normal shutdown and routine maintenance. The unit should shut itself down on high reboiler temperature, flame failure, building fire and other events as recommended. All shutdown devices shall also be connected to the communications system for alarm in the control center in town.

Instrumentation shall be sufficiently complete to monitor the operation of all parts of these systems. Instrumentation shall also be sufficiently accurate for such purpose over the projected range of operations. Blowout-proof burners are essential. Dry gas shall be used for instrumentation, as required, as well as fuel and stripping gas.

Metering of the dry gas shall be provided with a 3-pen recorder provided locally. Equipment shall be provided to transmit flowrate, temperature and pressure to town via radio. Service gas - fuel, control and stripping - will be metered and totalized.

Control valves shall be selected for operability over the expected range of operations. All routine operations shall be automatically controlled. An emergency shutdown valve shall be provided for the control gas system to return all control valves to their fail safe position on local or remote command.

A methanol injection system shall be provided with each inlet separator/glycol module.

Glycol addition facilities shall also be provided.

Vessels and piping shall be provided with drains. Minimum corrosion allowances shall be 1.6 mm except 3.2 mm up to the glycol contactor. Process piping shall be welded. Piping and vessels protruding outside the building shall either be designed for -50°C or provided with suitable weather protection.

Each inlet separator and glycol system shall be skid-mounted for mounting on piles or a gravel pad in the field. Rough handling of skids must be anticipated.

The equipment layout must allow access to all equipment items, all valves and all controls. The number of field connections must be minimized.

Guards shall be provided for moving and high temperature equipment.

Each building shall be strong enough for transport and for all wind loads. A metal clad insulated building is envisaged with suitable doors and windows. Explosion-proof infra-red gas heaters are anticipated to keep the building at 15°C during equipment shutdown in mid-winter. Manual louvres at floor and ceiling are also anticipated.

A fire detection system shall be provided in each building.

3.2.5 Air Cooler

The air cooler will normally provide all the cooling of the sales gas from the 22 to 27°C temperature of the glycol contactor outlet to the -5°C temperature for the pipeline. The refrigeration system will supplement the air cooler when ambient temperatures preclude all cooling in the air cooler.

A very high degree of reliability is required in the air cooler. It should have an absolute minimum of moving parts. However, as the sales gas hydrate temperature may go to -20°C on occasion the temperature of air for cooling must he kept above that point. (Methanol injection points will be provided but only for "last resort" use.) Thus air recirculation appears essential. At least two fans are required.

The air cooler must be capable of operation between 10% and 100% of capacity under any climatic conditions.

The air cooler will sit outdoors with wind and weather protection as appropriate. It will be designed for the same pressure and maximum temperature as the inlet separator, but all components must also be compatible with -50°C conditions.

Gas should be used for controls and electricity, if available, for motors. However, an alternate considering use of gas motors should be considered.

The status of air cooler operation must be transmitted to the town control centre.

The air cooler system must come to the field as to totally prefabricated package requiring only sales gas in/out, control gas and electricity connections. It will sit on piles or on a gravel pad. Packaging must allow for rugged handling en route to the site.

3.2.6 Refrigeration

The refrigeration system must have a hydraulic capacity equal to the maximum gas rates, but the thermal capacity need only be 125% of average gas flow being chilled from 27°C to -5°C with air at +15.2°C (July average maximum). Normally the inlet temperature will be significantly lower due to air cooler operation.

While the refrigeration system can be shut down for short periods - say 4 to 6 hours - even during warmer days, it should be designed for continuous unattended operation on a high reliability basis.

A standard ammonia or propane cycle system is suggested assuming the surge vessel is inside a building housing all but the refrigerant condenser. Equipment selection should only consider standard components available "off the shelf" and readily replaced with a minimum of effort. A gas engine drive should be considered as standard unless studies indicate better reliability and/or lower cost for other alternates. The high turndown required should be noted and all equipment must be compatible. There must be the ability to run gas through the system continuously when refrigeration is not required.

The control system must be self-contained except for control gas and alarm electricity supply. Alarm must sound locally and in town in the event emergency.

The refrigeration system will be housed in a building similar to those used for the glycol systems.

3.2.7 Controls and Communications

The field facilities will run unattended with automatic switchover from parallel to single train and from one train to the other (at low rates) operation of the inlet separator/glycol systems. The air cooler and refrigeration systems will be bypassed in case of their shutdown. Each module must be designed to operate both reliably and safely.

Control system generally should be as simple as possible, consistent with reliability and adequacy of control. Manual operation cannot be assumed as immediately available in the event of upset - it will take the operator up to six hours to get to the site.

The field facilities will be self-contained with only gas in/out connections plus radio.

Gas detectors will be provided in all buildings - ceramic bead type - to alarm (in field and to town) at 20% of the lower explosive limit and to shut down the affected equipment at 40%. Combined ultraviolet/infrared type sensors shall also be provided for fire detection - alarm at low level (equivalent to match) and shutdown at a higher level.

A dual radio channel system shall be provided between the field facilities and town - one channel for voice and one for control/alarm, in emergency either channel can handle both voice and control/alarm.

The control/alarm channel shall transmit:

- Status indicators - modules in operation
- Process data - sales gas flow, gas temperature, gas pressure, flow (raw-sales), glycol circulation flow and temperature
- Alarm data - gas detection, fire detection, high levels, high temperatures (glycol, glycol reboiler, refrig compressor discharge and bearings, etc.), low pressure fuel gas, low battery voltage, etc.
- Shutdown Advice - What and when
- Control Signals - Shutdown any module

A simple data logger plus analog light and horn system is anticipated at the town end to log all changes in status, alarms, etc. and to periodically record all flows. If an operator is not in attendance in town, the system will call out the appropriate personnel.

All appropriate approvals shall be obtained for the communications system.

A mobile radio system will connect operators in the field or on the way with the town and with the field control centre.

3.2.8 Miscellaneous Field Facilities

A separate building shall serve as the centre of field operations - with alarm panel , radio communication links, fixed and mobile, etc. It will also serve as an emergency shelter in the event personnel must remain in the field for any length of time, and a first aid centre will be included.

This building shall have a storage area for normal spare parts. Also an electrical room will be included for battery systems and electrical generator system. A separate thermal or other small generating system will be provided to support the batteries in the event of generator failure.

Study is needed to more properly define all electrical systems, and of heating and sanitary arrangements for the entire field complex. Water and waste glycol surge systems also need to be developed.

Natural gas taken off before the air cooler will be used for both lease fuel and controls. A highly-reliable system must be provided.

All relief valves and all vents in any one building shall tie into a common header for release at least 5 meters from the building vertically at a location which will not allow a backwash towards the building or towards the building and/or glycol reboiler and/or gas engine flue gas emissions.

All year access must be provided between all field facilities (and a connecting road will be run by others from town).

The above scope and comments must be considered very preliminary and conceptual. A highly-reliable, safe, economic facility must emerge from the design.

3.3 Pipeline

3.3.1 General

This section outlines the standards and design approaches for the main pipeline portion of the system from chilling to town.

Construction techniques must be consistent with maximum use of local contractors and/or their equipment.

Generally the pipeline engineering consultant shall work closely with overall project management and the geotechnical consultant in the development of approaches, drawings, specifications, a construction plan and construction inspection.

3.3.2 Codes and Standards

Standards followed in the design of the flowline facilities and material selection are as follows:

Pipeline Design	1.	CSA Z 4-M1982
	2.	COGLA Regulations
Pipe	1.	CSA Z245.1-M1982
	2.	ASTM A333 GR.6
	3.	Owner's Specific Requirement/Specification
Valves	1.	CSA Z245.15-M1982
Fittings	1.	CSA Z245.10-M1979
	2.	ASTM A420 WPL-6
Electrical	1.	CSA C22.1-1982

The construction of the proposed flowlines will comply with the appropriate pipeline acts or regulations administered by Canada Oil and Gas Lands Administration (COGLA) along with the requirements of the Department of Public Waterways (DPW), the Canadian Coast Guard and CSA Z184-M1982.

