Transport of North Slope Natural Gas to Tidewater

Leveraging Issues

Configuration Descriptions & Issues

New Project Concept

Submitted to

ALASKA NATURAL GAS DEVELOPMENT AUTHORITY

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Submitted by

Baker

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Summary & Conclusions

Introduction

Three configurations for a North Slope natural gas project were debated in the 1970s: 1) a pipeline “over-the-top” of Alaska traversing down the Mackenzie River into Alberta, 2) the “Highway” pipeline generally following the Trans-Alaska Pipeline System to Delta Junction and then the Alcan Highway into Alberta, and 3) a pipeline to tidewater in south-central Alaska at which the gas would be liquefied for export.

Thirty years after the original debate, the three original project configuration options are again being discussed. The State of Alaska has essentially banned the over-the-top route by prohibiting state agencies from issuing the required permits. The US Congress passed in a bill in October of 2004 granting incentives to the highway route and these incentives were extended to an LNG project in another bill passed late in 2004.

ANGDA

The Alaska Natural Gas Development Authority (ANGDA) was established as a new public corporation to bring stranded North Slope gas to market. ANGDA’s primary goals are to achieve the lowest possible cost of service for the transportation of North Slope gas to tidewater for export and to maximize the benefits from a North Slope gas project to Alaskans.

ANGDA issued the “Interim Feasibility Report, All-Alaska LNG Project” in September of 2004 in which the viability of building a natural gas pipeline from Prudhoe Bay to tidewater and the associated liquefaction facilities were assessed. ANGDA found: 1) no reasons to believe that the all-Alaska LNG project is not viable, and 2) that ANGDA is justified in pursuing further studies to define the project and bring it to the stage where a decision can be made whether to make further investments for preliminary engineering.

Michael Baker, Jr., Inc.

Baker was contracted by ANGDA to further define the all-Alaska LNG project in three areas.

- ***Identify the key leveraging technical and design issues*** focusing on the hydrocarbon composition of the gas, transportation of natural gas liquids via the gas pipeline, and evaluation of pipeline economics up to, but not including, the LNG facilities. The scope of work excluded design of the project or recommendation of a specific project configuration.

- ***Complete a range of deliverables for four project configuration alternatives*** based on export of LNG from a facility at tidewater in south-central Alaska, including route characterizations, geotechnical issues, special design and construction areas, permitting and environmental issues, schedules, and resource issues.

- ***Advise ANGDA of concepts and issues*** that ANGDA has not studied and discuss their applicability to the all-Alaska LNG project. Baker completed a conceptual specification and economic analyses for the Enriched Gas Small Pipeline (EGSP) project consisting of a 24-inch diameter pipeline following the shortest route from Prudhoe Bay to Nikiski.

The focus of this report is the gas hydrocarbon reserves within the Prudhoe Bay Pool, although it is acknowledged that other gas sources may be available.

All-Alaska LNG Project

The economics of the all-Alaska LNG project will be influenced by economies of scale, and a proven strategy for lowering the cost of service is simply to increase the size of the project. Unfortunately, it becomes progressively more difficult to secure markets to absorb the LNG product in a timely manner as the size of the project increases. Achieving an acceptable balance between the size of the project and the ability of the markets to absorb the end products is crucial to the success of the all-Alaska LNG project.

Large LNG export projects throughout the world require facilities to remove contaminants from the gas (referred to as 'gas conditioning'), a liquefaction process to condense the gas, tanks to temporarily store the LNG, and a fleet of tankers to transport the LNG to market. Storage and re-gasification facilities for the end market are typically constructed by the LNG buyers. Assuming that the gas supply and market are available, the overall capacity of these LNG export projects can be expanded incrementally by adding more liquefaction capacity, storage tanks, and tankers.

The all-Alaska LNG project differs from most other worldwide LNG export projects in that the gas conditioning and liquefaction portions of the project are separated by an 800-mile long pipeline. The capital expense for the pipeline and gas compressor stations is a significant portion of the overall project, thus development of the all-Alaska LNG project must consider pipeline economics along with those of the gas conditioning, liquefaction, and LNG tankers.

Conclusions and Results

The information contained in this report was developed only to a conceptual level as required to support narratives or illustrate a leveraging technical or design issue that ANGDA may wish to pursue in the future, *and should be used for no other purpose*. Selection of a configuration for the all-Alaska LNG Project and subsequent demonstration of economic viability will require a vast amount work.

The results of the various evaluations completed for this report support the following conclusions and recommendations regarding development of the all-Alaska LNG project:

All-Alaska LNG project leveraging technical and design issues

- ***Installation of a pipeline that is expandable*** by adding compressor stations is preferable to the installation of a smaller diameter pipeline with more compressor stations for the same throughput capacity;

- ***Increasing the content of non-methane hydrocarbons*** in the gas stream enhances project economics; ***significant amounts of non-methane hydrocarbons*** from the Prudhoe Bay Pool are concentrated into a single stream by the existing Central Gas Facility (CGF);

- ***A quicker ramp-up*** (i.e., the rate at which the project increases to the design throughput) enhances project economics and a protracted ramp-up of the project flow rate should be avoided;

- Limited information exists in the public record regarding the future operation of the Prudhoe Bay facilities after termination of the Prudhoe Bay Miscible Gas Project; ***ANGDA should obtain estimates of the remaining reserves of natural gas liquids at Prudhoe Bay as well as forecasts of various stream flow rates and compositions***; and

- ***A high pressure natural gas pipeline*** allows the transport of large amounts of non-methane hydrocarbons without encountering the formation of liquids and the resulting liquid slug flow that can damage the pipeline and attendant equipment.

Evaluations completed for this report support the following conclusion and recommendation regarding development of a project not previously considered:

- ***A small diameter pipeline from Prudhoe Bay to Cook Inlet transporting a highly enriched gas is a new project concept that*** may provide utility grade natural gas to communities along the Rail Belt at moderate prices and make propane available for transport to rural and coastal communities throughout Alaska; this, or a similar scenario, merits further evaluation.

Leveraging Issues – Natural Gas

Natural gas consists of a mixture of hydrocarbons that exist in the gas phase at the operating conditions of the processing facilities of an oil and gas production field. The composition of natural gas leaving an oil and gas field varies depending upon the characteristics of the oil and gas reservoir and how the hydrocarbons are processed.

Natural gas typically consists of methane with ethane, propane, butane and pentane as well as heavier components present in progressively decreasing amounts. The energy, or thermal, content of the natural gas can vary significantly depending on the relative amounts of the non-methane components present in the mixture. Natural gas may also contain inert gases such a nitrogen and carbon dioxide that tend to lower the thermal content of the gas.

The composition of the natural gas within transmission pipelines is adjusted to meet a number of criteria including prevention of condensation of hydrocarbons within the pipeline. Liquid formation within a pipeline must be avoided since these liquids tend to collect in low areas of the pipeline and when finally mobilized due to the gas flow result in liquid slugs. Pipelines are designed to avoid slug flow because the slugs can damage the pipeline as well as associated gas-handling facilities along the pipeline.

Essentially all sponsors of major gas pipeline projects from the North Slope have proposed the use of pipelines operating at pressures that are much higher than typical gas pipelines operating in the Lower 48. The gas within these high-pressure pipelines is in a physical state known as the "dense phase" (discussed in Section 3.3). A major advantage of a dense phase pipeline is that large quantities of non-methane hydrocarbons can be transported without producing a separate liquid phase thereby avoiding slug flow.

Crude oil, condensate, and natural gas liquids (NGL) are marketed from the North Slope via the Trans Alaska Pipeline System (TAPS). The amount of butane in the NGL is adjusted to meet criteria governing the liquid hydrocarbon mix tendered to TAPS. The remaining butane, propane, ethane, and methane produced with the oil are re-injected into the Prudhoe Bay reservoir or consumed as lease fuel.

The high-pressure pipelines currently being proposed for the various gas projects allow the transport of butane, propane, and ethane with methane in a dense phase state thereby avoiding two-phase liquid and gas flow. All of the hydrocarbons from the North Slope can be sent to market utilizing the transport capabilities of both TAPS and a dense phase gas pipeline project

Although vast amounts of methane exist on the North Slope, this hydrocarbon is perhaps the least economic to transport because it contains the least amount of usable energy per unit volume. The ability to transport non-methane hydrocarbons in a gas pipeline provides opportunities for project designers to affect the project economics by adjusting the composition of the gas.

All of the analyses contained within this report are based on the use of three gas streams within the Central Gas Facility at Prudhoe Bay. ***The recoverable quantities and availability of the non-methane hydrocarbons from Prudhoe Bay is a key issue and is the focus of much of this report.***

Gas Enrichment *(Section 3.1)*

A natural gas pipeline system can be viewed as a series of individual pipe segments connected end to end with the flow through the entire system limited by the flow through any individual segment. Gas compressors are installed at the nodes between pipe segments in order to return the gas to the maximum operating pressure of the pipeline.

The diameter of the pipeline, the length of the pipe segments between compressor stations, compression horsepower at the stations, and capital costs are determined based primarily on the volumetric flow of gas through the pipeline.

Pipeline unit operating costs, also known as the cost-of-service (COS), refer to the fees required to return the capital investment and operate the system over the life of the project. For the purposes of this report, COS is defined as the difference between the wholesale price of gas delivered at the pipeline terminus and the gas purchase price on the North Slope.

COS can be expressed on a volumetric basis (e.g., standard cubic feet per day or scfd), but such practice can cause confusion since it does not account for energy flow through the pipeline. Natural gas purchase and sales contracts are almost always expressed on a thermal basis (e.g., btu) since energy and not volume is the commodity of interest. Expressing COS on a thermal basis allows contractual, engineering, and economic aspects of the project to be expressed on a common basis.

Gas enrichment is advantageous since it increases the thermal flow through the system thereby increasing the revenue per unit volume transported and the revenue per unit of capital invested as compared to transport of gas that is relatively lean in non-methane hydrocarbon components. The degree of the increase in revenue per unit capital, or conversely the decrease in COS, depends on the amount of gas enrichment.

Market Diversification

Gas enrichment benefits the all-Alaska project by diversifying the end markets thereby reducing the amount of product that needs to be placed in any one given market. Replacing some of the methane in the pipeline gas with NGL such as ethane, propane, and butane will provide project revenues from the sale of NGL while reducing the amount of utility gas and/or LNG that must be placed into markets. Such “spiking” of NGL will also reduce the unit cost of the pipeline on a thermal basis by increasing the heating value of the gas. The value of the separate NGL product streams outweighs the costs for separation of these components.

Access to Hydrocarbons at Prudhoe Bay *(Section 3.2)*

The all-Alaska LNG project can benefit from the advantageous use of the existing facilities at Prudhoe Bay. The Central Gas Facility (CGF) as currently configured, concentrates ethane, propane, and butane from approximately 8,000 MMscfd of feed gas into a single stream of less than 500 MMscfd that can be accessed by the all-Alaska LNG project. The option also exists to enrich the pipeline gas by using unprocessed gas from Prudhoe Bay as feed to the project instead of the relatively hydrocarbon lean residue gas from the CGF.

Access to and disposition of the various components of natural gas is fundamental to a gas pipeline project from the North Slope. Some of the conceptual analyses contained in this report are based on gas compositional data for the Prudhoe Bay field that is over 10 years old. It is recommended that ANGDA verify the applicability of this data or obtain new data prior to commencement of project feasibility studies.

ANGDA will have to satisfy itself that the design and economic analysis of the all-Alaskan project are based on sound data. The degree to which ANGDA will need to pursue acquisition of data regarding North Slope gas to support the economics for the all-Alaska project will depend on ANGDA's acceptance of risk as the project progresses from conceptual to preliminary to final design.

Collectively, the Prudhoe Bay Unit (PBU), Alaska Oil & Gas Conservation Commission (AOGCC), Alaska Department of Natural Resources (ADNR) and Alaska Department of Revenue (ADOR) should have current data and forecasts for future operation of the Prudhoe Bay Pool. The AOGCC has recently commenced hearings regarding the future operation of the Prudhoe Bay Pool.

ANGDA may wish to address the following items regarding the availability of hydrocarbons from the Prudhoe Bay Pool:

- Obtain forecasts of the volume and composition of CGF residue gas and stabilizer overhead gas
- Obtain a forecast of the composition of unprocessed gas obtained by adding separation to increase the overall volume of field gas off-take
- Obtain the established estimate of the volume of recoverable ethane, propane and butane hydrocarbon reserves remaining within the Prudhoe Bay Pool at the proposed start-up date of the gas project

Optimization of the PBU liquid and gas recovery from the Prudhoe Bay Pool necessitates a closer review of the complex current and forecast operation of the field. ANGDA may also, therefore, wish to complement the AOGCC in their evaluation of various PBU field operational issues, which includes assessment of:

- The prospects for using the carbon dioxide byproduct from the gas conditioning plant for enhanced oil recovery
- The possibility of accelerating implementation of EOR production patterns to maximize the use of MI prior to spiking MI components into a gas project
- The operation of the CGF with regard to current and future production of MI
- The relative amount of oil loss attributable to various project alternatives; the relative merits of the various proposed gas projects with regard to oil loss could be better understood if answers to the following were obtained:
    - How does oil loss vary as a function of project size? Do larger projects result in more oil loss?
    - What are the merits of increasing Prudhoe Bay field gas off-take to increase near term oil production with the gas used as feed to the gas project as compared to a feed of CGF residue gas?
    - What would be the oil loss, if any, attributable to spiking a large portion of MI components into a gas project? Can the CGF be operated to increase the MI rate to compensate for spiking of MI components into a gas project?
    - Is there an economic balance of project size with oil loss? That is, is there an overall economic gain with a larger project considering gas sale revenues and potential oil loss?

Dense Phase Pipelines *(Section 3.3)*

The term "***dense phase***" refers a condition of a natural gas mixture at high-pressure at which it is impossible for distinct liquid and gas phases to exist. An analysis of phase envelopes shows that a wide range of potential hydrocarbon mixtures can be transported via a high-pressure dense phase pipeline provided that the pipeline and stations are configured to avoid operating conditions within the two-phase region. Designation of a minimum operating pressure of approximately 1,500 psia appears sufficient to avoid the two-phase region of most cases were an enriched gas is to be transported. Specification of a pipeline with a maximum operating pressure (MOP) of 2,500 psia would provide a 1,000-psi differential pressure between compressor stations thereby providing sufficient driving force to move reasonable quantities of gas through the pipeline.

Spur Line Take-Off Project from Highway Pipeline Project *(Section 3.4)*

The Take-off pipeline from the Highway Project refers to removal of a portion of hydrocarbons from a large diameter pipeline at Delta Junction, and then transporting these hydrocarbons via pipeline to Cook Inlet, Port Valdez, or a combination of both. ANGDA specifically requested that multiple configurations of the Take-off project be addressed.

Numerous schemes for processing the gas flowing through the Highway Pipeline project can be postulated to produce natural gas with a wide range of potential compositions for delivery to the inlet of a spur line at Delta Junction. The complexity of this processing facility will depend on how the individual NGL components are to be extracted for delivery to the spur line. It may be possible to install a relatively simple processing facility if the spur line can accommodate a mixture of NGL components.

It is recommended that ANGDA complete a NGL marketing analysis as part of the feasibility study to determine the best means of disposing the hydrocarbons extracted from the Highway project and transported via the Take-off project. Consideration should be given to identification of a scheme by which each hydrocarbon processing service is installed only once. Installation of a processing service multiple times to effect sequential partial separations of hydrocarbons will result in increased capital costs. Consideration should also be given to a centralized processing facility and trucking extracted propane to the various markets in the Alaskan Interior.

Leveraging Issues – Pipeline

The facilities at either end of the natural gas pipeline can be installed in discrete units with the capacity of these facilities expanded as needed to accommodate the schedule for ramp-up of the project throughput. Once installed, however, the diameter of the pipeline cannot be increased and the pipeline capacity can be expanded via the addition of compressor stations, "looping" the pipeline by installing parallel pipelines between stations, or a combination of both. ***A key leveraging issue for the all-Alaska LNG project is the specification of the diameter of the natural gas pipeline.***

For a given flow rate of gas, options exist to install a larger diameter pipeline with fewer compressor stations or install a smaller pipeline with more compressor stations. The relative economic merits of these two options depend on the schedules of capital outlays relative to the operating revenues obtained from the prescribed ramp-up schedule of flow.

The COS and Return on Investment (ROI) analyses in this study show that multiple configurations of pipelines with differing pipeline diameters and number of compressor stations exist that yield approximately the same project economics over the 1 to 2 Bscfd flow rates being considered by ANGDA for the all-Alaska LNG project. ***Selection of a larger diameter pipeline with fewer stations would be more favorable than selection of a smaller diameter pipeline with more stations because the capacity of the larger diameter pipeline can be expanded by simply adding more gas compression and compressor stations***. Expansion of the capacity of a smaller diameter pipeline will require looping the pipeline between stations which is much more problematic and costly.

Selection of Expandable Pipeline *(Section 4.3)*

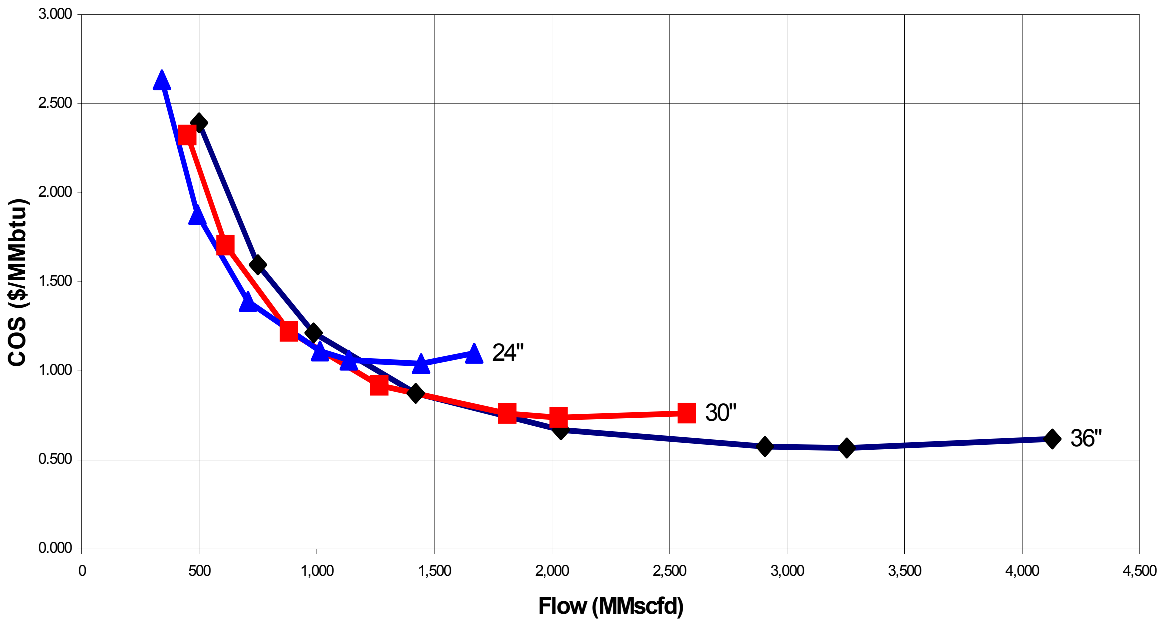
The demand for utility grade natural gas for residential and commercial use tends to increase gradually over time with the growth of the community, and utility gas transmission systems are designed accordingly. Typically, smaller diameter gas transmission pipelines are installed to match the very protracted ramp-up of flow with the initial increments of flow handled with little or no compression. The initial capital outlay for the smaller diameter pipeline is less than that of the larger pipeline for the first increment of flow. Theoretically, use of a smaller pipeline for a protracted utility type ramp-up schedule allows the capital costs for the compressor stations to be deferred thereby enhancing project economics relative to installation of a larger pipeline with fewer stations.

An industry standard approach for comparison of pipeline and station configurations is to express pipeline COS as a function of flow rate. The COS of service will tend to decline with increased pipeline flow obtained by the addition of compressor stations. Eventually, the number, capital costs, and operating costs of the compressor stations required for larger flow rates become so high that the COS will begin to trend upward. The plot of COS versus flow rate for a given pipeline is called a “J-curve” because the shape of the curves resembles a backward “J.” Economies of scale are indicated by a progressive decrease in the COS obtained using larger diameter pipelines operating at higher flow rates.

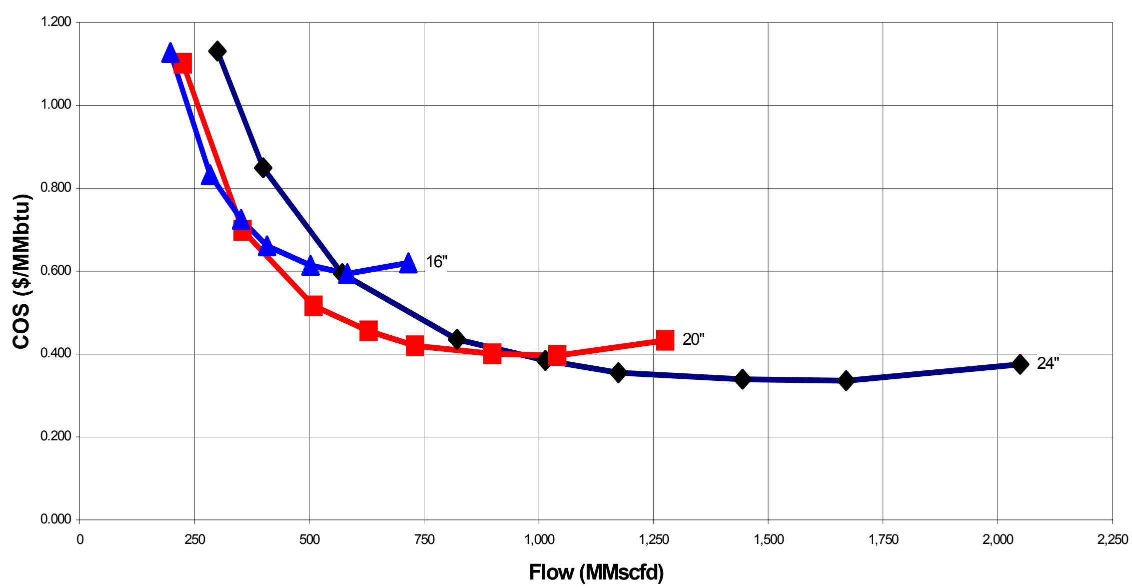
J-curves are typically prepared by completing a series of individual economic analyses to determine the COS at various flow rates for a particular diameter pipeline. J-curve analyses are based on the assumption that the market can accommodate a prescribed volume of gas flow on the first day of operation. For example, a COS value corresponding to a flow rate of 2 Bscfd (billion standard cubic feet per day) is based on the assumption that the market will accommodate 2 Bscfd beginning the first day of pipeline operation and on each day throughout the life of the project. This assumption may not be applicable to the all-Alaska LNG project. *ANGDA has identified selection of the initial project flow rate as an issue and has specified four project configurations with various flow rates up to 2 Bscfd.*

J-curves for pipelines of varying diameters and with lengths are shown in Summary Figure 1 and Summary Figure 2. The COS for a 24-, 30-, and 36-inch pipelines are approximately the same at a flow rate of 1 Bscfd and the COS for the 30- and 36-inch pipelines remain approximately the same through flow rates up to approximately 2 Bscfd.

It would be preferable to select a larger versus smaller diameter pipeline for the all-Alaska project at rates of 1 to 2 Bscfd because: 1) the economics of the initial project would not be adversely impacted by selection of the larger diameter pipeline, and 2) the larger pipeline would provide significant upside potential for project expansion simply by the addition of compression.



Summary Figure 1: J-curves for 800-mile Pipelines of Varying Diameter



Summary Figure 2: J-curves for 300-mile Pipelines of Varying Diameters

Project Size and Ramp-up Schedule *(Section 4.4)*

The COS and ROI analyses completed in this study show the same economic trends regarding selection of the size of the pipeline. ROI analyses, however, allow assessment of the benefits achieved by adjusting the rate of flow ramp-up. ROI analyses for various pipeline and stations configurations were completed based on a pipeline COS of $1.00/MMbtu. The results of the ROI analyses are summarized in Summary Table 1.

Summary Table 1: Summary of ROI Results, Percent by Flow Increment

500 MMscfd Increment						
Project year	**1**	**2**	**3**	**4**	**5**	**6**
MMscfd	**500**	**1000**	**1500**	**2000**	**2500**	**3000**
36-inch	2.50	7.96	10.99	12.83	13.99	14.38
30-inch	3.48	8.71	11.34	12.47		
24-inch	4.31	8.52				

1000 MMscfd Increment			
Project year	**1**	**2**	**3**
MMscfd	**1000**	**2000**	**3000**
36-inch	8.29	13.82	15.93
30-inch	9.06	13.25	
24-inch	8.80		

The ROI values are presented in a manner that shows the benefits achieved with each increment of expansion. For example, the ROI of 2.50 percent for the 36-inch pipeline at 500 MMscfd refers to a project that starts at 500 MMscfd and never expands past this rate. The ROI of 7.96 percent for the 36-inch pipeline at 1000 MMscfd refers to a project that starts at 500 MMscfd, expands to 1000 MMscfd in the second year, and then remains at 1,000 MMscfd for the remainder of the project life. Similarly, the ROI of 10.99 percent refers to a ramp-up schedule of 500, 1,000 and 1,500 MMscfd in years one, two, and three respectively and not expanding thereafter.

The results in Summary Table 1 show how adjusting the project ramp-up can enhance project economics. For example, a 36-inch diameter pipeline ramping up to a design rate of 2 Bscfd in 500 MMscfd increments over a four-year period shows a ROI of 12.83 percent. For the purposes of this example, assume that this ROI is 1 percent below the threshold of project viability. The ROI could be increased by approximately 1 percent by either building a larger project that ramps-up to 2.5 Bscfd over 5 years, or increasing the rate to 2 Bscfd over 2 years instead of 4 years. Marketing considerations may favor one approach over the other.

Although the benefits achieved by accelerating the ramp-up schedule may appear relatively inconsequential, the project clearly benefits from a quicker ramp-up schedule and all attempts should be made to configure a project based on a quick ramp-up of capacity. Overall, achieving the economic threshold for the all-Alaska LNG project may be contingent on successful implementation of a series of small optimizations such as accelerating the project ramp-up.

Configuration Descriptions and Issues

Conceptual Routes *(Section 5)*

Conceptual routes for a gas pipeline were developed for corridors from Prudhoe Bay to optional end points at Port Valdez, Nikiski, and Enstar Natural Gas Company's 20 inch-diameter pipeline located southwest of Palmer. The route corridors are as follows:

1. Prudhoe Bay to Port Valdez via the shortest practical route possible within the existing TAPS corridor ending at Anderson Bay in Port Valdez;
2. Prudhoe Bay to Nikiski via the shortest practical route possible to Nenana, then generally following the Parks Highway to the upper Matanuska-Susitna Valley, then south along the west side of the Susitna River and Cook Inlet to a subsea crossing of Cook Inlet;
3. Prudhoe Bay to Enstar's 20-inch pipeline located southwest of the junction of the Parks and Glenn Highways near Palmer via the shortest practical route, and
4. Glennallen to the 20-inch diameter Enstar pipeline via the shortest practical route.

The proposed pipeline corridors were selected with consideration of minimizing the total pipeline length, avoidance of known environmentally sensitive areas where practical, ease of construction, and utilization of existing infrastructure to the extent possible and appropriate. Special construction areas along each route were identified. Geotechnical considerations along the corridors include permafrost, frost bulb, frost heave, thaw settlement, soil slope stability, seismic hazards, liquefaction, and active faults.

Permitting and Environmental Challenges *(Section 5.10)*

There have been four environmental impact statements written for pipeline projects within the Prudhoe Bay to Port Valdez corridor in the last thirty years. Environmental baseline information has been updated by each subsequent project and there exists an extensive database of geotechnical conditions within the corridor. Permitting of a new pipeline route within the corridor would be expected to be relatively straight forward and to require a minimal lead time.

Extensive environmental baseline studies would be expected to be required for the corridor south of TAPS Pump Station 7 to Nikiski. Additionally, a detailed geotechnical assessment would be needed to support both the environment impact statement and the permitting process. A subsea crossing of Cook Inlet would require a special technical evaluation and marine study to determine feasibility and marine environment impacts before finalizing a pipeline location. A permitting effort for the Project 3 corridor to Palmer would be expected to encounter difficultly with conflicts associated with private land ownership and population centers south of Willow.

Schedules, Manpower, and Training Resources *(Section 6.1)*

Schedules showing major activities, manpower requirements and cost estimates, potential competition for construction labor, and available training resources for the Alaska work force were completed for the project.

Route Specific Issues *(Section 6.2)*

Project configuration and economic issues vary between the four routes depending on the location of the end terminus of the project. Route specific issues were identified and briefly discussed. These issues included integration of utility gas sales with the design of a liquefaction plant in Cook Inlet, differences in marine infrastructure and the marketing of end products from a large "Y-line" project.

Enriched Gas Small Pipeline Project *(Section 7)*

ANGDA stated the following in their 2004 Interim Feasibility Report regarding their bullet line project option:

> "The goal of the bullet line is to get North Slope gas to the existing industrial complex at Nikiski by the fastest, cheapest, and most direct route thereby replenishing existing natural gas supplies from Cook Inlet which are projected to be unable to meet demand within ten years. The bullet line is geared more to satisfying Alaska needs, and particularly as a source of replacing dwindling Cook Inlet gas supplies, rather than being driven by LNG exports."

The potential for sale of LPG to coastal communities within Alaska by barge is identified in the Interim Feasibility Report, but the report contains no mention of the sale of LPG to Asian Pacific Rim markets. The LPG market in Asia has been very robust historically and represents a potentially significant market for an Alaska project.

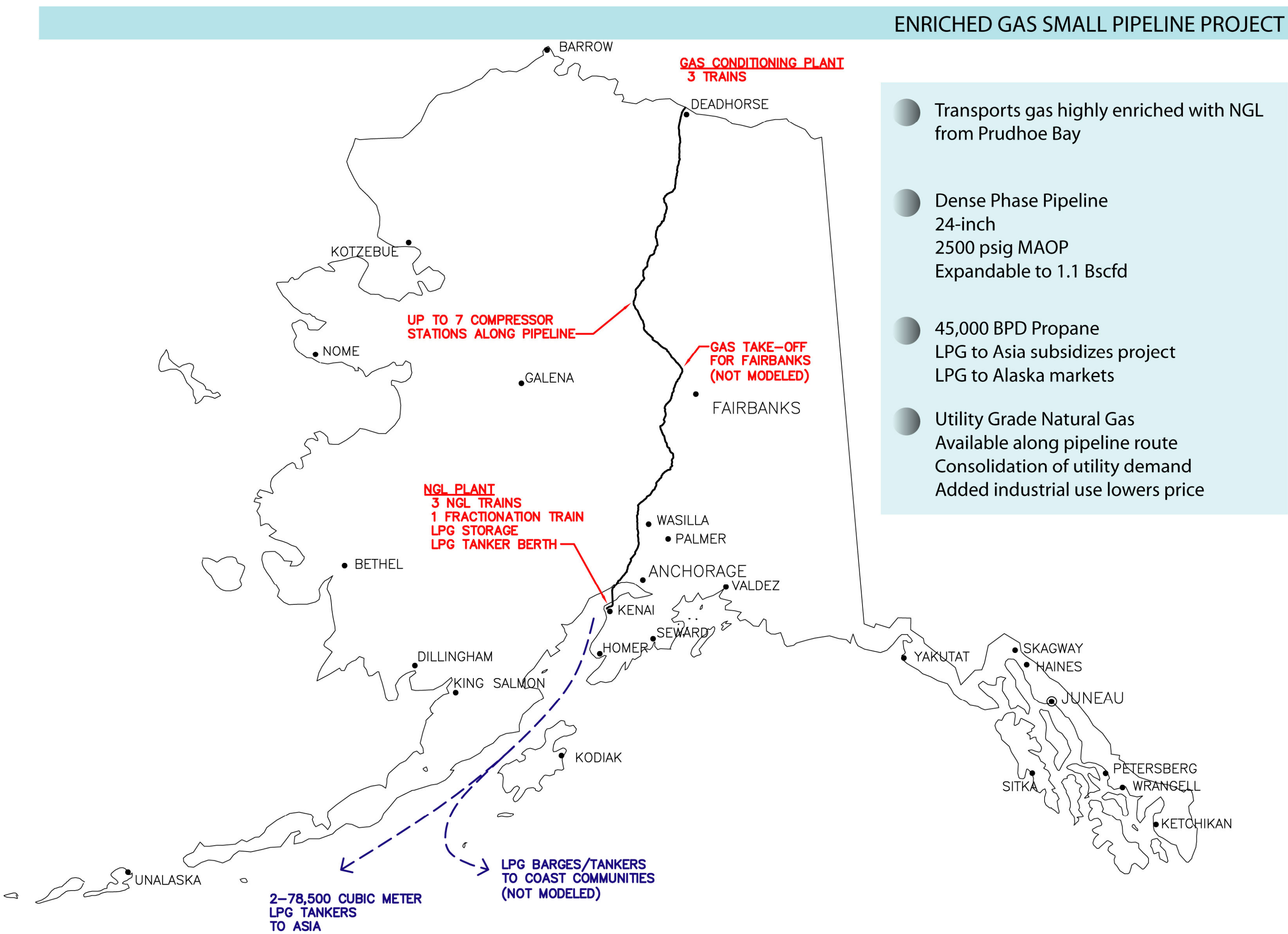
An ***Enriched Gas Small Pipeline (EGSP)*** project that is similar to ANGDA's 30-inch bullet line project was evaluated. The EGSP project is configured to deliver natural gas from the North Slope to Cook Inlet without being contingent on the installation of one of the larger gas projects that have been proposed. The purpose of investigating the economic viability of the EGSP project was to determine if this or a similar project merits further consideration by ANGDA. The capacity of the EGSP project is expandable to approximately 1 Bscfd, but is not large enough, nor intended, to market the vast quantities of natural gas that exist on the North Slope.

The EGSP project differs from ANGDA's bullet line concept in two significant ways: 1) a smaller 24-inch diameter pipeline is specified to target a smaller initial gas volume delivered to Cook Inlet than what would otherwise be required to justify installation of a 30-inch diameter pipeline, and 2) the pipeline gas is enriched with large amounts of propane for extraction and sale as LPG to Asian markets.

The EGSP project is based on the use of a small quantity of methane as a medium to transport large quantities of non-methane hydrocarbons via a dense phase pipeline. The revenues obtained from the sale of the non-methane hydrocarbons essentially subsidize the delivery of North Slope natural gas, i.e. the methane transport medium, to Cook Inlet. The EGSP project differs from the other larger proposed North Slope gas projects in that the pipeline cost of service on a thermal, or btu, basis is reduced by transporting a highly enriched gas stream instead of increasing the size of the project to achieve economies of scale.

EGSP Project Configuration *(Section 7.2)*

The EGSP project is based on the installation of a 24-inch diameter pipeline with a 2,500 psig MOP from Prudhoe Bay to Nikiski following the route down the west side of the Susitna Valley as described in Section 5 of this document. A NGL extraction plant would be located in Nikiski to remove and separate ethane, propane, and butane and heavier components (butane+) such that the residue gas from the facility would be utility grade with a higher heating value of approximately 1,030 btu/scf. It was assumed that the ethane and butane+ would be sold as feed to a petrochemical facility located in Nikiski although other options may exist for the disposition of these components. The project is configured to separate and store propane as LPG in Nikiski for subsequent delivery to markets both within Alaska and along the Pacific Rim in Asia. An overview of the EGSP project is shown in Summary Figure 3.



Summary Figure 3: Overview of the EGSP Project

To complete the study evaluation within the time and scope allotted, the simplifying assumption was made to base project revenues only on the sale of utility gas within Cook Inlet, petrochemical feed to a facility in Nikiski, and LPG sales to Asia. The economic model for the project does not address the extraction of either utility grade gas or propane upstream of Nikiski for use in the interior of Alaska, nor revenues from the sale of LPG to coastal communities. These are not oversights and the project could certainly serve Alaska markets other than those modeled.

The EGSP project is based on the assumption that non-methane hydrocarbons could be obtained from Prudhoe Bay for blending into unprocessed gas from Prudhoe Bay as needed to achieve a liquid equivalent of 45,000 barrels per day of propane in the feed to the project. The term ***liquid equivalent*** refers to the amount of liquid propane that would be produced if the propane content of the gas stream were condensed.

A discussion of the major streams at, and operation of, the CGF is contained in Section 3. The EGSP project is based on the premise that MI components would be available for spiking into the project feed by start-up in 2011 regardless of whether these components were obtained by additional MI production or a portion of the current MI stream would be diverted to the EGSP feed.

Flow Scenarios and Capital Costs *(Section 7.6)*

Material balances for the EGSP project were completed for operation at low flow (400 MMscfd), medium flow (800 MMscfd) and high flow (1,150 MMscfd). The low flow scenario is based on the assumption that the project would start at 400 MMscfd and the capacity would never increase past this rate. The medium flow scenario is based on operation at 400 MMscfd in the first year of operation, expanding to 800 MMscfd in the second year, but never expanding past this rate. Similarly, the high flow scenario is based on rates of 400, 800, and 1,150 MMscfd in years 1, 2, and 3 respectively with the flow remaining at 1,150 MMscfd for all years thereafter.

After consideration of various stream compositional changes along the project, about 45,000 barrels per day of propane product can be extracted at the NGL facility in Nikiski for subsequent transport to Asian LPG markets using two 78,500 cubic meter tankers. LPG tankers of 78,500 cubic meters were selected for the economic screening studies simply because information on these tankers was available and this capacity coincidently matched the approximate LPG sales rate envisioned for the project.

A summary of the overall capital outlays for the three flow scenarios of the EGSP project are shown in Summary Table 2.

Summary Table 2: Capital Outlays by Flow Scenario Expressed in 2005 dollars

Scenario, MMscfd	400	800	1,150
Gas Conditioning Plant	498	977	994
Pipeline	2,483	2,483	2,483
Pipeline & Stations	29	158	441
NGL Extraction Plant	275	350	425
LPG Tankers	300	300	300
Total	**3,585**	**4,268**	**4,643**

Economic Results *(Section 7.3)*

The low, medium, and high flow scenarios result in utility gas rates of 254, 624, and 930 MMscfd respectively in Nikiski with the remainder of the flow attributable to NGL and project fuel. Economic screening analyses were completed to determine the wholesale price of utility gas in Cook Inlet required to justify the EGSP project assuming that the collective gas demand along the Rail Belt could absorb these rates.

The threshold of economic viability was assumed as 13.5 percent return-on-equity (ROE) for a privately financed project. The economics are based on purchase of all hydrocarbons on the North Slope at $1.00/MMbtu. The sales price of propane sold as LPG and ethane/butane sold as petrochemical feedstock were held constant at $5.60/MMbtu and $2.50/MMbtu respectively. The wholesale prices of utility gas in Nikiski required to achieve the 13.5 percent ROE threshold of economic viability for the three scenarios of the EGSP project are shown in Summary Table 3.

Summary Table 3: EGSP Project, Wholesale Price of Utility Gas in Nikiski

Flow scenario	Low	Medium	High
Pipeline Inlet (MMscfd)	400	800	1,150
Utility grade gas in Cook Inlet (MMscfd)	254	624	930
Wholesale gas price in Cook Inlet($/MMbtu)	3.59	2.54	2.28

Material balances and schedules for capital outlays, revenues and expenses for the three flow scenarios were prepared in-house and provided to AG Edwards for completion of the economic screening analyses. As requested by ANGDA, the economics were based on “representative” financing assumptions. ANGDA will need to review these assumptions as their project progresses.

The economic results in Summary Table 3 show that a project consisting of a small diameter pipeline transporting a gas heavily enriched with non-methane hydrocarbons merits further investigation regarding whether such a project can deliver natural gas to the Rail Belt of Alaska at acceptable prices. Demand along the Rail Belt will have to be consolidated and utility gas preferentially purchased from the EGSP project in order to achieve the sale rate shown for the low flow scenario. Consolidation of utility and industrial demand, such as that of the Agrium and LNG facilities in Nikiski, would increase the overall throughput of the EGSP project resulting in a lower wholesale gas price for all the end consumers. Development of new gas demand along the Rail Belt could benefit all consumers by lowering the price of the utility gas.

Alternative Configurations *(Section 7.4)*

To simplify the analyses, the economics for the EGSP project are based on installation of a single NGL extraction facility in Nikiski with all hydrocarbons marketed from Cook Inlet. Other viable configurations exist for this project and should be evaluated by ANGDA.

Utility gas and/or propane can also be extracted from the EGSP project for use in the Fairbanks area. NGL extraction facilities similar to those described for Cook Inlet could be installed with fractionation facilities configured depending upon the local demand for the non-methane hydrocarbons.

The option exists to install the NGL plant on the north side of Cook Inlet and ship a methane free NGL product to Nikiski via a subsea pipeline where it would be fractionated into ethane, propane, and butane products. Installation of the NGL extraction plant on the north side of Cook Inlet west of the Susitna River would allow the utility gas from the EGSP project to flow into Enstar's 20-inch pipeline traversing the north side of Cook Inlet. Gas from the EGSP project could then flow either east to the Wasilla-Palmer area, southwest to the Beluga area, or both. A subsea pipeline from an NGL extraction facility in North Cook Inlet to a fractionation facility with marine terminal in Nikiski would avoid the need for installation of marine facilities in North Cook Inlet.

The J-curves produced for a 300-mile spur line (Summary Figure 2) show that the COS of 20-inch pipeline is less than that of a 24-inch pipeline at the 400 MMscfd rate of the low flow scenario of the EGSP project. Selection of the optimum pipeline diameter will depend on the volume targeted for the project. Installation of a smaller diameter pipeline may be preferable if the primary goal is to provide the lowest priced gas to Cook Inlet at lower flow rates, but at the expense of future expansion.

Table of Contents

Appendices

Tables

Figures

Acronyms

ADNR	Alaska Department of Natural Resources
ADOR	Alaska Department of Revenue
ADOT	Alaska Department of Transportation & Public Facilities
AEA	Alaska Energy Authority
AGA	American Gas Association
ANGDA	Alaska Natural Gas Development Authority
ANGTS	Alaska Natural Gas Transportation System
ANS	Alaska North Slope
AOGCC	Alaska Oil & Gas Conservation Commission
APSC	Alyeska Pipeline Service Company
BHp	Brake horsepower (operating horsepower)
BLM	Bureau of Land Management
Bscfd	Billion standard cubic feet per day
btu	British Thermal Unit
CFR	Code of Federal Regulations
CGF	Central Gas Facility at Prudhoe Bay
COS	cost of service
deg F	Degrees Fahrenheit
DSCR	Debt service coverage ratio
EGSP	Enriched Gas Small Pipeline
EIS	Environmental Impact Statement
EOR	Enhanced oil recovery
FGL	fuel gas line
GCP	Gas conditioning plant
GDP	Gross domestic product
GHX	Gas handling expansion
GOR	gas-to-oil ratio
GVEA	Golden Valley Electric Association
HHV	Higher heating value
Hp	Horsepower (installed capacity)
JT	Joule-Thompson
LHV	Lower heating value
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MOP	Maximum operating pressure
Mbbls	thousand barrels
MEA	Matanuska Electric Association
MI	Miscible injectant
MMbtu	million British Thermal Units
MMscfd	million standard cubic feet per day
MP	Sequential milepost along a conceptual alignment where MP = 0 is the start
Mscf	thousand standard cubic feet
MTA	million metric tons per annum
NGL	Natural gas liquids
PBMGP	Prudhoe Bay Miscible Gas Project
PBU	Prudhoe Bay Unit
PBUOA	Prudhoe Bay Unit Operating Agreement
ppmv	parts per million by volume
psi	Pounds per square inch (differential pressure)
psia	Pounds per square inch absolute (psig + 15 psi; used in calculations)
psig	Pounds per square inch gage
RFP	Request for proposal
ROE	Return on equity
ROI	Return on investment
scf	Standard cubic feet (gas at 1 atmosphere and 60 deg F)
TAPS	Trans Alaska Pipeline System
TCF	Trillion cubic feet
USGS	United States Geological Survey
VMT	Valdez Marine Terminal
WIO	Working Interest Owner

Section 1. Background

1970s

Three configurations for a North Slope natural gas project were debated in the 1970s: 1) a pipeline "over-the-top" of Alaska then traversing down the Mackenzie into Alberta, 2) the "Highway" pipeline generally following the Trans-Alaska Pipeline System (TAPS) to Delta Junction and then following the Alcan Highway into Alberta, and 3) a pipeline to tidewater in south-central Alaska at which the gas would be liquefied for export. The Carter administration selected the Alaska Natural Gas Transportation System (ANGTS) highway project, the federal government passed the Alaska Natural Gas Transportation Act and a treaty was signed with Canada regarding this project. The ANGTS project was not implemented in the 1980s as planned and a vast amount of infrastructure has been installed at Prudhoe Bay to re-inject the natural gas produced with the oil back into the Prudhoe Bay Pool.

1990s

A view widely held among Alaskans throughout the 1990s was that a natural gas pipeline project was not economic and that the sale of gas from Prudhoe Bay would result in an unacceptable amount of lost oil recovery. As a result, there was little discussion regarding the technical aspects of a gas pipeline project.

2000s

The North Slope gas producers announced in the summer of 2000 that marketing North Slope natural gas was a priority. A large study effort was organized and implemented in 2001. The gas producers developed two project options; the Highway Project at a rate approximately twice that of the previous proposals, and an over-the-top project. Trans-Canada and Enbridge are also pursuing pipeline projects along the highway route to Alberta. Yukon Pacific Corporation and the Alaska Gasline Port Authority appear to have merged efforts regarding pursuit of a pipeline to Port Valdez at which a liquefied natural gas (LNG) facility would be located.

Thirty years after the original debate, the three original project configuration options are again being discussed. The State of Alaska has essentially banned the over-the-top route by prohibiting state agencies from issuing the required permits. The US Congress passed in a bill in October of 2004 granting incentives to the highway route and these incentives were extended to an LNG project in another bill passed late in 2004.

ANGDA

A small group of Alaskans drafted Ballot Measure #3 for the 2002 General Election to establish a new public corporation to bring stranded North Slope gas to market. Ballot Measure #3 was passed by 62.3 percent of the voters thereby establishing the Alaska Natural Gas Development Authority (ANGDA). Governor Murkowski appointed the ANGDA board in 2003, the board appointed a Chief Executive Officer, and ANGDA began work on a project to transport natural gas via pipeline from Prudhoe Bay to Valdez, where it would be liquefied for export to the US West Coast and possibly Asia. ANGDA's charter includes development of a natural gas spur line from the LNG project to Cook Inlet and delivery of fuel to coastal communities throughout Alaska.

ANGDA's primary goals are to achieve the lowest possible cost of service for the transportation of North Slope gas to tidewater for export and to maximize the benefits from a North Slope gas project to Alaskans.

ANGDA issued the "Interim Feasibility Report, All-Alaska LNG Project" in September of 2004 in which the viability of building a natural gas pipeline from Prudhoe Bay to tidewater and the associated liquefaction facilities were assessed. ANGDA found: 1) no reasons to believe that the all-Alaska LNG project is not viable, and 2) that ANGDA is justified in pursuing further studies to define the project and bring it to the stage where a decision can be made whether to make further investments for preliminary engineering.

All-Alaska LNG Project

The economics of the all-Alaska LNG project will be influenced by economies of scale, and a proven strategy for lowering the cost of service is simply to increase the size of the project. Unfortunately, it becomes progressively more difficult to secure markets to absorb the LNG product in a timely manner as the size of the project increases. Achieving an acceptable balance between the size of the project and the ability of the markets to absorb the end products is crucial to the success of the all-Alaska LNG project.

Large LNG export projects throughout the world require facilities to remove contaminants from the gas (referred to as 'gas conditioning'), a liquefaction process to condense the gas, tanks to temporarily store the LNG, and a fleet of tankers to transport the LNG to market. Storage and re-gasification facilities for the end market are typically constructed by the LNG buyers. Assuming the gas supply is available, the overall capacity of these LNG export projects can be expanded incrementally by adding more liquefaction capacity, storage tanks and tankers.

The all-Alaska LNG project differs from most other worldwide LNG export projects in that the gas conditioning and liquefaction portions of the project are separated by an 800-mile long pipeline. The capital expense for the pipeline and gas compressor stations is a significant portion of the overall project, thus development of the all-Alaska LNG project must consider pipeline economics along with those of the gas conditioning, liquefaction, and LNG tankers.

Section 2. Report Overview

ANGDA issued State of Alaska Department of Revenue (ADOR) Request for Proposal (RFP) ASPS 2005-0400-0144 for LNG PROJECT DEFINITION OF THE ALL-ALASKA LNG PROJECT on October 15, 2004. The purpose of the RFP was for a contractor to help ANGDA identify the key leveraging technical and design issues for the all-Alaska LNG project and prepare a written report to be included in the public record.

Michael Baker Jr., Inc. (Baker) submitted a proposal on November 17, 2004, in response to the RFP that was accepted by ANGDA without modification. During the kick-off meeting on January 6, 2005, ANGDA requested that the contract scope of work be changed to de-emphasize issues related to the liquefaction plant and focus more on the hydrocarbon composition of the gas, transport of natural gas liquids via the gas pipeline, and evaluation of pipeline economics. Baker modified the scope accordingly and the information contained in this report was prepared per the modified scope approved by ANGDA.

ANGDA contracted Baker to identify leveraging design and technical issues that impact an all-Alaska gas project.

Baker's work will assist ANGDA with future planning and will add to the general knowledge base.

Baker's scope of work was restricted to identification of key leveraging technical and design issues regarding the portions of the all-Alaska LNG project up to, but not including, the LNG facilities. The scope of work excluded design the project or recommendation of a specific project configuration.

ANGDA requested a range of deliverables for the following four configuration alternatives based on export of LNG from a facility at tidewater in south-central Alaska:

1) ANGDA Stand-alone Project with 2 Bscfd capacity

2) ANGDA Stand-alone Project with 1 Bscfd capacity

3) Take-off from Highway Pipeline

4) Bullet Line from the North Slope to Cook Inlet

ANGDA, through the RFP, encouraged the contactor to advise ANGDA of concepts and issues that ANGDA has not studied and to discuss their applicability to the all-Alaska LNG project. Baker responded by completing a conceptual specification and economic analyses for the Enriched Gas Small Pipeline (***EGSP***) project consisting of a 24-inch diameter pipeline following the shortest route from Prudhoe Bay to Nikiski.

The information contained in this report was developed only to a conceptual level as required to support narratives or illustrate a leveraging technical or design issue that ANGDA may wish to pursue in the future, *and should be used for no other purpose*. Selection of a configuration for the all-Alaska LNG Project and subsequent demonstration of economic viability will require a vast amount work. This study was commissioned by ANGDA for use in the planning of future work.

This report has been structured to be as internally consistent as possible. Analyses and discussions in one portion of the report are illustrated based on information contained elsewhere in the report. *For example*, the discussion of natural gas phase envelopes is based on material balances developed for specific project configurations described in the report. Inherent in this approach is that the report contains numerous cross-references.

The contents of this report are described in the following sections.

2.1. Gas Composition

Although vast amounts of methane exist on the North Slope, this hydrocarbon is perhaps the least economic to transport because it contains the least amount of usable energy per unit volume transported. High-pressure pipelines, as currently being proposed for the various gas projects, allow the transport of butane, propane, and ethane with methane. The ability to transport non-methane hydrocarbons in a gas pipeline provides opportunities for project designers to affect the project economics by adjusting the composition of the gas. ***The recoverable quantities and availability of the non-methane hydrocarbons from Prudhoe Bay is a key issue and is the focus of much of this report.***

The following items are addressed in Section 3:

- Impact of gas composition on pipeline unit costs
- Potential sources of hydrocarbons from Prudhoe Bay
- Transportation of enriched natural gas via a dense phase pipeline
- NGL processing facilities in the context of ANGDA's take-off project from the Highway pipeline project to Alberta
- Gas conditioning to remove carbon dioxide to produce pipeline and LNG grade gas

2.2. Pipeline Configurations and Economics

Another basic issue is the selection of the size of the gas project, which essentially boils down to the economics of the pipeline. The economics of the pipeline project along the Alcan Highway to Alberta are driven primarily by the economics of the pipeline because this component comprises the majority of total project costs. The economics of an LNG project to south-central Alaska are driven less by pipeline economics since the cost of the pipeline is less than half of the total project costs.

A large portion of this report is dedicated to pipeline economics and a description of the attendant compressor facilities. Discussions of the following issues are contained in Section 4:

- Configuration and operation of compressor stations including extraction of fuel and refrigeration
- Comparative capital cost estimates for 16-, 20-, 24-, 30-, and 36-inch pipelines
- Capital cost estimates for compressor stations
- Preparation of J-curve and ROI analyses
- Location of compressor stations
- Matching of pipeline, gas conditioning and liquefaction capacity to achieve the overall project capacity

2.3. Description of Alaska Pipeline Route Options

ANGDA is investigating pipeline options that terminate in Port Valdez, Nikiski, and Palmer. Section 5 contains descriptions of the pipeline corridors from Prudhoe Bay to these three respective end locations. Geotechnical considerations, special design and construction areas, and permitting and environmental challenges are discussed.

2.4. Project Management

ANGDA requested that schedules showing major project activities and manpower requirements be prepared for the four project configuration alternatives to export LNG from a facility at tidewater in south-central Alaska. ANGDA also requested that the resources available for training of the Alaska work force be assessed. This general project management information is contained in Section 6, along with comments on other various issues affecting the project configurations.

2.5. Enriched Gas Small Pipeline (EGSP) Project

A conceptual specification and screening quality economic study for a small diameter pipeline transporting an enriched gas from Prudhoe Bay to Cook Inlet is contained in Section 7. The study assessed the economic viability of a pipeline project to deliver natural gas from the North Slope to Cook Inlet that was not contingent on the installation of one of the larger gas projects that have been proposed. The purpose of the study was to determine if a project similar to the EGSP merits further investigation. The EGSP project also provides a practical illustration of some of the gas compositional issues described in this report.

The following information is contained in Section 7:

- General description of the EGSP project including a block flow diagram and overall map
- Economic premises and assumptions including capital cost estimates, operating cost estimates, material balances and pricing assumptions; and
- Results of the economic screening evaluation.

2.6. Work Approach

2.6.1. Work Phases

The work described in this report was completed in four phases. Phase I consisted of identification of key leveraging technical and design issues in a written report. DEM Services in Anchorage, Alaska, was subcontracted to prepare budget level capital cost estimates for five different pipelines of varying diameters and lengths. Willbros Engineers Inc. in Tulsa, Oklahoma, was contracted to prepare factors that could be used to generate budget level cost estimates for various configurations of compressor stations along the pipeline.

Phase II consisted of characterization of the pipeline routes for Projects 1 through 4 as identified by ANGDA in the Interim Feasibility Report issued in September of 2004. The description of the routes was subcontracted to MC Metz and Associates in Anchorage, Alaska, and was completed concurrent with Phase I.

Phase III consisted of preparation of deliverables based on the results of Phases I and II. These deliverables included a qualitative assessment of considerations for a market entry project, schedules of major construction activities, identification of available manpower resources in Alaska and associated training requirements, and characterization of the EGSP project. The assessment of Alaska labor resources, training, and competition with other regional projects was subcontracted to Northern Economics in Anchorage, Alaska.

Phases I, II, and III were completed with a working draft submitted to ANGDA on March 2, 2005, for their review and comment. Phase IV consisted of revision of the draft report based on the comments provided by ANGDA with the final report issued by April 7, 2005.

2.6.2. Methods and Qualifiers

An in-house economic model was used to prepare the return-on-investment calculations that were required for many of the report deliverables. The financial management company, AG Edwards in Seattle, Washington, provided guidance with regard to the applicability of the economic analysis methods used. AG Edwards prepared the return-on-equity calculations for the EGSP project based on capital outlay, revenue, and expense information developed in-house.

The HYSYS® process simulation software, licensed from Aspen Technology, Inc., was used to prepare models of various gas processing schemes to support the material balances[1] described in the report. The HYSYS software performs rigorous gas physical property calculations and energy balances around various types of process equipment as configured by the user of the software. Simulation of process facilities was outside the scope of the work and the models were developed only to provide reasonable approximations of stream rates and composition based on specific assumptions. The process simulations were not optimized and flow diagrams shown throughout this report are representative of general process, but are not to be construed as recommended designs.

The analyses contained in this report are based on composition information in the public record regarding three gas streams of the Central Gas Facility (***CGF***) at Prudhoe Bay. The data for the feed gas to, and residue gas from, the CGF was obtained from information provided by the operators of the Prudhoe Bay Unit (PBU) to the Alaska Oil & Gas Conservation Commission (AOGCC) in 1995. The third steam consisted of average miscible injectant produced in the CGF during 2003, with the data for this stream obtained from annual surveillance reports provided by the PBU to the AOGCC. The data for these three streams was considered sufficiently representative of the operation of the Prudhoe Bay field for the scope of this report.

[1] A material balance is a mathematical accounting of the amount of gas entering and leaving a system on a component by component basis.

Section 3. Natural Gas – Compositional Issues

Natural gas consists of a mixture of hydrocarbons that exist in the gas phase at the operating conditions of the processing facilities of an oil and gas production field. The composition of natural gas leaving an oil and gas field varies depending upon the characteristics of the oil and gas reservoir and how the hydrocarbons are processed.

Natural gas typically consists of methane with ethane, propane, butane and pentane as well as heavier components present in progressively decreasing amounts. The energy, or thermal, content of the natural gas can vary significantly depending on the relative amounts of the non-methane components present in the mixture. Natural gas may also contain inert gases such a nitrogen and carbon dioxide that tend to lower the overall thermal content of the gas.

The composition of the natural gas within transmission pipelines is adjusted to meet a number of criteria including prevention of condensation of hydrocarbons within the pipeline. Liquid formation within a pipeline must be avoided because these liquids tend to collect in low areas of the pipeline, which result in liquid slugs when finally mobilized due to the gas flow. Pipelines are designed to avoid slug flow because the slugs can damage the pipeline as well as associated gas-handling facilities along the pipeline.

Sponsors of major gas pipeline projects from the North Slope have proposed the use of pipelines operating at pressures much higher than typical of gas pipelines operating in the Lower 48. The gas within these high-pressure pipelines is in a physical state known as the "*dense phase*" (discussed in Section 3.3). A major advantage of a dense phase pipeline is that large quantities of non-methane hydrocarbons can be transported without producing a separate liquid phase thereby avoiding slug flow.

Crude oil, condensate, and natural gas liquids (NGL) are marketed from the North Slope via the Trans Alaska Pipeline System (TAPS). The amount of butane in the NGL is adjusted to meet criteria governing the liquid hydrocarbon mix tendered to TAPS. The remaining butane, propane, ethane, and methane produced with the oil are re-injected into the reservoir or consumed as lease fuel.

The high-pressure pipelines currently being proposed for the various gas projects allow the transport of butane, propane, and ethane with methane in a dense phase state. Between TAPS and a dense phase gas pipeline project, all of the hydrocarbons from the North Slope can be sent to market.

Although vast amounts of methane exist on the North Slope, this hydrocarbon is perhaps the least economic to transport because it contains the least amount of usable energy per unit volume transported. *Enriching the natural gas of a dense phase pipeline with non-methane hydrocarbons increases the thermal content of the gas, increases the revenue per unit volume of gas transported, and increases the revenue per unit of capital expended for the pipeline.* ***The recoverable quantities and availability of the non-methane hydrocarbons from Prudhoe Bay is a key issue and is the focus of much of this report.***

Discussions of the impact on the thermal content of the natural gas, volumetric flow through the pipeline and impact on the pipeline tariff due to gas enrichment with non-methane hydrocarbons are contained in the following sections.

3.1. Gas Enrichment Fundamentals

Gas enrichment involves substitution of methane with non-methane hydrocarbons.

3.1.1. Gas Heating Value (btu/scf)

The primary use for natural gas is as a fuel, thus, natural gas is bought and sold according to the amount of energy that is produced when it is burned. Although the value of natural gas is sometimes expressed on a volumetric basis such as $/Mscf, this does not account for the energy content of the gas. Natural gas contracts are almost always expressed on a thermal basis ($/MMbtu) since energy, not volume, is the commodity of interest.

The amount of energy released per unit volume of gas burned is referred to as the ***heating value*** of the gas. Two types of heating values are commonly used, lower and higher. The lower, or net, heating value (***LHV***) is used by engineers for fuel calculations. The higher, or gross, heating value (***HHV***) is the amount of heat released subject to controlled laboratory conditions and is typically used as the basis for gas contracts.

The HHV of individual components that can be found in natural gas are shown in Table 3.1.

Table 3.1: Higher Heating Values (HHV) of Natural Gas Components

Hydrocarbon	HHV (btu/scf)
Methane (C_1)	1010
Ethane (C_2)	1769.6
Propane (C_3)	2516.1
i-Butane ($I\text{-}C_4$)	3251.9
n-Butane ($N\text{-}C_4$)	3262.3
i-Pentane ($I\text{-}C_5$)	4000.9
n-Pentane ($N\text{-}C_5$)	4008.9
n-Hexane ($N\text{-}C_6$)	4755.9
Nitrogen (N_2)	0
Carbon dioxide (CO_2)	0

The HHV of a mixture of natural gas is calculated by multiplying the heating values of the individual components by the volume percentage that the component bears to the total mixture. *For example*, the heating value of a mixture of 90 percent methane, 8 percent ethane, and 2 percent carbon dioxide would be 1051 btu/scf (1010*0.90 + 1769.9*0.08 + 0*0.02).

The natural gas burned by residential users is known as ***utility grade gas*** and typically has a HHV between 950 and 1050 btu/scf. Utility grade natural gas consists primarily of methane (HHV = 1010 btu/scf) and the variation in HHV depends upon whether the methane is diluted with inert gases such as nitrogen or carbon dioxide, or enriched with small amounts of ethane and heavier components.

One Mscf of natural gas equates to one MMbtu of gas when the heating value of the gas is 1000 btu/scf. The mathematical relationship between Mscf and MMbtu for a 1000 btu/scf gas is as follows:

1 Mscf * (1000 scf / Mscf) * (1000 btu / scf) * (MMbtu / 1,000,000 btu) = 1 MMbtu

The values $/Mscf and a $/MMbtu are sometimes used interchangeably for utility grade gas since the heating value is essentially 1000 btu/scf. *Expressing the value on a thermal basis is advantageous with respect to the Alaska gas pipeline projects since the opportunity exists to significantly increase the heating value of the gas by spiking non-methane hydrocarbons into a dense phase pipeline.*

3.1.2. Gas Enrichment – Impact on Volumetric Flow and Thermal Content

Ethane, propane, butane, and pentane components have relatively high heating values compared to methane (see Table 3.1). The pipeline gas heating value can be increased by enrichment with these non-methane hydrocarbons, thereby increasing the revenue per unit of volume of gas transported through the pipeline.

The volumetric flow of gas through a pipeline varies with the differential pressure across the pipe segment and the physical properties of the gas. The American Gas Association (AGA) equation for gas flow through large diameter transmission pipelines (reference: Gas Processors Suppliers Association, Engineering Data Book Volume II, Tenth Edition) is shown below.

Equation for Gas Flow through Large Diameter Transmission Pipelines

$$Q = 38.77 * (T_b/P_b) * E * (4 * \log_{10}(3.7 * D/e)) * ((P_1^2 - P_2^2)/(S * L_m * T_{avg} * Z_{avg}))^{0.5}$$

Where

Q = flow rate (cubic feet per day at base conditions)
T_b = base absolute temperature
P_b = base absolute pressure
E = pipeline flow efficiency factor
D = internal pipe diameter
e = absolute roughness of interior pipe wall
P_1 = inlet pressure
P_2 = outlet pressure
S = specific gravity of flowing gas
L_m = length of pipeline
T_{avg} = average flowing gas temperature
Z_{avg} = average compressibility factor

The following example is provided to demonstrate the benefits of enriching the pipeline gas. The example is based on a 24-inch diameter pipeline with inlet and outlet pressures of 2,500 and 1,500 psig respectively. The gas flow rate through the segment is approximately 500 MMscfd.

For this example, T_b, P_b, E, D, e, P_1, P_2 and L_m are constant regardless of the gas composition and the AGA equation can be simplified to the following:

$$Q = \text{Constant} * (1 /(S*T_{avg}*Z_{avg}))^{0.5}$$

Calculations of specific gravity (S), average temperature (T_{avg}), average gas compressibility (Z_{avg}), relative volumetric and thermal flow for various gas compositions are shown in Table 3.2. The composition of Case 1 reflects residue gas from the Prudhoe Bay Central Gas Facility (CGF) after reducing the carbon dioxide content to 1.5 mole percent. Case 2 reflects a slightly enriched stream, while Case 3 is a highly enriched stream. Case 3 reflects the composition similar to the first ramp-up increment of flow through the EGSP project (described in Section 7).

Table 3.2 shows that the volumetric flow through the example 24-inch pipeline is essentially independent of gas composition, whereas the energy flow through the pipeline, (i.e., flow on a thermal or btu basis) varies significantly with gas composition. Case 3 would result in 38 percent more revenue than Case 1 for the same rate of gas flow, assuming that the price obtained per btu delivered was the same in both cases. *The actual revenues obtained through gas enrichment will depend upon the respective end markets for the various gas components separated at the pipeline terminus.*

Table 3.2: Relative Volumetric and Thermal Pipeline Flow

	Case 1	Case 2	Case 3
Gas composition (mole %)			
Carbon dioxide	1.50	1.50	1.50
Nitrogen	0.69	0.70	0.27
Methane	89.92	81.3	59.61
Ethane	5.72	8.0	16.85
Propane	1.74	6.0	18.99
I-butane	0.13	1.0	1.13
N-butane	0.21	1.0	1.20
N-pentane	0.09	0.5	0.44
Total	100.0	100.0	100.0
Pipeline operating assumptions			
Inlet pressure (psia)	2,515	2,515	2,515
Outlet pressure (psia)	1,515	1,515	1,515
Inlet temperature (deg F)	28	28	28
Outlet temperature (deg F) *	19	19	26
Calculated values			
Average pressure (psia) **	2,056	2,056	2,056
Average temperature (T_{avg} degrees F) ***	24	24	27
Average temperature (T_{avg} degrees R)	484	484	487
Gas compressibility (Z_{avg})	0.65	0.56	0.45
Specific gravity (S)	0.62	0.71	0.88
$(1/(S * T_{avg} * Z_{avg}))^{0.5}$	0.072	0.072	0.072
Relative volumetric flow (Q / constant)			
	1	1	1
Higher heating value (HHV btu/scf)			
	1,068	1,199	1,472
Relative thermal flow (Q * HHV)			
	1	1.12	1.38

* Outlet temperature from simulation with approximation of heat transfer through pipe wall.
** Average pressure = 2/3 $(P_1 + P_2 – P_1 * P_2/(P_1 + P_2))$.
*** Average temperature = $(T_1 + T_2) / 2$ where T_1 = inlet and T_2 = outlet.

Case 1 reflects residue gas from the Prudhoe Bay CGF after reducing the carbon dioxide content to 1.5 mole percent.; **Case 2** reflects a slightly enriched stream; **Case 3** is a highly enriched stream.

3.2. Potential Sources of Enriched Gas from Prudhoe Bay

The Prudhoe Bay Pool is the largest known oil and gas reservoir in North America. The production of crude oil from Prudhoe Bay began in 1977 with production of natural gas liquids commencing a few years later. To date, natural gas has not been sold from Prudhoe Bay other than for limited use on the North Slope and for fuel to Alyeska Pipeline Service Company (***APSC***) Pump Stations 1 through 4.

A large infrastructure has been installed at Prudhoe Bay to gather the wellhead production, separate the gas, oil, and water; and then re-inject the natural gas back into the reservoir. The amount of oil that can be produced is constrained by the capacity to handle and re-inject the gas. Gas Handling Expansion 1 (GHX-1) was installed in 1992 to increase the field gas off-take from 3.7 to 5.3 Bscfd. GHX-1 also included facilities to produce a miscible injectant (MI) for enhanced oil recovery. GHX-2 was installed in 1994 to increase the field gas off-take from 5.3 to 7.5 Bscfd and produce more MI. GHX-1 and GHX-2 are collectively referred to as the Prudhoe Bay CGF.

A schematic diagram of the CGF is shown in Figure 3.1. Currently, an annual average of approximately 8 Bscfd of natural gas from various flow stations and gathering centers is processed in the CGF.

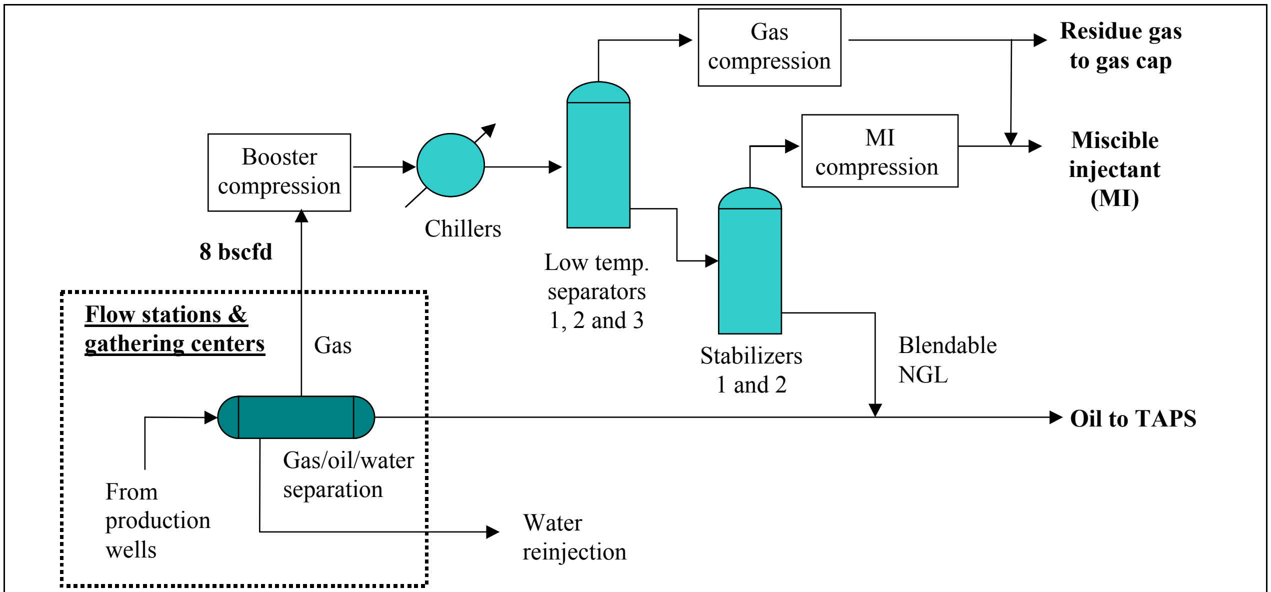


Figure 3.1: Prudhoe Bay Central Gas Facility, Simplified Schematic

The CGF is operated to extract the maximum amount of NGL from the field gas for blending with crude oil tendered to TAPS. MI is produced as a secondary product with the remaining residue gas re-injected into the reservoir. The residue gas has a lower heating value than the unprocessed CGF feed gas because non-methane components are stripped out of the feed for use as blendable NGL and MI.

As currently configured, the CGF extracts ethane, propane, and butane from 8 Bscfd of produced gas into a single stream, thus providing the opportunity to spike these non-methane hydrocarbons into the gas sold to a major gas project, thereby significantly enriching the gas without adversely impacting NGL sold to TAPS.

3.2.1. Description of the CGF

Unprocessed separator overhead gas from the Flow Stations and Gathering Centers is piped to booster compressors in the CGF where the pressure of the gas is increased to around 700 psia. The compressed gas passes through propane chillers to reduce the gas temperature to approximately –35 deg F, or slightly colder, causing non-methane hydrocarbon components to condense to a liquid. The condensed liquids are separated from the process gas in one of three low temperature separators and are then routed to two stabilizer columns. The gas leaving the top of the low temperature separators is called ***residue gas***. The residue gas leaving the low temperature separators is compressed to the pressure required for re-injection into the gas cap of the Prudhoe Bay reservoir.

The condensed liquid leaving the bottom of the low temperature separators contains ethane, propane, butane, pentanes, and heavier components along with some methane and carbon dioxide. This mixture of liquids contains components that are too volatile to blend into the crude oil tendered to TAPS and the liquids must be stabilized so that the mixture of crude oil and NGL meets the TAPS vapor pressure limit.

The stabilizer columns contain numerous trays designed to allow liquids to cascade down the column while allowing vapor to bubble up through the liquids at each tray. The most volatile hydrocarbons remaining in the liquids at the bottom of the column are vaporized in a reboiler, thereby providing the upward flow of vapor within the column. The least volatile hydrocarbons remaining in the gas at the top of the column are condensed and returned to the column. The countercurrent flow of the more volatile hydrocarbons upward through the column and the less volatile hydrocarbons downward through the column results in separation of the hydrocarbons according to their relative volatilities.

The stabilizer columns are operated to split the butane between the overhead gas and bottom NGL product as required so when mixed, the crude oil and NGL meet the TAPS vapor pressure specification. The overhead gas (the most volatile hydrocarbons) will contain ethane, propane, and butane with trace amounts of pentane and heavier components. The NGL bottom product (the least volatile hydrocarbons) will contain pentane and heavier components, some butane and trace amounts of propane.

The stabilizer overhead gas stream is compressed to re-injection pressure separately from the residue gas and is then split into two streams. A small portion of the compressed residue gas is blended into the stabilizer overhead gas. The term ***miscible injectant (MI)*** refers to the blended streams of stabilizer overhead and residue gas. One of the two MI streams produced in the CGF is routed to the Eastern Operating Area for injection into the waterflood portion of the field for enhanced oil recovery (***EOR***). The other MI stream is routed to the Western Operating Area for the same purpose.

The composition of the two MI streams is similar, but is not exactly the same. The PBU submits a report to the AOGCC titled "Annual Reservoir Surveillance Report, Water and Miscible Gas Floods, Prudhoe Oil Pool." Appendix A contains excerpts from these reports regarding historical flow and composition data for the MI.

3.2.2. NGL Content in Streams around the CGF

Various means exist to enrich the feed to a major gas pipeline project, some of which result in the transport of significant quantities of non-methane hydrocarbons. Specification of gas enrichment scenarios must be done with consideration of the total reserve of hydrocarbons available within the Prudhoe Bay Pool. Care must be taken so that enrichment schemes don't propose the cumulative sale of more of a particular hydrocarbon than exists in the reservoir.

Compositional analyses of the CGF feed, CGF residue, and MI gas streams along with theoretical estimates of potential NGL production rates, NGL estimated reserves, average removal rates, and HHVs (discussed in the following sections) are shown in Table 3.3.

The available information regarding the present operation of the CGF is insufficient to accurately identify the amount of hydrocarbons contained in the various CGF process streams. The values in Table 3.3 *are presented only for the purpose of identifying leveraging issues regarding the potential acquisition of hydrocarbons for gas enrichment. The data shown in* Table 3.3 *may not necessarily be internally consistent, but is adequate for a discussion of potential sources of enriching hydrocarbons.*

Table 3.3 shows the estimates of the liquid equivalent rates of NGL contained in the CGF feed, CGF residue, and MI streams. The liquid equivalent rates of NGL in the CGF feed are based on an average annual feed rate to the CGF of 8 Bscfd. The estimate of NGL content in the CGF residue is based on the assumption that the average rate of residue gas injection is approximately 85 percent of the feed. The MI rate for 2003 is based on the 2003 surveillance report.

3.2.3. Hydrocarbon Reserves

It is recommended that ANGDA contact Alaska state agencies and/or BP, as operator of the PBU, regarding the amount of recoverable ethane, propane, and butane that exist at Prudhoe Bay. In the absence of such information, two rough estimates of the hydrocarbons reserves have been made to illustrate design issues and support the material balances used for the EGSP project (Section 7).

The first approximation of NGL reserves is based on the composition of the unprocessed gas produced from Prudhoe Bay that is routed to the inlet of the CGF. The second approximation is based on the assumption that the composition of all the gas at Prudhoe Bay is the same as the CGF residue gas that has been re-injected into the gas cap. *This rough estimation approach is sufficient for the purposes of this report and should not be construed as definitive estimates of potential NGL reserves.*

Table 3.3: Composition of CGF Streams & Hydrocarbons Reserve Estimate

	CGF Feed	CGF Residue	2003 MI
Gas composition (mole %)			
Carbon dioxide	12.07	11.55	19.81
Nitrogen	0.57	0.62	
Methane	76.11	80.74	33.84
Ethane	6.11	5.14	19.58
Propane	3.07	1.56	24.37
I-butane	0.41	0.12	1.29
N-butane	0.83	0.19	1.08
Pentanes+	0.83	0.08	0.03
Total	100.00	100.00	100.00
Reference	*1*	*1*	*2*
HHV			
HHV (btu/scf)	1028	959	1380
HHV without CO_2 (btu/scf)	1169	1084	1721
NGL rates – CGF daily flow			
Volume basis, MMscfd	8000	6800	321
Potential NGL rates (Mbbls/day)			
Ethane	310	222	40
Propane	161	69	51
I-butane	25	6	3
N-butane	50	10	3
Pentane+	57	5	0
Assumed gas reserve			
Gas reserve including CO_2, TCF	25	25	
CO_2 free gas reserve, TCF	22	22	
Estimated NGL reserves (MMbbls)			
Ethane	970	813	
Propane	502	254	
I-butane	80	23	
N-butane	155	35	
Pentane+	178	17	
Average removal rate over a 25 year project life (Mbbl/day)			
Ethane	106	89	
Propane	55	28	
I-butane	9	3	
N-butane	17	4	
Pentane+	20	2	

Reference 1: AOGCC, NGL/MI Ultimate Recovery – May 16, 1995 Public Hearing, Corrected ARCO Exhibit 128
Reference 2: AOGCC, Annual Reservoir Surveillance Report, Water and Miscible Gas Floods, Prudhoe Oil Pool – 2003

TCF = trillion cubic feet

The NGL reserve estimates shown in Table 3.3 are based on the assumption that at the start-up of a major gas project, there will be 22 trillion cubic feet (TCF) of recoverable natural gas remaining in the Prudhoe Bay Pool after removal of carbon dioxide, less fuel and NGL blended into TAPS. The estimated reserves shown in Table 3.3 are calculated by simply applying the respective compositional analyses for the CGF feed and residue stream to a volume of 22 TCF. The average removal rates shown in Table 3.3 are simply the respective NGL reserve estimates divided by the assumed life of the gas project, which in this case is 25 years.