3.3.3 Data to be Provided by the Client

The following is a list of the design criteria and information which should be verified and/or provided by the client:

a) Environmental Protection Plan.

b) Geotechnical and Hydrological reports for the crossing location in Tuktoyaktuk Harbour (including field profile survey)

c) Route Assessment Report and Route Map.

d) Geotechnical Report for preferred route(s).

e) Details of pipeline connections.

f) Flowline operating pressures and temperatures.

g) Typical drawings of warning signs and aerial markers.

This information will be incorporated into the design of the flowlines and in the preparation of material specifications, drawings and construction specifications.

3.3.4 Design Philosophy

The engineering consultants shall adhere to the listed codes (Section 3.3.2), experience and proven industrial standards and practices.

Preferences for designs, material selections, or facility orientations and layouts expressed by the client as documented in minutes of meetings, correspondence, sketches and other drawings will be incorporated into the design.

3.3.5 Class Location and Design Factors

In accordance with CSA Z184-M1982, the pipeline is classified as a HPB flowline with an associated design factor of 0.8.

The pipeline diameter, minimum wall thickness, grade and category have been specified as follows:

114.3 mm 0.0. x 4.78 mm W.T. Gr. 290 kPa Cat. II
60.3 mm 0.0. x 3.18 mm W.T. Gr. 290kPa Cat. II

Other sizes shall be similarly specified. Special sectors shall be considered individually if heavier wall pipe is considered necessary at any point.

3.3.6 Routing and Right-of-Hay

Routing

The route shall deselected to minimize pipeline costs consistent with good access and safety (of both line and environment), good practice and applicable codes.

Right-of-Way

The width of the right-of-way will be 13 meters with the pipeline located 5 meters from one boundary. At any stream crossings tghe width of right-of-way will be extended to 25 metres and as much as 50 meters right-of-way width will be allocated to the harbour crossing. The contractor will request extra work space at specific locations, as required.

3.3.7 Depth of Cover

The minimum depth of cover will generally be 0.75 meters for the over-land pipeline and 1.5 meters for the submarine pipeline. In specific instances such as small stream crossings, road crossings, sensitive areas and locations where the design deems extra depth of cover is required, the depth of cover will be increased to suit the design requirements. Insuation shall be as specified by the geotechnical consultant.

3.3.8 Pigging Facilities

The 114.3 mm diameter pipeline, launching and receiving scraper traps and other assemblies will be designed to facilitate internal pipe inspection by means of the linealog electronic pig.

Trap facilities will be designed to a 0.6 design factor with all material suitable for operation to a design temperature of -60°C. ANS 1 600 rated valves and flanges will be incorporated into the design. The traps will be supported on piles.

3.3.9 Bending

Pipe bending ratios will be selected on the basis of the following criteria:

a) Field cold bends will be limited to 1-1/2° per length equal to the outside pipe diameter.

b) Factory hot bends will be utilized where it is necessary to exceed the above degree of bending at various locations.

3.3.10 Water Crossings

A site specific design drawing will be prepared for the pipeline crossing of Tuktoyaktuk Harbour based on input from the appropriate geotechnical and hydrological reports. This will show details of bend radii.

Any other water crossings will either be covered by a typical drawing or a site specific drawing, as required, and will adhere to the details of Section 3.3.9.

Other stream crossings or areas where there is a possibility of summer thaws causing swamp conditions will be designed to ensure that the pipeline has a minimum of 10% negative buoyancy.

3.3.11 Other Crossings

Road Crossings

Road crossings will be designed in accordance with the requirements of the regulatory authority having jurisdiction. Installation will be undertaken by slip bore methods or by open cutting as appropriate. The method of installation will be in accordance with the appropriate typical drawing.

Foreign Pipeline and Underground Cable Crossings

All crossings of foreign lines and/or underground cables will be in accordance with the appropriate typical crossing drawing. The CSA regulation (or latest draft thereof) relative to pipeline and power line interference shall be strictly adhered to.

3.3.12 Pipeline Marking and Identification

Warning Signs

Pipeline warning signs will be installed at all highway, road and river or stream crossings in accordance with typical drawings. Signs will conform to the client's standards and, in addition, for the pipeline crossing of Tuktoyaktuk Harbour, the signs will comply with requirements of the Canadian Coast Guard.

Aerial Markers

Aerial markers will be installed at intervals of 3.2 km (2 miles) in accordance with typical drawings.

3.3.13 Inspection

All welding will be in accordance with the requirements of Clause 4 of CSA Z184-M1982 and the construction specifications.

All pipeline welds will be 100% radiographed in accordance with CSA Z184-M1982 and the construction specifications. All radiographs will be identified with a coded weld tag numbering system. Weld tags will be supplied by the client and affixed by X-ray contrator.

3.3.14 Cathodic Protection

External pipe corrosion protection will be provided using an extruded polyethylene coating complemented with wrap-around shrink sleeves at the weld joint cutbacks. Polyethylene tape will be used for the repair of holidays.

Cathodic protection will be provided in the form of a single anode ground bed near an existing power source.

Flange insulating kits will be installed at the trap assemblies located at each end of the pipeline.

3.3.15 Testing

A strength and leak test will be performed for the flowline in accordance with the requirements of CSA Z184-M1982 and the appropriate COGLA regulations. The minimum test pressure will be 1.25 maximum operating pressure which will be 10,340 kPa. The test medium will be either water/methanol mixture or air. A study will be undertaken to determine the most suitable medium.

3.4 Terminal and Medium Pressure System

3.4.1 General

This section covers the system from the point where the pipeline arrives in the east end of Tuktoyaktuk until medium pressure gas arrives at users and the start of the low pressure community system.

This portion of the system is the key to customer satisfaction and also is assumed to include the overall system monitoring and control function.

At this point easements and access to land become very important and will necessitate close co-ordination with the project manager. The project manager will provide an analysis of the gas demands for each customer and the community. In most cases conversion and/or replacement of existing equipment will be required and a good project/industry rapport will be needed,

The pressure level of medium pressure, industrial distribution, system, has been somewhat arbitrarily set herein and this will need study. In practice, as high a level possible consistent with hydrate temperature and user needs will provide the most surge in the system and will be preferable.

In the case of many controls, high turndown will be required and multiple valves may be required.

3.4.2 High to Medium Pressure Letdown odorizing and' Operating Centre

3.4.2.1 Description

The high pressure gas will first be heated in 2 - 100% line heaters to a sufficient temperature to produce a -5°C temperature in the medium pressure system. The line to the heaters will be insulated from below ground to prevent any portion of the line dropping below the -30°C hydrate point of the gas from the field.

In order to protect against freezeups, two parallel pressure let down systems will be provided complete with methanol injection points. Special attention must be paid to the local fuel gas system to be sure it is fully reliable.

A standard odourizing system will be provided with odourant rate ratio controlled relative to total gas flow rate. A spare odourant pump and metering system will be kept on hand in case of problems with the one in use. (Up to 2 or 3 hours can be allowed for replacement.) A small heated building will house the odourizer facility.

All alarms and controls for the system will be centralized where economically feasible at the depressurizing/odourizing site. A building will be provided to act as a control centre, to store spare parts and to house a system-wide repairs shop*. A garage also will be required for gas system vehicle storage and repair. The latter facilities are expected to be primarily used by the community distribution system and appliance servicing.

The depressuring/odourizing site has not been selected and that will be a high priority in the consultant's activities.

All equipment, etc. will be to the standards set out previously and designed to be entirely suitable for the site, for the local climatic conditions and the need for a very reliable, albeit small, system.

Local control systems will be used with indication in the control centre of flow rate and pressure and temperature to/from the heater and after the pressure letdown, as well as of the status of heaters and odorizing system. A panel will provide indication of the field functions transmitted over the radio system, and of the main low pressure system's operation - pressure and propane/air system operation. Also this centre will serve as the town end of both voice systems. A second mobile system to serve just the town distribution system requires study and definition.

In the event of a supply emergency not automatically shutting down field facilities, the control centre operator will be able to shut down the field and to cut off medium pressure system users, protecting the

* An office in the community is assumed provided for accounting, appliance sales, and general office needs - but could well be at the control centre.

community low-pressure system insofar as possible. It appears likely that industrial users will each have some sort of alarm that cutoff may occur - telephone communication may take too long and it will take a few minutes to convert to alternate fuel .