3.2.4. Blending of CGF Streams – Sustained NGL Content

A consequence of CGF operations is that ethane, propane, and butane extracted from the feed are re-injected in one portion of the Prudhoe Bay field as MI, while the residue gas is re-injected in another portion. The long-term operation of the CGF results in a redistribution of hydrocarbon components within the field. Eventually, the re-injected hydrocarbon components will return to the surface, but the schedule at which they return will vary depending upon how the field is operated.

It may be possible to configure a gas project that would initially extract NGL components from Prudhoe Bay at a higher rate than what could be sustained over a 25-year period. *Care must be taken when configuring the gas project so as to not overstate the sale of NGL reserves.*

For example, assume that all of the MI from the CGF was to be spiked into 2 Bscfd of unprocessed gas from Prudhoe Bay. Assume that the composition of the unprocessed gas is the same as the CGF feed as shown in Table 3.3 and that the MI composition is also the same as that shown in the table. The propane content in 8 Bscfd of CGF feed gas is approximately 161,000 barrels per day which means one fourth of this amount, approximately 40,250 barrels per day, would be contained in 2 Bscfd of the unprocessed gas feed to the gas project. The propane content of the entire MI stream as shown in the table is approximately 51,000 barrels per day. Mathematically, the propane content in a stream consisting of all the MI blended into 2 Bscfd of unprocessed gas would be approximately 91,250 barrels per day (40,250 + 51,000).

Table 3.3 shows that the propane reserve calculated assuming 22 TCF of gas reserves and the composition of the CGF feed would be completely exhausted over 25 years at a removal rate of 55,000 barrels per day. The 91,250 barrel per day propane rate postulated for the above example could not be sustained over a 25-year project of a gas project.

Another way of viewing this issue is that the opportunity exists to front-end load the sale of enriching hydrocarbons to move project revenues forward thereby enhancing project economics. According to this scenario, the amount of the enriching hydrocarbons sold would progressively decrease over the life of the project.

An evaluation of front-end loading the sale of non-methane hydrocarbon reserves, if indeed this is an issue, should address the long-term use of installed capital required for handling and disposition of these hydrocarbons. For example, a project configuration may be based on the extraction of ethane at the pipeline terminus for use as feed to a petrochemical plant. Front end loading of ethane removal from the North Slope would require construction of a petrochemical plant sized according to the initial ethane rate. The installed capital for the petrochemical plant would be underutilized if the rate of ethane were to decline in later years. This same situation could be encountered regarding the volume of propane storage and the number of liquefied petroleum gas (LPG) tankers required to sell propane as LPG to Pacific Rim and Alaska markets.

3.2.5. Use of Unprocessed Gas as a Pipeline Feed

The respective heating values of the CGF feed gas, CGF residue gas, and 2003 annual average MI streams are shown in Table 3.3. The compositional data for the CGF feed and residue gas streams are nine years old; however, this data is considered as reasonably representative of current conditions because the operation of the field and CGF has not changed appreciably over this period.

Table 3.3 shows that the heating value of the CGF feed gas is about 7 to 8 percent greater than that of the residue gas. *The unit operating costs of the pipeline would be reduced if the feed to the gas project consisted* *of unprocessed field gas instead of CGF residue gas* (see Section 3.1.2). The content of propane in the unprocessed field gas is approximately twice that of the residue gas and the economics of the gas project would benefit from extraction and sale of this incremental propane.

Use of the unprocessed field gas as feed could benefit the PBU as well as the gas project. The rate of oil production at Prudhoe Bay is constrained by the capacity of the CGF to handle the natural gas produced along with the oil. *The opportunity may exist for the PBU to increase near term oil production by installing more gas/liquid separation capacity, increasing the overall field gas off-take and then routing the incremental gas from these separators to the feed of the gas pipeline project.* A block flow diagram of this scenario is shown in Figure 3.2.

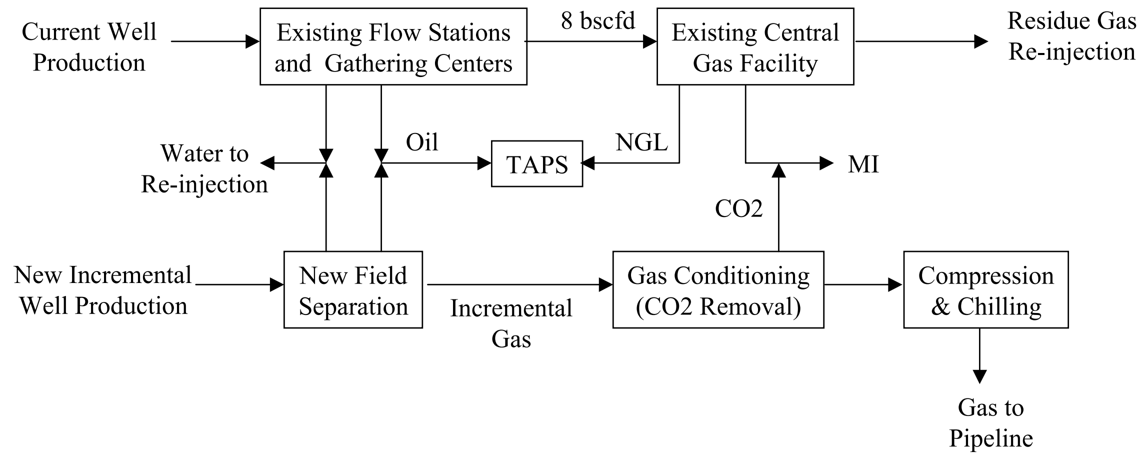


Figure 3.2: Block Flow Diagram – Unprocessed Gas Feed to Gas Project

The gas handling expansions GHX-1 and GHX-2 were implemented to increase the field gas off-take thereby allowing more recovery of oil, more NGL for blending with TAPS, and the production of more MI. Presumably, a GHX-3 project has not been implemented because the incremental revenues from an increase in near term oil and NGL production do not justify the associated costs for field separation, gas handling, and re-injection equipment.

The Prudhoe Bay field is operated to preferentially produce the lowest ***gas-to-oil ratio*** (***GOR***) production wells since oil production is constrained by the ability to handle the associated gas. One would expect the wells operated subject to a GHX-3 scenario to have higher GORs than the production to GHX-1 and GHX-2, thus the cost of gas handling per barrel of oil produced would progressively increase with each increment of gas handling expansion.

The unprocessed gas scenario depicted in Figure 3.2 is essentially GHX-3, except that the gas producers would only bear the costs for field separation equipment since the gas project would bear the costs to handle the gas downstream of the separators. ***Recognizing that evaluation of increasing field gas off-take will require the expertise of reservoir engineers, the unprocessed gas feed scenario appears to be a potentially leveraging issue that ANGDA may wish to address.***

The PBU has identified cycling of CGF residue gas through the gravity drainage portion of the reservoir as an oil recovery mechanism. The hydrocarbon lean residue gas strips hydrocarbons from the immobile oil left behind in the gravity drainage portion of the field as the level of the gas/oil interface drops. *The sale of any gas from the Prudhoe Bay field will theoretically impact oil production since it will result in a drop of reservoir pressure.* Selling residue gas to a gas pipeline project may have an additional adverse impact on oil recovery due to a reduction in the amount of gas cycled through the reservoir. Use of unprocessed feed gas as depicted in Figure 3.2, however, should have less adverse impact on oil recovery from gas cycling since the volume of CGF residue gas re-injected for cycling through the reservoir will remain unchanged.

3.2.6. Spiking MI into Residue or Unprocessed Gas Feed to the Gas Project

The Prudhoe Bay CGF concentrates ethane, propane, and butane from approximately 8 Bscfd of gas into a single stabilizer overhead stream that is mixed with residue gas and re-injected into the reservoir as MI.

The average annual rate of MI re-injected into the reservoir from 1991 through 2003 and the concentrations of ethane, propane, and butane in this MI are shown in Figure 3.3. The MI rate is depicted as the black line without data markers and is referenced to the right vertical axis. The relative content of ethane, propane, and butane are shown as mole percent and are referenced to the left vertical axis. The data shown in Figure 3.3 was obtained from annual surveillance reports for the ***Prudhoe Bay Miscible Gas Project (PBMGP)*** (contained in Appendix A).

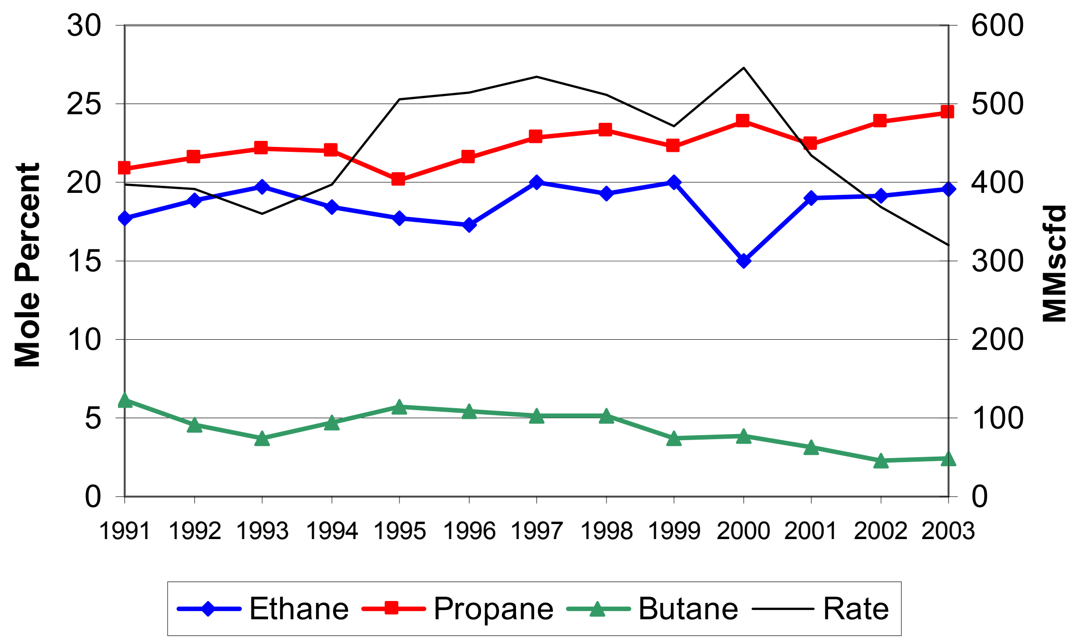


Figure 3.3: Historical MI Rates and Compositions

The MI rate has varied over time with a peak rate of 546 MMscfd in the year 2000 after the ***MI expansion, or MIX project***, was installed in 1999. The goal of the MIX project was to increase the MI rate from around 520 MMscfd to a rate in excess of 600 MMscfd. Limited technical information about the MIX project is available in the public record and the exact MI target rate for the project is unknown. It is also unknown why the annual rate of MI has declined to 321 MMscfd in 2003 after installation of the MIX project.

The respective concentrations of ethane and propane in the MI have remained approximately the same for over a decade. The amount of ethane and propane potentially available for spiking into a gas pipeline project will likely depend on the rate of MI that can be generated within the CGF.

The liquid equivalent of ethane, propane, and butane that has been re-injected into the Prudhoe Bay reservoir since 1991 is shown in Figure 3.4.

Based on the information shown in Figure 3.3 and Figure 3.4, one would anticipate that more than 60,000 and 80,000 barrels per day of ethane and propane respectively would potentially be available for a gas project if the CGF with the MIX project upgrades could generate 600 MMscfd or more of MI.

The Prudhoe Bay CGF is operated to meet the TAPS blending limits and a significant amount of butane is sold as NGL tendered to TAPS. The remaining butane can be used as MI at Prudhoe Bay or possibly exported to manufacture MI for other North Slope reservoirs. The amount of butane potentially available for spiking into a gas pipeline project will depend on the future of EOR projects and the volume of butane that can be marketed via TAPS.

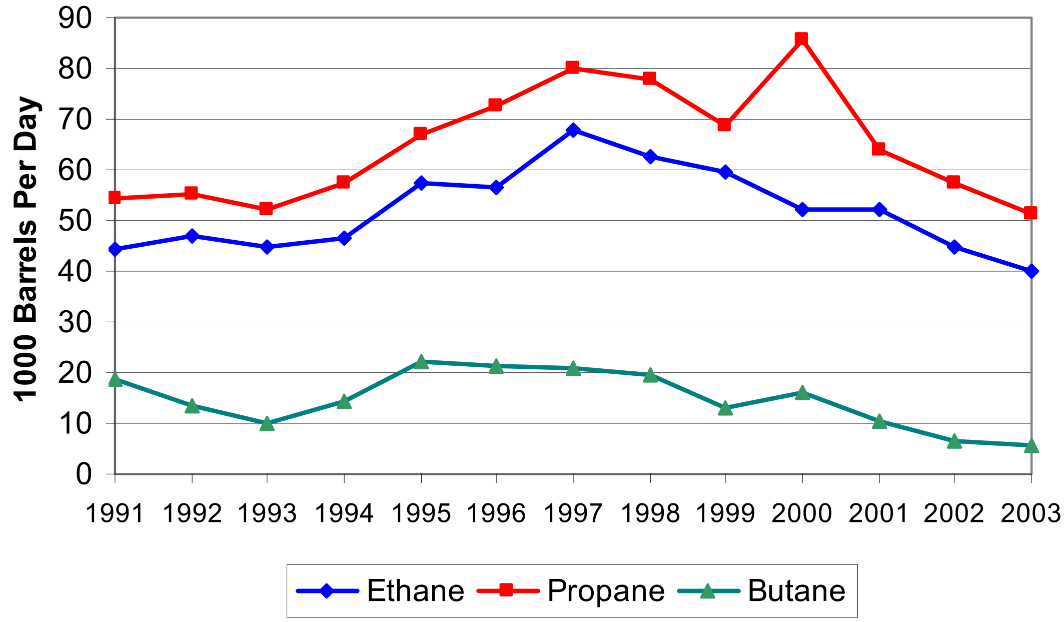


Figure 3.4: Historical Volume of NGL Re-injected as MI

The MI stream consists of a blend of stabilizer overhead and residue gas (see Section 3.2.1) and the surveillance reports provide the rates and compositions after these streams have been blended. ***The spiking of MI components into a gas project would most likely consist of tapping directly into the stabilizer overhead stream prior to compression and routing this lower pressure stream to the gas conditioning plant for removal of carbon dioxide.***

3.2.7. Availability of MI Hydrocarbon Components – PBU Contracts

The operation of the Prudhoe Bay Miscible Gas Project (PBMGP) was discussed in depth during hearings before the AOGCC, Alaska Department of Natural Resources (ADNR), and ADOR during 1995 and 1996. The testimony of the unit operators at these hearings is replete with references to 2015 as the end date of the PBMGP. *Removal of MI components prior to the end of the PBMGP for spiking into a gas pipeline project may have an adverse impact on enhanced oil recovery, thus requiring an assessment of the best use of these MI hydrocarbons*.

The regulatory hearings in 1995 and 1996 involved a similar issue regarding the best use of MI hydrocarbons. In that case the issue was whether butane should be used to manufacture MI for enhanced oil recovery or be blended into the NGL for sale via TAPS. The issue was resolved, at least in part, via an engineering solution consisting of implementation of the MIX project to increase MI production (discussed in Section 3.2.6). Engineering solutions may also exist to allow spiking a portion of the MI hydrocarbons without premature shutdown of, or significant adverse impacts to, the miscible gas project.

Contractual issues within the PBU were also identified during the 1995 and 1996 regulatory hearings. Collectively, the ***1977 Prudhoe Bay Unit Operating Agreement (PBUOA)*** and the following subsequent agreements govern the operation of the field and the CGF (Reference: AOGCC, CO 360):

1983 – Prudhoe Bay Unit NGL/EOR Operating Procedures and Flow Station 3 Injection Project Operating Procedures

1988 – Prudhoe Bay Unit Gas Handling Expansion Agreement

1990 – Prudhoe Bay Issues Resolution Agreement (IRA), effective in 1990, but not signed by all parties until 1993

1992 – Amended and Restated Prudhoe Bay Unit NGL/EOR Operating Procedures and Flow Station 3 Injection Project Operating Procedures, effective in 1992, but not signed by all parties until 1993

1996 – Agreed to implement the MIX project as resolution of the MI/NGL hearings before the AOGCC, ADNR, and ADOR

2000 – Agreed to modify working interest ownership in the oil rim and gas cap so that each Working Interest Owner (***WIO***) percentage ownership in the gas cap would be the same as their respective ownership in the oil rim.

It is not currently clear what possibilities and/or requirements are in place to enable access to the gas and MI streams for the PBU. It is recommended that ANGDA, through the AOGCC, obtain clarification as to these issues.

3.2.8. Potential Impact on Oil Production

A wide range of project configurations have been proposed for an Alaska gas project. The gas producers have proposed a 4.5 to 5.6 Bscfd project through Canada. LNG projects ranging from 1 to 4 Bscfd have been proposed. The EGSP project as described in this report (Section 7) is based on a small volume of highly enriched gas with an initial rate of less than 1 Bscfd.

The potential for adverse impact on oil production due to implementation of a gas project has been discussed for decades. Various stakeholders have articulated mechanisms by which adverse impact on oil production due to a gas project could occur, including:

- Condensation of hydrocarbons from the dense phase gas in the reservoir to a liquid as the reservoir pressure drops due to a gas sale. Less of these condensed hydrocarbons will be recovered than if they were produced via a dense phase gas since the mobility of the liquids through the reservoir is less than that of the gas.

- A drop in reservoir pressure due to a gas sale will decrease the differential pressure from bottom of the well bores to the surface thereby impeding the well flow.

- A drop in reservoir pressure due to a gas sale will require that the composition of MI be adjusted to ensure that the injectant remains miscible. Such reformulation would most likely result in a loss of MI volume and a corresponding loss of oil recovery.

- The sale of MI hydrocarbons as NGL to TAPS or as an enriching stream to a gas project would reduce the volume of MI and result in oil loss at Prudhoe Bay and would preclude the possible use of this MI for enhanced oil recovery in other fields.

- The sale of CGF residue gas to a gas project would result in a reduction of gas cycled through the gas cap with an adverse impact on the recovery of immobile oil remaining in the gravity drainage portion of the reservoir as the gas/oil interface drops. Currently, certain hydrocarbons are stripped out of the immobile oil into the lean residue gas as it is cycled through the reservoir.

Collectively, the above adverse impacts could reduce the economic viability of Prudhoe Bay, potentially resulting in premature shutdown of the field and the associated loss of late life oil production. A reduction in oil production due to a gas sale may complicate operation of TAPS and potentially result in its premature shutdown.

Mitigation measures that have been proposed to reduce the adverse impacts on oil loss due a major gas sale include:

- Increase water injection to maintain reservoir pressure similar to the gas cap water injection program currently underway;

- Use the carbon dioxide byproduct from the gas conditioning plant as a basis for MI either at Prudhoe Bay or in other fields;

- Implement a “lean gas chase” or “carbon dioxide chase” through the EOR portion of the field to recover MI components that remain in the reservoir after the target EOR oil has been produced;

- Install more field separation to provide for an increase in field gas off-take (discussed above);

- Preferentially begin with gas from Point Thomson, and/or potentially other fields, thereby delaying use of gas from Prudhoe Bay.

The potential for oil loss could vary significantly depending on the configuration of a gas project and the loss mitigation measures employed. Detailed information and reservoir-specific expertise to assess the relative impacts on oil production attributable to the respective project configurations are required to further analyze the potential impacts. This is mentioned solely for the purpose of advising ANGDA that these issues may impact their feasibility work regarding the all-Alaska LNG project. Recommendations regarding how ANGDA may wish to address these issues are contained in the following section.

3.2.9. Recommendations and Leveraging Issues – Access to Hydrocarbons

As owner of the project, ANGDA will have to satisfy itself that the design and economic analysis of the all-Alaska LNG project are based on sound data. The need for accurate data increases as the project progresses from conceptual to preliminary and then final design.

Access to and disposition of the various components of natural gas is fundamental to a gas pipeline project from the North Slope. The conceptual analyses contained in this report are based on gas compositional data for the Prudhoe Bay field that is over 9 years old. *It is recommended that ANGDA verify the applicability of this data or obtain new data prior to commencement of their planned project feasibility studies.*

The degree to which ANGDA pursues acquisition of data regarding North Slope gas will depend on ANGDA’s acceptance of risk for each progressive stage of an all-Alaska project. Collectively, the PBU, AOGCC, ADNR, and ADOR should have current data and forecasts for future operation of the Prudhoe Bay field. The AOGCC has recently commenced hearings regarding the future operation of the Prudhoe Bay Pool.

ANGDA may wish to address the following items regarding the availability of hydrocarbons from the Prudhoe Bay Pool:

1) Obtain forecasts of the volume and composition of CGF residue gas and stabilizer overhead gas

    - Historically, the PBU has proposed use of CGF residue gas as feed to a gas project.

    - MI consists of a blend of compressed stabilizer overhead gas and CGF residue gas (Figure 3.1). It may be advantageous to secure MI hydrocarbons directly from the stabilizer overhead stream prior to compression and blending since this stream is richer in non-methane hydrocarbons and at a pressure more typical of a feed to carbon dioxide removal facilities.

    - At issue is whether the PBU would continue to operate the CGF to extract NGL for blending into TAPS after the miscible gas project has been terminated. A forecast of the volume and composition of the stabilizer overhead gas before and after termination of the PBMGP should be obtained.

2) Obtain a forecast of the composition of unprocessed gas obtained by adding separation facilities to increase the overall volume of field gas off-take

- The possibility may exist for the PBU to increase near term oil production by installing field separation facilities with the separator gas routed to the feed of the gas pipeline project (Figure 3.2). The CGF feed gas composition may not be representative of unprocessed gas generated by adding separation to increase overall field gas off-take.

- Non-methane hydrocarbons are preferentially extracted in the CGF and re-injected into the reservoir as MI. A portion of the MI components will vaporize from the produced EOR oil in the field separators and be returned to the CGF as part of the feed. The concentration of non-methane hydrocarbon components in the CGF feed may be artificially high due to extraction of MI components from the gas cap gas and re-cycling these through the EOR portion of the field. The concentration of non-methane components in the unprocessed field gas may decrease as these hydrocarbons leave the Prudhoe Bay system via a gas pipeline project.

3) Obtain the established estimate of the volume of recoverable ethane, propane and butane hydrocarbon reserves remaining within the Prudhoe Bay Pool at the proposed date of start-up of a gas project

Optimization of the PBU liquid and gas recovery from the Prudhoe Bay Pool necessitates a closer review of the complex current and forecast operation of the field. ANGDA may also, therefore, wish to complement the AOGCC in their evaluation of various PBU field operational issues, which includes assessment of:

1) The prospects for using the carbon dioxide byproduct from the gas conditioning plant for enhanced oil recovery

   - All of the major Alaska North Slope (***ANS***) gas projects that have been recently proposed include a gas conditioning plant on the North Slope to remove carbon dioxide from the gas prior to shipment via pipeline. The carbon dioxide byproduct may have value for EOR within Prudhoe Bay or other fields. The volume of carbon dioxide byproduct produced from gas conditioning could be significant.

2) The possibility of accelerating implementation of EOR production patterns to maximize the use of MI prior to spiking MI components into a gas project

   - A finite amount of MI is required to recover a finite target amount of EOR oil. A reduction in MI volume due to spiking the MI components into the feed to the gas project may only defer the production of EOR instead of causing an oil loss. The potential impact on oil due to reducing or modifying the MI stream would depend on the late life economics of the PBMGP and whether a reduction in MI would lead to premature shutdown of the project.

   - AOGCC hearing testimony in 1995 indicated that the efficiency of the MI to produced oil, as measured by the volume of MI injected per barrel of oil recovered, progressively declines as more MI is injected into a given production pattern. The start-up date of a gas pipeline project will be known years prior to commissioning. It may be possible to plan operations accordingly and direct MI supply to the most promising EOR prospects preferentially as well as move to new EOR patterns more quickly. If one assumes that MI components will be sold to a gas project, this approach could result in a more effective use of MI with any decline in EOR oil attributable to the marginal recovery rates associated with the least efficient use of MI within each production pattern.

3) The operation of the CGF regarding current and future production of MI

4) The relative amount of oil loss attributable to the various project alternatives; the relative merits of the various projects with regard to oil loss could be better understood if the following information was developed:

   - How does oil loss vary as a function of project size? Do larger projects result in more oil loss?

- What are the merits of increasing field gas off-take to increase near term oil production as compared to use of CGF residue gas with a potential adverse impact on the gas cycling oil recovery mechanism?

- What would be the oil loss from the PBMGP, if any, attributable to spiking a large portion of MI components into a gas project?

- Is there an economic balance of project size with oil loss? That is, is there an overall economic gain with a larger project considering sales revenues and potential oil loss?

3.3. Transport of Enriched Gas via a Dense Phase Pipeline

Hydrocarbons tend to condense from the vapor state to a liquid as the pressure of the system is increased and/or the temperature decreased. The pressure and temperature conditions at which liquids will begin to condense from a mixture of hydrocarbon gases can be calculated based on equation of state correlations. A phase envelope is a plot of the boundary conditions within which both liquid and gas phases will be present for a particular mixture of hydrocarbons. A phase envelope for CGF residue gas after removal of carbon dioxide is shown in Figure 3.5.

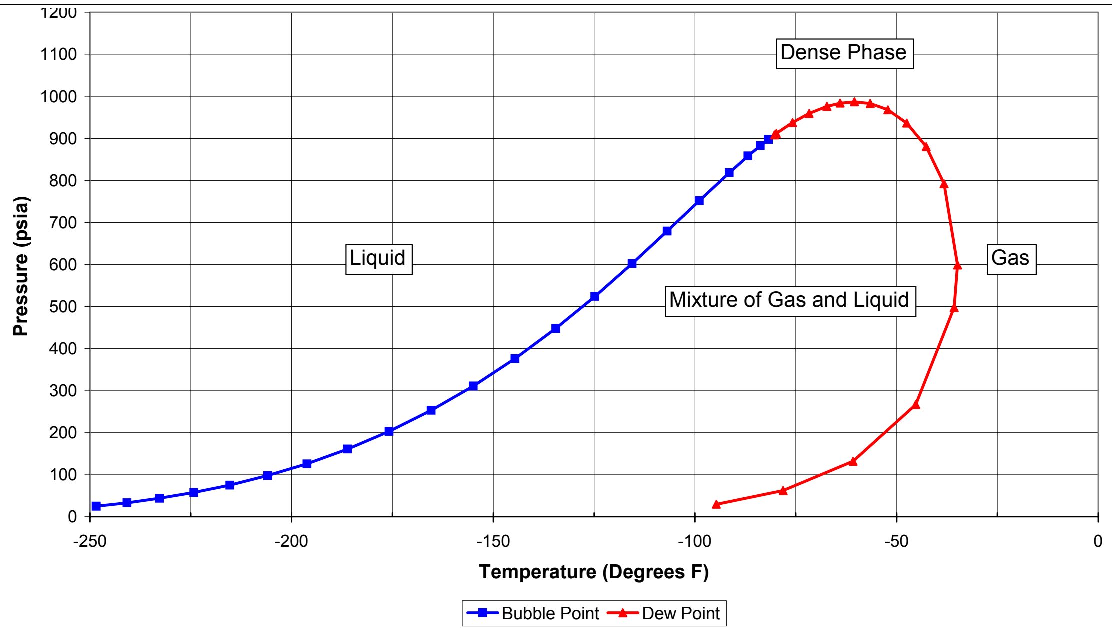


Figure 3.5: Phase Envelope – CGF Residue Gas (Scenario 1)

The hydrocarbon mixture will be entirely in a liquid state at the pressure and temperature combinations to the left of the envelope and will be a gas at the conditions to the right of the envelope. Both liquid and gas phases will be present at the conditions within the envelope. The relative amounts and respective compositions of the gas and liquid phases will vary depending upon the particular pressure and temperature combinations within the envelope.

The bubble point curve refers to the conditions at which gas will just begin to form within a mixture of hydrocarbons in the liquid phase. Referring to the CGF residue gas shown in Figure 3.5, a sample of this hydrocarbon mixture gas would be a liquid at 600 psia and –150 deg F. Gas would begin to form if the sample were heated at a constant 600 psia pressure to a temperature of approximately –116 deg F. A progressively larger portion of the mixture would transition from the liquid to gas phase as the sample was heated to a temperature of approximately –35 deg F at 600 psia, and above this temperature no liquid would be present.

The curve at which the last portion of liquid vaporizes, or conversely the point at which the first liquid appears as the mixture is cooled, is known as the dew point.

Figure 3.5 shows that a distinct liquid phase cannot be present at pressures above 1,000 psia regardless of the temperature. The area above the phase envelope is known as the ***dense phase region***.

Most of the sponsors of gas pipeline projects from Alaska have proposed pipelines with a maximum operating pressure (MOP) of around 2,400 to 2,600 psig, thus these pipelines will be operating in the dense phase gas region. Phase envelopes are useful in the design of the pipeline to ensure that a liquid phase will not be encountered over the range of operating conditions anticipated for the pipeline. The pipeline and compressor stations are configured to avoid conditions that can result in the condensation of liquids and subsequent formation of liquid slugs that can damage the pipeline and/or the compressor stations.

The composition of the gas mixture has a significant impact on the shape of the phase envelope. Enriching natural gas with non-methane hydrocarbons tends to shift the two-phase region of the envelope to include conditions of higher temperatures and pressures.

The following example of a hypothetical pipeline operating subject to various scenarios of gas composition will be used to illustrate the impact of gas composition on pipeline design. For the purposes of the example, it will be assumed that the minimum allowable pipeline pressure at the inlet of a compressor station will be 1,400 psia. It will be assumed that the pipeline operating temperature will be maintained between 10 and 60 deg F, and that the MOP of the pipeline is 2,515 psia.

Discussions of phase envelopes generated for the gas composition scenarios shown in Table 3.4 are contained in the following sections. Uniform scales for the pressure and temperature axes were used to illustrate the relative impact of gas composition on the shape of the envelope.

Table 3.4: Gas Compositions for Phase Envelope Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Gas composition (mole %)					
Carbon dioxide	0.00	1.50	2.59	1.51	1.51
Nitrogen	0.70	0.60	0.03	0.31	0.57
Methane	91.29	82.81	50.09	62.73	80.96
Ethane	5.81	7.81	19.61	15.65	8.54
Propane	1.76	4.93	15.48	17.09	5.96
I-butane	0.14	0.52	2.33	1.05	0.58
N-butane	0.21	0.95	4.84	1.16	1.00
Pentanes+	0.09	0.88	5.03	0.50	0.88
Total	100.00	100.00	100.00	100.00	100.00
HHV (BTU/scf)					
	1,084	1,182	1,678	1,433	1,205

3.3.1. Scenario 1 – CGF Residue Gas after removal of carbon dioxide

Scenario 1 consists of residue gas from the Prudhoe Bay CGF after processing to remove essentially all the carbon dioxide to a LNG quality specification. The phase envelope for Scenario 1 is shown in Figure 3.6 and is identical the curve shown in Figure 3.5 except that the scale of the axes has been changed. This scenario reflects gas that is lean in non-methane enriching hydrocarbons since most of these components are removed from the Prudhoe Bay gas within the CGF.

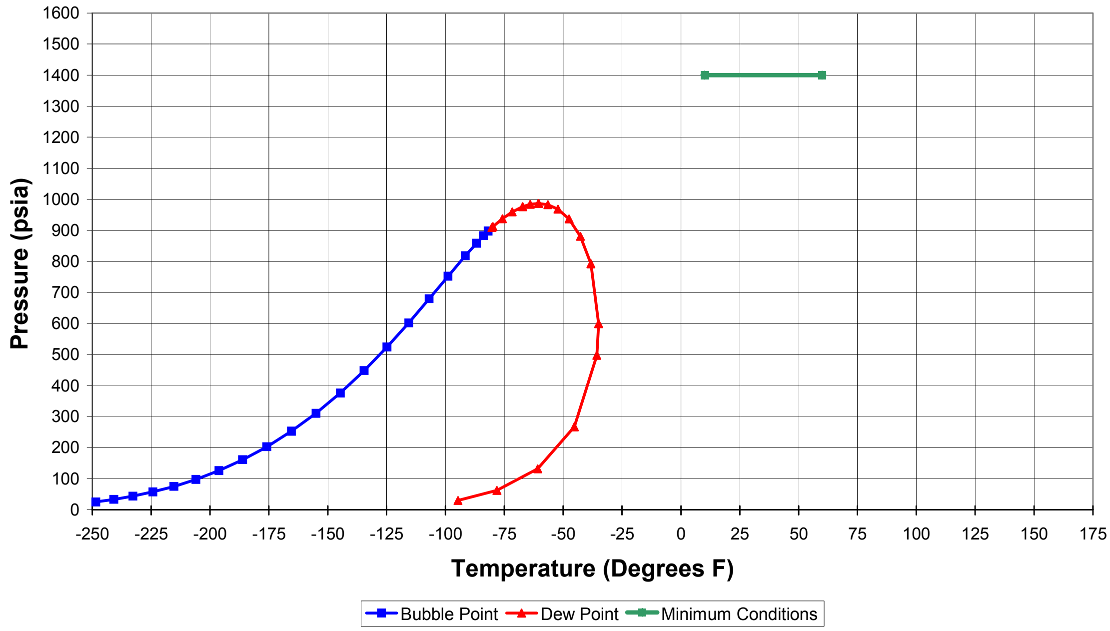


Figure 3.6: Phase Envelope – CGF Residue (Scenario 1)

The minimum pipeline operating conditions are depicted in Figure 3.6 as a horizontal line at 1,400 psia from 10 to 60 deg F. Pipeline operation at the minimum pressure and temperature conditions of the hypothetical example pipeline will be well outside of the two-phase region of phase envelope, thus the pipeline can be designed with little concern for encountering two-phase flow during normal pipeline operations.

3.3.2. Scenario 2 – ANGDA's "maximum conservation case"

Scenario 2 is based on the use of unprocessed gas from the Prudhoe Bay field spiked with MI equivalent to the average rate and composition of MI reported to the AOGCC for the year 2003. The composition of the unprocessed gas was assumed to be the same as the feed gas to the CGF according to data available in 1995. The amount of unprocessed gas was adjusted so that a pipeline inlet rate of 4.5 Bscfd was achieved after removal of carbon dioxide to a concentration of 1.50 mole percent. The phase envelope for Scenario 2 is shown in Figure 3.7.

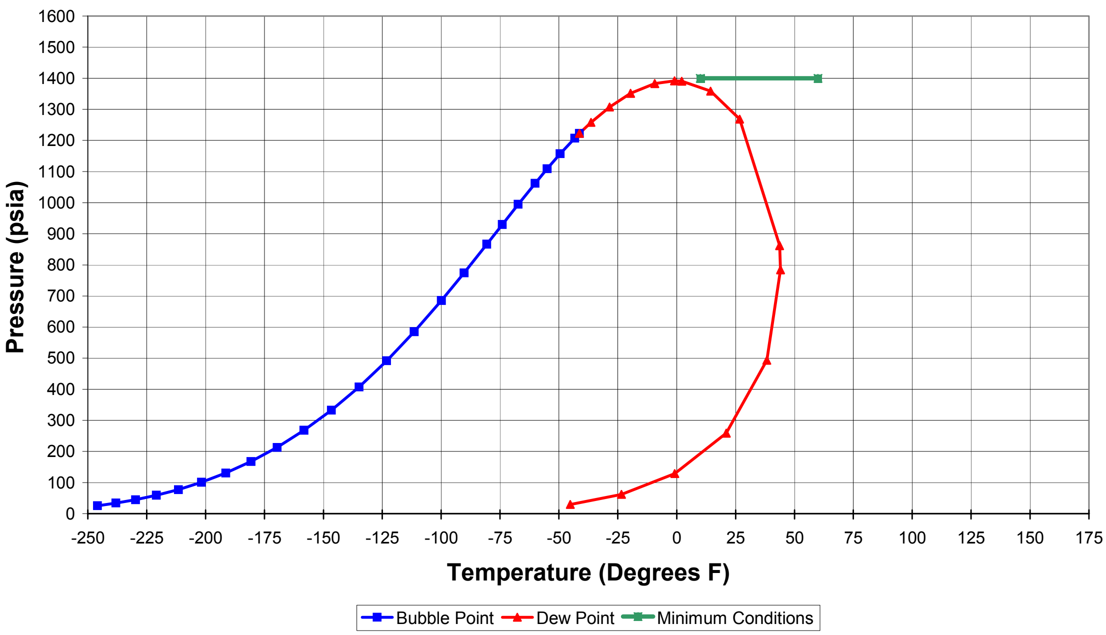


Figure 3.7: Phase Envelope – Maximum Conservation Case (Scenario 2)

The gas composition of Scenario 2 has a much higher content of non-methane hydrocarbons than the CGF residue gas of Scenario 1. The addition of these enriching compounds shifts the two-phase region of the phase envelope to much higher pressures and temperatures. The suction conditions of 1,400 psia and 10 deg F as postulated for the hypothetical pipeline example would result in pipeline operation very close to the phase envelope with little margin to avoid the two-phase flow region should there be an excursion of pipeline operations outside of design conditions.

3.3.3. Scenario 3 – ANGDA's "NGL split with Alberta case"

Scenario 3 is based on the selective extraction of hydrocarbons from 4.5 Bscfd of flow through a pipeline to Alberta to produce a feed to a spur line of approximately 500 MMscfd. Scenario 3 is described in detail in Section 3.4.2. The spur line gas is highly enriched with non-methane hydrocarbons with the concentrations of butane and pentane being the greatest of all five scenarios. The impact of this gas enrichment is to significantly shift the phase envelope, shown in Figure 3.8, to include higher pressures and warmer conditions.

Figure 3.8 shows that the two-phase region of the envelope extends to pressures above the 1,400 psia minimum operating pressure assumed for the example pipeline; however, this high-pressure region of the envelope occurs outside of the projected operating range of the pipeline thus two-phase flow would be avoided. The designers of a pipeline operating subject to this scenario would need to scrutinize summer operation of the pipeline, especially subject to low flow conditions, to ensure that operating temperatures above the 60 deg F postulated for the example would not be encountered at the compressor suction.

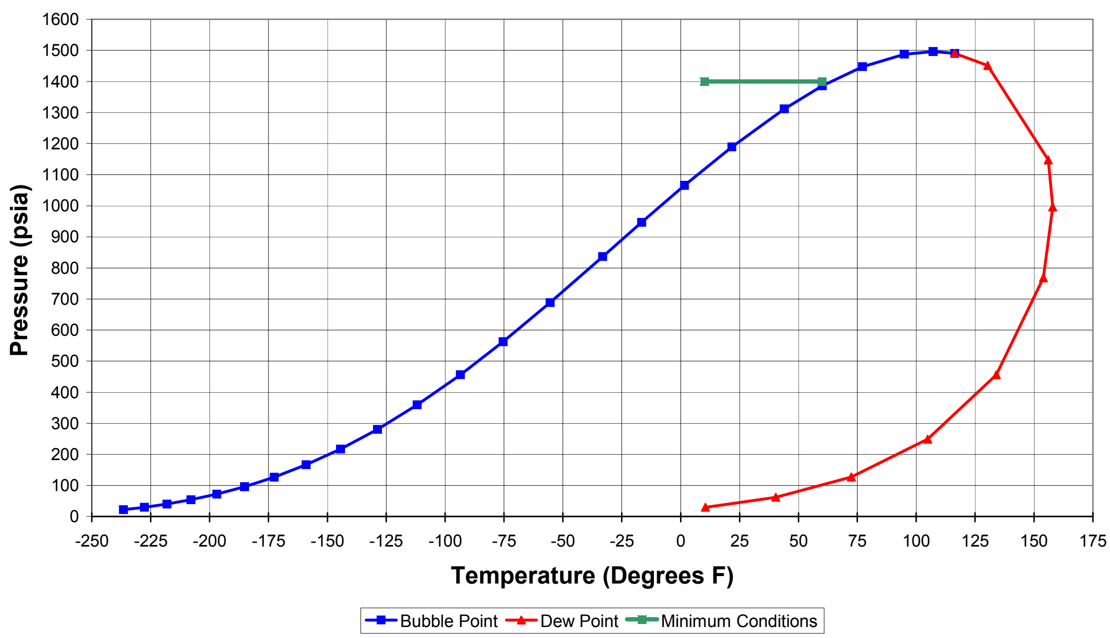


Figure 3.8: Phase Envelope – NGL Split with Alberta (Scenario 3)

Increasing the pressure from the minimum operating conditions of 1,400 psia, and *for example*, 20 deg F, to the 2,515 psia MOP of the example pipeline would result in the gas moving from the liquid phase at the compressor/pump suction to the dense phase at the discharge without passing through the two-phase region of the phase envelope. Theoretically, the pipeline could operate in the liquid and dense phase regions without encountering two-phase flow.

If the discharge gas at 2,515 psia were warmed to 150 deg F and then the pressure reduced to 1,400 psia, while still maintaining the 150 deg F temperature, the mixture would move from the dense phase to the gas phase, again avoiding the two-phase region. Moving from a liquid phase to a gas phase in the manner described would result in the complete vaporization of the mixture without ever encountering a distinct liquid-gas interface. If, however, this same mixture had simply been heated from 20 to 150 deg F at a constant 1,400 psia pressure, a portion of the mixture would have condensed and then re-vaporized as it moved from the liquid to the gas region.

The preceding discussion illustrates that a pipeline designer has significant latitude regarding specification of the pipeline provided that the anticipated range of operating conditions lie above or on either side of the phase envelope for the gas to be transported. A margin of error with regard to pipeline operation close to the phase envelope should also be provided to allow for temporary excursions from normal operating conditions.

Consideration must also be given to the impacts of potential changes in gas composition over the life of the project.

3.3.4. Scenario 4 – EGSP Project: Low Flow Case

The EGSP project consists of a 24-inch diameter pipeline transporting various mixtures of unprocessed field gas and MI after removal of carbon dioxide to approximately 1.50 mole percent. The low flow case (400 MMscfd) for the EGSP project consists of an enriched gas of about 1,433 btu/scf achieved by combining a relatively small amount of unprocessed gas with a relatively large amount MI. The blend of unprocessed gas and MI at the feed to the gas conditioning plant would contain approximately 45,000 barrels per day of propane. The phase envelope for Scenario 4 is shown in Figure 3.9.

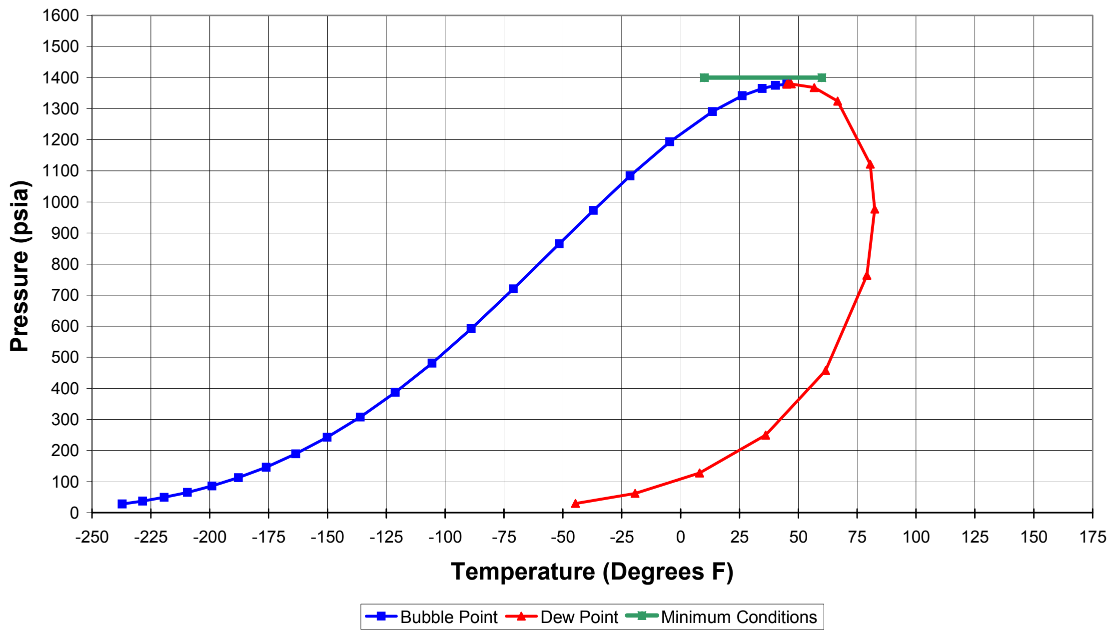


Figure 3.9: Phase Envelope – EGSP Project at 400 MMscfd (Scenario 4)

The minimum pipeline operating conditions (1,400 psia and 10 to 60 deg F) lie slightly above the portion of the two-phase region of the phase envelope. Although the minimum operating conditions are outside of the two-phase region, designing the pipeline for a minimum allowable suction pressure to 1,500 psia would appear prudent for this scenario in order to provide a margin of error regarding pipeline operation near the two-phase region.

3.3.5. Scenario 5 – EGSP Project: High Flow Case

Scenario 5 reflects the high flow case (1.15 Bscfd) for the EGSP project that is obtained by mixing a relatively large quantity of unprocessed gas with MI to again achieve feed to the conditioning plant containing 45,000 barrels per day of propane. The heating value of the mixture is less than that of Scenario 4 because relatively less MI is blended into the unprocessed gas. The phase envelope for Scenario 5 is shown in Figure 3.10.

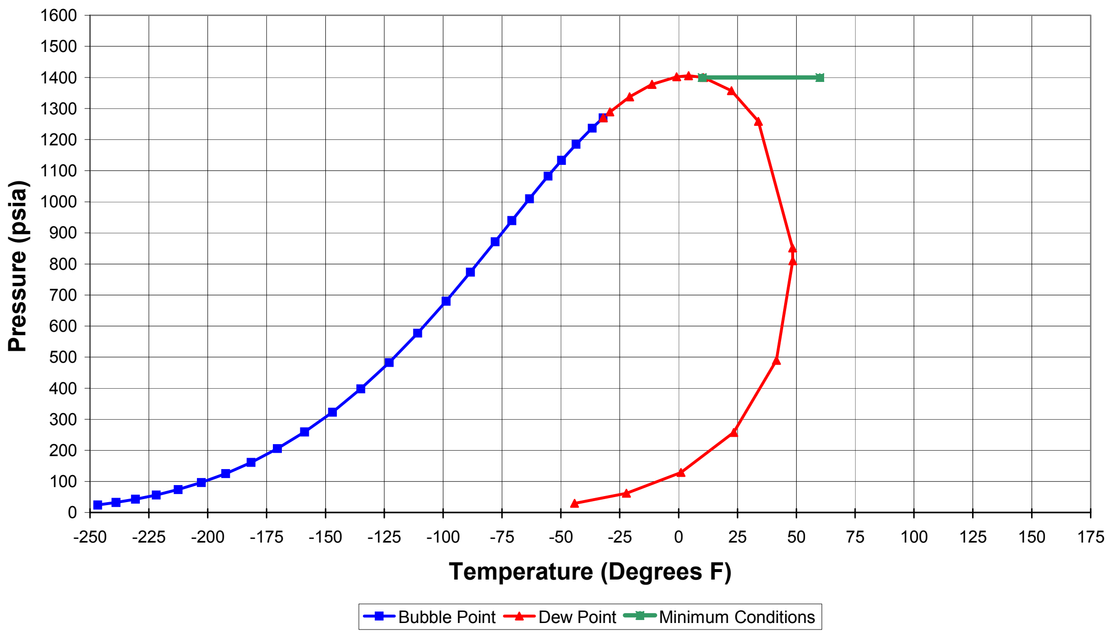


Figure 3.10: Phase Envelope – EGSP Project at 1.15 Bscfd (Scenario 5)

The minimum operating conditions of the hypothetical pipeline intersect the top of the phase envelope, thus providing no margin to allow for excursions in pipeline operations from design conditions. Specifying the pipeline and compressor station configuration based on a minimum allowable operating pressure to 1,500 psia would appear appropriate for this scenario.

Phase envelopes for all potential gas compositions anticipated over the life of the project should be developed and addressed in the pipeline design. In this case, phase envelopes for unprocessed gas and MI mixtures necessary to generate flows of 600, 800, and 1,000 MMscfd would be reviewed with regard to potential impact on the pipeline design and operation.

3.4. Take-off Pipeline from the Highway Project – Extremely Enriched Gas

The take-off pipeline from the Highway Project refers to removal of a portion of hydrocarbons from a large diameter pipeline generally following the road infrastructure from the North Slope to Alberta, and then transporting these hydrocarbons via pipeline to Cook Inlet, Port Valdez, or a combination of both. The hydrocarbons would be removed from the Highway Project by a processing plant located at Delta Junction. This concept is sometimes referred to as the "***Y-line***" because the configuration of pipelines from the North Slope to Delta Junction, from Delta Junction to Alberta, and the spur line from Delta Junction to Port Valdez and/or Cook Inlet resemble a "Y."

The opportunity exists to install a facility in Delta Junction to extract enough non-methane hydrocarbons to produce a utility grade gas for transport to Alberta. The feed gas to the spur line could be extremely enriched since the non-methane hydrocarbons contained in 4.5 Bscfd could be concentrated into a relatively small volume of gas entering the spur line. A discussion of this extremely enriched gas scenario is contained in Section 3.4.1.

Another approach to the take-off concept is to split the NGL components with Alberta by configuring the facility at Delta Junction to extract only a portion of the non-methane hydrocarbons. A discussion of this scenario is contained in Section 3.4.2.

The results presented in the following two sections reflect material balances based on particular assumptions for stream flow and compositions without consideration of the total hydrocarbons reserves at Prudhoe Bay.

3.4.1. Extremely Enriched Gas

The HYSYS software was used to prepare a model of a simple ***Joule-Thompson (JT)***-type straddle plant to selectively extract non-methane hydrocarbons from 4.5 Bscfd of gas flowing through a pipeline from Prudhoe Bay to Alberta. The HYSYS model, shown in Figure 3.11, was used to prepare material balances for two scenarios of the take-off project, one based on a feed consisting of unprocessed Prudhoe Bay gas and the other based on CGF residue gas.

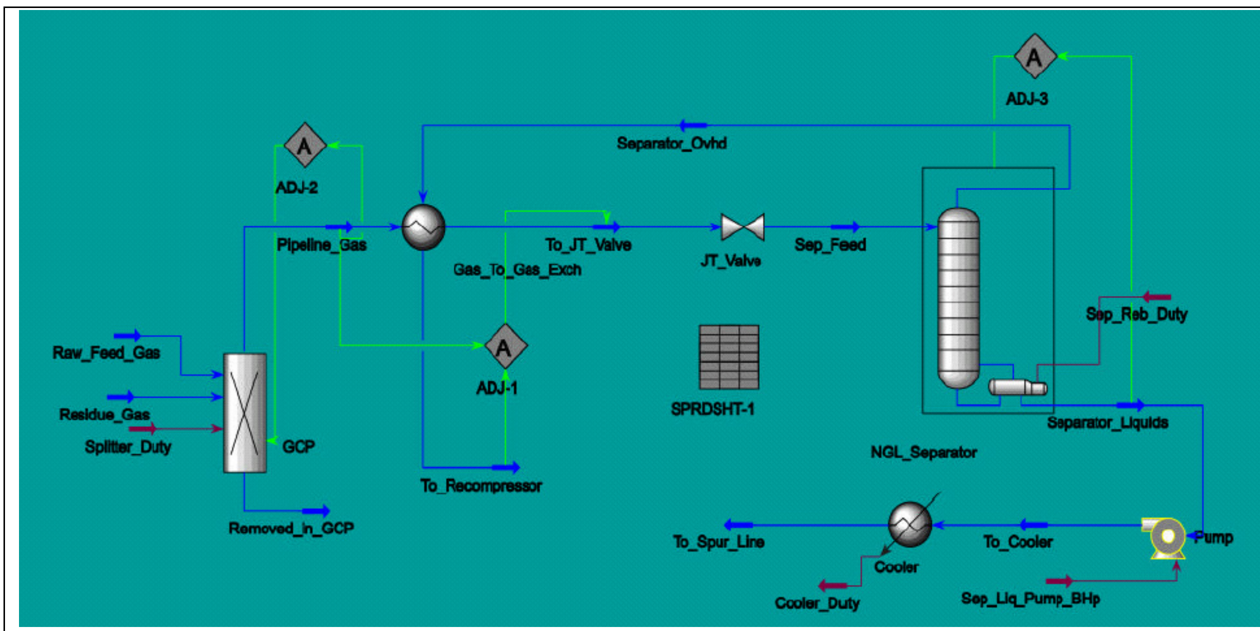


Figure 3.11: Flow Diagram for JT-type NGL Plant

The model of the JT plant was prepared for the sole purpose of generating reasonable material balances for a generic facility and should not be construed as representing a rigorous facility design or a design that has been optimized in any manner. The model is simply an efficient tool to approximate the rate and composition of streams of a "notional" facility.

Beginning at the left portion of the Figure 3.11, a component splitter was used to adjust the carbon dioxide content of the feed gas to 1.50 mole percent prior to entering the pipeline. It was assumed that 4.5 Bscfd of pipeline gas would arrive at the facility at 1,800 psig and 25 deg F. The pipeline gas is cooled through a heat exchanger ("Gas_To_Gas_Exch"); the pressure is lowered to 650 psia through the JT-valve, and then fed to a reboiled gas/liquid separator ("NGL_Separator"). The operation of the separator is adjusted to reject methane overhead as required to produce a liquid rate leaving the separator equivalent to 500 MMscfd gas flow. The overhead gas from the NGL separator, or residue gas, is warmed via cross exchange with the plant feed and then routed to compressors, coolers, and chillers as required to return the gas to pipeline operating conditions.

Unprocessed Gas from Prudhoe Bay

The results shown in Table 3.5 were generated using the HYSYS model assuming a 4.5 Bscfd feed consisting of unprocessed field gas from Prudhoe Bay. The simple JT-type plant provides reasonable recoveries of propane and heavier hydrocarbons and yields a utility grade gas for transport to Alberta. Propane recoveries in excess of 95 percent could probably be achieved with a more sophisticated process facility, but with the downside of higher capital costs and potentially more complicated operation.

Table 3.5: Highly Enriched Gas to the Spur Line – Unprocessed Gas Feed

	Feed from Pipeline	Utility Grade Gas & Fuel	Gas to Spur Line
Stream name			
	"Pipeline_Gas"	"To_Recompressor"	"To_Spur_Line"
Rate, MMscfd			
	4,500	3,999	501
Mole Percent			
Carbon dioxide	1.50	1.21	3.82
Nitrogen	0.64	0.72	0.00
Methane	85.26	93.62	18.49
Ethane	6.84	3.69	32.06
Propane	3.44	0.66	25.62
I-butane	0.46	0.04	3.83
N-butane	0.93	0.05	7.94
Pentane+	0.93	0.01	8.24
HHV (btu/scf)			
	1,151	1,031	2,113
Liquid content (barrel/day)			
Ethane	195,779	93,711	102,067
Propane	101,268	17,300	83,968
I-butane	16,073	1,152	14,921
N-butane	31,351	1,537	29,814
Pentane+	36,043	496	35,547
Percent liquid recovery			
Ethane			52
Propane			83
I-butane			93
N-butane			95
Pentane+			99

The product feed to the spur line consists of a methane rich liquid with an extremely high heating value. The methane content of the spur line feed can be adjusted by modifying the operation of the NGL separator (Figure 3.11) to allow more methane to leave with the bottom liquids. The 500 MMscfd gas equivalent flow for the spur line was selected arbitrarily for the purposes of the example.

The phase envelope for the spur line stream is shown in Figure 3.12. The mixture could be transported via a high-pressure pipeline without generating two-phase flow.

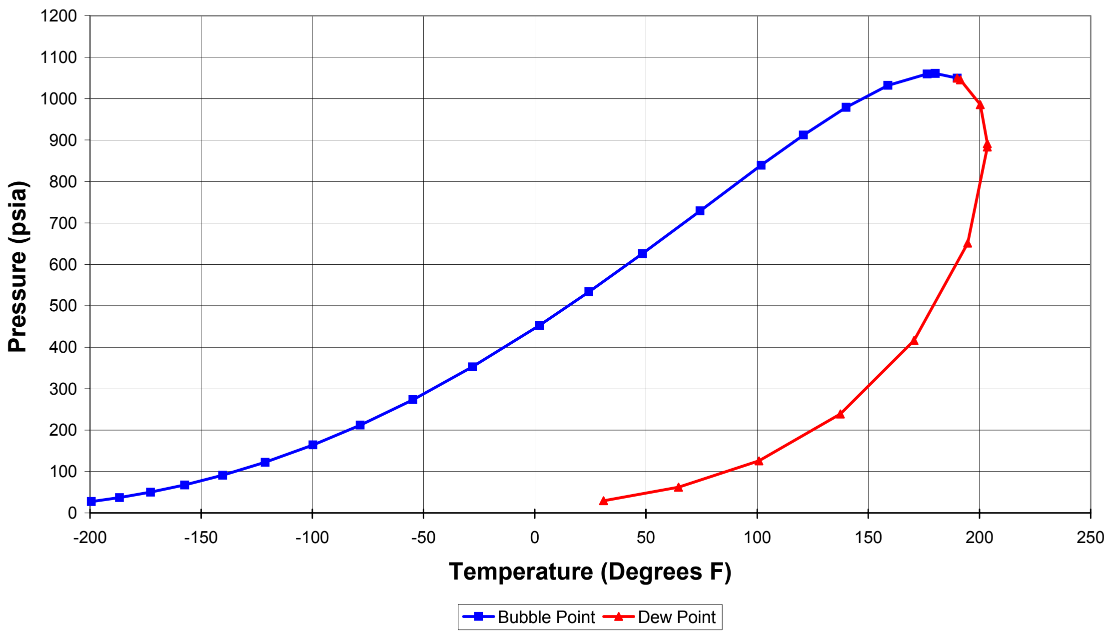


Figure 3.12: Phase Envelope – Enriched Gas to Spur Line, Unprocessed Gas

CGF Residue Gas from Prudhoe Bay

The overall material balance for a simple JT-type facility processing 4.5 Bscfd of residue gas from the Prudhoe Bay CGF is shown in Table 3.6. The phase envelope for the resulting product stream to a spur line is shown in Figure 3.13. The non-methane content of the CGF residue gas is much less than that of unprocessed gas from Prudhoe Bay and, accordingly, the material balance, composition of the spur line stream, and corresponding phase envelope differ from those generated based on a unprocessed gas feed.

A simple gas processing facility can achieve a reasonably good recovery of hydrocarbons while producing a utility grade gas for transport to Alberta, regardless of whether the feed consists of unprocessed gas or CGF residue gas.

The option exists to install a fractionation at Delta Junction to further process the spur line gas to extract propane for distribution within the Interior of Alaska. Regardless of the composition of the feed gas, a significant quantity of propane can be extracted from 4.5 Bscfd of gas being transported via a Highway pipeline project. *The option also exists to remove the propane at a facility located near tidewater at either Port Valdez or Cook Inlet and then truck propane to the Alaska markets in the Interior.* A review of the relative merits of these options was outside the scope of the current study.

Table 3.6: Highly Enriched Gas to the Spur Line – CGF Residue Gas

	Feed from Pipeline	Utility Grade Gas & Fuel	Gas to Spur Line
Stream name			
	"Pipeline_Gas"	"To_Recompressor"	"To_Spur_Line"
Rate, MMscfd			
	4,500	4,000	500
Mole Percent			
Carbon dioxide	1.50	1.16	4.24
Nitrogen	0.69	0.78	0.00
Methane	89.91	94.51	53.17
Ethane	5.72	3.13	26.49
Propane	1.74	0.40	12.46
I-butane	0.13	0.01	1.09
N-butane	0.21	0.02	1.77
Pentane+	0.09	0.00	0.78
HHV (btu/scf)			
	1,068	1,021	1,444
Liquid content (barrel/day)			
Ethane	163,718	79,512	84,206
Propane	51,152	10,380	40,772
I-butane	4,676	449	4,227
N-butane	7,134	503	6,631
Pentane+	3,453	81	3,372
Percent liquid recovery			
Ethane			51
Propane			80
I-butane			90
N-butane			93
Pentane+			98

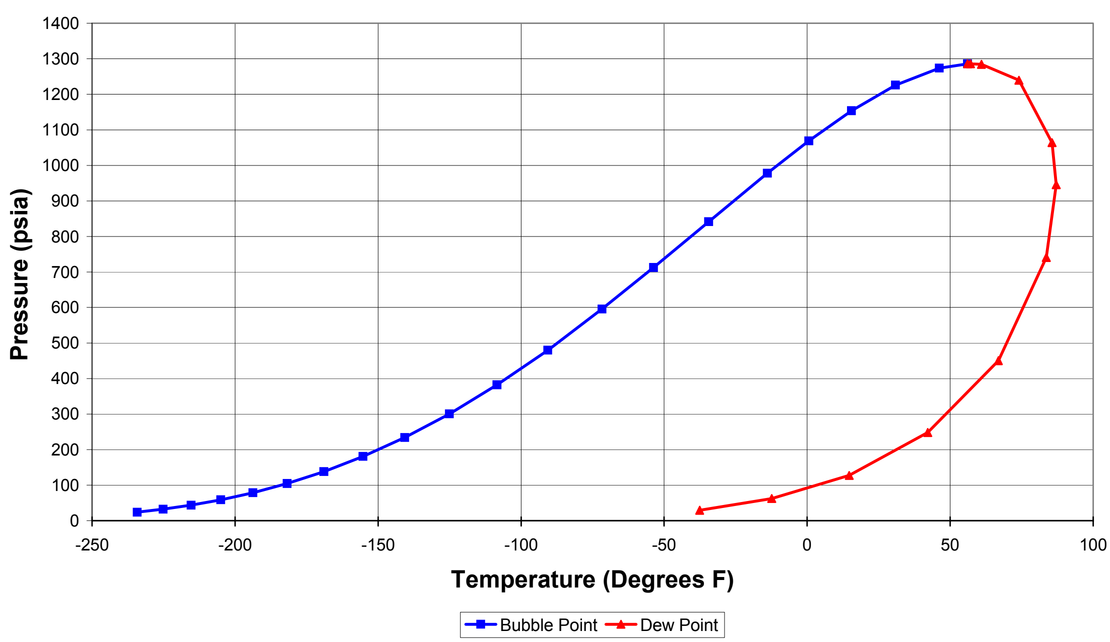


Figure 3.13: Phase Envelope – Enriched Gas to Spur Line, Residue Gas

3.4.2. Split Propane with Alberta

ANGDA is considering a configuration of the take-off concept in which the propane being transported via a Highway pipeline project would be split equally at a facility in Delta Junction with half going to the spur line and the other half sent to Alberta. This approach would not result in a utility grade gas being sent to Alberta, and another gas processing facility would be required in Alberta or elsewhere downstream to extract NGL to ultimately produce utility grade gas.

The processing facility at Delta Junction can be configured in numerous ways to achieve an equal split of propane between the spur line and the pipeline to Alberta if there is flexibility regarding the amount of ethane, butane, and heavier components that are also recovered. Material balances were prepared for feeds of unprocessed gas and CGF residue gas using the JT-type configuration shown in Figure 3.14. A much more complicated facility, including liquid fractionation, would be required if the content of ethane and butane in the spur line were limited such that a utility grade gas would be obtained from spur line gas after removal of propane.

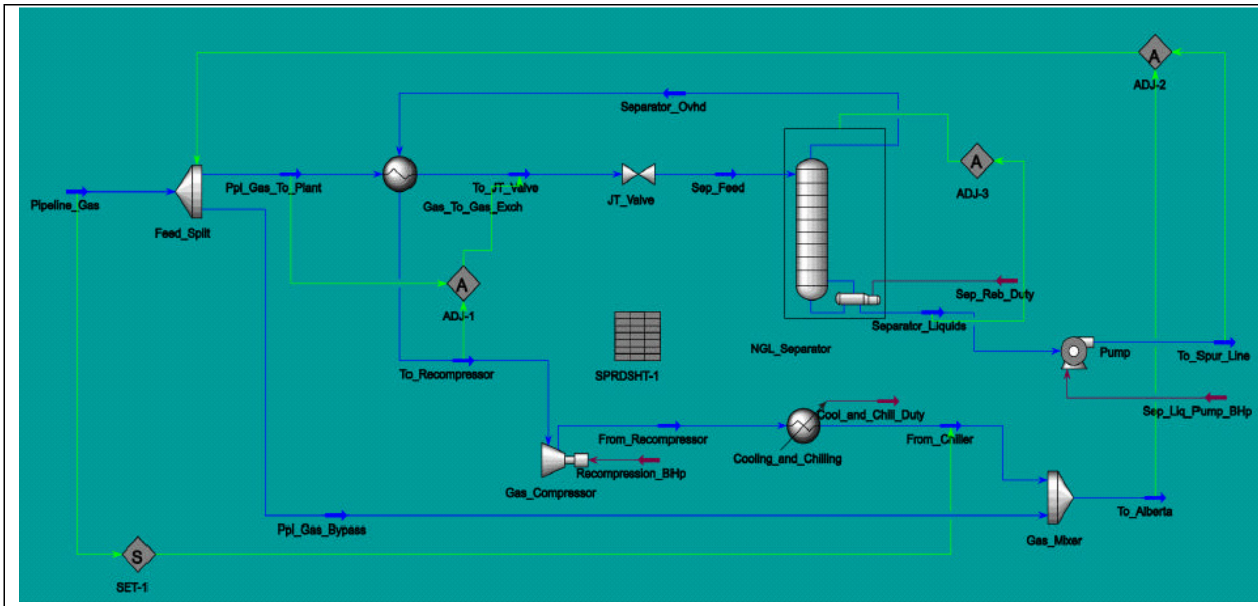


Figure 3.14: JT-type Facility for Equal Split of Propane

The configuration shown in Figure 3.14 is the same as the facility discussed in the previous section, except that a portion of the feed gas is allowed to bypass the processing facility. As before, the operation of the NGL separator is adjusted so that a liquid stream at a rate of 500 MMscfd gas equivalent is produced for the spur line. The bypass around the plant is combined with the overhead gas from the NGL separator to form the stream that is sent to Alberta. The split governing whether the gas is sent to the facility or bypassed around the facility is adjusted so that the amount of propane contained in the recombined stream to Alberta is the same as that of the stream to the spur line. The material balance does not account for plant fuel.

Unprocessed Gas from Prudhoe Bay

The material balance for a simple JT-type facility to achieve an equal split of propane between the spur line and the line to Alberta is shown in Table 3.7. A review of this table shows that the propane in the feed has been split equally between the two product streams with less than 50 percent of the ethane and around 60 percent of the butane and heavier recovered hydrocarbons to the spur line. The phase envelope for composition of the spur line is shown in Figure 3.8 (page 3-19).

Table 3.7: Material Balance – Propane Split to Spur Line, Unprocessed Gas

	Feed from Pipeline	Gas to Alberta	Gas to Spur Line
Stream name			
	“Pipeline_Gas”	“To_Alberta”	“To_Spur_Line”
Rate, MMscfd			
	4,500	4,000	500
Mole Percent			
Carbon dioxide	1.50	1.36	2.59
Nitrogen	0.64	0.72	0.03
Methane	85.26	89.65	50.10
Ethane	6.84	5.24	19.61
Propane	3.44	1.93	15.48
I-butane	0.46	0.23	2.33
N-butane	0.93	0.44	4.84
Pentane+	0.93	0.42	5.03
HHV (btu/scf)			
	1,151	1,086	1,678
Liquid content (barrel/day)			
Ethane	195,649	133,340	62,309
Propane	101,295	50,647	50,648
I-butane	16,097	7,036	9,062
N-butane	31,359	13,244	18,114
Pentane+	36,051	14,398	21,654
Percent liquid recovery			
Ethane			32
Propane			50
I-butane			56
N-butane			58
Pentane+			60

CGF Residue Gas

The material balance for a JT-type facility processing residue gas to split the propane between the spur line and the line to Alberta is shown in Table 3.8. Removal of half the propane and slightly more of the butane and heavier components for feed to the spur line results in a gas to Alberta with a heating value within utility grade specifications. Further processing of the gas to Alberta would not be required unless NGL were to be extracted for a petrochemical industry.

3.4.3. Utility Grade Gas to Spur Line

Although the subject is gas enrichment, it is worth noting that utility grade natural gas could be obtained for the spur line using a facility similar to the JT process described above. Instead of processing the entire pipeline gas stream, a smaller slipstream would be processed to produce the desired volume of utility grade gas entering the spur line. The liquids from the process facility could then be fractionated to extract propane for distribution to Alaska markets with the remainder liquids re-injected into the pipeline to Alberta.

Subject to the above scenario, utility grade gas could be obtained at any point along the spur line. The gas exiting the spur line in Palmer could enter the Enstar gas distribution system by simply lowering the pressure.

Table 3.8: Material Balance – Propane Split to Spur Line, CGF Residue Gas

	Feed from Pipeline	Gas to Alberta	Gas to Spur Line
Stream name			
	"Pipeline_Gas"	"To_Alberta"	"To_Spur_Line"
Rate, MMscfd			
	4,500	4,000	500
Mole Percent			
Carbon dioxide	1.50	1.33	2.83
Nitrogen	0.69	0.76	0.12
Methane	89.92	92.36	70.40
Ethane	5.72	4.37	16.51
Propane	1.74	0.98	7.83
I-butane	0.13	0.06	0.68
N-butane	0.21	0.10	1.13
Pentane+	0.09	0.04	0.51
HHV (btu/scf)			
	1,068	1,041	1,280
Liquid content (barrel/day)			
Ethane	163,613	111,114	52,498
Propane	51,236	25,616	25,620
I-butane	4,549	1,923	2,626
N-butane	7,081	2,854	4,227
Pentane+	3,489	1,276	2,213
Percent liquid recovery			
Ethane			32
Propane			50
I-butane			58
N-butane			60
Pentane+			63

3.4.4. Design Considerations for a Spur Line Project

Numerous schemes for processing the gas flowing through the Highway Pipeline project can be postulated to produce natural gas with a wide range of potential compositions for delivery to the inlet of a spur line beginning at Delta Junction. The complexity of this processing facility will depend on how the individual NGL components are to be extracted for delivery to the spur line. It may be possible to install a relatively simple processing facility if the spur line can accommodate a mixture of NGL components.

Individual components of a NGL extraction facility are shown in Figure 3.15. The general design approach for a NGL extraction facility is to use heat exchange and pressure drop to cool the gas and cause condensation of hydrocarbon liquids. The NGL separator can consist of a simple separator or a reboiled column depending on the desired quantity and composition of the feed gas to the spur line. The de-methanizer and NGL separator can be combined if the goal is to transport only ethane and heavier components down the spur line.

Among others, the option exists to separate a utility grade natural gas from NGL components in Glennallen, send the gas to Palmer and the NGLs to Port Valdez. Referring to Figure 3.15, such a scenario would require installation of a de-methanizer in Glennallen with the remaining fractionation columns installed in Valdez as necessary to meet market specifications. Routing a methane rich spur line stream to Palmer would require that a de-methanizer and NGL fractionation be installed at Palmer.

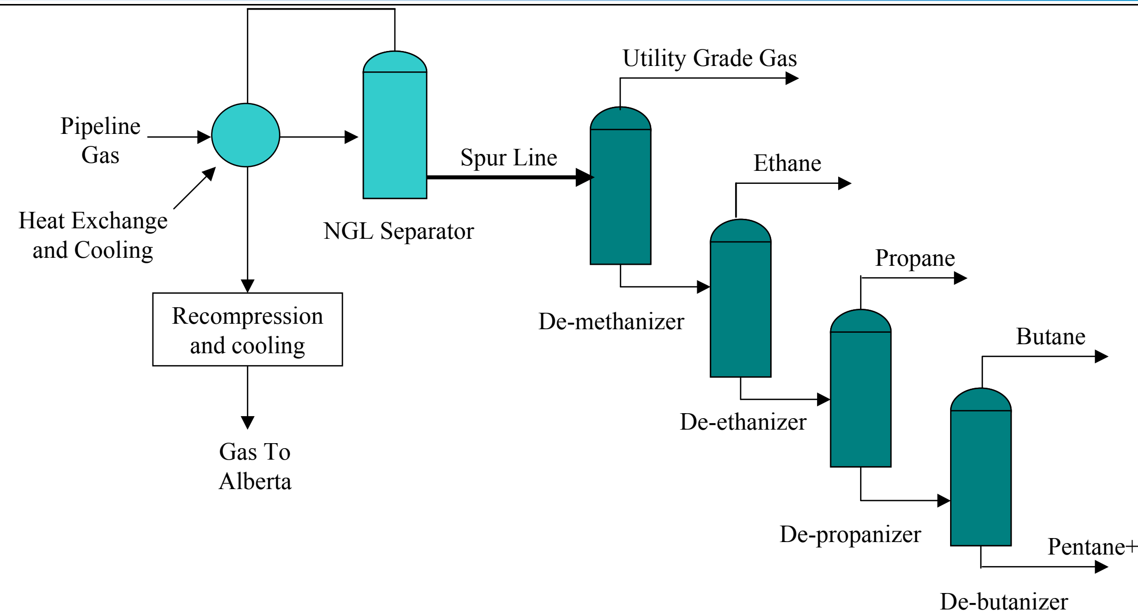


Figure 3.15: Overall Component Facilities of the Take-off Project

Extraction of hydrocarbon components generally requires that the entire stream be processed. *For example*, extraction of a large percentage of the propane and heavier components from the Highway Project will require that the entire 4.5 Bscfd of pipeline gas be processed and then recompressed for return to the pipeline. Extraction of the propane from the spur line in Glennallen would require processing of the entire spur line stream.

It is recommended that ANGDA complete a NGL marketing analysis as part of the feasibility study to determine the best means of disposing the hydrocarbons extracted from the Highway Project and transported via the Take-off project. Consideration should be given to identification of a scheme by which each hydrocarbon processing service is installed only once. Installation of a processing service multiple times to effect sequential partial separations of hydrocarbons will result in increased capital costs. Consideration should also be given to centralizing a processing facility and trucking extracted propane to the various markets in the Alaska Interior.

3.5. Carbon Dioxide Content of Pipeline Gas – Conditioning Plant

The gas in the Prudhoe Bay Pool contains approximately 12 percent carbon dioxide. All of the recent proposals for a major gas project include a facility on the North Slope to remove carbon dioxide prior to the gas entering the pipeline. The amount of carbon dioxide removed depends on whether the gas is destined for delivery to the Lower 48 markets via a pipeline through Canada or via liquefaction in a facility located in south-central Alaska.

Carbon dioxide and hydrogen sulfide form acids in the presence of water and are sometimes referred to as ***acid gases***. A gas containing hydrogen sulfide is sometimes referred to as ***sour gas*** while a gas that contains no hydrogen sulfide is called ***sweet gas***. ***Gas conditioning*** is sometimes referred to as ***acid gas removal*** or as ***gas sweetening***. A general schematic of an amine process for acid gas removal is shown in Figure 3.16. Amine plants have been specified for gas conditioning by the North Slope gas producers both for the Alaska North Slope LNG Project proposed in 2001 and the 4.5 to 5.6 Bscfd Highway Project proposed in 2002 (see Appendix H).