3.4.3 Industrial Distribution

A 1000 kPa distribution system is envisaged to move gas to the larger industrial users and to the start of the community's low pressure distribution system. Some small localized low pressure systems may also be fed off the 1000 kPa system.

Generally industrial supply lines will not be looped as customers will have backup liquid fuel capability and, hence, service can be stopped for short periods with notice (via alarm) whenever possible.

Each industrial user will have a master meter/regulator system designed as a standard part of the overall distribution system. Spare meters will be kept available for all sizes in use to allow servicing at any time. It is expected that individual users may have widely varying pressure requirements.

Note that these systems will be buried and normally operate in the -5° to -10° range. Insulation will be required from permafrost to meter as the line comes out of the ground. Also meters and regulators should have housings to keep heat in in winter and to prevent tampering. Nevertheless, materials must be suitable for exposure to -50°C conditions.

3.5 Low Pressure Distribution

3.5.1 Preamble

Figure 3. 5.1 provides a very preliminary concept for the low pressure distribution portion of the overall system. Generally the low pressure distribution system will provide gas to all but the larger users in the east end of the community.

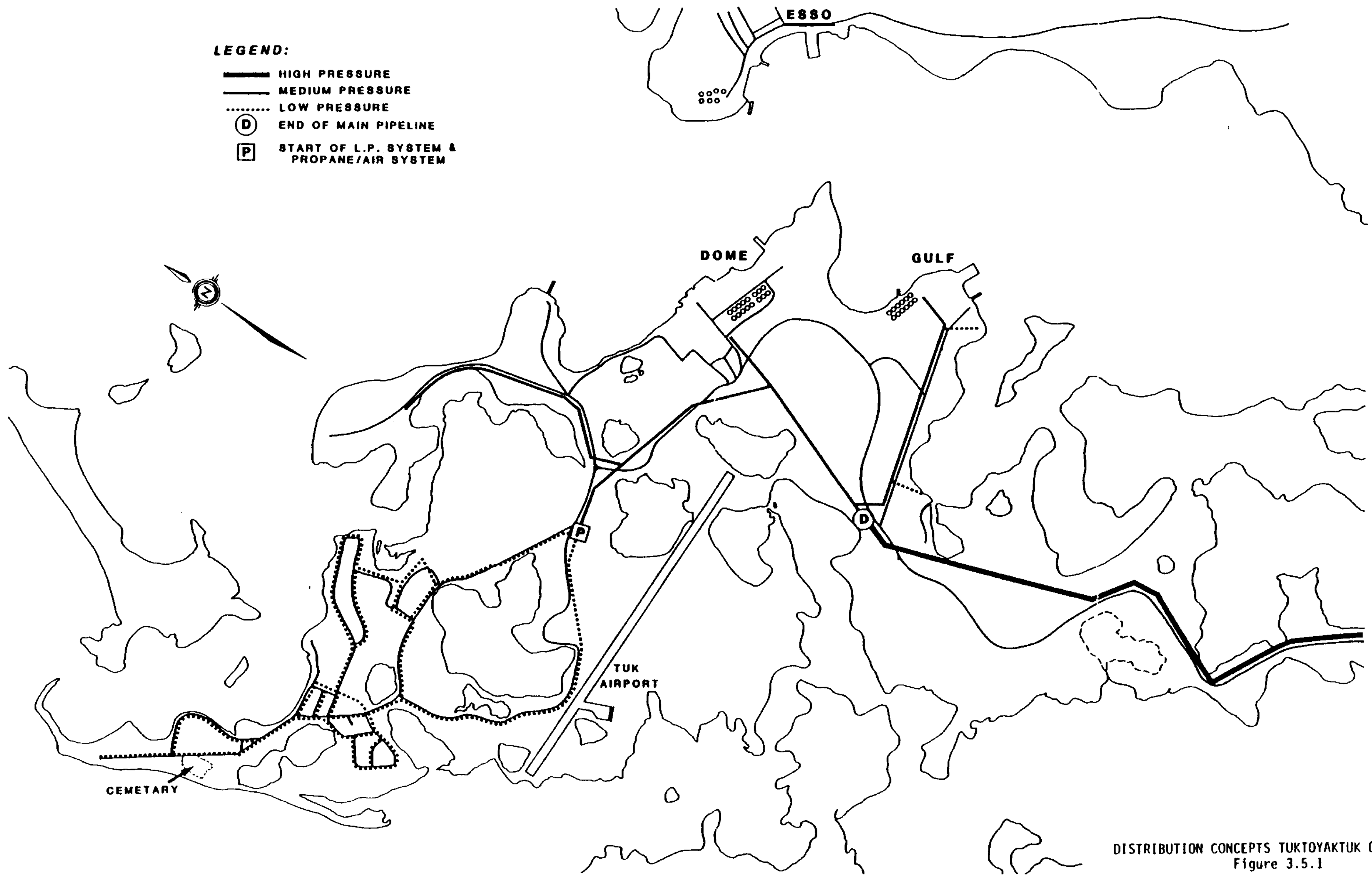
In order to provide an alternate gas source should the normal gas supply system be inoperative for any reason, a propane/air standby system will be provided. The low pressure system will normally operate at 280 to 350 kPa, well above the 140 kPa from the selected propane/air system. Thus piping must be sized to provide peak hour demands at the 140 kPa level.

While this sytem will be designed in accordance with CSA Z184 and B149 codes for gas pipelines and gas burning equipment, respectively, adequate consultation with local construction personnel is essential to ensure a design practical for installation by local capability and consistent with proven practices. The Government of the Northwest Territories may also impose design constraints, with at least numerous questions to be anticipated.

3.5.2 Distribution

The IPC will be negotiating access and right-of-way agreements for the entire system. It will be essential for the consultant to work closely with the IPC in optimizing routing. There have been problems with telephone lines buried beside roads, but space between roads and housing is often minimal and no formal back lanes exist.

Where possible, distribution mains should be in the form of loops, so that gas can be fed to any user from two directions, to allow for servicing any portion of the system. Adequate block valves and inter-connections should be provided to permit repairs on the system. Where loops are not feasible appreciable regard must be given to the security of such portion.



DISTRIBUTION CONCEPTS TUKTOYAKTUK GAS SYSTEM
Figure 3.5.1

Due to permafrost concerns, a steel distribution system is now anticipated but the consultant must analyze plastic versus steel systems and provide a recommendation to the project manager.

Mains should be routed at least 5 meters from single and 7 meters from multi-storied buildings. Burial depth for mains and service lines should be minimum to maintain lines in permafrost and still provide protection from physical damage. A minimum depth of 60mm is assumed herein, but deeper burial may be required in places.

3.5.3 Individual SuPply

A standard service hook-up for single dwellings will be developed complete with take-off connection, 3/4" steel service line, shut-off valve, regulator/relief valve and vent and meter, all accessible from the exterior of the building. Flexibility of the connection to match shifting of pile supports must be provided.

All such hook-ups must have a maximum degree of prefabrication and minimum of field effort.

Services shall be run underground to the edge of the building and then rise outside, even in the case of multiple dwellings where a single meter is used. Gas lines through crawl spaces must be avoided.

To minimize gas accumulation in buildings, if completely outside meter and regulator/relief valve are impracticable, an add-on box is to be developed, deriving enough heat from the building yet without providing access to enclosed areas of the building for any leaking gas. Meter reading should be from outside the building.

The consultant will develop appropriate supply systems for larger users. He will also work with the appliance selectors to minimize the cost of servicing such appliances and maximize the safety of such supply.

3.5.4 Propane Air Standby Gas Plant

3.5.4.1 Introduction

A propane/air plant produces a gaseous fuel interchangeable with natural gas. This properly blended mixture of propane vapour and air is used directly in any natural gas fired equipment without any equipment changes or adjustments. Propane air plants are used as standby by many North American gas utility companies where there is concern about the reliability of gas supply, and generally a fair degree of standardization has developed.

The propane/air system should be located at the point of pressure letdown from the medium pressure system to the low pressure system, to provide unidirectional flow through the system insofar as practical.