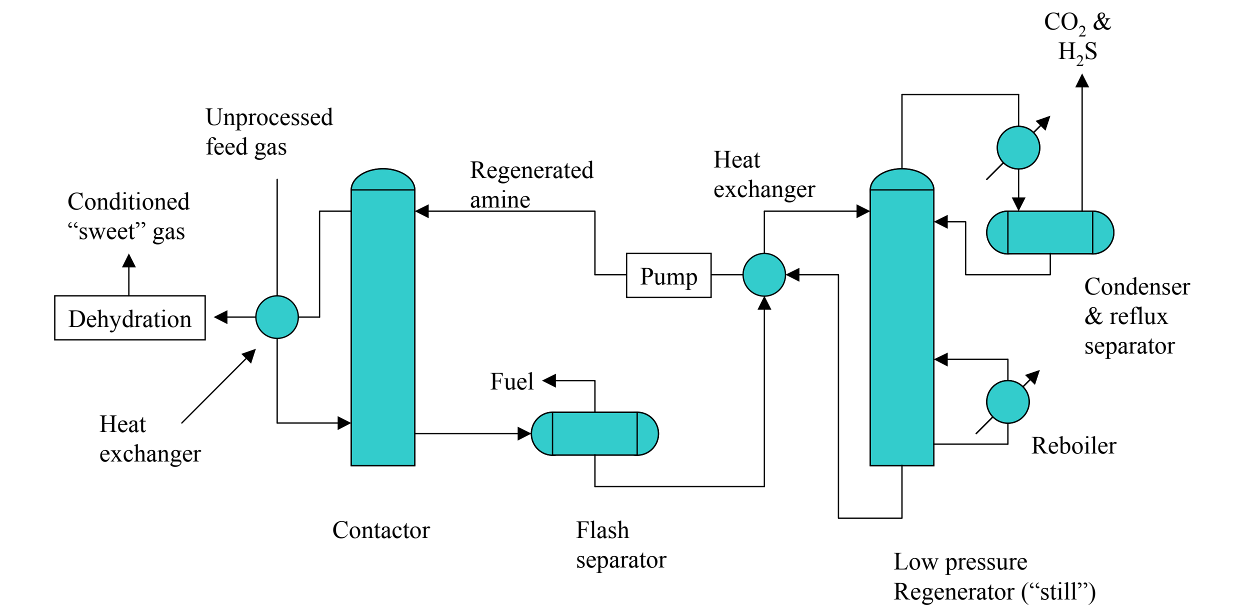


Figure 3.16: Amine Gas Conditioning Process, Simplified Schematic

Referring to Figure 3.16, the unconditioned feed gas at a pressure of approximately 600 to 700 psia is warmed slightly as it passes through a heat exchanger and then is routed to the bottom of the contactor. The feed gas passes upward through the contactor while the regenerated amine solvent flows downward through the column. Packing or trays within the column are used to cause the gas to bubble through or "contact" the amine solvent and the acid gases are removed from the feed gas by chemically bonding to the amine. The conditioned gas leaving the top of the tower is cooled slightly by cross exchange with the feed gas and then is sent to a dehydration facility to remove water picked up from the aqueous amine solvent.

The amine from the contactor is sent to a flash separator at which the pressure of the amine is reduced and absorbed hydrocarbons are vaporized and removed. The amine leaving the flash separator is routed to a heat exchanger and then to the top of the regeneration column. The regeneration column is essentially an atmospheric still with a reboiler at the bottom and a condenser at the top. The carbon dioxide and hydrogen sulfide are stripped from the amine as it passes down the still. The regenerated amine passes through a heat exchanger where it is cooled while warming the amine feed to the regeneration column. A pump is used to increase the pressure of the regenerated amine to the pressure of the contactor. Water vapor in the acid gases leaving the top of the still is condensed using air coolers and then returned to the top of the still as reflux. The carbon dioxide leaving the top of the regeneration column will be recompressed for re-injection into a reservoir.

3.5.1. LNG Quality Gas

The complexity and expense of the amine system depends on the degree of acid gas removal with the most costly facility required to achieve a LNG quality gas. The concentration of carbon dioxide in the feed to a gas liquefaction process must be in the range of 75 parts per million by volume (***ppmv***) or less in order to prevent the formation of solid carbon dioxide within the liquefaction process.

The counter current flow within the contactor results in the progressive removal of acid gases as the feed flows from the bottom to the top of the contactor, while simultaneously resulting in the enrichment of carbon dioxide in the amine as the solvent flows from top to bottom. Most of the carbon dioxide has been removed from the feed gas by the time it reaches the top of the column and contacts the newly regenerated amine. The top of the column is sometimes referred to as the "***polishing***" section because it is here where the final amount of carbon dioxide is removed by newly regenerated amine to achieve the very low concentrations of acid gas required for feed to a LNG plant.

3.5.2. Pipeline Quality Gas

A typical contractual specification for pipeline quality natural gas allows for approximately 3 percent total inert gases. The term "***inert gas***" refers to gas components such as nitrogen and carbon dioxide that have no heating value and provide no energy when the gas is combusted. The natural gas at Prudhoe Bay has approximately 0.7 mole percent nitrogen. The North Slope gas producers specified a conditioned gas of 1.5 mole percent carbon dioxide for their large diameter pipeline project to Alberta.

An amine system to achieve a conditioned gas with 1.5 mole percent carbon dioxide can be designed with less stringent equipment specifications than an amine plant designed to achieve an LNG quality gas. A 1.5 mole percent carbon dioxide concentration equates to 15,000 ppmv as compared to the 75 ppmv specification for the LNG specification gas.

For the same volume of feed gas, the capital costs for an amine plant to produce a 15,000 ppmv carbon dioxide conditioned gas would be expected to be less than a plant designed to produce a 75 ppmv LNG quality gas since: 1) the amine contactor does not have to be designed with a "polishing" section, 2) the still does not have be designed to regenerate the amine to remove as much carbon dioxide before the amine returns to the contactor; and 3) there would be less equipment required to handle the extracted carbon dioxide since less of the carbon dioxide is removed. *Operation of an amine plant to achieve a pipeline quality gas specification would be anticipated to be less problematic than an amine plant to achieve a LNG quality specification since the operating tolerances for the prior configuration would be more relaxed.*

3.5.3. Impact on Downstream Facilities

Removal of the carbon dioxide from the gas on the North Slope reduces the amount of non-revenue producing gas transported via the pipeline and provides the opportunity to use the carbon dioxide byproduct for enhanced oil operations. Carbon dioxide has no heating value and provides no revenues to the project. Removal of the bulk of the carbon dioxide from the gas prior to entering the pipeline will increase the revenue per unit of volume transported via the pipeline and the revenue per unit of capital expended for the pipeline.

Removal of essentially all of the carbon dioxide to achieve an LNG quality gas has the advantage of allowing all downstream gas processing facilities to be designed without concern for potential formation of solid carbon dioxide in the process equipment. This concern is mostly limited to facilities designed to achieve a very high recovery of ethane from the plant feed. Process simulations completed for this report indicate that facilities can be designed for a very high recovery of propane without encountering formation of solid carbon dioxide provided from a feed gas with a carbon dioxide concentration of 1.5 mole percent or less.

ANGDA is considering the option to remove a portion of the gas from a large pipeline Highway Project to be transported via a spur pipeline to south-central Alaska for use as utility gas and/or as feed to a new or existing LNG facility. Subject to this scenario, a second gas conditioning plant would be required somewhere along the spur pipeline to remove the carbon dioxide to LNG feed specifications. Essentially, the gas feed to the LNG plant would have to be conditioned twice, once on the North Slope and again along the spur line. Generally, project capital costs tend to be the lowest if a specific processing service is installed only once throughout the system. The costs for two gas conditioning plants would raise the unit costs of a feed to a LNG plant obtained via the spur line scenario.

Section 4. Pipeline – Configuration and Economics

The facilities at either end of the natural gas pipeline can be installed in discrete units with the capacity of these facilities expanded as needed to accommodate the schedule for ramp-up of the project throughput. Once installed, however, the diameter of the pipeline cannot be increased and the pipeline capacity can be expanded via the addition of compressor stations, "looping" the pipeline by installing parallel pipelines between stations, or a combination of both. ***A key leveraging issue for the all-Alaska LNG project is the specification of the diameter of the natural gas pipeline.***

For a given flow rate of gas, options exist to either install a larger diameter pipeline with fewer compressor stations or install a smaller pipeline with more compressor stations. The relative economic merits of these two options depend on the schedules of capital outlays relative to the operating revenues obtained from the prescribed ramp-up schedule of flow.

The COS and ROI analyses in this study show that multiple configurations of pipelines with differing pipeline diameters and number of compressor stations exist that yield approximately the same project economics over the 1 to 2 Bscfd flow rates being considered by ANGDA for the all-Alaska LNG project. Selection of a larger diameter pipeline with fewer stations would be more favorable than selection of a smaller diameter pipeline with more stations because the capacity of the larger diameter pipeline can be expanded by simply adding more gas compression and compressor stations. Expansion of the capacity of a smaller diameter pipeline will require looping the pipeline between stations which is much more problematic and costly.

4.1. Pipeline Compressor Stations

The pressure of the gas flowing through the pipeline will decrease in the direction of flow along the pipe. The purpose of the compressor station is to return the pressure of the gas to the maximum operating pressure. Descriptions of the general configuration of a compressor station with propane refrigeration system, fuel conditioning, power consumption at a compressor station, and the possible co-use of Alyeska facilities are contained in the following sections.

4.1.1. Conceptual Design for Compressor Stations

Depending on the mode of pipeline operation, a refrigeration system may be required to cool the compressor discharge gas to a temperature below 32 deg F prior to the gas reentering the pipeline. Thermal-hydraulic simulation of the pipeline is required to determine the seasonal refrigerant loads since the operation of both the gas compression and refrigeration system will vary seasonally. The refrigerant load will be the greatest during the warmer periods of the year with minimal to no refrigerant loads encountered during the winter.

A general process flow diagram for a typical gas compression system with propane refrigeration of the discharge gas is shown in Figure 4.1. The operating conditions contained in the following description were used to determine the peak refrigerant loads and the capital costs for the refrigeration systems specified throughout this study.

A HYSYS process simulation of the refrigerant loop was prepared based on a hypothetical summer operating mode consisting of pipeline gas arriving at the station inlet at 20 deg F and 1,515 psia, then being compressed to 2,530 psia. The temperature of the station inlet was selected to reflect warmer summer pipeline operations of seasonally reduced flow and warmer ground temperatures. The inlet pressure is consistent with the minimum operating pressure necessary to remain outside of the two-phase region of the phase envelope for some highly enriched gas scenarios (Section 3.3). The gas was compressed to 2,530 psia to allow for a 15 psi drop through the chiller and station discharge piping. It was assumed that the compressor discharge gas would be cooled to 28 deg F prior to re-entering the pipeline.

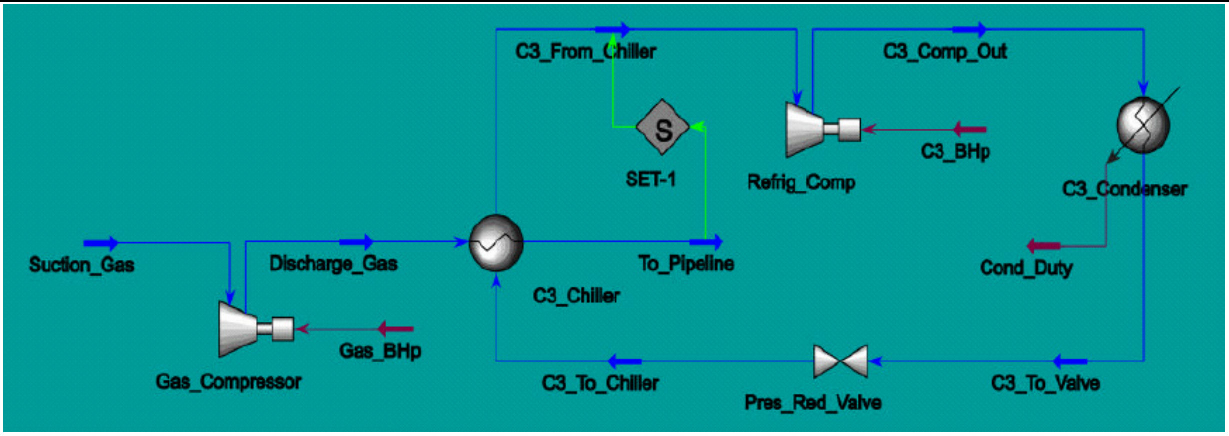


Figure 4.1: Typical Process Flow Diagram, Compressor Station with Refrigeration

The temperature of the gas at the discharge of the compressors (labeled “Gas_Compressor” in the figure) will vary depending on the efficiency of the compressor, the ratio of compressor discharge and suction pressures, and the temperature of the suction gas. A chiller is a heat exchanger consisting of numerous tubes immersed in a bath of liquid propane refrigerant. The warm discharge gas flows through the tube side of the refrigerant chiller (“C3_Chiller”) where it is cooled to 28 deg F while the liquid refrigerant in the chiller vaporizes. The vaporized refrigerant (“C3_From_Chiller”) is compressed to the pressure necessary for it to condense using ambient air as the cooling medium (“C3_Comp_Out”). The condensed refrigerant leaving the air-cooled condensers (“C3_To_Valve”) passes through a pressure reduction valve (“Pres_Red_Valve) and then is returned to the chiller. A portion of the refrigerant will vaporize as the pressure is reduced through the valve and this vapor passes through the chiller to the suction of the refrigerant compressor.

The operating conditions of the propane within the chiller depend on the target temperature for the compressed gas reentering the pipeline. Typically, the temperature of the refrigerant is maintained at approximately 5 deg F below that of the target temperature for the cooled pipeline gas. For example, cooling the pipeline gas to 28 deg F would require that the refrigerant be maintained at 23 deg F. There is a unique pressure at which the propane refrigerant will boil at 23 deg F, thus setting the refrigerant temperature also sets the operating pressure of the refrigerant side of the chiller. The pressure of the boiling refrigerant in the chiller is approximately 57 psia.

The vapor from the refrigerant compressor (“Refrig_Comp”) is condensed by passing it through numerous tubes contained in a cooler housing while large fans force ambient air around the exterior of the tubes (“C3_Condenser”). The refrigerant condensers are designed to allow for a difference in temperature between the condensed refrigerant and the ambient air being used as the cooling medium. Air cooled type condensers are typically specified based on a 15 to 20 deg F difference, or “approach,” between the ambient air temperature and condensed refrigerant.

The pressure to which the refrigerant vapors must be compressed in order to be condensed increases as the temperature of the ambient air increases. *The refrigerant loads in this study are based on an ambient air temperature of 70 deg F, a condenser approach of 20 deg F, and thus a refrigerant condensation temperature of 90 deg F.* Based on the refrigerant composition assumed in this study, the refrigerant will entirely condense to a liquid at 90 deg F and a pressure of approximately 179 psia. It was assumed that there would be a 10 psi pressure drop through the air-cooled refrigerant condenser, thus the refrigerant vapor leaving the chiller at 57 psia must be compressed to approximately 189 psia in order for the refrigerant to be condensed at 90 deg F.

The refrigeration system will operate more efficiently during the winter because the cooler ambient air temperature will allow the refrigerant vapor to be condensed at a lower temperature, and correspondingly, a lower pressure than during the summer. The operating pressure of the refrigerant side of the chiller, however, will not change seasonally as long as the target temperature of the discharge gas reentering the pipeline remains at 28 deg F. The differential pressure between the suction and discharge of the refrigerant compressor will drop during the winter, thereby reducing the load on the refrigerant compressor and the fuel consumption.

The temperature of the ground surrounding the pipeline upstream of the station will cool from summer to winter resulting in a corresponding reduction of the temperature of the gas at the compressor suction due to heat transfer through the wall of the pipe. A reduction in compressor suction temperature will result in a cooler compressor discharge gas and a reduction of the refrigerant load. The refrigerant loads will be lower during the spring and autumn with essentially no load encountered during the winter due to the combination of cooler discharge gas temperatures and increased efficiency of the refrigeration system.

The HYSYS simulation of the refrigeration system was adjusted to determine the operating horsepower at a 27 deg F ambient air temperature, which is the mean annual average at Fairbanks. The simulation results show that the refrigerant would have to be compressed to approximately 107 psia to be condensed at 47 deg F (20 deg F approach to 27 deg F). The refrigerant compression horsepower required at the average ambient conditions at Fairbanks is approximately 42 percent of the installed refrigerant horsepower based on refrigerant condensation at 90 deg F.

The installed horsepower for the refrigeration systems in this study are based on condensation of the refrigerant using warm ambient air during the summer and refrigerant condensation at 90 deg F. The average annual fuel consumption of the refrigeration system is based on an average refrigerant condensation temperature of 47 deg F and operation of the refrigerant compressor at 42 percent of the installed horsepower.

A conceptual layout of a “typical” compressor station with refrigeration is shown in Figure 4.3. The purpose of presenting Figure 4.3 is to show the general configuration of a typical compressor station. The relative loads and equipment sizing should not be construed from the number or size of equipment items shown.

4.1.2. Fuel Conditioning

In practice, a portion of the gas flow through a pipeline will be removed for fuel at every compressor station along the route. The calculations in this study are based on the assumption that the fuel would be extracted from pipeline gas entering the compressor station at 1,515 psia and 20 deg F. The composition of the fuel was estimated based on a HYSYS simulation of a simple JT-type facility to remove any liquids that may condense as the pressure of the fuel was decreased to that of the fuel system. The process flow diagram of the JT plant simulation is shown in Figure 4.2. The composition of the pipeline gas and fuel from the JT plant are shown in Table 4.3 (page 4-9).

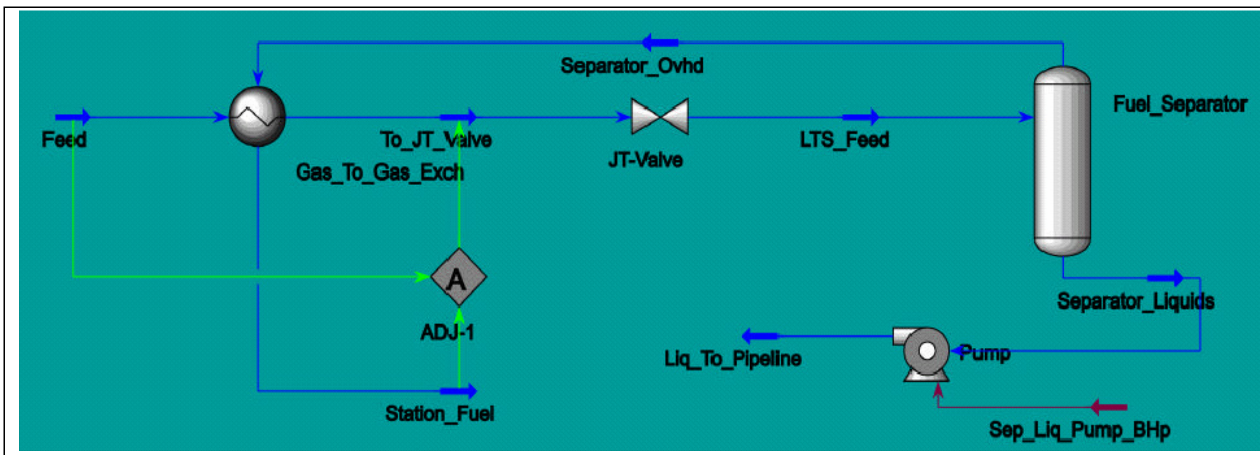


Figure 4.2: Fuel Processing Plant at Compressor Station

Referring to Figure 4.2, a slip-stream from the pipeline gas is routed through a heat exchanger where it is cooled while warming gas from the fuel separator. The gas then passes through a valve to reduce the pressure, thereby utilizing JT cooling of the methane rich gas to further reduce the temperature. Condensed liquids are separated from the gas and either fractionated to extract individual components, such as propane, or pumped into the dense phase pipeline gas leaving the station. The fuel separator overhead gas is warmed via heat exchange with the feed. The pressure of the liquid separator is adjusted so that the pressure of the fuel leaving the JT plant will be sufficient to enter the fuel system feeding the gas turbine compressor drivers.

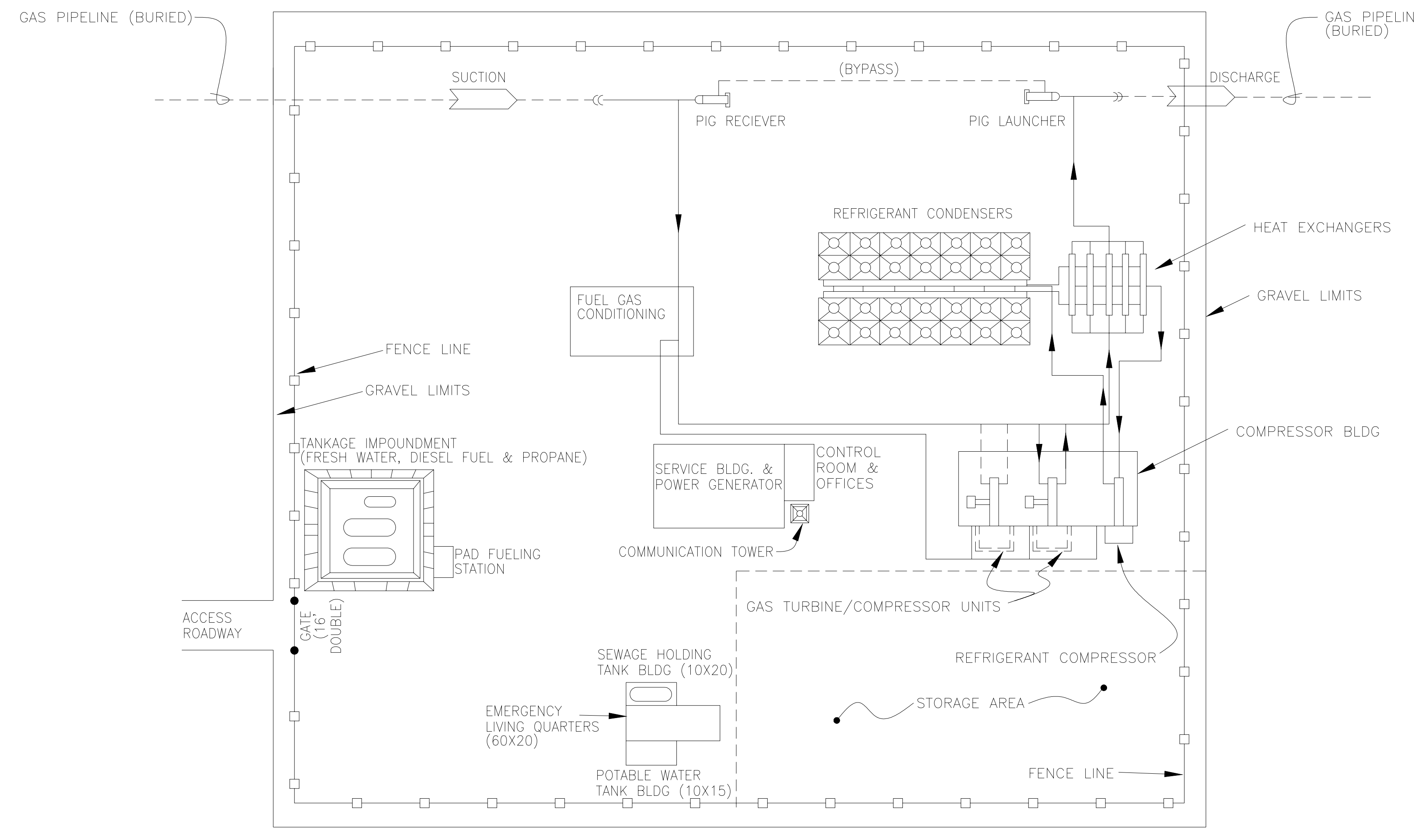


Figure 4.3: Typical Compressor Station Layout

4.1.3. Power Requirements

Compressor station power requirements consist of gas compression, refrigerant compression, and generation of utility power. The evaluations contained in this report are based on the use of natural gas fired equipment with the fuel extracted from the pipeline gas as described in the previous section. The scope of work for this study specifically excludes evaluation of the relative merits of electric motors versus gas-fired turbines for use as compressor drivers.

Fuel consumption was estimated based on the operating horsepower of the turbine drivers determined via hydraulic simulation on a configuration-by-configuration basis. A relatively small amount of fuel will be required for on-site electric power generation. A small amount of energy will also be required for building heat. Neither utility power nor building heat are leveraging issues that will materially influence the project design and, therefore, are not evaluated in this study.

4.1.4. Possible Co-Use of APSC Facilities

There are several advantages and disadvantages associated with the possible co-use of APSC pump station facilities.

Advantages include:

- Existing access for construction
- Existing access for operations
- Understanding of geotechnical conditions
- Acceleration of the permitting process
- Reduction of overall compressor station footprint

Disadvantages include:

- Locations not optimal for pipeline hydraulics
- Reconditioning/upgrading of existing facilities
- Liability for site clean-up and restoration

Since APSC facilities already have permanent access (and in some cases multiple access points) from public roads, co-use of these facilities will have a direct impact on construction costs and schedule. Likewise, co-use of APSC facilities reduces the amount of subsurface investigation required to perform compressor station design, although this will not completely eliminate the need to collect soils data as cursory verification as a minimum of existing data will still be required.

Co-use of APSC facilities may help to accelerate the permitting process, but carte blanche approval is not a given. Based on review of the conceptual compressor station layout presented in Figure 4.3, there are several locations where co-use of APSC facilities may result in a reduction in the overall footprint. Since the majority of APSC pump stations have helipads either within the boundaries of the site proper or in close proximity, co-use would remove the need for a stand-alone helipad dedicated to the compressor facilities. Likewise, the majority of APSC stations have permanent living quarters and it is reasonable to assume that these facilities could be utilized periodically, thus removing the need for the emergency living quarters, the sewage holding tank building, and the potable water tank building. Other locations where reductions may be possible are the tankage impoundment, offices, service and maintenance building, and the designated heavy equipment and material storage.

The advantages for co-use of APSC facilities may in large part be nullified by the disadvantages. The primary disadvantage is that locations of existing facilities will likely not coincide with the optimal locations as determined through hydraulic design of the pipeline (see Section 4.6). Even relatively modest deviations from the optimal locations can have large impacts on the amount of installed horsepower.

Another important consideration when looking at possible co-use, or more significantly re-use of mothballed locations, is the fact that the existing APSC facilities were, for the most part, designed and constructed 30 years ago. The applicable codes (building, electrical, fire, plumbing, etc.) have changed substantially over this period and the APSC facilities may not meet all current standards. Thus, substantial efforts might need to be expended to recondition/upgrade these facilities to allow use for this project.

One issue that has seen much discussion when re-use of existing pads has been proposed in the past is the potential liability for site clean-up and restoration. Over thirty years even the most conscientiously operated facility will experience some level of contamination due to, at a minimum, an accumulation of small events. Contamination from large events will likely not be of great concern since clean-up of such events in all probability was completed shortly after the event took place.

The advantages and disadvantages discussed here should by no means be considered completely comprehensive since other issues may arise as the design progresses.

4.2. J-curve and ROI Premises

An industry standard approach for comparison of pipeline and stations configurations is to express pipeline ***cost of service (COS)*** as a function of flow rate. The COS will tend to decline with increased pipeline flow obtained by the addition of compressor stations. Eventually, the number, capital costs, and operating costs of the compressor stations required for larger flow rates become so high that the COS will begin to trend upward. The plot of COS versus flow rate for a given pipeline is called a "***J-curve***" because the shape of the curves resembles a backward "J." Economies of scale are indicated by a progressive decrease in the COS obtained using larger diameter pipelines operating at higher flow rates. J-curve analyses are based on the assumption that the market can accommodate a prescribed volume of gas flow on the first day of operation.

The flow through the all-Alaska LNG project will likely increase in discrete increments to match the capacities of the individual liquefaction and conditioning ***trains***[2] installed at either end of the pipeline. ***Return on Investment (ROI)*** analyses are useful to assess the benefits achieved by adjusting the rate of flow ramp-up. ROI analyses are based on setting the COS and allowing the ROI to float, depending on the particulars of the configuration being evaluated

The J-curve and ROI analyses presented in this report are based on approximately fifty individual economic analyses of specific configurations of pipelines and compressor stations. J-curves were prepared for 16- to 30-inch diameter pipelines with lengths ranging from 300 to 800 miles. ROI analyses were completed only for 24-, 30-, and 36-inch diameter pipelines with a length of 800 miles. Due to the large number of analyses, certain simplifying assumptions were made to complete the work within the allotted scope and schedule. Rigorous evaluation of the operation of individual pipeline and station configurations was outside the scope of this study.

The basic procedure used to generate the individual economic analyses required to construct the J-curve and ROI plots was:

1) Prepare capital cost estimates for pipelines with diameters from 16 through 36 inches

2) Select a gas composition and estimate the composition of the compressor station fuel

3) Complete hydraulic analyses to determine the number and spacing of compressor stations, and the gas compression horsepower required at each station

4) Prepare factors that when applied to the installed horsepower would generate a reasonable estimate of the capital costs of a compressor station

5) Estimate fuel consumption based on the operating horsepower at the compressor stations

[2] Large gas processing facilities are typically split into multiple self-contained facilities that collectively provide the desired overall throughput capacity. These smaller identical facilities are referred to as process "***trains***" and can be operated independently of each other.

6) Prepare an economic model, select economic premises, and generate economic analyses

Discussion of each of these steps (1 – 6) are contained in the following sections.

4.2.1. Capital Cost Estimates – Pipelines

The pipe cost estimates were developed to support a comparison of the relative merits of various pipeline diameter and compressor station scenarios and should not to be used for any other purpose.

Budget level cost estimates were prepared for 16-, 20-, 24-, 30-, and 36-inch diameter pipelines subject to similar design criteria and cost estimation methodology. Capital costs for the 24-, 30- and 36-inch pipelines were based on an 800-mile route from Prudhoe Bay to Port Valdez within the existing pipeline corridor. The costs for the 16- and 20-inch pipeline were based on a 300-mile route to roughly approximate a spur line from Delta Junction to Palmer.

All pipeline cost estimates were based on construction of American Petroleum Institute (API) specification 5L X80 steel pipe with a maximum operating pressure (MOP) of 2,500 psig through areas defined as Location Class 1 per Title 49 of the Code of Federal Regulations (CFR) 192. A summary of the pipeline cost estimates is contained in Table 4.1.

The purpose for preparing the cost estimates was not to generate an absolute value for a given pipeline configuration, but to provide representative values for comparison of the relative merits of the various configurations. The estimates were prepared based on a strict application of a consistent methodology. Costs that were independent of the pipeline diameter are shown under the heading "Project indirects – owner" and were applied uniformly to all five estimates. The remaining costs that vary with pipeline diameter were prepared for winter and summer construction modes using a crew-up estimation methodology. The crew-up costs for the various diameter pipelines were applied to the respective lengths of the winter and summer construction modes projected for the route.

The crew-up estimation methodology accounts for the terrain encountered along the route with costs increasing through areas of difficult terrain. Overall, the cost estimates reflect more difficult terrain for a higher percentage of the 800-mile route than the 300-mile route.

The size of the construction equipment required to handle the pipe varies with the diameter of the pipeline. The cost estimates for the 16- and 20-inch diameter pipeline are based on the use of lighter weight equipment than that used for construction of the 24-, 30-, and 36-inch pipelines.

The J-curve and ROI analyses are time-value-of-money evaluations that depend on the schedule of net operating income relative to the distribution of capital outlays. The estimates are based on a five-year period from the start of detailed engineering through commissioning. The estimated schedules of capital outlays for the construction of the pipelines used in the economic analyses are shown in Table 4.2.

Baker has produced two cost estimates for a 24-inch pipeline for ANGDA, one for a report issued in August of 2004 and another for the current work. A third cost estimate will be produced for ANGDA as part of the Spur Line right-of-way work being completed by Baker for ANGDA under a separate contract. None of the estimates are based on an actual pipeline design with field verification of the route and the estimation methodology for each has differed slightly to be fit-for-purpose according to the particular ANGDA work scope. The cost estimate for the 24-inch pipeline in this report is again fit-for-purpose regarding identification of leveraging technical and design issues. A premise of this report is that all capital costs will be revisited by ANGDA during feasibility studies before selecting a configuration for the pipeline and compressor stations.

Table 4.1: Comparative Capital Costs of Pipelines, $million

	16-inch	20-inch	24-inch	30-inch	36-inch
	Delta Junction – Palmer		Prudhoe Bay – Port Valdez		
Length, miles	300	300	800	800	800
Pipe wall thickness, inches	0.347	0.434	0.521	0.651	0.781
Contractor Costs					
Direct	160	162	656	705	738
Indirect	58	58	238	228	231
Sub-total	218	220	893	932	970
Contractor mark-up (20%)					
	44	44	179	186	194
Material					
	120	186	827	1,187	1,568
Miscellaneous					
Cathodic protection	5	5	12	12	12
SCADA	5	5	13	13	13
Camp rent, mob. & demob.	88	88	250	250	250
Handle pipe & materials	4	6	24	37	53
Gravel	0	0	2	2	2
Sub-total	102	104	301	290	331
Project indirects – owner					
Detailed engineering	31	31	81	81	81
Surveying	5	5	13	13	13
Permitting	6	6	16	16	16
Quality control	18	18	49	49	49
Project management	40	40	108	108	108
Purchasing & expediting	6	6	16	16	16
Sub-total	106	106	282	282	282
Project total					
	588	**659**	**2,482**	**2,903**	**3,345**
Unit costs ($ / inch dia. – mile)					
	122,500	110,000	129,300	121,000	116,200

Table 4.2: Pipeline Costs – Annual Schedule of Capital Outlay

	Year 1	Year 2	Year 3	Year 4	Year 5	Start-up	Total
$million by year							
36-inch	47	70	1,308	1,413	498	9	3,345
30-inch	47	70	1,069	1,226	481	9	2,903
24-inch	47	70	846	1,048	462	10	2,483
20-inch		27	247	261	122	1	659
16-inch		27	206	232	122	1	588
Percent by year							
36-inch	1.4	2.1	39.1	42.2	14.9	0.3	100
30-inch	1.6	2.4	36.8	42.3	16.6	0.3	100
24-inch	1.9	2.8	34.1	42.2	18.6	0.4	100
20-inch	0.0	4.1	37.5	39.6	18.6	0.2	100
16-inch	0.0	4.6	35.0	39.5	20.7	0.2	100

4.2.2. Composition of Pipeline Gas and Compressor Station Fuel

The pipeline hydraulic calculations were based on the use of residue gas from the CGF at Prudhoe Bay. Composition data for the CGF residue gas is shown in Table 4.3 (see Section 3.2 for a discussion on the CGF). The references for the compositional data regarding various gas streams at Prudhoe Bay are contained in Appendix A. It was assumed that the carbon dioxide would be removed in a conditioning plant on the North Slope to a concentration of 1.50 mole percent prior to entering the pipeline (see Section 3.5).

Table 4.3: Gas Composition for Pipeline Hydraulic Calculations

	CGF Residue	CGF Residue to Pipeline	Compressor Station Fuel
Mole percent			
Carbon dioxide	11.55	1.50	1.19
Nitrogen	0.62	0.69	0.79
Methane	80.74	89.91	94.74
Ethane	5.14	5.72	3.00
Propane	1.56	1.74	0.26
I-butane	0.12	0.13	0.01
N-butane	0.19	0.21	0.01
Pentanes+	0.08	0.09	0.00
Total	100.00	100.00	100.00
HHV (btu/scf)			
		1,068	1,017
Reference	*1*		
Reference 1: AOGCC, NGL/MI Ultimate Recovery – May 16, 1995 Public Hearing, Corrected ARCO Exhibit 128			

4.2.3. Pipeline Hydraulic Calculations

HYSYS Model

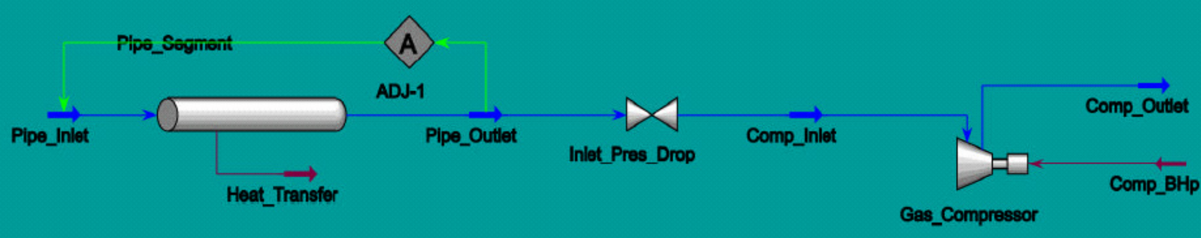
All of the hydraulic and gas compression calculations used for the J-curve and ROI analyses were generated using the HYSYS model shown in Figure 4.4. The HYSYS model consists of a pipe segment, a valve, and a gas compressor. The conditions of the gas at the inlet of the pipeline were set at 28 deg F and 2,515 psia (2,500 psig) for all of the hydraulic runs.

Data for the J-curves was generated by varying the length of the pipe segment to predetermined values and then adjusting the gas flow as necessary to obtain a pressure of 1,515 psia at the discharge of the segment. This approach determines the maximum flow through the pipeline as a function of distance between compressor stations.

Data for the ROI analyses was generated by setting the flow to prescribed incremental values, and then adjusting the length of the segment to yield a pressure of approximately 1,515 psia at the segment outlet. The lengths of the pipe segments were limited to five or six predetermined values that provided the desired spacing of compressor stations.

A maximum operating pressure (MOP) of 2,515 psia was selected since it provides a pipe stiffness that is widely considered in the industry as favorable to resist the effects of differential movement of the pipeline caused by either frost heave or thaw settlement (see Section 5.9). A station inlet pressure of 1,515 psia was selected as it avoids the two-phase area of the phase envelope of an enriched pipeline gas (see Section 3.3) and avoids inefficient operating conditions immediately upstream of compressor stations that may exacerbate frost heave as well as increase the loads on the station equipment.

Pipe_Segment		
Pipe Length (Pipe Length_1)	150.0	miles
Inside Diameter (Inside Diameter_1)	22.96	in
Outside Diameter (Outside Diameter_1)	24.00	in
Outlet Vapour Velocity	17.99	ft/s



Streams						
		Pipe_Inlet	Pipe_Outlet	Comp_Inlet	Comp_Outlet	Comp_BHp
Temperature	F	28.00	5.817	5.571	67.89	
Pressure	psia	2515	1515	1510	2530	
Std Gas Flow	MMSCFD	822.0	822.0	822.0	822.0	
Heat Flow	hp	-1.306e+006	-1.299e+006	-1.299e+006	-1.284e+006	1.556e+004
Vapour Fraction		1.0000	1.0000	1.0000	1.0000	

Figure 4.4: Hydraulic Simulation Flowsheet

A valve was used to simulate a 5 psi pressure drop through piping between the station inlet and the suction of the compressor. Discharge from the gas compressor was set at 15 psi above the MOP of the pipeline to account for pressure drop through the gas refrigeration chillers (modeled separately) and downstream discharge piping. An average compressor efficiency of 77.5 percent (adiabatic) was used for gas compression calculations.

Detailed thermal-hydraulic simulation is required to assess the combined impact of JT cooling, pipe wall heat transfer, and seasonal climatic changes on the temperature of the flowing gas. Such thermal-hydraulic modeling was, however, outside of the current scope of work. The segment discharge temperatures were approximated assuming a uniform ground temperature of 30 deg F and the standard heat transfer correlations in the HYSYS model based on the assumption that the pipeline was buried in moist sand.

Approach and Assumptions

The pipelines in this study were characterized hydraulically by simply repeating the pipe segment and compressor configuration shown in Figure 4.4 as many times as necessary to model an 800-mile pipeline. This approach is appropriate for the scope of this work, but is not adequate to characterize an Alaska pipeline along a route with significant elevation changes and topography that limits the location and number of compressor stations.

The hydraulic calculations in this study are based on a pipeline traversing level ground and do not address changes in operating pressure associated with fluid head of a dense phase gas and elevation change. The hydraulic calculations are based on the premise that compressor stations can be located at any point along the pipeline, thus the capacity determined for the pipeline at higher flow rates may be overstated since it is based on uniform spacing of the compressor stations which is unlikely to occur on an Alaska pipeline (see

Section 4.6). The hydraulic calculations also do not account for any downtime of compressor stations, since pipeline operability reviews were outside the scope of the study.

The hydraulic simulations are based on continuous year-round operation with no adjustment for seasonal variation in flow due to the effects of ambient air temperature on available compressor power. The simulations do not address potential variations in pipeline flow due to seasonal changes in the capacity of facilities at either end of the pipeline such as the gas conditioning and/or liquefaction plants.

Installed Horsepower

A simplifying assumption was made to not adjust the installed horsepower for downstream stations to account for a progressive reduction in pipeline gas flow due to extraction of fuel at each station along the pipeline. The assumption was necessary to expedite production of hydraulic calculations for the approximately fifty different configurations of pipeline and compressor stations evaluated in this study. Additionally, this assumption is considered as reasonably reflecting the practical approach of installing identical equipment at each station along the pipeline. This approach does, however, introduce a potential bias in the J-curves for scenarios with the very largest gas flow rates.

In practice, a portion of the gas flow through a pipeline will be removed for fuel at every compressor station along the route. The overall fuel consumption that was estimated for the various configurations of pipelines and compressor stations contained in this study varied from zero for low flow scenarios with no stations to a maximum of approximately 6.25 percent for very high flow scenarios with 15 stations over the 800-mile pipeline. The hydraulic models do not address fuel consumption and all pipe segments were modeled as having the same inlet gas flow as the first segment beginning on the North Slope.

Calculations of the theoretical change in gas compression horsepower from the first to the last compressor station along a 36-inch diameter pipeline are shown in Table 4.4.

Table 4.4: Theoretical Horsepower, First to Last Station, 36-inch Pipeline

Station spacing (Miles)	Fuel pct of inlet (%)	Flow, 1st segment (MMscfd)	Flow after Fuel removal (MMscfd)	BHp end of 1st segment BHp	BHp after fuel BHp	Change in BHp (%)
50	6.25	4,129	3,871	73,700	57,480	-22
80	3.76	3,255	3,133	58,540	50,370	-14
100	2.98	2,907	2,820	52,550	46,640	-11

The flow, fuel, and operating horsepower shown for the first segment are those used in the study. The flow after removal of fuel refers to the theoretical flow through the very last segment of the pipeline after removal of fuel. The last two columns in the table show the horsepower required at the reduced rate after removal of fuel and the resulting reduction in compression horsepower at a theoretical station located at the end of the pipeline.

The term ***brake horsepower (BHp)*** will be used throughout this report as reflecting operating horsepower while the term ***horsepower (Hp)*** will refer to installed horsepower.

Table 4.4 shows that the assumption that horsepower will remain the same at all stations along the pipeline results in the overestimation of theoretical horsepower at the last station by approximately 22 percent, 14 percent and 11 percent for the 50-, 80-, and 100-mile station spacing scenarios, respectively. Less compression horsepower is required for the downstream segments because the flow rate is lower and there is less pressure drop between stations at lower rates resulting in a higher compressor suction pressure. The ”Change in BHp” values shown in the table reflect the worst scenario encountered only at the last station and the average margin over all the stations would be approximately half these values.

The 50-mile spacing scenario is presented only for the purposes of establishing a bound for the J-curve analysis and it is considered highly unlikely that an 800-mile pipeline traversing Alaska would be equipped with 15 stations. A pipeline with such a large number of stations would experience a significant drop in flow rate if any one of the 15 stations were off line, and would be relatively more complex to operate.

4.2.4. Capital Cost Estimates – Compressor Stations

The purpose of the J-curve and ROI analyses is to identify leveraging technical and design issues regarding selection of the pipeline diameter and compressor stations. Detailed specification of the gas compressor packages and accompanying propane refrigeration systems is outside of the scope of work and is not required for identification of economic trends regarding selection of pipeline and compressor station configurations.

Capital costs for compressor stations were estimated by developing individual cost factors for the installation of station components and then applying the factors to station operating loads estimated via hydraulic simulation. Willbros Engineers, Inc. (Willbros) was contracted to develop factors for: 1) the installed cost per horsepower of gas compression, 2) the installed cost per horsepower of refrigerant compression, and 3) the installed cost for all equipment other than gas compression and refrigeration. The report for the compressor station cost factors produced by Willbros is contained in Appendix B. The cost factors are summarized in Table 4.5.

Analyses required to assign individual compressor packages to the compressor stations were outside the current scope of work and are unnecessary to identify economic trends via J-curve analyses. The installed costs for the gas compression was based on an arithmetic average of the cost factors for the 10,000, 15,000, and 20,000 Hp units shown in Table 4.5. The simulation results show that stations along the 16-inch pipeline generally required less than 7,500 Hp of gas compression and, accordingly, the costs of these units were estimated using the cost factor for the 7,500 Hp package. The operating horsepower estimated via the hydraulic simulations was increased by 10 percent to account for aging of the turbine compressor drivers and power de-rating for altitude.

Table 4.5: Compressor Station – Capital Cost Factors

	$ / Installed Hp
Gas Compression (Willbros)	
7,500 Hp	668
10,000 Hp	547
15,000 Hp	583
20,000 Hp	462
Refrigeration (Willbros)	
	2,121
Values Used in Calculations	
Less than or equal to 7,500 Hp	668
Greater than 7,500 Hp	531
Refrigeration	2,121
Note: Station cost, excluding compression and refrigeration, is $22.5 Million	

Most of the designs that have been proposed for large gas transmission pipelines traversing Alaska are based on the assumption that the pipeline will operate in the ***cold mode*** through permafrost and through areas where there is generally more permafrost than thawed soil. *A cold operating mode refers to pipeline operation subject to flowing gas temperatures of less than 32 deg F with refrigeration installed to cool the gas from the discharge from the gas compressors prior to the re-entering the pipeline.* Refrigeration is not required in the southern portion of the route where the pipeline traverses mostly thawed soil. *Pipelines with flowing gas temperatures above 32 deg F are referred to as operating in the **warm mode**.*

The cost estimates for the 800-mile pipeline are based on a route from Prudhoe Bay to Port Valdez. It was assumed that the pipeline would operate in the cold mode from Prudhoe Bay through the Alaska Range and that refrigeration units would be required at any gas compressor station located at or north of Summit Lake at milepost (MP) 600. Subject to this approach and 100-mile station spacing, the pipeline would switch to warm mode operation at the next station at MP 700 just south of Glennallen.

It was assumed that refrigeration would be required for stations along the first 100 miles of a 300-mile spur line, thereby providing for transition from cold to warm mode approximately half to two-thirds of the distance along the pipeline depending on the number of stations.

The operation of the closed loop propane refrigeration system is described in Section 4.1.1. The HYSYS software was used to model a hypothetical summer operating mode based on the use of propane refrigerant. The HYSYS model results for the hypothetical summer operation show that almost exactly 1 BHp of refrigerant compression is required for every 2 BHp of gas compression. Accordingly, the installed capital costs for the refrigeration system were estimated by applying the refrigerant cost factor shown in Table 4.5 to 50 percent of the operating gas compression horsepower determined via hydraulic simulation.

The calculations of the compressor station costs for the J-curve and ROI analyses are contained in Appendices C and D respectively. These calculations also contain estimates for station fuel as discussed in the following section.

4.2.5. Fuel Consumption

The term "***heat rate***" refers to the energy consumption of a turbine driver for a gas compressor. The cost information provided by Willbros was based on the use of Solar™ turbine-compressor sets. The heat rate of the 7,500 Hp Solar turbine-compressor package, which is approximately 8,000 btu/BHp-hr, was used to estimate the fuel consumption for all operating horsepower regardless of whether it was for gas or refrigerant compression. It is likely that the turbine drivers for the refrigeration system will be smaller than those installed for gas compression. The heat rate generally varies inversely with the size of the unit and use of the heat rate of the smallest unit provides a slight margin of conservatism to compensate for fuel consumption of minor equipment other than the turbine drivers.

The lower heating value (LHV) of a gas refers to the energy released when the fuel is burned at field conditions. The higher heating value (HHV) refers to heat released from burning the gas under controlled laboratory conditions. The LHV is 0.90 of the HHV for the fuel composition used in this study. The LHV was used to calculate the rate of fuel consumption while HHV was used for all other calculations. The station fuel consumption was determined on a thermal basis and then adjusted by a factor of 1/0.90 to convert to a HHV basis for use in the study.

The fuel consumption of the gas compression is based on the operating horsepower calculated via hydraulic simulation. The average annual fuel consumption for the refrigerant compressors was based on 42 percent of the installed refrigerant horsepower. The composition of the fuel is shown in Table 4.3.

4.2.6. Economic Evaluation Methods

An existing in-house economic model was used to complete the numerous analyses required for preparation of both the J-curve and ROI evaluations. A standard ROI calculation based on annual cash flows after consideration of net operating income, property taxes, and state and federal corporate taxes was conducted.

The following assumptions were adopted for the economic analyses:

1) 25 year project life
2) 2 percent property tax beginning at the start of operations with an exemption on property tax for capital outlays during construction prior to start-up
3) 25 year straight line book depreciation for purposes of property tax calculation
4) 35 percent federal corporate tax
5) 9.4 percent state corporate tax
6) 7 year depreciation for both federal and state corporate taxes (per recently enacted federal legislation)
7) 2.5 percent GDP deflator for expression of monies on a nominal yearly basis (i.e., no real inflation)
8) No leveraged financing or interest during construction due to ROI calculation method
9) All capital, non-fuel operating expenses, revenues, and gas purchase prices were based on year 2005 dollars
10) $25 million annual operating cost for monitoring and maintenance of the pipeline regardless of the diameter of the pipeline
11) Non-fuel operating costs for the compressor stations were set at 3.5 percent of the installed cost of the compressor stations

The ROI calculations frequently produced negative state and federal taxes for one or more years immediately after start-up depending on the scenario. It was assumed that these tax benefits could be applied corporate-wide and thus were retained in the calculations.

The pipeline hydraulics and economics were based on the assumption that conditioned gas with a carbon dioxide concentration of 1.50 mole percent could be purchased at outlet of the gas conditioning plant at $1.50/MMbtu. The COS for the J-curve analyses was determined as the difference between the purchase price and the sales price of the gas delivered to Port Valdez required to yield a 10 percent ROI. A 10 percent ROI is equivalent to a higher percent return on equity (ROE) and was assumed as an acceptable economic threshold for the purposes of project comparison.

The purchase price of the gas does impact the COS and comparative ROI calculations in this study because it sets the cost of the fuel. The cost of fuel is never directly determined and is addressed in the economic models by simply selling less gas on a thermal basis that was purchased on the North Slope. The purchase price of the gas is thus the cost of fuel. A reduction in the gas purchase price will tend to raise the ROI for the same COS, while raising the purchase price will reduce the ROI.

4.3. Preparation of J-curves, Expandable Pipelines

J-curves were prepared for pipelines with diameters of 16-, 20-, 24-, 30- and 36-inches subject to a range of gas flow rates. The number and spacing of the compressor stations along each pipeline were varied to reflect operating scenarios ranging from under-utilization of the installed pipeline capacity to over-utilization achieved by installing an unrealistically large number of stations.

J-curves are based on two fundamental premises, first that the gas flow initially starts at a prescribed rate and never increases; and second, that the market can accommodate the flow rate of gas in the first year of operation. J-curves typically do not address scenarios in which the flow ramps up over a number of years. The influence of flow ramp-up is addressed in the ROI analyses (Section 4.4).

4.3.1. Supporting Hydraulic Calculations

J-curves were generated by completing a series of individual economic analyses for various configurations of a pipeline and attendant compressor stations. The flow through the pipeline is a function of the number of compressor stations installed along the pipeline. Since the installed cost of the pipeline is the same for all scenarios, the J-curve analysis is essentially an evaluation of revenues obtained with increase pipeline flow compared to the cost of the compressor stations required to achieve these flows.

Pipeline hydraulic simulations were completed to determine the rate of gas flow and compression requirements as a function of the segment length between compressor stations. The length of the pipe segment was set and then the rate of gas flow adjusted so that an inlet pressure of 2,515 psia would yield 1,515 psia at the outlet of the pipe segment. The simulation was also used to determine the corresponding gas compression horsepower required to return the gas pressure to 2,515 psia prior to entering the next downstream pipe segment (see Section 4.1). The results of the pipeline hydraulic simulations are contained in Appendix C. Summaries of these results are shown in Table 4.6 and Table 4.7.

4.3.2. J-curves for 800-mile Pipeline

The J-curves for 800-mile 24-, 30-, and 36-inch diameter pipelines is shown in Figure 4.5. All of the curves display a classic profile in which the COS declines as throughput increases to a point at which the COS begins to increase. The J-curves reflect the impact of the large number of stations and corresponding amount of horsepower and fuel required to achieve large flow rates through a given pipeline. The impact on flow as a function of the number of compressor stations is shown numerically in Table 4.6 and graphically in Figure 4.6.

Referring to Figure 4.6, a flow of approximately 1,000 MMscfd can be achieved with the 800-mile 36-inch pipeline without installing any intermediate compressor stations along the route. Flows of approximately 2,000, 3,000, and 4,000 MMscfd can be achieved by installing 3, 7, and 15 compressor stations respectively. *Stated another way, the first 1,000 MMscfd of flow can be achieved with no stations, the second 1,000 MMscfd increment requires installation of 3 stations, the third 1,000 Bscfd requires 4 more stations, and the fourth 1,000 MMscfd increment requires the addition of 8 more stations.*

Table 4.6 shows that the compression horsepower at each individual station increased as more stations are placed on line to increase pipeline flow, thus the total amount of installed horsepower increases significantly for each 1,000 MMscfd increment of capacity increase.

The COS for a 24-, 30-, and 36-inch pipelines are approximately the same at a flow rate of 1 Bscfd and the COS for the 30- and 36-inch pipelines remain approximately the same through flow rates up to approximately 2 Bscfd. ***It would be preferable to select a larger versus smaller diameter pipeline for the all-Alaska project at rates of 1 to 2 Bscfd because: 1) the economics of the initial project would not be adversely impacted by selection of the larger diameter pipeline, and 2) the larger pipeline would provide significant upside potential for project expansion simply by the addition of compression.***

Table 4.6: Hydraulic Results, 800-mile Pipeline

Station Spacing Miles	Number of Stations	Flow MMscfd			Gas Compression per Station BHp			Compression Station Costs $million			Fuel percent of Pipeline Inlet on a Thermal Basis		
		24-inch	30-inch	36-inch	24-inch	30-inch	36-inch	24-inch	30-inch	36-inch	24-inch	30-inch	36-inch
37.5	21	1,670			29,900			1,397			8.71		
50	15	1,444	2,575	4,129	25,990	46,100	73,700	929	1,387	2,015	6.30	6.27	6.25
80	9	1,136	2,029	3,255	20,760	36,690	58,540	481	695	988	3.82	3.78	3.76
100	7	1,014	1,811	2,907	18,710	32,990	52,550	365	523	740	3.04	3.01	2.98
200	3	708	1,267	2,038	13,700	23,960	37,990	139	193	267	1.40	1.37	1.35
400	1	492	882	1,420	10,070	17,660	27,920	40	53	71	0.49	0.48	0.48
800	0	342	613	987	0	0	0	0	0	0	0.00	0.00	0.00

Table 4.7: Hydraulic Results, 300-mile Pipeline

Station spacing Miles	Number of Stations	Flow MMscfd			Gas Compression per Station BHp			Compression Station Costs $million			Fuel percent of Pipeline Inlet on a Thermal Basis		
		16-inch	20-inch	24-inch	16-inch	20-inch	24-inch	16-inch	20-inch	24-inch	16-inch	20-inch	24-inch
25	11	716	1,276	2,049	12,850	22,830	36,520	390	501	653	4.24	4.23	4.22
37.5	7	583	1,041	1,670	10,570	18,720	29,900	225	278	350	2.69	2.67	2.65
50	5	503	899	1,444	9,227	16,290	25,990	161	198	249	1.99	1.96	1.95
75	3	408	731	1,174	7,662	13,460	21,400	90	107	130	1.20	1.18	1.17
100	2	352	630	1,014	6,739	11,800	18,710	63	73	89	0.85	0.83	0.81
150	1	284	510	822	5,638	9,853	15,560	27	28	32	0.40	0.39	0.38
300	0	198	355	572	0	0	0	0	0	0	0.00	0.00	0.00

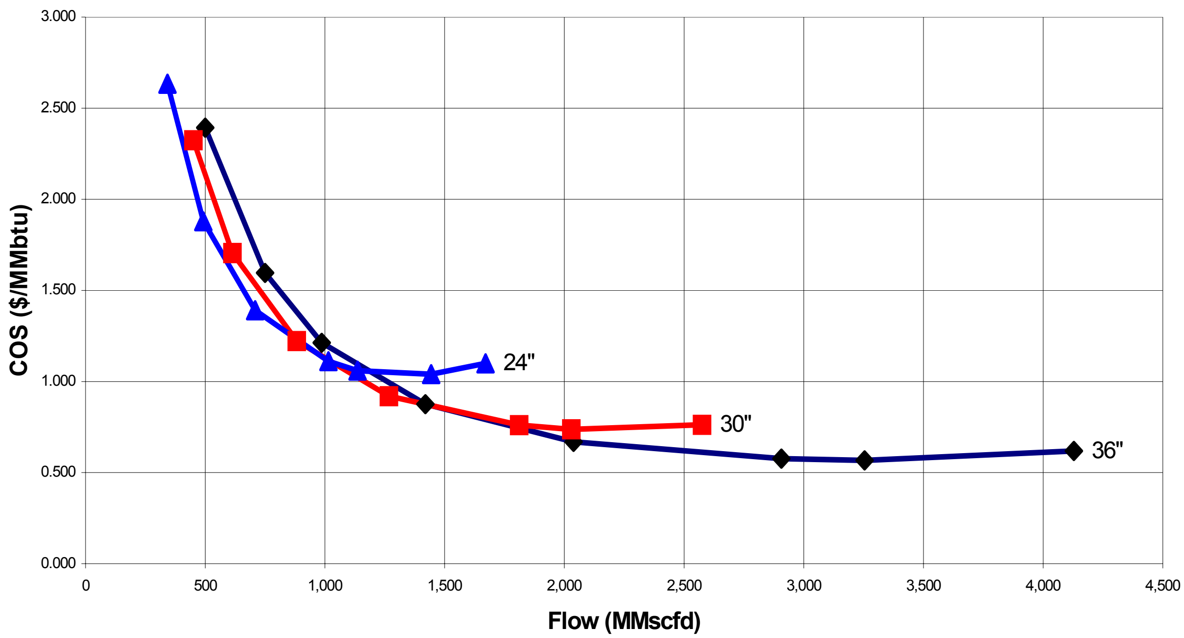


Figure 4.5: J-curves for 800-mile Pipelines

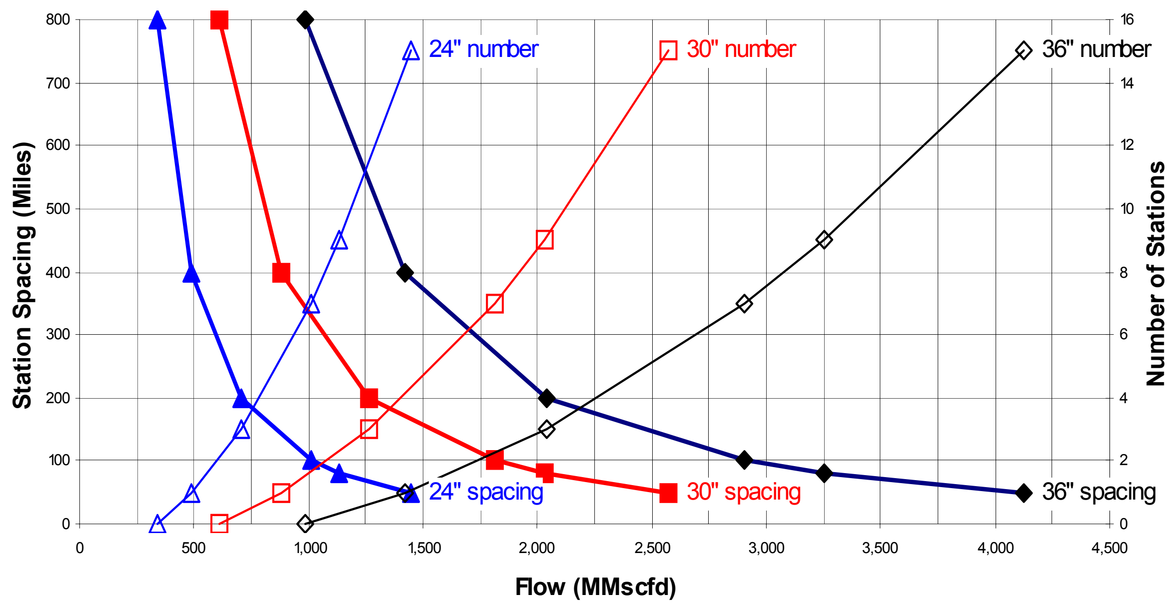


Figure 4.6: Flow Relative to Station Number and Spacing, 800-mile Pipeline

The J-curves prepared for this study do not address the on-line availability of the individual gas compressor units at the various stations. The overall flow through the pipeline is limited by the flow through any individual pipe segment between compressor stations. Referring to the previous 36-inch pipeline example, if any one of the 15 stations required to achieve 4,000 MMscfd of throughput was to drop off line, the overall flow through the pipeline would be limited by the flow through a 100-mile segment (stations installed at 50-mile intervals) and would drop to approximately 3,000 MMscfd. The probability that any single compressor station would be off-line at a given time increases with the number of compressor stations. Thus, one would expect flow curtailment for a greater percentage of time as the number of compressor stations increase.

Theoretically, the capacity of the pipeline can be increased indefinitely by adding more stations. In addition to economic considerations, there is a limit on the number of stations that can reasonably be installed along a pipeline. A minimum station spacing of 50 miles was adopted solely for the purposes of constructing the J-curves for the 800-mile pipelines presented in this study. A 50-mile spacing is impractical for a pipeline from Prudhoe Bay to Port Valdez because of the large number of stations required and extreme unlikelihood that 15 stations can be installed precisely at 50-mile intervals along the route after consideration of topographical, environmental, thermal-hydraulic, and other constraints that will govern station location.

4.3.3. J-curves for 300-mile Pipeline

J-curves for the 300-mile spur line from near Delta Junction to Cook Inlet are shown in Figure 4.7. The impact on flow as a function of the number of compressor stations along the 300-mile route is shown numerically in Table 4.7 and graphically in Figure 4.8. The principles and concepts discussed in the previous section for the 800-mile pipelines are applicable to the 300-mile spur line as well.

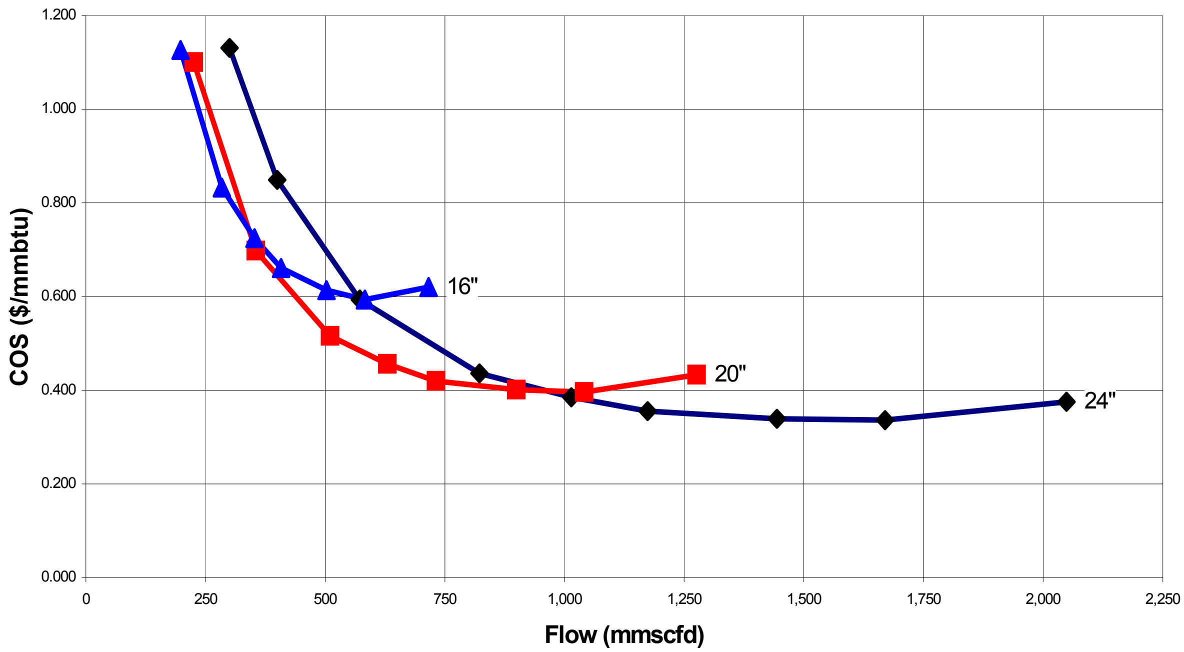


Figure 4.7: J-curves for 300-mile Pipelines

The capital costs for the various pipelines are discussed in Section 4.2.1. A step change in the size of construction equipment occurs between the 20- and 24-inch pipelines. Additionally, the cost for the 24-inch spur line was factored from the estimate of the 800-mile 24-inch pipeline and reflects more difficult terrain. These two factors combine to shift the J-curve for the 24-inch spur line upward relative to the other two spur line scenarios.

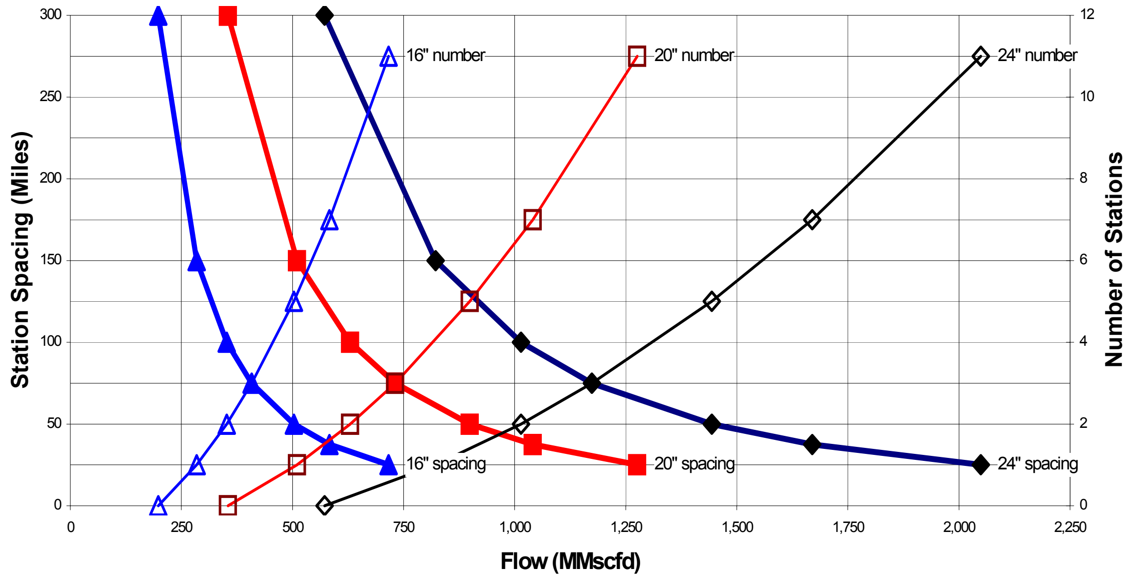


Figure 4.8: Flow Relative to Station Number and Spacing, 300-mile Pipeline

4.4. ROI Plots for Various Pipeline Configurations

The J-curves presented in the prior section are useful for comparing the relative economic merits of various pipeline diameters as a function of flow rate. The J-curves are based on the assumption that a pipeline will operate at a given flow rate beginning on the first day through the end of the project. However, the flow through the all-Alaska LNG project will likely increase in discrete increments to match the capacities of the individual liquefaction and conditioning trains installed at either end of the pipeline. The purpose of the ROI analyses is to show that a protracted ramp-up schedule is detrimental to project economics and to roughly quantify the gains to the project economics by decreasing the duration of the ramp-up.

ROI calculations were generated assuming an annual ramp-up increment of 500 MMscfd through pipelines of 24-, 30-, and 36-inch diameters. A second set of ROI calculations was generated assuming an annual ramp-up increment of 1 Bscfd. The compressor station costs and fuel estimates were prepared using the same procedures used for the J-curve analyses and are contained in Appendix D. The pipeline hydraulic simulations, however, were performed differently for the ROI analysis than for the preparation of the J-curves.

4.4.1. Hydraulic Simulation Results

The hydraulic simulations were completed by adjusting the length of the pipe segments between the compressor stations with the goal of achieving a station inlet pressure (or segment discharge pressure) of 1,515 psia. Various scenarios at discrete increments of flow were simulated for each diameter pipeline. It would be ideal if a single pipe segment length could be found that would result in a 1,515 psia compressor suction pressure at all stations subject to all flow scenarios, however, this is not possible and segments lengths were selected that gave the best compressor suction pressures over the flow scenarios modeled. It was found that a segment length of 100-miles could be used for the 24- and 36-inch diameter cases to reasonably accommodate a ramp-up increment of 500 MMscfd. An 80-mile segment length best fit the 30-inch diameter pipeline scenario.

A summary of pertinent hydraulic information is contained in Table 4.8.

Table 4.8: Summary of Hydraulic Results, ROI Analyses

Flow, MMscfd	500	1000	1500	2000	2500	3000
Station spacing, miles						
36-inch	800	800	400	200	100	100
30-inch	800	320	160	80		
24-inch	400	100				
Station horsepower, BHp						
36-inch	0	0	35,870	35,190	29,920	59,880
30-inch	0	16,390	33,330	34,650		
24-inch	10,890	17,720				
Station inlet pressure, psia						
36-inch	2,287	1,480	1,366	1,559	1,807	1,435
30-inch	1,898	1,493	1,375	1,549		
24-inch	1,471	1,547				
Increment of CapEx, $million						
36-inch	0	0	85	167	237	332
30-inch	0	88	197	383		
24-inch	42	312				
Fuel, percent of pipeline inlet						
36-inch	0.00	0.00	0.58	1.28	1.97	3.29
30-inch	0.00	0.74	2.06	3.62		
24-inch	0.53	2.92				

Table 4.8 shows that most of the scenarios modeled provided compressor station suctions reasonably near 1,515 psia. The 1,500 MMscfd scenarios for the 30- and 36-inch pipelines resulted in fairly low station inlet pressures that may not be acceptable for a pipeline gas heavily enriched with non-methane hydrocarbons. The ROI analyses were based on the use of lean residue gas from the CGF and two-phase flow will not be encountered at these pressures (see Section 3.3). These scenarios were considered acceptable for identification of leveraging technical and design issues.

4.4.2. Economic Assumptions

The same economic assumptions used to develop the J-curves were adopted for the ROI analyses. *In contrast to the J-curve development procedure where the COS was adjusted to yield a 10 percent ROI, the ROI analyses are based on setting the COS and allowing the ROI to float depending on the particulars of the configuration being evaluated.*

A COS of $1.00/MMbtu was adopted because it produced mathematically defined ROI values at the low flow rates without generating unrealistically high ROIs at higher flow rates. The purchase price of the conditioned gas on the North Slope and delivered price at the end terminus of the pipeline were held constant at $1.50 and $2.50/MMbtu respectively for all scenarios evaluated.

4.4.3. ROI Results

The results of the ROI analyses are summarized in Table 4.9. The ROI values reflect projects of different sizes and are structured to show the benefits of each increment of expansion.

For example, the ROI of 2.50 percent for the 36-inch pipeline at 500 MMscfd refers to a project that starts at 500 MMscfd and never expands past this rate. The ROI of 7.96 percent for the 36-inch pipeline at 1000 MMscfd refers to a project that starts at 500 MMscfd, expands to 1000 MMscfd in the second year, and then remains at 1,000 MMscfd for the remainder of the project life. Similarly, the ROI of 10.99 percent refers to a ramp-up schedule of 500, 1,000 and 1,500 MMscfd in years one, two, and three respectively and not expanding thereafter.

Table 4.9: Summary of ROI Results, Percent by Flow Increment

500 MMscfd Increment						
Project Year	**1**	**2**	**3**	**4**	**5**	**6**
MMscfd	**500**	**1000**	**1500**	**2000**	**2500**	**3000**
36-inch	2.50	7.96	10.99	12.83	13.99	14.38
30-inch	3.48	8.71	11.34	12.47		
24-inch	4.31	8.52				

1000 MMscfd Increment			
Project Year	**1**	**2**	**3**
MMscfd	**1000**	**2000**	**3000**
36-inch	8.29	13.82	15.93
30-inch	9.06	13.25	
24-inch	8.80		

The ROI results for the 500 MMscfd ramp-up scenarios are represented graphically in Figure 4.9. *The progressive flattening of the curves with expansion increments indicates that benefit to the initial project from each increment of expansion declines with each increment.* Again referring to the 36-inch scenario, a project configured for an initial design capacity of 1,000 MMscfd has an ROI of 7.96 percent. A project designed to ramp-up to 1,500 MMscfd has a ROI of 10.99 percent, thus the 500 MMscfd increment from 1,000 to 1,500 MMscfd has the benefit of increasing the overall ROI of the initial project by 3.03 percent (10.99 – 7.96), but with the downside of requiring the successful marketing of 50 percent more product.

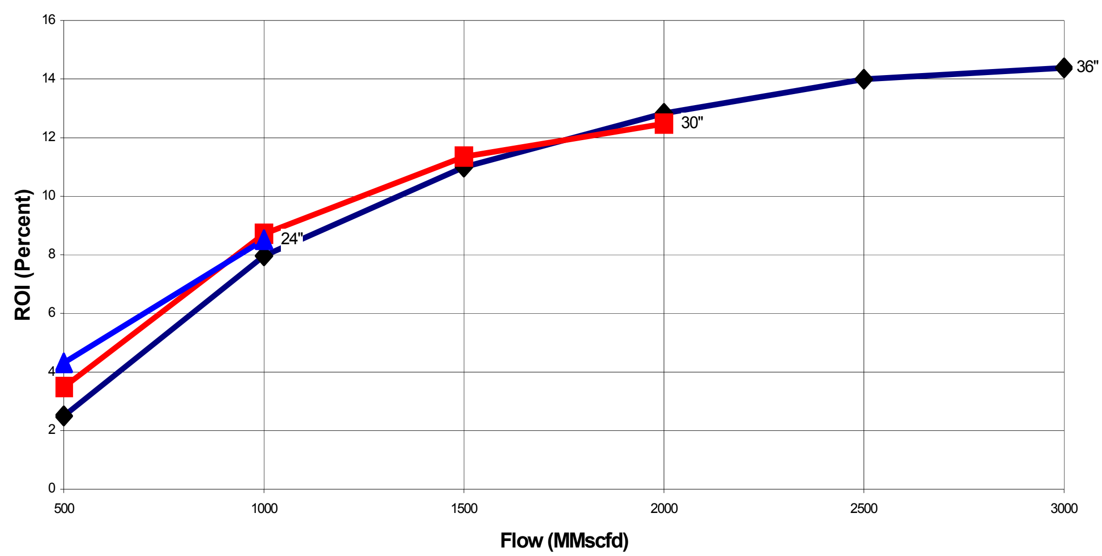


Figure 4.9: ROI Results for 500 MMscfd Ramp-up Scenarios

The ROI of a 36-inch diameter pipeline project ramping up to 2,000 MMscfd over four years has a ROI of 12.83 percent which is 1.84 percent more than an initial project stopping at 1500 MMscfd. Similarly, the 500 MMscfd increment from 2,000 to 2,500 MMscfd increased the ROI of the initial project by 1.16 percent.

The reason for the progressive decline in benefits from increments of flow ramp-up is primarily due to the time value of money and the schedule of revenues achieved from these increments compared to the schedule of capital outlays for construction of the pipeline. Revenues from increments of expansion that occur years after start-up are discounted relative to the capital expenditure for the pipeline that occur before the project start-up for the purposes of calculating an ROI.

Another factor influencing the decline in benefit due to incremental expansions is that the COS declines with increasing volume only to a point and then tends to remain constant at higher flow rates. This trend is shown in the J-curves discussed in the previous section.

The above example shows that each increment of ramp-up benefits the initial project less than the previous increment while progressively complicating the project marketing efforts by requiring that contracts be secured for larger amounts of product. The project development team may determine that means other than increasing the project throughput should be pursued to increase the ROI for the initial entry project.

Obtaining more revenues earlier in the life of the project will result in an increase in the project ROI. ROI values obtained by doubling the volume of each ramp-up increment from 500 to 1,000 MMscfd are shown in Table 4.9. The ROI values for the 1,000 MMscfd ramp-up scenarios were determined in the same manner as those for the 500 MMscfd scenarios.

Doubling the ramp-up rate provides little benefit for smaller sized projects, but becomes more significant as the size of the project increases. Referring to the 36-inch scenario, doubling the ramp-up rate from 500 to 1,000 MMscfd increases the ROI by 0.33, 0.99 and 1.55 percent for projects stopping at throughputs of 1,000, 2,000, and 3,000 MMscfd.

4.5. Limitations of the J-curve and ROI Analyses Contained in this Report

The J-curves were constructed by adjusting the COS until a 10 percent ROI was achieved at prescribed flow rates. The ROI analyses are based on a COS of $1.00/MMbtu. These economic criteria were selected for the sole purpose of illustrating leveraging technical and design issues impacting the all-Alaska LNG project and should not be construed as a recommendation regarding an acceptable threshold of project economic viability.

The economic analyses contained in this report are based on private ownership models and do not reflect the unique financing options available to ANGDA. It is recommended that the future feasibility studies include economic comparisons of pipeline and compressor station options based on economic data and threshold criteria developed specific for ANGDA's needs.

4.6. Location of Pipeline Compressor Stations

4.6.1. Location Based on Maximum Capacity

The location of the compressor stations along the pipeline should be determined based on the largest flow rate anticipated through the pipeline over the life of the project. The location of stations is much less critical for a pipeline operating at reduced flow rates.

The flow through the overall system limited by the flow through any one of the individual segments. The flow through any single pipe segment between compressor stations is limited by the allowable differential pressure from the inlet to the discharge of the segment. Moving the location of a station on a pipeline with a relatively high flow rate has a much larger impact on the differential pressure through the adjacent pipeline segment than moving the station the same distance along the same pipeline operating at reduced flow rates.