3.5.4.2 Description

The propane air plant will be a standard design, using standard equipment with some modifications because of the remote location and the low ambient winter temperatures. It will be tested once a month to a small flare system in order to show that it is fully operable. But otherwise it will be activated only when the pressure in the low pressure distribution system drops below 250 kPa.

The plant will include two or more storage tanks with a capacity of thirty days of normal service. This capacity should adequately serve during an interruption in the winter until the problem is corrected or until more propane can be delivered to the plant. This same storage should also be adequate if the problem occurred during the summer season or during breakup.

Section 2.7 above generally described the recommended propane/air system configuration. That concept requires checking and confirmation. It is the intent that a complete package be purchased, pretested as to operation, from one vendor (except for storage drums). Vendor suggestions as to a simpler more reliable system are to be analyzed.

Horizontal vessels will be used for storage of the propane. At 1 east two must be provided. Facilities for truck receipt of propane must be provided.

Modifications to standard equipment and design are required for this plant, although supply from traditional propane/air system vendors is received. The equipment must be designed for both operation and standby at the very cold (-50°C) ambient temperatures at Tuktoyaktuk, except when adequately housed. These changes include metals that are satisfactory for these temperatures, a system to keep the pressure up in the propane tanks under very low ambient conditions, modifying the vaporizers so that they can burn either natural gas or propane and operating their pilots continually during the winter months, and proper weather protection of the plant without sacrificing reasonable safety requirements.

Building standards will be set on a system-wide basis by the project manager, but the equipment to be housed should come on skids complete with buildings.

The plant with these modifications should adequately serve as a backup for the natural gas service in case of interruption of the natural gas supply due to whatever cause. As the NCPC electrical system should become even more reliable after gas is available, electric operation of compressors and propane pumps and all controls may be considered. However, the consultant must review this assumption in detail.

A flare system sufficiently large to allow testing at up to 25% of capacity shall be provided with spacing as appropriate.

3.5.4.3 **Controls**

The propane/air system must be automatic in start-up and shut-down, except for periodic testing. Insofar as possible controls should be self- or gas-operated and independent of outside interfaces. However, devices must be provided to telemeter system status and alarms - fire, startup, shutdown - to the central control centre.

Propane drums shall be equipped with load cells as well as level gauges.

APPENDIX 10.

Tuktoyaktuk Gas Pipeline Study: Supplementary Reports for Harbour Crossing and Tuktoyaktuk to Inuvik Line, Canuck GIE Engineering Ltd. January, 1986.

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TUKTOYAKTUK GAS PIPELINE STUDY
(SUPPLEMENTARY REPORT FOR HARBOUR CROSSING)

JANUARY 1986

PREPARED BY:

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TABLE OF CONTENTS

1.0 INTRODUCTION

This report incorporates the preliminary pipeline analysis and a cost estimate for a 60.3 mm diameter pipeline from a lateral take-off point assumed to be approximately 0.5 km west ~~east~~ of Nallok Point, near Tuktoyuktuk, across the harbour to a location just south of Saviktok Point and on to Esso Resources Canada Limited's base on the east ~~west~~ side of the harbour. See Figure 1.1 for details.

The overall length of pipeline is of the order of 1.6 km of which 0.6 km is the submarine crossing.

All costs used in this report have been based on "in-house" information and verbal quotations from suppliers, for the construction procedures proposed. Other data from previous studies on northern pipelines has been used to assist in the cost preparation. Costs are based on present day values. This report should be read as a supplement to our previous report titled, "Tuktoyuktuk Gas Pipeline Study" dated December 1985.

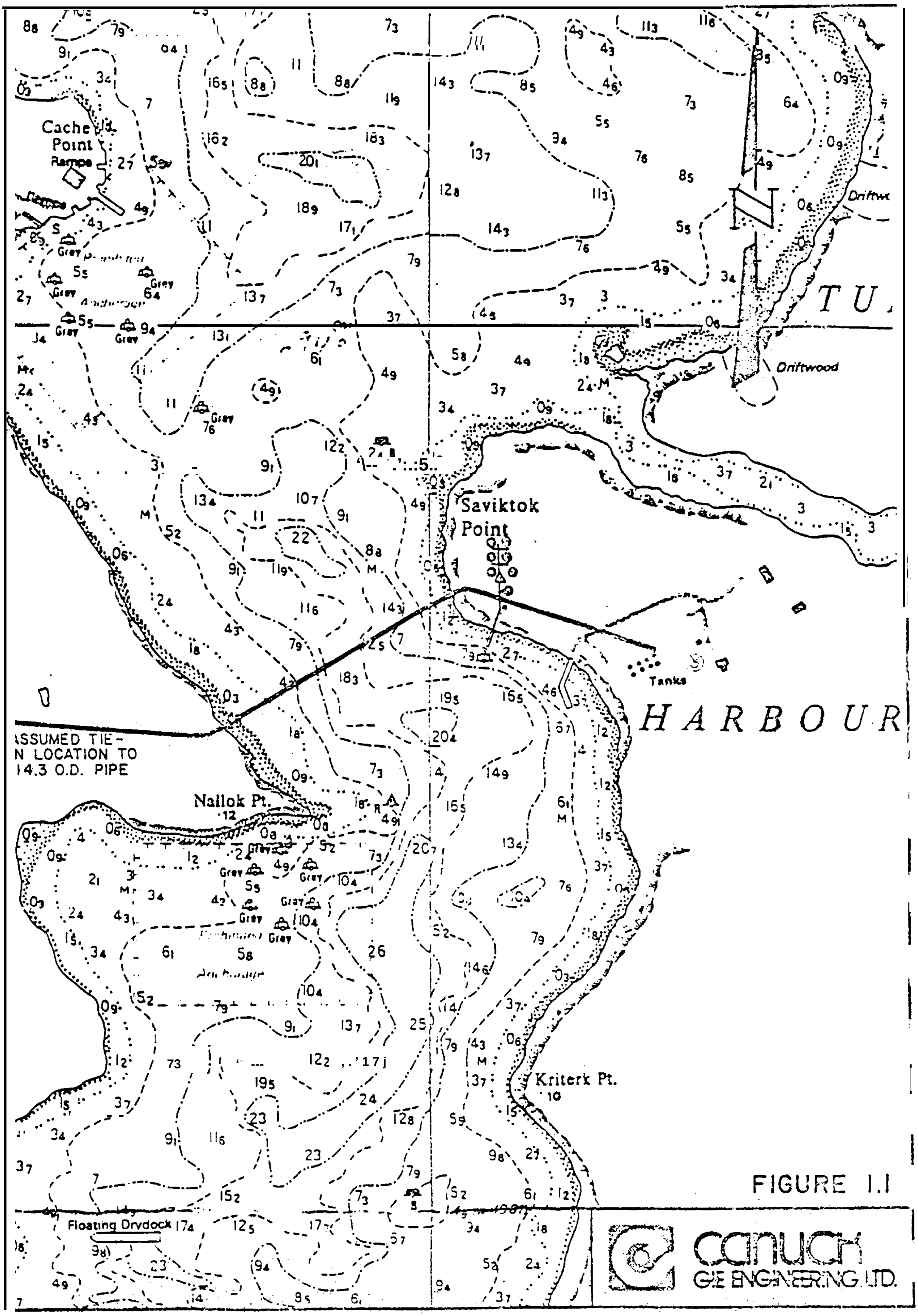

Cache Point
Ramps
Saviktok Point
Nallok Pt.
Kriterk Pt.
HARBOUR
TU
Driftwood
Tanks
ASSUMED TIE-
N LOCATION TO
14.3 O.D. PIPE
Floating Drydock
canuck
G.E. ENGINEERING LTD.

FIGURE 1.1

2.0 DESIGN CONSIDERATIONS

2.1 Route Selection

The initial start point for the 60.3 mm pipeline was deemed to be of an arbitrary nature. This was essentially governed by the choice of the eastern landfall.