The impact of station location as a function of flow rate and differential pressure is easily illustrated using a simple pipeline hydraulic model. The relative impacts of moving a compressor station by 10 miles upstream and downstream along a 30-inch diameter pipeline are shown in Table 4.10. The values in this table are based on the same flowing gas composition used to prepare the J-curves and ROI analyses (presented in Sections 4.3 and 4.4) and a pressure of 2,515 psia at the inlet to the pipe segment. The flow rates were selected to achieve a differential of 1,000 psi for the two base scenarios with the compressor stations spaced at 80- and 200-mile intervals. The compression horsepower refers to the gas compression required at the downstream station to return the gas pressure to the assumed MOP of 2,530 psia (2,515 psia after pressure drop through discharge chillers and piping).

Table 4.10 shows that moving the location of the compressor stations has a greater impact on the differential pressure and horsepower of the downstream station at higher flow rates than at lower flow rates. Moving the stations 20 miles along the route with the high flow scenario results in almost a 40 percent change in the amount of compression horsepower as compared to an approximately 17 percent for the same relative change in location, but subject to the lower flow rate.

Table 4.10: Impacts of Moving Station Locations Along 30-inch Diameter Pipeline

Inlet at 2,515 psia	Spacing (miles)	Segment Outlet (psia)	Compression Horsepower (BHp)	Change in Pressure (psia)	Change in Power (percent)
Flow at 2,029 MMscfd					
	70	1,662	30,100	147	-18.0
	80	1,515	36,700	Base	Base
	90	1,356	44,700	-159	21.8
Flow at 1,267 MMscfd					
	190	1,577	22,000	62	-8.3
	200	1,515	24,000	Base	Base
	210	1,451	26,200	-64	9.2

4.6.2. Location Based on Ramp-up

The number, location, and specification of the compressor stations along the pipeline may differ significantly depending upon the number of trains required. A market entry project should include a plan for installation of pipeline compression based on the number trains and corresponding increment of volume ramp-up.

A pipeline compression plan for a project based on the installation of one train with no potential for expansion is trivial since the project will have no flow when the train is off-line. A pipeline compression plan for a project based on two trains must address pipeline operation at 50 and 100 percent of ultimate pipeline capacity. Compression for a project based on three trains must address operation subject to flows of 33, 66 and 100 percent flow. Similarly, a project ultimately consisting of four trains must address increments of 25 percent.

Although specification of a pipeline compression plan to accommodate varying increments of pipeline flow may seem trivial, it is not, especially considering that the pipeline should also be designed based on thermal hydraulic considerations. The plan is further complicated by the fact that not only will the number of compressor stations increase with pipeline flow, but the horsepower at existing stations may need to be increased as well.

4.6.3. Locate Stations Based on Thermal-hydraulic Design

Thermal-hydraulic design refers to the rigorous evaluation of the thermal interaction of the pipeline and the soil in which it is buried. A description of thermal aspects regarding the design of an Alaskan pipeline is contained in Section 5.9. This section contains a brief discussion of thermal-hydraulic design with regard to how it may influence the location of compressor stations.

Frost heave (see Section 5.9.3) is exacerbated by operating at relatively cold temperatures through areas of permafrost interspersed with frost susceptible thawed soils. Freezing of the previously thawed frost susceptible soil could result in differential movement of the pipeline and induced stress on the pipe. The potential for frost heave of the pipeline can be mitigated by maintaining a constant cool, but not cold, operating temperature by simply locating a compressor station immediately upstream of the problem area.

For example, assume that an initial pipeline design that is based on operation in the cold mode results in a temperature of 15 deg F through about five miles of frost susceptible soil immediately upstream of a compressor station. Moving the compressor station upstream by five miles would allow the gas temperature through this same soil to be adjusted using the upstream compressor station as required to mitigate frost heave. Relocation of compressor stations is one of many potential options to mitigate frost heave (e.g., overexcavation of frost susceptible soil and replacement with select fill, and re-alignment of the pipeline to avoid problem areas).

This approach works similarly for a pipeline operating in the warm mode traversing thaw unstable soils located immediately downstream of a compressor station. The gas warms as it is compressed and the relatively hot discharge temperature from the station could exacerbate thawing of the thaw unstable soil. The pipeline operating temperature through this thaw unstable soil could be lowered by simply moving the compressor station downstream.

4.7. Overall Project Capacity – Pipeline and Processing Trains

4.7.1. Train Size and Matching of Capacity

Economies of scale can be achieved with gas liquefaction trains as evidenced by the industry trend toward larger train sizes. Currently, liquefaction trains approaching 1,000 MMscfd are being proposed for facilities in Qatar. Trains of this size or larger should be possible for a facility in south-central Alaska due to the beneficial impact of the relatively low average annual ambient air temperatures on what is essentially a large refrigeration process.

The North Slope gas producers have proposed individual gas conditioning trains with a capacity of approximately 1,125 MMscfd. (see Section 7.6.1). These trains were specified based on an amine process to reduce the carbon dioxide concentration of the gas to approximately 1.5 mole percent prior to entering the pipeline; however, it should be feasible to remove essentially all of the carbon dioxide to achieve an LNG quality gas using a similarly sized plant.

It is likely that the capacity of an individual gas conditioning train on the North Slope could be sized to match the capacity of an individual liquefaction train at tidewater in south-central Alaska. The capacity of a conditioning plant train must be sized slightly larger than that of the liquefaction train to account for fuel consumption of the pipeline. *Matching capacities of the equipment at either end and along the pipeline will enhance project economics by providing better utilization of the installed capital.*

4.7.2. Expandable Pipeline, Utilization of Capital, and Train Size

The general approach regarding specification of the number of liquefaction and conditioning trains remains unchanged regardless of the size of a market entry project. A reasonable expectation is that a market entry project will be based on the installation of two trains; however, a small project may need only one train, and a larger project may require three. Selection of train sizes at either end of the pipeline must be done concurrent with selection of the pipeline diameter.

For example, Figure 4.6 shows that a market entry volume of 2,000 MMscfd could be accommodated using a 30-inch or 36-inch diameter pipeline. The capacity of the 36-inch pipeline could be expanded to approximately 3,000 MMscfd by the addition of compressor stations. Assuming an initial in-state gas demand of 400 MMscfd expanding ultimately to 600 MMscfd, selection of two 800 MMscfd liquefaction trains would provide for a 2,000 MMscfd (2 x 800 MMscfd + 400 MMscfd) market entry project and allow the build-out capacity of the 36-inch pipeline to be achieved using three trains (3,000 MMscfd = 3 x 800 MMscfd + 600 MMscfd). A similar analysis can be done for projects based on pipelines of other diameters.

Use of a large LNG train in the above example would also be consistent with specification of a market entry project with a quick ramp-up. The market entry scenario above could be met by ramp-up increments of 50 percent over a two-year period.

Section 5. Description of Pipeline Routes

5.1. Overview

Conceptual routes for a gas pipeline were developed for corridors from Prudhoe Bay to optional end points at Port Valdez, Nikiski, and Enstar Natural Gas Company's 20 inch-diameter pipeline located southwest of Palmer. The route corridors are as follows:

1. Prudhoe Bay to Port Valdez via the shortest practical route possible within the existing TAPS corridor ending at Anderson Bay in Port Valdez;

2. Prudhoe Bay to Nikiski via the shortest practical route possible to Nenana, then generally following the Parks Highway to the upper Matanuska-Susitna Valley, then south along the west side of the Susitna River and Cook Inlet to a subsea crossing of Cook Inlet;

3. Prudhoe Bay to Enstar's 20-inch pipeline located southwest of the junction of the Parks and Glenn Highways near Palmer via the shortest practical route, and

4. Glennallen to the 20-inch diameter Enstar pipeline via the shortest practical route.

The mile posts (MP) described in this section refer to the route drawings contained in Appendix E. An overview of the route corridors is shown in Figure 5.1.

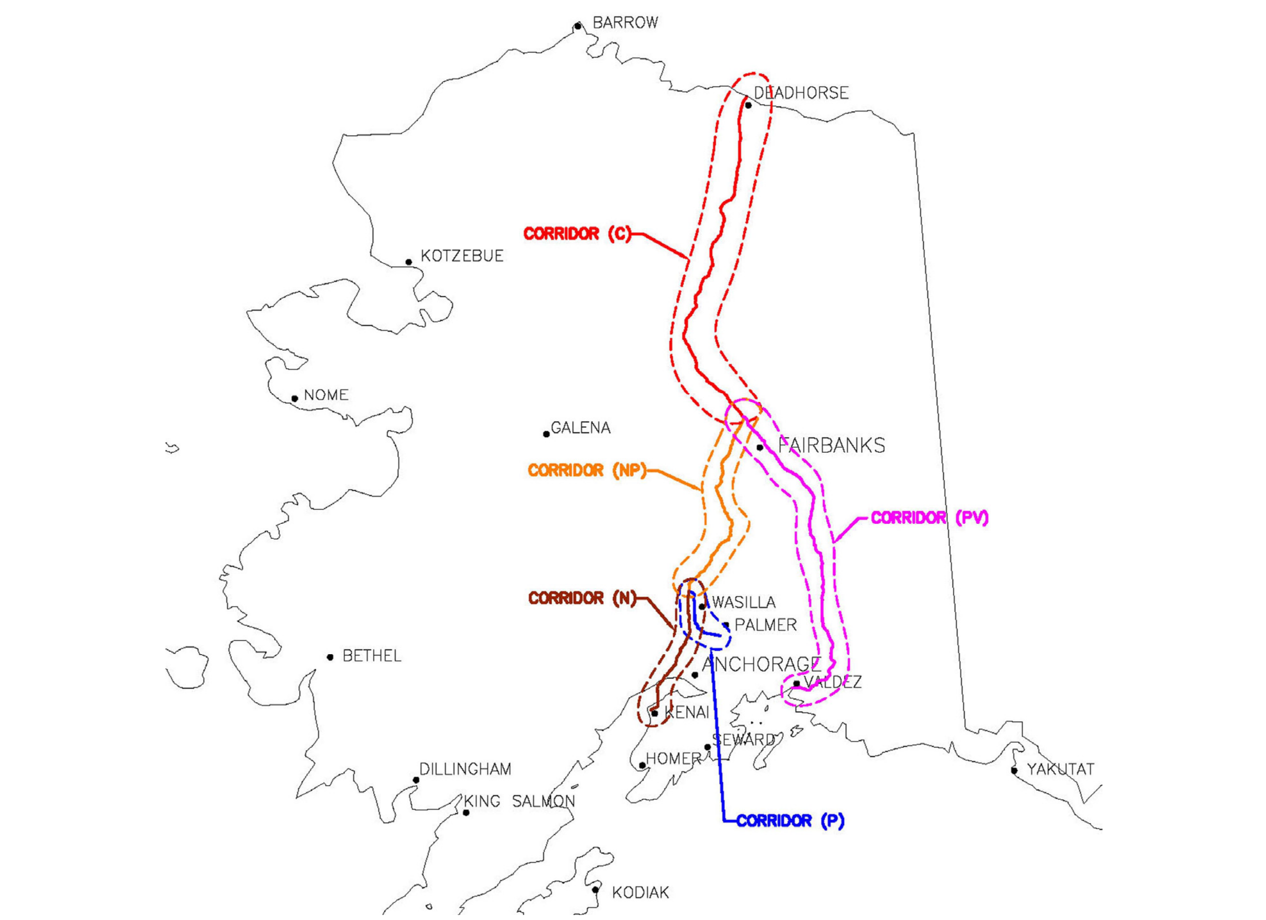


Figure 5.1: Overview of Route Corridors

Routes 1 through 3 share a common corridor from Prudhoe Bay to TAPS Pump Station 7 at MP 408.8. Routes 2 and 3 end in Cook Inlet and share a second common corridor from TAPS Pump Station 7 to where the Parks Highway crosses the Susitna River north of the road cut off to Talkeetna.

Throughout this Section 5, the route segments are designated according to the following corridors:

Common Corridor (C)

- Begins at Prudhoe Bay - MP 0
- Ends at TAPS Pump Station 7 - MP 408.8
- Total length - 408.8 miles

Nikiski-Palmer Common Corridor (NP)

- Begins at TAPS Pump Station 7 - MP 408.8
- Ends at Parks Highway crossing of Susitna River - MP 667.9
- Total length – 260.7 miles

Port Valdez Corridor (PV)

- Begins at TAPS Pump Station 7 - MP 408.8
- Ends at Anderson Bay in Valdez - MP 793.9
- Total length - 793.9 miles (including the Common Corridor)

Nikiski Corridor (N)

- Begins at Parks Highway crossing of Susitna River - MP 667.9
- Ends at Nikiski - MP 788.4
- Total length – 788.4 miles (including Common Corridor (C) and Nikiski-Palmer Common Corridor (NP))

Palmer Corridor (P)

- Begins at Parks Highway crossing of Susitna River MP 667.9
- Ends at Palmer - MP 734.7
- Total length – 734.7 miles (including Common Corridor (C) and Nikiski-Palmer Common Corridor (NP))

A brief overview of Corridor 4, the Glennallen to Palmer corridor, is provided in this report. This corridor was described in a separate report prepared by Baker titled *24-Inch Spur Line from Glennallen to Palmer, Conceptual Alignment and Budget Level Cost Estimate* submitted to ANGDA in August, 2004.

ANGDA articulated the following goals and objectives regarding the identification of route corridors:

- Corridors should stay, if practical, within reasonable access distance of existing infrastructure such as ADOT highways and the Alaska Railroad.
- Identified corridors should be the shortest practical routes.
- Alternatives should be proposed, where practical, for areas presenting major engineering, construction, and permitting challenges.
- Route corridors should be defendable for a technically feasible project, but not necessarily optimized. Corridors identified herein should be viewed as being at least 5,000 feet wide.

This study is limited in scope and detail due to the following:

- Aerial photography was not provided or available.
- Field reconnaissance was not authorized for this conceptual study.
- The study must rely on public information developed for other purposes such as oil, product, and gas pipelines.

Therefore, route optimization prior to permitting must be accomplished during subsequent, in depth, air photo analysis and field investigation.

Since it is a goal of this study to obtain a conceptual corridor for each option that represents a “workable” and “doable” project, the assessment of construction related issues pertaining to the chosen routes is based on the judgment and past experience. This is reflected in the route corridors as shown on the attached 1:250,000 scale maps (Appendix E).

Proposed corridor routing was based on public documents and maps filed and distributed by previous detailed studies related to TAPS, the Alaska Natural Gas Transportation System, the Trans-Alaska Gas System and the Denali Pipeline Project.

Proposed routing in areas not covered by previous proposed projects is primarily based on topography. The nature and scope of this work effort prohibited application of the resources required to specify and characterize a detailed alignment. Such resources include air photo interpretation, field reconnaissance, geotechnical evaluation, environmental review, constructability review, and economic optimization. Future detailed routing and optimization of the selected pipeline route is expected to add approximately one to one and one half percent to total route lengths.

Common practice is to assign alignment mile posts sequentially in the direction of gas flow for reference. MPs have been provided on the accompanying maps for general reference only and are tied to the centerline of the 5,000 foot wide corridor.

5.2. General Description of Options

ANGDA specified three termini for the identification of conceptual route corridors. All three options originate at Prudhoe Bay near the CGF and consequently share the same corridor north of TAPS Pump Station 7 (MP 408.8) located south of Livengood, Alaska.

While routes to all three termini share a common corridor (C) north of TAPS Pump Station 7, the route corridor to Port Valdez (PV) continues to the east, south of this point, within the TAPS corridor, for a total estimated length of 793.9 miles.

A common route to Nikiski and Palmer (NP) with terminus located southwest of Palmer, leaves the TAPS corridor and proceeds southwest, cross-country to MP 470.0, then south within the Parks Highway and Alaska Railroad corridors to the west side of the Parks Highway bridge crossing of the Susitna River south of Talkeetna (MP 667.9). At this point, the corridor to Nikiski (N) turns south toward Cook Inlet and the corridor to Palmer (P) continues along the Parks Highway and Alaska Railroad corridors to the junction of the Parks and Glenn Highways with a total estimated length of 734.7 miles.

The route to Nikiski (N) starts on the west side of the Parks Highway bridge at the Susitna River (MP 667.9) and proceeds south to Tyonek (MP 757), then crosses Cook Inlet and terminates at Nikiski for a total length of 788.4 miles.

The proposed pipeline corridors described in detail below were selected to enhance the following factors:

- Minimum total pipeline length
- Avoidance of known environmentally sensitive areas, where practical
- Ease of construction
- Utilization of existing infrastructure to the extent possible and appropriate

5.3. Common Corridor (C) – Prudhoe Bay to TAPS Pump Station 7

Segment 1 (C) – Prudhoe Bay (MP 0.0) to Sagwon Bluff Area (MP 70)

All route corridors begin at the point of discharge from gas conditioning facilities located proximate to the CGF at Prudhoe Bay. The proposed corridors begin on Alaska's Arctic Coastal Plain and proceed into the northern foothills of the Brooks Range. The length of this corridor segment is minimized by proceeding overland in a straight line, nearly due south, from Prudhoe Bay to the Sagwon Bluffs area (MP 70). This route largely avoids existing facilities; however existing roads in the Prudhoe Bay oil field and the Dalton Highway still allow reasonable construction access from corridor segment ends and intermediate access at MP 30, 44, 49, and 56.

The area is characterized predominantly by fine-grained, lowland loess and lake basin deposits overlying coastal marine or abandoned floodplain deposits. Approaching the northern foothills of the Brooks Range upland silts are underlain by shallow bedrock. The soils are continuously frozen, cold permafrost (less than –23 deg F mean annual ground temperature) with a shallow ***active layer*** (top layer of soils that reacts to seasonal freezing and thawing).

This route segment crosses the Putuligayuk River, Kuparuk Pipeline and five gathering lines in the PBU. Road crossings include the Spine Road and five well pad access roads, also in the PBU. After passing to the west of TAPS Pump Station 1, the route proceeds generally cross country and is located one half mile or more away from TAPS, the TAPS fuel gas line (FGL), and the Dalton Highway.

Route Alternatives Segment 1 (C) – North Slope:

Alternative A

Located parallel to TAPS from Pump Station 1 to the TAPS crossing of the Dalton Highway then along the western side of the highway to the end of the segment, this route alternative maximizes the use of existing infrastructure. Total length of this alternative is 70.5 miles, 3.9 miles longer than the shortest route to Sagwon Bluff. Soils and thermal conditions are similar.

Alternative B

This route alternative is located parallel to Prudhoe Bay in-field roads and old trails reaching the Dalton Highway two miles south of the Deadhorse Airport. It maximizes use of existing infrastructure and minimizes conflicts with TAPS. The total length of this alternative is 72.2 miles, 5.6 miles longer than the shortest route to Sagwon Bluff. Soils and thermal conditions are similar.

Segment **1 (C)** and alternatives are shown on drawing C-001.

Segment 2 (C) – Sagwon Bluffs Area (MP 70) to Ice Cut Hill Area (MP 94)

This segment lies west of the Dalton Highway from the Sagwon Bluffs to a point just north of Ice Cut Hill. The route follows the generally flat terrain along the Sagavanirktok River Valley for a short distance, then climbs out of the valley into gently rolling hills and is adjacent to both the Dalton Highway and the TAPS FGL.

The terrain in this segment is mostly gently rolling hills. Soils are predominately upland silts with shallow bedrock at the northern end. At the southern end of this segment, silts are generally underlain with glacial till. The soils are continuously frozen, cold permafrost with a shallow active layer. Deep active layers and some thawed areas may be found in the Sagavanirktok River floodplain proximate to flowing water.

The route crosses Happy Valley Creek (MP 84) and several minor streams in this segment but does not cross the Dalton Highway, TAPS or the TAPS FGL.

Segment **2 (C)** is shown on drawing C-001.

Segment 3 (C) – Ice Cut Hill Area (MP 94) to Slope Mountain Area (MP 117)

This route segment begins to the west of the Dalton Highway at Ice Cut Hill, bypassing Ice Cut Hill by staying above the Sagavanirktok River Floodplain. This route is significantly shorter than an alignment that follows the Sagavanirktok River, crossing gently rolling topography in a nearly straight-line from Ice Cut Hill to Slope Mountain.

Soils in this area are characterized by upland silt underlain by glacial till. Previous experience here indicates the presence and common occurrence of massive ice. Soils are continuously frozen, cold permafrost with a shallow active layer.

No roads will be crossed in this segment. The route is far removed from existing facilities until it reaches Slope Mountain where it crosses an aboveground section of TAPS (MP116).

Segment **3 (C)** is shown on drawing C-001.

Segment 4 (C) – Slope Mountain Area (MP 117) to Galbraith Lake Access Road (MP 133)

The common corridor continues along the west side of the Dalton Highway and crosses to the east side of the highway before crossing the Kuparuk River (MP 127). At this point, the terrain becomes steeper as the route leaves gently rolling topography and enters the high foothills of the Brooks Range. It then follows a more direct route than TAPS toward Galbraith Lake and crosses TAPS south of the Toolik access road (MP 133), then moves to the west side of the highway and proceeds south paralleling the Dalton Highway to Island Lake. It then crosses back to the east side of the Dalton Highway (MP 137) and parallels the Highway to the Galbraith Lake access road (MP 137.5).

Soils in this segment are glacial tills, overlain by fine-grained, re-transported soils. Construction difficulty is high from MP 125 to MP 134 where numerous exposures of boulder till occur. The soils are continuously frozen, cold permafrost with a shallow active layer.

Route Alternatives Segment 4 (C) – Slope Mountain to Galbraith Lake:

Alternative A – Toolik

This alternative follows a less direct path between the Kuparuk River and Galbraith Lake access by following the TAPS route, maximizing the use of existing infrastructure. The total length of this alternative is 11.9 miles, 1.5 miles longer than the shortest route. Soils and thermal conditions are similar. This alternative increases the length through extremely difficult ditching conditions.

Segment **4 (C)** is shown on drawing C-001.

Segment 5 (C) – Galbraith Lake Access Road (MP 133) to the Upper Atigun River Crossing (MP 160)

This segment begins at the Galbraith Lake access road (MP 137.5) and enters the drainage basin of the Atigun River. The route proceeds south on the east side of the Dalton Highway, between the highway and an aboveground section of TAPS, to a point approximately one mile north of the Atigun River. At this point, the route crosses TAPS and the Atigun River (MP 142). The Atigun River crossing is east, and downstream, of the TAPS crossing.

Immediately south of the first Atigun River crossing, the route continues between the aboveground TAPS section and the base of the adjacent mountain. At this point (MP 143) the route is very close to the Arctic National Wildlife Refuge boundary. The route remains on the east side of the highway, past TAPS Pump Station 4 to the Upper Atigun River where the route crosses both the highway and the Atigun River (MP 160).

The northern portion of this segment consists of glacial till with a blanket of continuously frozen colluvial silt. Along the east side of the Atigun River valley, soil conditions include coarse-grained fans, fine-grained fans, mudflow debris, glacial till over bedrock and bedrock in isolated areas. The soils are mostly continuously frozen, cold permafrost with a shallow active layer. Thawed areas are commonly found near rivers and streams and associated with surface and groundwater flow from the steep hillside tributaries. Alluvial and debris fans along valley margins may be unfrozen with seasonal groundwater flow.

Segment **5 (C)** is shown on drawing C-001.

Segment 6 (C) – Upper Atigun River Crossing (MP 160) to Chandalar Shelf (MP 174)

The route proceeds south to Atigun Pass on the west side of the Dalton Highway. The terrain in this segment is steep, with cross-slopes to 50 percent and longitudinal slopes to 30 percent. The proposed route crosses the highway and a belowground TAPS section on the north side of Atigun Pass. Atigun Pass (MP 165 to 168) is a very difficult construction area with close proximity to TAPS, the Dalton Highway and other proposed pipeline routes. ***Construction through this area will require special construction techniques.*** The route crosses Atigun Pass on the east side of the Highway, then crosses to the west side of the highway and descends the south side of the pass to the Chandalar River where it continues across very steep terrain in its decent down the Chandalar Shelf (MP 173 to 174). ***Construction through this area will require special construction techniques.***

The north side of Atigun Pass is characterized by fine- and coarse-grained fans, debris fans, and glacial till over bedrock. Glacial till and talus deposits predominate on the south side of the pass with glacial till and fine-grained fan deposits over bedrock on the Chandalar Shelf. The soils are mostly continuously frozen, cold permafrost with a shallow active layer. Thawed areas are commonly found near rivers and streams and associated with surface and groundwater flow from steep hillside tributaries. Alluvial and debris fans along valley margins may be unfrozen with seasonal groundwater flow.

Segment **6 (C)** is shown on drawing C-001 and C-002.

Segment 7 (C) – Chandalar Shelf (MP 174) to Wiseman (MP 225)

The route segment begins along the west side of the Dalton Highway near the Chandalar Shelf and proceeds to MP 178 where the route crosses the Dietrich River and Dalton Highway. The route then parallels the east side of the highway until the lower Dietrich River Crossing at MP 205. The route continues to cross the Dalton Highway several more times before ending up along the west side of the road near Wiseman.

The route is situated on the lower hillside predominately above the floodplain. This segment is in moderately steep terrain where cross-slopes 5 to 20 percent are typical.

Soils in the lowland portions of this segment are principally floodplain deposits with a cap of fine-grained floodplain over bank soils and re-transported fine-grained soils. River bed deposits are typically coarse-grained. The route crosses fine- to coarse-grained alluvial fans. Re-transported silts, glacial till, colluvium and alluvial fans are present over bedrock on the hillsides. Soils are generally frozen (warm permafrost – greater than 23 deg F mean annual temperature), with the exception of some portions in active floodplains and near lakes. Active layers can be locally very deep and icing (***aufeis***) is common in the Dietrich River active floodplain. Alluvial and debris fans along valley margins may be largely unfrozen with seasonal groundwater flow.

The segment north of Sukakpak Mountain (MP204) crosses the Dietrich River (MP 178), and several tributaries to the Dietrich. These tributaries flow from steep mountain valleys that border the Dietrich River Valley. They are characterized by steep gradients and generally low flows during the summer but are subject to flash flooding during summer thunderstorms. At Sukakpak Mountain the route crosses the Dietrich River and the Middle Fork of the Koyukuk River at MP 205 and 207 and crosses to the west side of the Dalton Highway at MP 224.

Segment **7 (C)** is shown on drawing C-002.

Segment 8 (C) – Wiseman (MP 225) to South Fork of the Koyukuk River (MP 256)

The route generally follows the Dalton Highway through this segment traversing gentle, lower valley slopes, avoiding the active floodplain. The corridor is routed to the east of Coldfoot (MP 236) to avoid the BLM development node. The route rejoins the Dalton Highway near the base of Cathedral Mountain. South of Cathedral Mountain from MP 245 to 255 the route avoids conflicts with TAPS and the Dalton Highway by routing to the east of TAPS. The route crosses the South Fork of the Koyukuk River upstream and east of both TAPS and the Dalton Highway Bridge at MP 256.

Soil conditions vary along this segment and include glacial till, re-transported fine-grained soils, and glaciofluvial deposits. Shallow bedrock is locally present on the valley slopes. Slopes above the floodplain are generally frozen, warm, discontinuous permafrost (80 to 95 percent frozen). Thawed conditions are found in lower valley areas, floodplains, and stream crossings.

Segment **8 (C)** is shown on drawing C-002.

Segment 9 (C) – South Fork of the Koyukuk River (MP 256) to the Kanuti River (MP 301)

From the South Fork Koyukuk River crossing, the route corridor is east of the Dalton Highway and TAPS. At MP 266 the route leaves the highway and continues to the east of Prospect Creek and rejoins the highway at MP 285. From MP 287 to MP 296 the route again leaves the highway and traverses extremely rugged terrain paralleling TAPS in the Fish Creek area. From MP 296 to the Kanuti River the route follows the east side of the Dalton Highway.

The topography from MP 256 to Prospect Creek (MP 276) is generally gently rolling. Soils are fine-grained, re-transported, and underlain by glacial deposits from the north end of this segment to Prospect Creek. The terrain becomes much steeper between Prospect Creek and the Kanuti River flats. Subsurface conditions consist of shallow bedrock with re-transported fine-grained soils on lower slopes and flood-plain deposits in valleys. Soils are generally frozen, warm, discontinuous permafrost (70 to 90 percent frozen). Thawed conditions are found in lower valley areas, floodplains, and stream crossings.

Segment **9 (C)** is shown on drawing C-002.

Segment 10 (C) – Kanuti River (MP 301) to No Name Creek (MP 327)

After crossing the Kanuti River, the route corridor remains on the east side of the Dalton Highway. The route crosses TAPS and the highway near MP 307 and remains on the west side of the highway to No Name Creek (MP 327).

This segment traverses rolling hills with longitudinal slopes to 25 percent and cross-slopes to 10 percent. Subsurface conditions consist of shallow bedrock with localized occurrences of re-transported, fine-grained soils on lower slopes and in drainages. Soils are generally frozen, warm, discontinuous permafrost (80 to 95 percent frozen).

Segment **10 (C)** is shown on drawing C-002.

Segment 11 (C) – No Name Creek (MP 327) to the Yukon River (MP 350)

After crossing No Name creek, the route corridor remains parallel to the Dalton Highway. The route crosses TAPS at MP 337 and MP 345. The route crosses the highway from east to west near MP 342 and west to east near MP 349. The route crosses the north abutment to the Yukon River Bridge and crosses the river on the downstream brackets located on the west side of the highway bridge.

Soils in this segment are typically re-transported fine-grained soils, with some floodplain terrace deposits over bedrock. Locally bedrock soils occur in the Fort Hamlin Hills area above the Ray River. Soils are generally frozen, warm, discontinuous permafrost (70 to 90 percent frozen). Unfrozen conditions commonly occur in bedrock areas.

Segment **11 (C)** is shown on drawing C-002 and C-003.

Segment 12 (C) – Yukon River (MP 350) to North Side of TAPS Pump Station 7 (MP 408.8)

From the Yukon River to north side of TAPS Pump Station 7, the route corridor generally parallels the existing TAPS alignment. Numerous crossings of Dalton Highway and TAPS occur in this segment. The route is generally remote from the Dalton Highway to the east between MP 373 and 390 and to the west from MP 390 to 408.8. Construction access in this segment will rely on existing TAPS infrastructure. Topography is for the most part steep to rolling, with occasional flat terrain in valley bottoms and ridge tops.

In the northern portion of this segment, the subsurface consists of thick upland silt deposits over bedrock. South of Isom Creek, shallow bedrock exists with locally thick deposits of upland silts and re-transported, fine-grained soils on lower valley slopes. The soil thermal state is highly variable. Fine-grained soils and north facing slopes are predominantly frozen. However, areas with outcropping bedrock, south facing slopes, and stream crossings are unfrozen to sporadically frozen.

Segment **12 (C)** is shown on drawing C-003.

At MP 408.8 route corridor options divide with the route to Port Valdez continuing south, mainly within the TAPS corridor. The Nikiski-Palmer (NP) route leaves the TAPS corridor and proceeds southwest cross-country.

5.4. Nikiski–Palmer Common Corridor (NP) – TAPS Pump Station 7 to Susitna River Crossing

Segment 13 (NP) – TAPS Pump Station 7 (MP 408.8) to Nenana (MP 469)

The common corridor to Nikiski and Enstar's 20 inch-diameter pipeline located southwest of Palmer leaves the TAPS corridor and proceeds southwest cross-country to Nenana (MP 469). The route follows the south edge of the Tatalina River Valley southwest to Washington Creek (MP 427), then southwest to the Chatanika River (MP 435), and then along the eastern margin of Minto Flats joining the Alaska Railroad alignment at Dunbar (MP 452). The route crosses Goldstream Creek north of Dunbar at MP 450. It then moves across the Alaska Railroad (MP 455) to the east side paralleling the Alaska Railroad to the Tanana River, crossing the river downstream of Nenana at MP 469. The route crosses the Parks Highway to the east at MP 465, and at MP 469 to the west.

In the northern portion of this segment, the subsurface consists of thick, re-transported, fine-grained soils deposited over alluvial deposits and bedrock. South of the Chatanika River (MP 435) lay locally thick deposits of organics and silts with re-transported fine-grained soils on lower valley slopes. The soil thermal state is highly variable. Soils are generally frozen, warm, discontinuous permafrost (70 to 95 percent frozen). Fine-grained soils and north facing slopes are predominantly frozen. However, areas with south facing slopes, lakes, and stream crossings are unfrozen to sporadically frozen.

Construction access is difficult between TAPS Pump Station 7 and the Alaska Railroad access at Dunbar. Access to the route can only be established from the ends of the segment.

Route Alternative Segment 13 (NP) – Pump Station 7 to Nenana

Fairbanks Alternative

This alternative allows the Nikiski-Palmer corridor to continue with the Port Valdez corridor to a point north of Fairbanks (MP 434.5 on drawing C-003) and south of the Chatanika River following a route to the northwest corner of Fairbanks at College, then along the Parks Highway, rejoining the Nikiski-Palmer route corridor at MP 463.7. The total length of this alternative from TAPS Pump Station 7 to MP 463.7 is 82.6 miles. While this alternative is 27.7 miles longer than the shortest route it allows Fairbanks easier access to gas, maximizes use of existing infrastructure, and is routed in generally more favorable soils.

Segment **13 (NP)** is shown on drawing C-004.

Segment 14 (NP) – Nenana (MP 469) to Nenana River Crossing (MP 496)

After crossing the Tanana River, the route corridor crosses the Nenana River and joins the Alaska Railroad alignment at MP 470 west of the Parks Highway. It then crosses the Alaska Railroad and proceeds south across flat terrain on the east side of the Nenana River and the railroad. It skirts the east side of Clear Air Force Base proceeding south along the west side of the highway between the railroad and the Parks Highway to the railroad and Nenana River crossing at MP 496.

In the northern portion of this segment, the subsurface probably consists of thick, fine-grained soils with locally thick deposits of organics over coarse-grained alluvial deposits. Where frozen the surficial soils are not thaw stable. Winter construction should be considered. Soils are discontinuous permafrost (80 to 95 percent frozen) from MP 469 to Clear Air Force base (MP 485). Areas close to lakes and streams are commonly unfrozen.

South of Clear Air Force Base soils consist of thin deposits of silts over coarse-grained alluvial deposits with the southern end of this section in discontinuous permafrost (50 to 70 percent frozen) composed mostly of thaw stable soils.

Segment **14 (NP)** is shown on drawing C-004.

Segment 15 (NP) – Nenana River crossing (MP 496) to Lignite (MP 520)

After crossing the Nenana River downstream of the Parks Highway Bridge the route corridor proceeds south-southeast paralleling the Alaska Railroad, and the Nenana River Valley on the west side of the Parks Highway to MP 511 where it crosses to the east side of the highway. From MP 511 to Lignite the route parallels the Golden Valley Electric Association (GVEA) power line between the Nenana River and the Parks Highway at Lignite (MP 520), but then leaves the power line for a route proximate to the east side of the Parks Highway near the north side of Lignite.

From south of the Nenana River crossing to Lignite the soils consist of thin deposits of silts over coarse-grained alluvial deposits on high terraces. This section is discontinuous permafrost (50 to 70 percent frozen) and composed mostly of thaw stable soils.

Segment **15 (NP)** is shown on drawing C-004.

Segment 16 (NP) – Lignite (MP 520) to Nenana River Canyon (MP 529)

The route then proceeds south on the east side of the Parks Highway to the mouth of Nenana Canyon on the east bank of the deeply incised Nenana River.

In this segment, the route encounters two active faults, the Healy Creek fault at approximately MP 521.5 and the Healy fault at approximately MP 524.7. These faults have Holocene (10,000 years or less) activity that crosses the route corridor and will require extensive field investigation and characterization to determine location, return period, and sense and magnitude of movement for proper design of the pipeline.

South of Lignite, the soils consist of thin deposits of silts over coarse-grained alluvial material. This section is sporadic permafrost (10 to 40 percent frozen) and composed mostly of thaw stable soils.

Segment **16 (NP)** is shown on drawing C-004.

Segment 17 (NP) – Nenana River Canyon (MP 529) to Montana Creek (MP 535)

This section is one of the most difficult construction challenges along the (NP) route. Here the route follows the Parks Highway right of way through Nenana Canyon and the Denali Park commercial tourist facilities along the Parks Highway between MP 533 and 534. Additionally, crossing of the deeply incised Nenana River Canyon at the north end of this segment will probably require an elevated structure over both the Alaska Railroad and the River. After the crossing, the entire route is on the east side of the Nenana River and outside the boundary of Denali National Park and Preserve.

The soils in this segment are mostly bedrock and man-made fill through the Nenana Canyon with alluvial material over bedrock on the south end near Montana Creek. This section is sporadic permafrost (10 to 30 percent frozen) and composed mostly of thaw stable soils.

Route Alternative Segment 17 (NP) – Nenana Canyon to Montana Creek

Moody Creek Alternative

This alternative starts at MP 520 and ends at MP 537. It is routed up the Moody Creek drainage around the northeast and southeast flank of Sugarloaf Mountain, then down Montana Creek to rejoin the route corridor two miles south at MP 537. This route is 4.8 miles longer, but avoids the difficult crossing of the Nenana River at the mouth of Nenana Canyon and avoids conflict with the Denali National Park commercial tourist facilities along the Parks Highway between MP 533 and 534. This alternative route does not avoid the crossing of the Healy Creek fault at approximately MP 521.5 and the Healy fault at approximately MP 524.7.

Segment **17 (NP)** is shown on drawing C-004.

Segment 18 (NP) – Montana Creek (MP 535) to Cantwell (MP 563)

From Montana Creek, a tributary of the Nenana River, the route corridor proceeds southeast to a crossing of the Yanert River (MP 540) and continues south on the east side of the Nenana River and Parks Highway until it emerges from the Alaska Range just north of Cantwell, crossing the Nenana River for the last time (MP 556). It then proceeds southwest along the east side of the Jack River to Cantwell, crossing the Denali Highway at MP 563.

In this segment the route crosses two active faults zones, The Denali/Hines Creek Strand fault zone at approximately MP 540.2 and the Denali/McKinley Strand fault zone at approximately MP 557.8. These faults have Holocene activity crossing the route corridor and will require extensive field investigation and characterization to determine location, return period, and sense and magnitude of movement for proper design of the pipeline.

South of Montana Creek the soils consist of silt deposits over glacial till and coarse-grained alluvial deposits. This section is discontinuous permafrost (50 to 70 percent frozen) and composed mostly of thaw stable soils.

The segment **18 (NP)** route is shown on drawing C-004.

Segment 19 (NP) – Cantwell (MP 563) to Hurricane (MP 602)

The route corridor continues south from Cantwell through Broad Pass to Hurricane, generally aligned with the Parks Highway and the Alaska Railroad. At MP 591 the route diverges to the east and crosses Little Honolulu Creek and Hurricane Gulch at locations less steep than the highway and railroad crossings of these drainages. The alignment then turns southwest, and returns to the Parks Highway at Hurricane (MP 602).