The maps and charts available showed cliffs along the southern and northeastern portions of Nallok Point and in an effort to simplify construction, a landfall was selected approximately 100 metres further up the northeastern coast where no cliffs were indicated. To reduce costs and to ease marine construction durations, the shortest straight crossing was adopted. Unfortunately, Saviktok Point has intermittent cliffs shown along its length. Thus, the western landfall was chosen in an attempt to minimize its severity. There was a further constraint in that the landfall should be located sufficiently distant from the northernmost loading jetty at Esso's base so as not to encroach on shipping activities.

Again, the terminal point of the line was left arbitrary. We have assumed this location to occur in the vicinity of the storage tanks in the base.

In the absence of further information, it is felt that these assumptions will suffice to give a preliminary design and cost estimate of the desired accuracy.

2.2 Hydraulic Analysis

2.2.1 Objective

Using the same properties as before, a hydraulic analysis was undertaken to substantiate th viability of a 60.3 mm diameter pipeline for the design flow of 7100 m^3/day for both summer and winter conditions. The results are contained in Appendix A.

2.2.2 Design Basis

Properties:	Methane	99.5
	Ethane	0.5
	Total	100.0

Density at Base Conditions: 0.681 kg/m^3

Ease Pressure: 101.325 k?a

Base Temperature: 15°C

Inlet Pressure: 0°C summer, -5° C winter

Ground Temperature: 5°C summer, -5° C winter

Ground Conductivity: 1.2 W/m°C.

On-shore Depth of Cover: 0.762 m

Marine Depth of Cover: 1.5 m

Pipe Roughness: 0.0457 mm

A pipeline profile was taken from the ground and harbour contours.

It was found conclusively, that for the flows concerned, the pressure drop wa . nominal and--that a 60.3 mm pipeline was, in fact, easily acceptable for this purpose.

3.0 PIPELINE DESIGN

3.1 On-Shore Pipeline

The predominant factors in the conceptual design of the on-land portion of the pipeline are throughput level, required pressure to overcome the friction resistance and the presence of permafrost.

The hydraulic analyses have shown that for the conditions considered the pressure losses due to friction, etc. , are minimal. In arriving at these results, very basic assumptions have been made for all the influencing factors. It is felt, however, that there is sufficient leeway in the results to suggest that the final pipeline configuration and operating restraints will not give cause to alter the pipeline size. The presence of permafrost should also have no effect on the overall pipeline concept, but it will necessitate important considerations in the initial and final design stages and, of course, will pose additional problems during construction. From discussions with a geotechnical consultant involved in this stage of the project, it has been indicated that in the genera! area of this pipeline approximately 80% of the ground will contain permafrost which is overlain by an active layer of 0.3 m, or less. In this situation, with the pipeline at the designated burial depth, it will be entirely within the permafrost zone. If the correct precautions are exercised (e. g., cooling and regulating gas temperatures) there should be no adverse affects on the security or long-term stability of the pipeline.

Extra special care may be required in locations where the active layer has been artificially lowered such as where the pipeline traverses a south facing slope or where excessive traffic occurs. Also areas where ice content in the soil is high will require to be investigated extensively. In some instances the active layer could be as thick as 1.5 m which will give rise to a cyclic freezing and thawing around the pipeline. This adverse effect could result in a settlement/ jacking situation and would cause overstress in the pipe wall. The initial suggestion from our geotechnical specialist was to place adequate insulation over the top of the pipeline, and thus, limit the extent of the active layer. It should be noted, however, that an extensive geotechnical evaluation will he required prior to final design.

In the other areas where the soil is shown to have high ice content, care must be exercised to ensure that no derogatory thawing ensues during or after pipeline construction.

The comments of the geotechnical consultant are contained in Appendix B.

3.2 Submarine Pipeline

The pipeline for the water crossing should be designed for both installation and operation cases. It must be ensured that the pipe remains stable in both conditions.

From the installation aspect, there are two possibilities. The pipeline may be installed using a conventional bottom pull technique or alternatively, if winter construction is adopted, the pipeline may be lowered through the ice in a controlled 'S' bend curve into the ditch.

For the purposes of both methods, let us assume a tidal current of 0.3 m/s at right. angles to the pipe. The required minimum submerged weight for stability in the bottom pull method is given by:

$$W_{SUB} = F_L + \frac{F_D}{f}$$

where:

F, is the left force
F_D is the drag force
f is the friction factor between pipe and bed

The lift and draft forces on the pipe are given by:

$$F_L = \tfrac{1}{2}\rho v^2 D C_L \quad \text{and} \quad FD = \tfrac{1}{2}\rho v^2 D C_D$$

For a 60.3 mm diameter pipe with 3.18 mm wall thickness and 25.4 mm of concrete weight coating, the pipe will remain stable during installation by bottom pull method (See Figure 3.1 - Pipe Data Sheet).

Should the pipe be installed using a "S" bend configuration from the ice to the harbour bed, there will be sufficient weight in the pipe already in the. trench to restrain the spanning pipe from lateral movement due to the effects of th currents in the harbour.

FIGURE 3.1

PIPE DATA SHEET

Materials

Steel pipe diameter	60.3 mm
Steel pipe wall thickness	3.18 mm
Steel grade	290 MPa
Steel density	7850 kg/m^3
Corrosion protection coating	Yellow Jacket
Thickness	34 mils
Density	950 kg/m^3
Concrete weight coating thickness	25.4 mm
Concrete density	2250 kg/m^3
Reinforcement	Steel Fabric

Weights

Weight of pipe, in air	20.34 kg/m
Weight of pipe, submerged	10.09 kg/m
Weight of water displacement	10.25 kg/m
Specific gravity	1.98

4.0 PROPOSED CONSTRUCTION METHODS

4.1 On-Land Pipelines

It is proposed to employ conventional pipeline installation practices over a winter period to lay to 60.3 mm diameter pipeline over the on-land portions on either side of the harbour. A minimum depth of burial of 0.75 m is proposed to provide adequate security for the line and to conform with CSA Z184-M1982, Gas Pipeline Transportation Systems.

Typical activities such as clearing, grading, trenching, welding, lower-in, backfill and clean-up will take place. Due to the short length of pipeline on either side, these will be condensed such that only one or two crews will be utilized to undertake the construction. Equipment will he adapted to serve various purposes, in an effort to reduce costs. It is anticipated that the majority of the equipment and manpower may be acquired locally and that only a small proportion of plant may be barged or trucked in along with the materials from Hay River or Norman Wells.

Initially, clearing and grading will ensue ant! an access road will be constructed along the pipeline right-of-way to allow movement of construction traffic. Stringing and welding will come immediately after this. The trenching will probably require the use of a dozer with a ripper tooth to facilitate the backhoe excavation, but should there be any environmentally sensitive areas, the use of a "rock saw" may be required. The pipeline will be lowered-in and backfilled using either native or select material as required, as soon as practically possible after trenching. Anv additional select backfill material should be worked into native backfill to minimize shrinkage due to seasonal thawing.

4.2 Pipeline Across Tuktoyuktuk Harbour

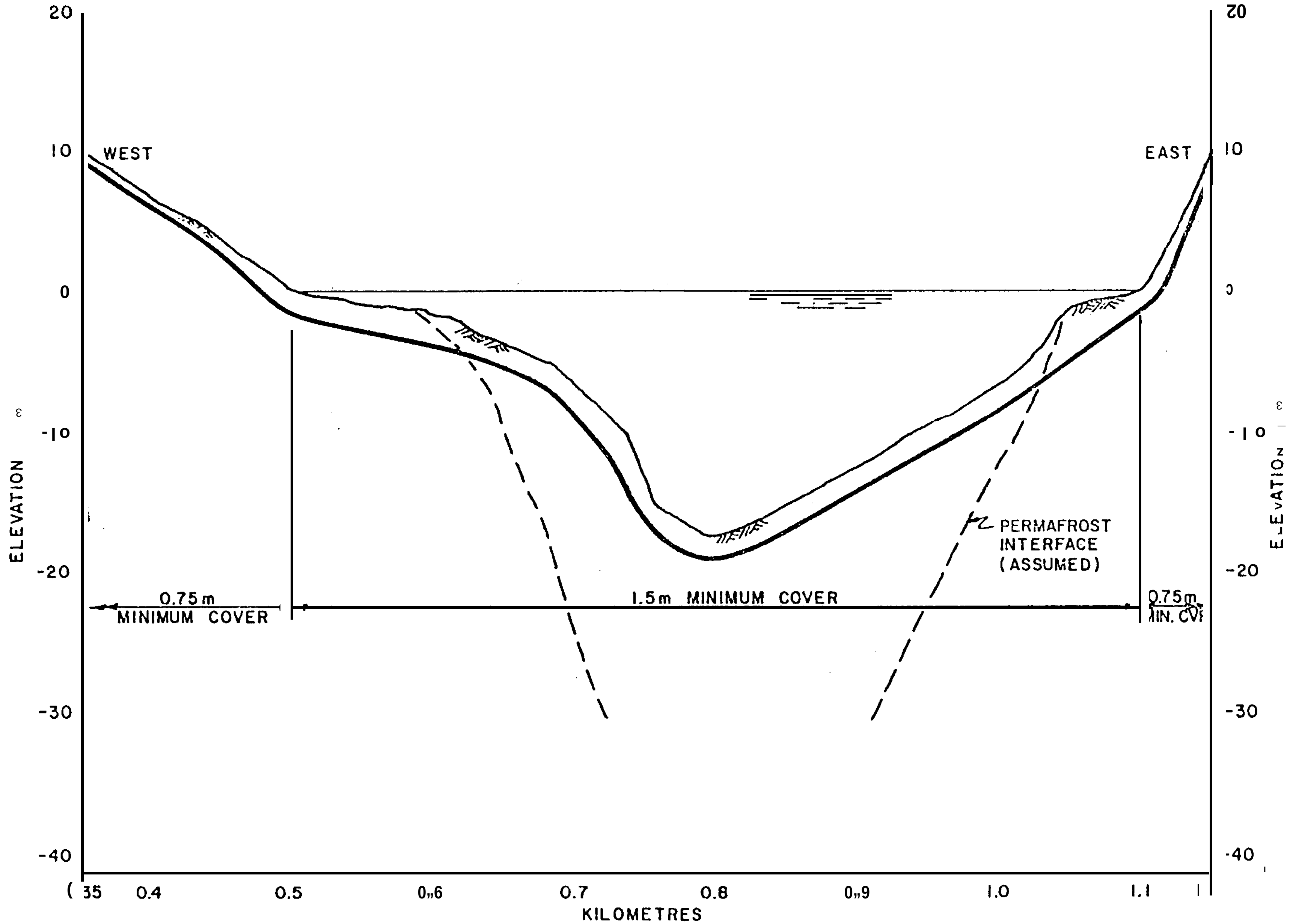
4.2.1 Winter Construction

Due to the northern location the harbour will be completely frozen over during winter. In fact, by around April there will probably be the order of 1.5 m of ice thickness which will allow construction equipment to work on its surface.

Our geotechnical consultant has suggested that there will be permafrost present at the surface of the harbour bed at water depths of 1.5 m and below (See Figure 4.1). The permafrost interface drops below the surface at greater water depths. For example, at 3 m water depth, the permafrost interface is likely to be as much as 6 m below bed level.

Trenching in the near-shore areas where permafrost is encountered will require great care. It is not known at this stage whether the intrusion of water from the harbour on the areas of permafrost will have an adverse affect on the stability of the trench slopes in these areas. It has been assumed that the trench will be excavated by first using a dozer with a ripper tooth then a backhoe. In the main channel the trench will be excavated using either backhoe or clamshell techniques. Sections of ice will be cut and removed to enable access to the harbour bed.

The actual installation of the pipe may be undertaken in two ways. The pipe may be welded up on the ice and lowered into the trench from the ice or the pipe may be welded up on shore and pulled into the trench using a dozer winch. The cost difference for either method will not be significant.



20
10
0
-10
-20
-30
-40
ELEVATION
WEST
EAST
0.75 m
MINIMUM COVER
1.5 m MINIMUM COVER
0.75m
MIN. CVR
PERMAFROST
INTERFACE
(ASSUMED)
0.35
0.4
0.5
0.6
0.7
0.8
0.9
1.0
1.1
KILOMETRES

FIGURE 4.1

When the pipe is in place and survey shows that its depth below bed level is adequate in all cases, then pressure testing and backfilling can commence.

Once the tie-ins have been made on either bank then the entire 60.3 mm lateral line can be pressure tested and dried.

4.2.2 Winter Construction (Temporary Pipeline on Ice)

A suggestion to lay the pipeline on the ice and only supply gas to the Esso Base over a restricted period was made, and subsequently, investigated. It is not thought that this concept is practical for the following reasons:

Inconvenience to Esso Base;
Potential risk of damage and/or accident; and
Problems with recovery and storage of line when not in use.

Conversely, the possible cost savings for the overall scheme are considerable. It is suggested that the conventional approach is adopted at this stage, but that this alternative be investigated at a later date when knowledge of environmental, regulatory and safety requirements have been acquired.

4.2.3 Summer Construction

Summer construction of this crossing is possible, but again great care and precautions would be required when trenching in permafrost material. Further study would again be required to establish design criteria for the pipe and limitations on excavation for these areas. This

5.0 COST ESTIMATE

5.1 General

The capital costs were undertaken using similar concepts to the initial study for this project. We have again incorporated a greater emphasis on the use of local labour and equipment wherever possible.

5.2 Cost Development

The scope of work with respect to the evaluation of construction costs was as follows:

Undertake a cost estimate for 0.5 km of 60.3 mm diameter pipeline on either side of Tuktoyuktuk Harbour as shown in Figure 1.1.

Undertake a cost estimate for the 0.6 km submarine pipeline crossing of the Harbour at the location shown on Figure 1.1. One estimate has been prepared for a summer construction schedule, and another for a winter construction schedule.

The costs are given in Figures 5.1, 5.2, and 5.3 and should be considered no more than order of magnitude costs at this stage. Once additional environmental , geotechnical and regulatory information is made available, these costs could be reviewed to give an improved degree of accuracy.

We do feel, however, that under the circumstances any engineering or cost assumptions taken in the preparation of this report are based on sound concepts and previous experience in an effort to give optimum results.

The procedures used in the evaluation of this pipeline cost include the following:

Evaluate the route from information in previous feasibility studies on 1:50,000 topographic maps and on navigation charts.

Review geotechnical information and environmental considerations for the specific area, as given from the geotechnical consultant.

Develop construction logistics details on the basis that as much of the equipment and labour as was practical would be utilized on the construction project.

Evaluate pipeline design and determine material requirements for the pipe and ancillaries. It has been assumed that all pipe materials will be transported from Edmonton via Hay River to Tuktoyuktuk at the end of the barging season of the year prior to construction.

Determine representative costs for locally supplied materials.

Select the manpower, equipment and consumables which constitute the various crews involved in the pipeline construction. Further evaluate the items of plant and labour which could be supplied locally.

Using the aforementioned data , extend all cost components in accordance with PLCA Union Agreement, PLCA Equipment Rental Rates and construction parameters for Arctic pipelining.

5.3 Direct Costs

Costs for major, materials (i.e. , pipe, coating) were based on verbal indications received from pipe and coating mills. costs for appurtenances such as valves, fittings, flanges, markers, test leads, etc. , have been included as an additional ten percent.

Transportation of material from the FOB point (assumed Edmonton) to Tuktoyuktuk has been--included at current commercial rates of $15.25 per 100 pound base, trucking to Hay River and then barging to Tuktoyuktuk via the Mackenzie River.

Construction costs were developed by selecting the personnel, equipment and consumables required to complete the work, and extending the cost components in accordance with applicable PLCA agreements. Contractor's mobilization costs were based on a winter move-in and move-out along the Dempster route. The cost per truck load from Edmonton to Tuktoyuktuk is estimated at $8,000 per trip.

Subsistence at. $135.00/day has been included for contractor's personnel working on the project.

Fuel costs for the contractor's equipment has been included at 8% of the above costs, based on historical information. Contractor's overheads and profits are estimated as an additional 15% of the total construction cost.

FIGURE 5.1
ON-LAND PIPELINE
PIPELINE COST SUMMARY
(60.3 mm)

Item	cost ($000)
Materials	
Pipe (1 km, 60.3 mm Dia. x 3.18 mm \'/. T.]	3.92
Coating (1 km, $114.28/100 m)	1.14
Material Transfer (10,000 lbs@ $15.26/ 100 lbs)	1.53
Subtotal	6.59
Construction	
Labour	24.78
Equipment	20.47
Miscellaneous	7.35
Mob/Demob	1.50
Camp/Subsistence	13.50
Fuel (@ 8%)	4.21
Overhead & Profits (@ 15%)	10.77
Subtotal	82.58
Field Monitoring	
Inspection (5%)	4.13
Field Engineering & Survey (5%)	4.13
Radiography (5%)	4.13
Subtotal	12.39
TOTAL PIPELINE COSTS	101.56

FIGURE 5.2
MARINE PIPELINE
(WINTER CONSTRUCTION)

Item	cost ($000)
Materials	
Pipe , 6 km, 60.3 mm Dia. x 3.18 mm W.T.)	2.35
Coating (0.6 km, $114.28/100 m)	0.69
Concrete ($18.00/ml	10.80
Material Transfer (28,250 lbs @ $15.26/ 100 lbs)	4.31
Storage in Tuktoyuktuk	1.00
Subtotal	19.15
Construction	
Labour	330.79
Equipment	164.21
Miscellaneous	38.50
Mob/Demob	30.00
Camp/Subsistence	133.65
Fuel (@8%)	42.68
Overhead & Profits (@15%)	110.97
Subtotal	850.80
Field Monitoring	
Inspection (3%)	25.52
Field Engineering & Survey (2.5%)	21.27
Radiography	5.00
Subtotal	51.79
TOTAL PIPELINE COSTS	891.22

FIGURE 5.3
MARINE PIPE LINE
('SUMMER CONSTRUCTION)

Item	Cost ($000)
Materials	
Pipe (0.6 km, 60.3 mm Dia. x 3.18 mm W.T.)	2.35
Coating (0.6 km, $114.28/100 m)	0.69
Concrete ($18.00/m)	10.80
Material Transfer (28,250 lbs @ $15.26/ 100 lbs)	4.31
Subtotal	18.15
Construction	
Labour	476.64
Equipment	187.14
Miscellaneous	38.50
Mob/ Demob	84.00
Camp/Subsistence	187.11
Fuel (@ 8%)	56.18
Overhead & Profits (@ 15%)	154.44
Subtotal	1184. (?1
Field Monitoring	
Inspection (3%)	35.52
Field Engineering & Survey (2.5%)	29.60
Radiography	5.00
Subtotal	70.12
TOTAL PIPELINE COSTS	1272.42

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA.104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	=	175.00 kPa-g
MAXIMUM OPERATING PRESSURE	=	689.50 kPa-g
MINIMUM OPERATING TEMPERATURE	=	-10.00 Deg C
MAXIMUM OPERATING TEMPERATURE	=	40.00 Deg C
ADIABATIC COMPRESSION EFFICIENCY	=	80.00 %
COOLER EFFICIENCY	=	80.00 %
COMPRESSOR INLET LOSS	=	50.00 kPa
COMPRESSOR OUTLET LOSS	=	50.00 kPa
DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	689.50 kPa-g
DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg C
DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40.00 Deg C
HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	10.00	7100.	13.0569	1.932	130268.	.004826	-5.00	689.50	
SEGMENT	.250	5.00	7100.	13.5313	1.865	130285.	.004826	-5.03	674.64	
SEGMENT	.500	.00	7100.	13.8765	1.818	130289.	.004826	-5.04	659.23	
SEGMENT	.600	-1.50	7100.	14.0765	1.792	130288.	.004825	-5.04	652.89	
SEGMENT	.700	-6.50	7100.	14.2771	1.767	130292.	.004826	-5.02	646.53	
SEGMENT	.800	-18.30	7100.	14.4307	1.742	130300.	.004826	-5.00	640.19	
SEGMENT	.900	-12.00	7100.	14.6929	1.717	130310.	.004826	-5.03	633.45	
SEGMENT	1.000	-6.00	7100.	14.9085	1.692	130318.	.004825	-5.05	626.62	
SEGMENT	1.100	.00	7100.	15.2883	1.650	130342.	.004825	-5.06	619.69	
SEGMENT	1.350	10.00	7100.	15.8507	1.592	130353.	.004825	-5.10	602.01	
ENDPOINT	1.600	12.00						-5.11	593.82	

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA.104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
.000	10.00	.762	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
.250	5.00	.762	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
.500	.00	1.000	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
.600	-1.50	1.500	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
.700	-6.50	1.500	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
.800	-18.30	1.500	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
.900	-12.00	1.500	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
1.000	-6.00	1.500	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
1.100	.00	1.500	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
1.350	10.00	.762	60.300	3.5800	.04570	.9500	-5.00	1.2000	.00	.00000
1.600	12.00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA.104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	=	175.00 kPa-g		COMPRESSOR INLET LOSS	=	50.00 kPa
MAXIMUM OPERATING PRESSURE	=	689.50 kPa-g		COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE	=	-10.00 Deg C		DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	689.50 kPa-g
MAXIMUM OPERATING TEMPERATURE	=	40.00 Deg C		DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg C
ADIABATIC COMPRESSION EFFICIENCY	=	80.00 %		DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40.00 Deg C
COOLER EFFICIENCY	=	80.00 %		HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	10.00	7100.	13.3938	1.884	127522.	.004842	.00	689.50	
SEGMENT	.250	5.00	7100.	14.0128	1.800	126567.	.004853	3.40	674.20	
SEGMENT	.500	.00	7100.	14.4310	1.749	126160.	.004857	4.56	658.14	
SEGMENT	.600	-1.50	7100.	14.5679	1.733	126796.	.004858	4.76	651.51	
SEGMENT	.700	-6.50	7100.	14.6645	1.722	127735.	.004847	1.49	644.88	
SEGMENT	.800	-13.30	7100.	14.8278	1.701	128163.	.004843	.38	638.33	
SEGMENT	.900	-12.00	7100.	15.0446	1.677	128216.	.004842	.16	631.40	
SEGMENT	1.000	-6.00	7100.	15.2674	1.652	128245.	.004842	.05	624.39	
SEGMENT	1.100	.00	7100.	15.7627	1.601	127577.	.004841	-.01	617.27	
SEGMENT	1.350	10.00	7100.	16.4958	1.529	126630.	.004853	3.34	579.00	
ENDPOINT	1.600	12.00						4.51	579.96	

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA.104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
.000	10.00	.762	60.300	3.5800	.04570	.9500	5.00	1.2000	.00	.00000
.250	5.00	.762	60.300	3.5800	.04570	.9500	5.00	1.2000	.00	.00000
.500	.00	1.000	60.300	3.5800	.04570	.9500	5.00	1.2000	.00	.00000
.600	-1.50	1.500	60.300	3.5800	.04570	.9500	.00	1.2000	.00	.00000
.700	-6.50	1.500	60.300	3.5800	.04570	.9500	.00	1.2000	.00	.00000
.800	-13.30	1.500	60.300	3.5900	.04570	.9500	.00	1.2000	.00	.00000
.900	-12.00	1.500	60.300	3.5800	.04570	.9500	.00	1.2000	.00	.00000
1.000	-6.00	1.500	60.300	3.5300	.04570	.9500	.00	1.2000	.00	.00000
1.100	.00	1.500	60.300	3.5800	.04570	.9500	5.00	1.2000	.00	.00000
1.250	10.00	.762	60.300	3.5800	.04570	.9500	5.00	1.2000	.00	.00000
1.300	12.00									

APPENDIX B

EBA Engineering Consultants Ltd.
EARTH-SCIENCES ENGINEERING

1986 January 15

GIE Canuck Engineering Ltd.,
200, 200 Rivercrest Drive S.E.,
Calgary, Alberta

0301-34227

Attention: Mr. G.A. Purves, P.Eng.

Dear Mr. Purves:

At our meeting of 1986 January 13, you requested that I prepare a brief summary of anticipated conditions that would be encountered by a gas pipeline crossing Tuktoyaktuk Harbour. This letter presents that information for a crossing between Saviktok Point (near ESSO'S base) to Nallok Point (south of Gulf's base). It must be remembered that these conditions are based on very little hard data and none that was directly along the proposed alignment.. Rather, it is a generalized interpretation based on a few borings completed at other locations in the harbour and on my general knowledge of the regional conditions, surficial geology, and permafrost conditions.

In summary, it is suggested that the following comments should be considered when planning a pipeline across Tuk Harbour.

1) Bathymetry: The bathymetric chart suggests that the maximum depth to be encountered will be between 18.5 and 20 m. Shallows with less than 2 m of water extend approximately 100 m on the south or west bank and 50 m on the north or east bank.

2) Bottom Sediments: In the deeper part of the crossing, sediment should consist of silt and clay overlying sand. A 1978 seismic program by Hardy and Associates suggest that these soft and unfrozen sediments willbe approximately 6 m deep at the deepest part of the crossing and average about 4 m deep except in the shallow areas mentioned previously.

   Below the silt and clay, the sediments are expected to be uniform fine to medium-grained (0.3 to 0.7 mm) sand. The sand extends across the entire Tuk region and will be encountered on the banks and within a metre of seabed on the shallow approaches to the banks. Locally, some gravel and some clay beds have been found in the sand so you should be prepared to handle them as well.

7175 12th STREET S.E., CALGARY, ALBERTA T2H 2S6 TELEPHONE (403) 253-7121

3) Permafrost; The depth to permafrost is dependent on many factors and is difficult to predict with any accuracy. The likelihood of encountering permafrost within the pipe burial zone diminishes from 1.5m to 3.0 m of water.

Where there is less than 1.5 m of water, the harbour ice will freeze to the bottom annually. In these areas frozen ground can be encountered from the seabed.

In the zone between 1.5 m and 3.0 m of water permafrost will likely be encountered somewhere between 1 m and 6 m below the seabed. Beyond 3.0 m of water, it is unlikely that permafrost will affect the. pipeline but if deep burial is required it may be a consideration.

4) Approach Slopes: A moderately high (5 to 10 m) bluff exists at Saviktok Point and I expect a similar, though perhaps not as high, bluff exists at Nallok Point. These bluffs, I believe, will consist of fine silty sand. They are exposed without any natural vegetation cover on the face because they are actively eroding and sluffing into the harbour. There will be permafrost in each bluff and the thermal integrety of the permafrost must be maintained after the pipe is installed or significant erosion will develop in one or two years.

5) Active Layer: Above the water line, the soil affected by seasonal thawing and refreezing is called the active layer. On the approaches to the harbour crossing the active layer will vary from about 0.3 m above the bluffs to as much as 2 m on the bluff 'faces. Soils within the active layer and the upper 3 m of the soil profile generally have the highest ground ice content. Although sand does not usually have a high ice content, locally silty zones or areas with peat cover may have a very high ice content and massive ice is not uncommon locally. I suggest designing for an average ground ice content of 25 percent in the pipeline ditch and backfill; however, special design will be needed for areas with massive ice.

6) Winter Construction Conditions: By late December, Tuk Harbour freezes into a relatively smooth potential work surface like any similar sized lake. Winter roads from the base camp make use of the ice surface for a wide variety of hauling operations. The ice thickness reaches a maximum of about 1.5 m by mid-March and begins to thin by May 1. Good conditions for winter work could be expected from mid-March to mid-April.

I hope the information presented above helps you. to understand the local conditions. Should you have any further questions, please do not hesitate to call.

Respectfully submitted,

EBA ENGINEERING CONSULTANTS LTD.

N.R. MacLeod, P.Eng.,
Project Director

NRM:jms

canuck
GIE ENGINEERING LTD.
200, 200 Rivercrest Drive SE.
Calgary, Alberta, Canada
T2C 2X5
(403) 236-6000 Telex: 03-826673
Telecopier (403) 236-3757
Affiliated with Gulf Interstate Engineering

1986-01-23

RTM Engineering Ltd.
#900, 5940 Macleod Trail South
Calgary, Alberta
T2H 2G4

Attention: Mr. T. McCann

Gentlemen:

Re: Costs for Proposed Pipeline from
Tuktoyuktuk to Inuvik
Our File: VM A-201

Please find enclosed details of the preliminary cost s for a 168.3 mm and 273.1 mm pipeline from Tuktoyuktuk to Inuvik. A direct cost summary table and overall cost summary table is given for each line size.

These costs should be treated as order of magnitude costs based on information taken from previous studies and "in-house" cost details. A more refined cost estimate would require somewhat more detailed information.

It should be noted that, unlike the previous estimates on the Tuktoyuktuk Gas Pipeline Study, these estimates include an overall cost incorporating pre-permit, engineering and regulatory aspects. A contingency of 15% is also included.

The pre-permit and regulatory costs should not appear in the construction of the flowlines to Tuktoyuktuk, but an allowance should be made in your overall flowline cost estimate for pipeline engineering and construction contingency. The estimates, as given in the reports, only reflect the direct construction costs.

I trust this will give you sufficient information for present purposes, but should there be any additional requirements, do not hesitate to contact our office.

Yours sincerely,

CANUCK GIE ENGINEERING LTD.

Andy Purves

Andy Purves, P.Eng.
Senior Project Engineer

AP/dmp
Enclosures

canuck
ENGINEERING LTD

PIPELINE COST SUMMARY
(168.3 mm)

ITEM	cost ($000
MATERIALS	
Pipe ($888.42/Tonne) - 130 km	2,208.24
Pipe Coating ($?66.75/100 m)	346.77
Miscellaneous (1 0% of the shove)	255.50
Material Transfer (6 ,070,00,0 lbs@ $17,25/" 00 lbs)	1,047.08
SUBTOTAL	3.857.59
CONSTRUCTION	
Labou r	7,350. .00
Equipment	3,490.84
Miscellaneous	135.50
Mobil ization/!3emohi lization	1,216.22
Camp/Subsistence	2,250. GO
Fuel (@8%)	878.01
Overhead & Profits (@15%)	2,148.09
SUBTOTAL	17,468.66
FIELD MONITORING	
Inspection (3.5%)	611.40
Field Engineering (1%)	174.69
Survey (1 .5%)	262.03
Radiography (2.0%)	349. 37
SUBTOTAL	1.397.49
TOTAL PI PELINE COSTS	22,723.74

Canuck Engineering Ltd

OVERALL COST SUMMARY

	cost ($000)
Total Direct Costs	22,723.74
Pre-Permit Costs (1.5% x Direct Costs)	340.86
Engineering Costs (8% x Direct Costs)	1,817.90
Regulatory Costs (2% x Direct Costs)	454.47
Contingency 15% above)	3,300.55
TOTAL	29,137.52

CANUCK ENGINEERING LTD

PIPELINE COST SUMMARY
(272.1 mm)

ITEM	Cost ($000)
MATERIALS	
Pipe ($888.42/Tonne) - 130 km	4,755.14
Pipe Coating ($404.57/100 m)	525.94
Miscellaneous (1 0% of the above)	528.11
Material Transfer	2,578.88
SUBTOTAL	8,388.07
CONSTRUCTION	
Labour	12,250.00
Equipment	5,816.67
Miscellaneous	225.83
Mobilization/ Demobilization	1,500.00
Camp/Subsistence	3,750.00
Fuel (@ 8%)	1,463.52
Overhead & Profits (@15%)	3.750.90
SUBTOTAL	28,756.92
FIELD MONITORING	
Inspection (2.5%)	718.92
Field Engineering (1%)	287.57
Survey (1.5%)	431.35
Radiography (2.0%)	575.14
SUBTOTAL	2,012.98
TOTAL PIPELINE COSTS	39,157.97

Canuck

OVERALL COST SUMMARY

	Cost ($000)
Total Direct Costs	**39,157.97**
Pre-Permit Costs (15% x Direct Costs)	**5&7.37**
Engineering Costs (8% x Direct Costs)	2,741.06
Regulatory Costs (2% x Direct Costs)	**783.16**
Contingency (15% above)	6,490.43
TOTAL	49,759.99