The soils consist of silts of varying thickness over glaciofluvial deposits, glacial till over bedrock, and bedrock and alluvial deposits in river floodplains. This section is discontinuous permafrost (50 to 70 percent frozen) and composed mostly of thaw unstable soils.

Segment **19 (NP)** is shown on drawings C-004 and C-005.

Segment 20 (NP) – Hurricane (MP 602) to Susitna River Crossing (MP 667.9)

Following the Parks Highway in this segment, the route is located on the east side of the Parks Highway to MP 639 where it moves to the west side for a crossing of the Chulitna River (MP 640). At MP 643 the route returns to the east side of the Highway, but crosses back to the west side at MP 656 to avoid the Trapper Creek area. The route stays on the west side of the Parks Highway to the north side of the Susitna River Crossing at MP 667.9. A major portion of the alignment traverses Denali State Park in this segment.

The soils north of the Chulitna River Crossing (MP 640) consist of silts of varying thickness over glaciofluvial deposits, glacial till over bedrock, and bedrock and alluvial deposits in river floodplains. This section is sporadic permafrost (10 to 20 percent frozen) and composed mostly of thaw unstable soils.

South of the Chulitna River crossing to the end of the segment soils consist of silts over glaciofluvial deposits, some glacial till, and bedrock and alluvial deposits in river floodplains. Permafrost is mostly absent but isolated pockets of permafrost may occur where protected by thick organics. Where permafrost occurs soils are thaw unstable.

Segment **20 (NP)** is shown on drawing C-005.

At MP 667.9 the route corridor options divide. The route to Palmer (P) continues south- southeast along the Parks Highway and Alaska Railroad. The corridor to Nikiski (N) leaves the Highway corridor and proceeds south cross-country toward Mount Susitna and Tyonek.

5.5. Nikiski Corridor (N) – Susitna River Crossing to Nikiski

Segment 21 (N) – Susitna River Crossing (MP 667.9) to Nikiski (MP 788.4)

Here the route corridor to Nikiski leaves the Parks Highway and proceeds south, cross-country to Tyonek (MP 757). The route follows the west side of the Susitna River, one to five miles west, to the base of Mount Susitna , then continues on to Tyonek with a subsea crossing of Cook Inlet to the Nikiski area and ends proximate to the north side of the Nikiski LNG Plant at MP 788.4. The route crosses numerous rivers, creeks and wetlands in this segment.

In this segment, the route also crosses the active Castle Mountain fault zone at approximately MP 724.9. This fault has Holocene activity and will require extensive field investigation and characterization to determine location, return period, and sense and magnitude of movement for proper design of the pipeline.

This route segment includes an 18-mile subsea crossing of Cook Inlet from the North Foreland to a point 2.5 miles east of Boulder Point. This crossing will require extensive field investigation to confirm final routing that takes into account other pipelines, currents, and bottom conditions.

South of the Susitna River crossing to Tyonek (MP 757), soils consist of silts and organics, muskeg deposits over glaciofluvial deposits, some glacial till, and alluvial deposits in river floodplains. Permafrost is mostly absent but isolated pockets may occur where protected by thick organics. Where permafrost occurs soils are probably thaw unstable.

Segment **21 (N)** is shown on drawing C-006.

Construction access is difficult between MP 668 and MP 740 – the Beluga Gas Field. Access to the route can only be established from the ends of the segment with primary access to the west side of Cook Inlet at the Parks Highway MP 668.

5.6. Palmer Corridor (P) – Susitna River Crossing to Junction of Parks and Glenn Highways

Segment 21 (P) – Susitna River Crossing (MP 667.9) to Houston (MP 712)

This segment crosses the Susitna River (MP 669) downstream of the existing Parks Highway Bridge and parallels the Highway to MP 681. The route is located south and west of the Parks Highway to MP 676, then east of the highway proceeding south to MP 681.

At MP 681, the corridor leaves the highway toward the east and is located next to a Matanuska Electric Association (MEA) power line right-of-way, intersecting the Alaska Energy Authority (AEA) Intertie alignment. It then turns southward along the Intertie, parallel to and approximately 1 to 3 miles east of the Parks Highway and the Alaska Railroad, to the southern terminus of the Intertie at Willow (MP 703). It continues south along a MEA power line to a point approximately 4 miles northwest of Houston (MP 709). From MP 709 to Houston the route follows the east side of the Parks Highway. This routing to the east minimizes conflicts with the populated area proximate to the Parks Highway north of Houston.

Soils consist of thick silts and organic deposits over glaciofluvial deposits, and alluvial deposits in river floodplains. Permafrost is mostly absent but isolated pockets of permafrost may occur where protected by thick organics. Where permafrost occurs soils are probably thaw unstable.

Segment **21 (P)** is shown on drawing C-005.

Segment 22 P – Houston (MP 712) to the Junction of Parks and Glenn Highways (MP 734.7)

At Houston the route corridor crosses to the west of the Parks Highway and the Alaska Railroad in order to intersect the Castle Mountain fault zone in a less populated area, then moves back to the east side of the highway at MP 715 and follows the Alaska Railroad to MP 721. From MP 721 to MP 733 the route is located to the south of the Alaska Railroad and Parks Highway to minimize conflict with populated areas in the Wasilla area. At MP 733, the route rejoins the Alaska Railroad to the end point at the junction of the Parks and Glenn Highways at MP 734.7 where it terminates at Enstar's 20-inch diameter pipeline.

The route crosses the Castle Mountain fault at approximately MP 713 where the fault zone is not well defined and may be as wide as 2.5 miles. This fault has Holocene activity and will require extensive field investigation and characterization to determine location, return period, and sense and magnitude of movement for proper design of the pipeline.

Soils consist of thick silts and muskeg deposits over glaciofluvial deposits and alluvial deposits in river floodplains. Permafrost is absent.

Route Alternative Segment 22 (P) – Houston to the Junction of the Parks and Glenn Highways

North MatSu Alternative

This alternative begins at Houston and follows the Little Susitna River upstream for approximately six miles. It then follows access roads around the north side of Wasilla north of Memory Lake to Finger Lake, then south to the Junction of the Parks and Glenn Highways. This route avoids the main population center at Wasilla but is 2.9 miles longer than the shortest route. This route still conflicts with private property owners and is less desirable for a crossing of the Castle Mountain Fault.

Segment **22 (P)** is shown on drawing C-005.

5.7. Port Valdez Corridor (PV) – TAPS Pump Station 7 to Anderson Bay

Segment 13 (PV) – TAPS Pump Station 7 (MP 408.8) to the Chatanika River (MP 434.5)

From TAPS Pump Station 7 (MP 408.8), the route corridor generally parallels the existing TAPS alignment west of the highway. The route crosses the Chatanika River at MP 433. Topography is generally steep to rolling with occasional flat terrain in valley bottoms and ridge tops.

Soils consist of shallow bedrock with locally thick deposits of upland silts and re-transported, fine-grained soils on lower valley slopes. Valley bottoms such as the Chatanika River are composed of silts over granular alluvial riverbed deposits. The soil thermal state is highly variable. Fine-grained soils and north facing slopes are predominantly frozen. Permafrost is more prevalent on lower slopes and valley bottoms than on ridge tops. Areas with outcropping bedrock, south facing slopes, and stream crossings are unfrozen to sporadically frozen.

The end point of this segment is the location of an alternate route for the corridor to Nikiski and Palmer. This route option skirts the northern edge of Fairbanks, thus allowing easier access to the gas. (See *Route Alternative Segment 13 (NP) – Pump Station 7 to Nenana Fairbanks Alternative.)*

Segment **13 (PV)** is shown on drawing C-003.

Segment 14 (PV) – Chatanika River (MP 434.5) to Upper French Creek (MP 479)

From the Chatanika River, the route corridor proceeds southeast and descends into the Chena-Tanana Lowland. The route passes Fairbanks several miles to the east, and remains east of the TAPS route and highway to the eastern edge of Eielson Air Force Base (MP 470) where the route rejoins and parallels the TAPS route to the end of the segment. Numerous road and stream crossings exist in this segment.

Topography in the uplands north of the Chena River is rolling to locally steep, while the topography south of the river in the Chena-Tanana Lowland is flat. In the northern portion of this segment, the subsurface consists of shallow bedrock on hilltops with thick, re-transported, fine-grained soils on lower slopes and in valleys. Floodplain deposits are found in the southern portion of this segment. Soils are sporadically frozen (25 to 50 percent) throughout this segment, with fine-grained soils generally frozen and coarser-grained soils generally unfrozen.

In this segment, the route crosses the Moose Creek Dam at MP 462.5. This crossing is a special design and construction area and the pipe should be designed to cross over rather than through the dam.

Segment **14 (PV)** is shown on drawing C-003.

Segment 15 (PV) – Upper French Creek (MP 479) to Shaw Creek Flats (MP 521)

The route corridor trends southeast from Upper French Creek through Shaw Creek Flats. The route parallels the TAPS alignment for the length of this segment beginning in the Chena-Tanana Lowlands where topography is flat to rolling and soils are thick, re-transported, fine silts, then transitions to the Salcha Uplands. In this area, terrain is rolling to locally steep, especially in the Salcha Bluff area north of the Salcha River (MP 488).

The route crosses the active Salcha River Seismic Zone at approximately MP 490. This zone has shown consistent seismic activity but no surface expression has been found to date. This seismic hazard will require extensive field investigation and characterization to determine if a surface fault exists, its location, return period, and sense and magnitude of movement for proper design of the pipeline.

South of the Salcha River floodplain deposits, shallow and exposed bedrock occur south of Gold Run Creek (MP 499). Locally thick deposits of re-transported, fine-grained soils are found on lower slopes and valleys. Terrain is locally steep near Minton and Rosa Creeks. Steep longitudinal and cross-slopes exist in this area, and the subsurface consists of shallow and exposed bedrock. The route then crosses sand dunes and re-transported sand dune deposits and rolling terrain as it descends Rosa Creek into the Shaw Creek Flats. In the flats, soils consist of thick lowland loess over floodplain gravel deposits. The thermal state of soils in this segment is highly variable. The entire segment is discontinuous permafrost (50 to 70 percent frozen). Fine-grained soils and north facing slopes are predominantly frozen. Permafrost is more prevalent on lower slopes and valley bottoms than on ridge tops. Areas with outcropping bedrock, south facing slopes, and stream crossings are unfrozen to sporadically frozen.

Segment **15 (PV)** is shown on drawings C-003 and C-007.

This route segment is remote from the existing state road system and construction access is limited to the TAPS pipeline workpad.

Segment 16 (PV) – Shaw Creek Flats (MP 521) to Richardson Highway Crossing (MP 544)

In this segment the route corridor crosses the Tanana River (MP 523). This very difficult crossing will be elevated on a new highway bridge across the river downstream and west of the TAPS crossing. The route crosses a belowground TAPS section and proceeds south on the east side of TAPS, skirting around the communities of Big Delta and Delta Junction. The segment continues along the east side of the Richardson Highway, crossing the Alaska Highway (MP 533), Jarvis Creek (MP 534), and Fort Greeley (MP 536) before ending at the Richardson Highway crossing at MP 544.

Topography in this segment transitions steep and hilly terrain on the north approach to the Tanana River, and flat terrain south of the Tanana River crossing. Soils consist of silt over bedrock, exposed bedrock, and re-transported, fine-grained soils north of the Tanana River, thin silt over floodplain gravels from the Tanana River to Jarvis Creek, and glacial outwash to the segment end. Soils are sporadically frozen (10 to 30 percent) in this segment, with fine-grained soils being generally frozen and coarser soils being generally unfrozen. Coarser-grained floodplain gravels and glacial outwash here are thaw stable.

Segment **16 (PV)** is shown on drawing C-007.

Segment 17 (PV) – Richardson Highway Crossing (MP 544) to Donnelly (MP 558)

After crossing the Richardson Highway to the west, the route corridor proceeds south past the west side of Donnelly Dome to a crossing of the Richardson Highway at MP 554, then cross-country to Donnelly (MP 558) where the route enters the floodplain of the Delta River.

The route crosses the Donnelly Dome Fault Zone west of Donnelly Dome between MP 550 and 552. This fault crossing was documented during the original design of TAPS but no fault trace was found crossing the pipeline route. Additional field investigation and characterization is warranted to determine the fault location, return period, and sense and magnitude of movement for proper design of the pipeline.

The soils in this segment are glacial tills, locally with thin silt cover. The entire segment is discontinuous permafrost (50 to 80 percent frozen). Soils, where frozen are not thaw stable.

Route Alternative Segment 17 (PV) – Richardson Highway Crossing to Donnelly

Donnelly Alternative

This alternative starts at MP 544.2 and returns to the route corridor at MP 561.2 traversing the east side of Donnelly Dome and intersecting the Donnelly Dome fault at a known location. The alternative is 3.0 miles longer than the shortest route but reduces the required length of the special design fault crossing to less than one mile. The alternative crosses Fort Greeley land.

Segment **17 (PV)** is shown on drawing C-007.

Segment 18 (PV) – Donnelly (MP 558) to Trims Creek (MP 578)

The route corridor continues south through the Alaska Range following the east side of the Delta River and parallels TAPS and the predominantly the east side of the Richardson Highway. It then travels along the west side of the highway between MP 562 and 565, proceeding through the Black Rapids Military Reservation (MP 570) and passing east of TAPS Pump Station 9 near MP 577 to Trims Creek (MP 578). The route is located east of the Richardson Highway to avoid conflict with the Delta Wild and Scenic Rivers Conservation Unit from Black Rapids to Phelan Creek (MP 595).

Topography is fairly steep from Donnelly south as the route ascends into the mountainous terrain of the Alaska Range that exists along the east valley wall of the Delta River.

As the route crosses the alluvial fans of steep gradient streams that flow into the Delta River south of Donnelly, soils exhibit conditions that alternate from floodplain deposits to coarse fan deposits to glacial till deposits over shallow bedrock. Soils from Donnelly to Ruby Creek (MP 562) are discontinuously frozen (50 to 70 percent), while those from Ruby Creek to Trims Creek are generally unfrozen.

The route in this segment, crossing steep gradient streams that flow into the Delta River, can experience heavy flows, erosion, and deposition during break-up and especially during large summer storms.

Segment **18 (PV)** is shown on drawing C-007.

Segment 19 (PV) – Trims Creek (MP 578) to Isabel Pass (MP 597)

South of Trims Creek the route corridor crosses Castner Creek (MP 579) and the Denali Fault (MP 581) on the east side of the Richardson Highway. The route crosses Miller Creek at MP 582 and closely parallels the Highway through Phelan Creek, moving to the west side of Phelan Creek (MP 587) abreast of Rainbow Ridge, crossing back to the east side of the creek and Highway at MP 590. From there, the route remains parallel with TAPS to Isabel Pass (MP 597).

The route crosses the Denali Fault which most recently ruptured in November of 2002. The fault has been extensively studied by an APSC team of seismic experts and the United States Geological Survey (USGS) and has been precisely located and characterized. Further study of the fault is probably unnecessary before pipeline design, provided data can be obtained from APSC.

A short section of till-covered bedrock is present at the north end of this segment, and silt- covered till and bedrock is present to the west of Phelan Creek. Floodplain and glaciofluvial deposits underlie the remainder of the northern portion of this segment. Glacial till is the predominant soil type in the southern portion of this segment.

Soils in this segment are generally unfrozen in the active floodplain areas and discontinuously frozen in the upland areas. The bedrock ridges west of Phelan Creek are generally frozen.

Segment **19 (PV)** is shown on drawing C-007.

Segment 20 (PV) – Isabel Pass (MP 597) to Hogan Hill Lake (MP 638)

In this segment, the route corridor remains generally parallel with TAPS to the east of the Richardson Highway from Isabel Pass to Hogan Hill where it enters the Copper River Basin.

Terrain in this segment is rolling. In the northern half of this segment, local longitudinal slopes and cross-slopes are steep. Soils in this segment are primarily glacial till, locally overlying shallow bedrock. This segment lies in discontinuous permafrost (70 to 90 percent frozen). However, areas with outcropping bedrock, south facing slopes, and stream crossings may be unfrozen to sporadically frozen.

Segment **20 (PV)** is shown on drawing C-007.

Segment 21 (PV) – Hogan Hill Lake (MP 638) to Glennallen (MP 675)

The route corridor into the Copper River Basin from Hogan Hill to the Glennallen was selected to avoid the Gulkana Wild and Scenic Rivers Conservation Unit. The route remains on the east side of the Richardson Highway, and is generally a mile or more from the highway south of MP 641, where the route takes a southwesterly course to the Gulkana River crossing the Richardson Highway at MP 648. The route then crosses the Gulkana River in aerial mode at MP 648. The route proceeds almost due south from the Gulkana River along the west side of the Richardson Highway crossing and generally paralleling the east side of the TAPS pipeline to Glennallen

The GL landform of the Copper River Lowland is one of the most complex and studied landforms on the TAPS route. The genesis of this landform is a large glaciolacustrine environment created by a glacially damned lake in what is known as the Copper River Basin. Non-lithified, non-sorted, or poorly sorted soils contain a wide range of particle sizes from clay/silt to cobbles and boulders, or drop stones, that are sometimes referred to as diamicton. “GL” soils include varved clay, silty clay, clayey silt, very fine sand, and occasional layers of sand, gravel, cobbles, and boulders. Finer-grained materials may have largely settled out of suspension in quiet waters while silt, sand, gravel, and cobbles rained down from melting icebergs floating in the lake. From Hogan Hill to Glennallen, soils are fine-grained with 70 to 85 percent silt and clay.

Thermal conditions in Copper River Basin are also complex. Here permafrost is particularly sensitive to even minor surface disturbance because the ground temperature is close to 32^{o}F. Additionally, surface and groundwater moving at depth normally preclude permafrost formation. Permafrost is generally more widespread and continuous near Hogan Hill at the northern edge of basin and is more discontinuous to the south near Glennallen.

Segment **21 (PV)** is shown on drawings C-007 and C-008.

Segment 22 (PV) – Glennallen (MP 675) to Willow Mountain (MP 700)

The route corridor continues along the west side of the Richardson Highway, paralleling TAPS on the east side from Glennallen south. At the Klutina River, the route crosses TAPS and the river upstream of the TAPS crossing. The route crosses the Tazlina River (MP 677) in aerial mode, and the Klutina River (MP 687) in buried mode. The route proceeds through the Copper River Basin to Willow Mountain at MP 700.

Topography in this segment is rolling to flat, with short stretches (typically entering river floodplains) where the longitudinal slopes and cross-slopes are steep.

Soils are of glaciolacustrine origin (see Segment 21 (PV) – Hogan Hill Lake (MP 638) to Glennallen (MP 675)) except near the Tazlina and Klutina Rivers where floodplain deposits overlay the glaciolacustrine soils. The route segment is discontinuous permafrost (60 to 80 percent frozen) with thermal transitions potentially occurring over short distances.

Segment **22 (PV)** is shown on drawing C-008.

Segment 23 (PV) – Willow Mountain (MP 700) to Little Tonsina River (MP 726)

The route corridor closely parallels the TAPS route along the west side of the highway to MP 715 crossing Squirrel Creek at MP 707. The route continues to parallel the TAPS route to MP 723 before diverting to the east around TAPS Pump Station 12 before crossing the Little Tonsina River and the Richardson Highway at MP 726. The Squirrel Creek crossing is a ***significant stream crossing challenge*** in this segment. Site work at this crossing is expected to be extensive because the Squirrel Creek Valley is incised with very steep walls.

Terrain in the segment is gently rolling transitioning to steep near major drainage systems.

Soils in this segment consist of glacial till and till over bedrock in the Stuck Mountain area, with glaciolacustrine deposits (see Section Segment 21 (PV) – Hogan Hill Lake (MP 638) to Glennallen (MP 675)) in most of the remaining route. From Willow Mountain to the Little Tonsina River, this landform is composed of 45 to 55 percent silt and clay. Sporadic permafrost is present throughout this route segment. Considerable variation in frozen and unfrozen conditions is possible over short distances.

Segment **23 (PV)** is shown on drawing C-008.

Segment 24 (PV) – Little Tonsina River (MP 726) to Thompson Pass (MP 762)

After crossing the Little Tonsina and the Richardson Highway, the route corridor enters the Chugach Mountains on the west side of the Highway. The route then proceeds down the Tiekel River Valley roughly parallel to TAPS and the Richardson Highway. East of the confluence of the Tiekel and Tsina Rivers (MP 755), the route continues to follow TAPS and the Richardson Highway up the Tsina River Valley. The route then follows the Ptarmigan Creek drainage above its confluence with the Tsina River and passes near Worthington Glacier, ascending to the top of Thompson Pass at MP 762.

Although this segment follows river valleys throughout its length, it traverses mountainous terrain along the valley walls with very steep longitudinal and cross-slopes.

Soils in this segment are glacial till over shallow bedrock with floodplain deposits on the valley floors and alluvial fans. This route segment is south of the southern boundary of permafrost.

Segment **24 (PV)** is shown on drawing C-008.

Segment 25 (PV) – Thompson Pass (MP 762) to Browns Creek (MP 774)

This section of the route corridor contains two of the most difficult construction areas, Thompson Pass and Keystone Canyon. The route descends the steep face of Thompson Pass (MP 762 to MP 765) on an alignment between the Richardson Highway to the south, and TAPS to the north. It follows the old highway alignment for much of this segment after it descends the steepest portion of the pass. Below the pass, the route follows comparatively smooth terrain along the Lowe River Valley to the mouth of Keystone Canyon. The route traverses Keystone Canyon (MP 769 to MP 773) adjacent to the Richardson Highway. ***Keystone Canyon is a very narrow rock canyon and will require special design and construction.*** From Keystone Canyon, the route roughly parallels TAPS on the south side of the Lowe River Valley to the crossing of Brown Creek (MP 774).

This segment is characterized by very steep topography. Soils in this segment are glacial till and till over bedrock, with floodplain deposits at stream crossings and in portions of the Lowe River Valley. Permafrost is absent.

Segment **25 (PV)** is shown on drawing C-008.

Segment 26 PV – Browns Creek (MP 774) to TAPS Valdez Marine Terminal (MP 788)

From Keystone Canyon, the route corridor roughly parallels TAPS on the south side of the Lowe River Valley and along the south side of Port Valdez to the TAPS Valdez Marine Terminal.

This segment is characterized by steep topography. Soils are mostly glacial till over bedrock and bedrock but include floodplain deposits in valley bottoms. The route crosses the Fort Liscum landslide at MP 783. Permafrost is absent.

Segment **26 (PV)** is shown on drawing C-008.

Segment 27 (PV) – TAPS Valdez Marine Terminal (MP 788) to Anderson Bay (MP 793.9)

The route corridor between MP 789 and Salmon Creek at MP 792 is located uphill on the bench behind the TAPS Valdez Marine Terminal, outside property owned by APSC. ***Design and construction for this segment, however, will require coordination with APSC and it should be considered a special construction area.*** The route parallels the south shore of Port Valdez close to the coast from Salmon Creek west to the Anderson Bay site, approximately 3.0 miles west of the marine terminal. ***Anderson Bay is the terminus of the Port Valdez corridor (MP 793.9).***

Terrain in this route segment is very steep and mountainous. Soils consist of bedrock and glacial till over bedrock. Permafrost is absent.

Segment **27 (PV)** is shown on drawing C-008.

5.8. Special Design/Construction Areas

Special construction areas currently identified along the Port Valdez route corridor include:

1) Atigun Pass
2) Chandalar Shelf
3) Yukon River
4) Moose Creek Dam
5) Phelan Creek
6) Keystone Canyon
7) TAPS Valdez Marine Terminal

Special construction areas currently identified along the Nikiski and Palmer route corridors include:

1) Atigun Pass
2) Chandalar Shelf
3) Yukon River
4) Nenana Canyon
5) Cook Inlet Crossing

Each of these locations represents an area with special engineering and construction constraints.

5.8.1. Atigun Pass – Segment 6 (C)

The route corridor over Atigun Pass is a special design area since it is a major "pinch point" where the pipeline must be routed with the Dalton Highway. Atigun Pass is the highest point crossed in the Brooks Range and forms the continental divide between the Arctic Ocean and the Bering Sea. The TAPS pipeline occupies the bottom of the valleys leading to the pass on both the north and south sides. The Dalton Highway takes a less direct route on the lower valley slopes to limit roadway grades.

The highway was constructed through the pass in 1974 by excavating bedrock and cutting and grading the toe areas of numerous talus slopes composed mainly of coarse-grained rock debris. The slopes above the highway are steep and talus slopes may be near the angle of repose for the rock debris. Below the highway on the south side of the pass, the TAPS pipeline encroaches on the toe of the roadway fill near the top of the pass. The best route for future pipelines on the south side of the pass is proximate to the highway near the upslope roadway ditch.

Approximately 5,000 feet of roadway will have to be redesigned and widened to make space for a pipeline. The Dalton Highway must therefore be reconstructed to allow space for a pipeline. All work activity must allow for the periodic passage of vehicles using this, the sole route to Prudhoe Bay.

5.8.2. Chandalar Shelf – Segment 6 (C)

The section is on a very steep (40 to 50 percent) longitudinal bedrock slope, where special construction procedures will have to be developed for installing a buried pipeline.

5.8.3. Yukon River – Segment 11 (C)

The common corridor for all routes must cross the Yukon River on their way south. The Dalton Highway extension north to Prudhoe Bay and construction of the TAPS required construction of a bridge across the Yukon River to handle heavy vehicle loads. TAPS construction involved use of brackets on the upstream side of the Highway Bridge to support the oil pipeline across the Yukon.

The gas pipeline will cross the Yukon River by utilizing an additional set of unused support brackets, on the downstream side of the existing Yukon River Bridge. The existing support brackets must be evaluated and modified as required. Special construction techniques must be developed for placement of the pipeline on the Yukon River Bridge. Engineering analysis and a risk assessment will need to be conducted to verify that the existing Yukon River Bridge is capable of supporting an additional pipeline.

The pipeline approach to the north side of the bridge will involve routing through the Yukon River floodplain. Design for protection against high river flood levels will necessitate special consideration at the north bank pipeline expansion loop. In addition, the alignment at the south bank of the river involves routing along steep cross-slopes.

5.8.4. Moose Creek Dam – Segment 14 (PV)

The route corridor crosses the Chena River Flood Control Project southeast of the Fairbanks area. The Moose Creek Dam is approximately 6.5 miles long and oriented perpendicular to the route. At the point of pipeline crossing, the dam height is approximately 40 to 45 feet with 2.5H:1V slopes on the upstream side and 2H:1V slopes on the downstream side. A special crossing over the top of the dam should be considered so that the crossing does not result in disturbance to the earthen dam structure, which could adversely affect its long-term integrity.

5.8.5. Phelan Creek – Segment 19 (PV)

The route corridor between the mouth of Phelan Creek and the crossing of lower Phelan Creek includes Richardson Highway co-use areas, and should be considered a special construction area. The total length of special construction is estimated to be one and one half miles. Final routing should consider a corridor parallel to the Richardson Highway in the active floodplain of Phelan Creek.

A site-specific investigation and evaluation of aufeis potential (icing formed when groundwater is forced to the surface in winter) and frost heave of the paved Highway surface should be made during final design.

5.8.6. Keystone Canyon – Segment 25 (PV)

The route through Keystone Canyon is along the Richardson Highway for most of its four mile length. The special construction area starts near the south end of the Richardson Highway bridge crossing of the Lowe River and ends at the pipeline crossing of the Highway at the mouth of Keystone Canyon.

The Richardson Highway through this section is routed proximate to the Lowe River in Keystone Canyon. The Lowe River is severely constricted in the canyon, and the Richardson Highway is closely flanked by the steep canyon walls and the river. In the upper canyon area, the highway is located on the east side of the river, whereas in the lower canyon area, the highway is located on the west side of the river. The Richardson Highway crosses three bridges within the canyon.

The maintenance of traffic during construction will be necessary since the Richardson Highway is the only land link to the City of Valdez.

5.8.7. TAPS Valdez Marine Terminal – Segment 26 (PV)

The corridor between the Fort Liscum slide area and the mouth of Salmon Creek will require routing in the area upslope of the TAPS Valdez Marine Terminal and private property. This pipeline segment is considered a special construction area due to the proximity of the pipeline upslope from the TAPS facilities. The total length of this special construction section is approximately 3.5 miles.

Further route evaluation and alignment design in this area will involve coordination with APSC. Selection of a specific route in the area of the VMT will be the result of detailed evaluation of design requirements and construction procedures. Special safety measures will need to be evaluated for application to design, construction, operations and maintenance of the route segment.

5.8.8. Nenana Canyon – Segment 17 (NP)

This segment is one of the most difficult construction sections on the Nikiski-Palmer corridor. The route follows the Parks Highway right of way through the Nenana Canyon and the Denali National Park commercial tourist facilities along the Parks Highway for a distance of approximately one mile. Additionally, the crossing of the deeply incised Nenana River Canyon at the north end of this segment will probably require a special elevated structure over both the Alaska Railroad and the river.

5.8.9. Cook Inlet Crossing – Segment 21 (N)

This segment involves an 18-mile subsea crossing of Cook Inlet from the North Foreland to Boulder Point. This crossing will require extensive field investigation to determine the confirmation of the final routing that takes into account other pipelines, currents, and sea floor conditions. Special offshore pipe laying equipment and contractors will be required for this crossing.

5.9. Geotechnical Considerations

Similar geotechnical considerations for all corridors must be considered in future study and route optimization.

5.9.1. Permafrost

Earthen material which remains frozen (<32 deg F) during the entire year for two or more years is defined as permafrost. Included in this definition are certain soils that may not be actually bonded by frost such as some salty and clayey materials, well-drained (dry frozen) sand and gravel, and solid rock. A surficial layer, which is subject to seasonal thawing and freezing, usually overlies permafrost. This is called the ***active layer***. Thickness of the active layer depends on ambient temperature variations, slope aspect and surface cover conditions.

The terms “***continuous***,” “***discontinuous***,” and “***sporadic***” are used to describe the distribution of permafrost on a regional basis. Areas classified as ***continuous*** may have some zones such as stream channels or the sediments under deep lakes that are unfrozen but, in general, the entire soil mass beneath the active layer is frozen. ***Discontinuous*** permafrost indicates an area that is generally frozen beneath the active layer but which may encompass significant zones of unfrozen material as found in south facing slopes in the Fairbanks area. ***Sporadic*** permafrost indicates that, in general, an area is unfrozen but significant zones of permanently frozen material are present. Isolated frozen zones should be anticipated even in areas classified as permafrost-free along the pipeline alignment.

Ambient temperature and depth of snow are controlling factors in the regional distribution of permafrost. As a result, latitude, elevation, and snow accumulation often determine distribution patterns. In northern Alaska and in the higher mountain ranges, permafrost is continuous. At lower elevations in the southern part of the state, permafrost distribution is more varied. Also the temperature of the permafrost tends to warm to the south. In many areas, particularly in sporadic zones, the permafrost is degrading under natural conditions. Where fire or other natural or man-made phenomena locally alter the surface cover, permafrost conditions may also be altered.

The creation or degradation of permafrost is not necessarily undesirable. Much of the route corridor is underlain by foundation conditions that are not significantly affected by changes in thermal state. In some cases, however, the effects of thermal change can be detrimental resulting in problems such as pipe stress and disrupted drainage patterns. Freezing unfrozen ground with cold pipelines may result in formation of a ***frost bulb***, which may cause ***frost heave*** (see Sections 5.9.2 and 5.9.3). Thawing of frozen ground with warm pipelines may cause ***thaw settlement*** as permafrost soils drain and consolidate (see Section 5.9.4). Changes to the surface cover and drainage patterns as a result of construction and operation activities can accentuate thermal change.

In addition to identifying the distribution patterns of frozen ground, it is important to delineate those areas that are sensitive to thermal change. The temperature of the permafrost and its ice content are the chief parameters to be considered in determining the thermal sensitivity of a given soil mass.

Where possible the final route selected should avoid the most sensitive areas. Established engineering techniques can be evaluated and selected to minimize the subsurface heat loss or gain resulting from the construction and operation of the pipeline and its related infrastructure.

Construction mitigation can include scheduling parameters. Seasonal construction and accelerated schedules can be used to limit the thermal exposure in the most sensitive areas.

5.9.2. Frost Bulb

If a belowground gas pipeline is maintained at temperatures below 32 deg F for an extended period of time, the surrounding unfrozen ground will begin to freeze. The newly frozen soil is called a frost bulb because it tends to grow outward in a circular or bulbous fashion. A buried cold gas line may initiate frost bulb growth.

The growth with time of the frost bulb will have certain impacts on the environment in the vicinity of the pipeline. The growth of the frost bulb in previously unfrozen soils will alter subsurface water flow patterns and temperatures. The growing frost bulb may restrict or redirect subsurface flows and can increase the potential for icings (aufeis) to develop. In some cases, the soil will be displaced upward relative to the surrounding terrain, and may interrupt existing surface flow. In stream crossing areas, it could lead to lower water temperatures that may affect aquatic life and biological organisms.

A growing frost bulb may tend to strengthen the supporting soil but where soils are frost susceptible, segregated ice may form, causing an irregular volumetric growth and frost heave. This activity may place the pipeline in distress.

5.9.3. Frost Heave

A cold gas pipeline passing through unfrozen soils will cause a zone, or “bulb" of frost to develop with time. For a large diameter, cold pipeline this bulb will continue to grow for many years. The presence of the freeze front (the outer limit of the frozen bulb) establishes temperature and pressure gradients within the adjacent unfrozen soils. These gradients move soil water to the freeze front. Frost heave of a soil mass results from the expansion due to the freezing of the pore water within the frozen bulb as well as the development of segregated ice lenses due to the freezing of soil water as it arrives at the freeze front. Of the two components, the second, ice lens growth at the freeze front, is the most significant.

In order for frost heave to occur, three conditions must exist concurrently: 1) soil moisture supply, 2) sufficiently cold temperatures to cause freezing of soil moisture, and 3) a frost-susceptible (fine-grained) soil. If drainage is impeded in non-frost-susceptible soils, freezing of the soil moisture may result in slight upward movements due only to volumetric expansion of water.

The amount of heave a given soil will generate upon freezing (assuming an adequate supply of soil water) is a function of many factors. These include physical soil properties (grain size, soil moisture and density, and the activity of clay particles), thermal gradient at the freeze front (pipe temperature, unfrozen soil temperature), and overburden pressure at the freeze front.

The growth of a frost bulb beneath the pipeline and any attendant frost heave will develop with time and displace the pipeline upward. Uniform displacement of the pipeline upward will not, however, cause any direct, adverse effects on the pipeline.

The pipeline will be affected by differential frost heave, which can occur site specifically such as at thermal transitions from permafrost to non-permafrost soils. This differential frost heave will displace the pipeline unevenly and may induce strains and associated stresses in the pipeline.

5.9.4. Thaw Settlement

Thaw settlement results from the volume reduction that occurs as over-saturated, ice-rich, frozen soils thaw. In general, thawing can occur anywhere the existing thermal equilibrium within permafrost areas is disturbed.

The drainage of excess water from thawing ice-rich permafrost soils leads to thaw consolidation (volume reduction), which most commonly manifests itself as thaw settlement. The depth of thaw and in-situ soil properties (frozen and unfrozen) determines how much thaw settlement will occur. The rate at which the settlement will occur depends on the amount of excess ice in the frozen soil, the permeability of the unfrozen soil, the rate of advance of the thaw front, and the depth from the surface to the thaw front.

The depth of thaw depends upon the magnitude of the thermal disturbance (surface disturbances, addition of a gravel pad, or a warm gas operating pipeline), the climatic conditions in the area, the frozen and unfrozen soil properties, the average ground temperature, and the impact of groundwater movements.

Thaw settlement generally results in the downward displacement of the pipeline (as opposed to frost heave that displaces the pipeline upward). Differential thaw settlement due to variation in soil types, soil ice contents, and thaw depths, and presence or absence of permafrost can induce strains and associated stresses in the pipe. As with frost heave, these differential movements can occur over relatively short distances and, when considered in conjunction with primary pipeline loading, can create unacceptable pipe strains.

The placement of a gravel (or crushed rock) workpad in permafrost areas may cause thaw settlement to occur adjacent to the pipeline and the thaw can extend laterally beneath the pipeline.

Right-of-way disturbances due to ditching, pipe installation, and backfilling may cause some thermal degradation (and possibly thaw settlement) of the near-surface soils during the period prior to pipeline operations.

Potential thaw settlement predictions are routinely made using estimates of thaw depth, of soil layer thickness and soil properties, and of thaw strain correlations. These predictions are used to design facilities and/or to develop mitigation measures.

5.9.5. Soil Slope Stability

The pipeline alignment will pass through areas of steep terrain and a variety of geologic regimes.

The types of slope instability that could affect a pipeline are summarized as follows:

- Static and dynamic failure of unfrozen soil slopes,
- Static and dynamic failure of thaw plugs on permafrost slopes,
- Static and dynamic failures of cut slopes, and,
- Static and dynamic failures of embankments including fill sections, dikes, and berms.

Negative impacts of pipeline construction and operation could include:

- Over-steepening of naturally stable slopes,
- Drainage diversion into sensitive areas,
- Over-loading statically stable rock slopes, and,
- Thawing of frost-bonded slopes and subsequent saturation with melt water.

The knowledge gained and geotechnical techniques developed during the construction of TAPS will be utilized wherever appropriate on this pipeline.

The potential for slope instability must be considered during route optimization. An initial evaluation will be made of the alignment for areas with relatively steep unfrozen slopes and moderate to steep frozen slopes occurring in landforms which exhibit scars indicative of naturally occurring instabilities and/or landforms which experience has shown are sensitive to construction activities. The product of this evaluation will be a listing of slopes requiring consideration for realignment and/or detailed stability analysis. Where a significant zone of potential instability is identified in the evaluation process, the potential benefits of realigning the pipeline to avoid the expense of slope stabilization will be considered.

Operational maintenance of drainage ways and slope faces, and visual and instrumented monitoring programs will assure that the pipeline will remain safe and stable throughout its projected lifetime.

5.9.6. Seismic Hazards

A major design criterion for this pipeline will be the ability of the entire system to withstand all reasonably anticipated effects of natural phenomena, including earthquakes. The design for seismic resistance will be based on modern, state-of-the-art seismic design criteria and practices. Extensive studies will be required in the development of project seismic design criteria and procedures. The knowledge gained and seismic techniques developed during the construction of TAPS will be utilized wherever appropriate on this pipeline.

5.9.7. Liquefaction

During long duration seismic events certain soil types may, if saturated, lose much of their shear strength and behave as a liquid mass with flow capabilities. Seismic liquefaction commonly occurs in loose, cohesion-less granular material that is saturated. Soil deposits will tend to decrease in volume as they consolidate under cyclic seismic shaking. If boundary conditions of the deposit do not permit a rapid drainage of excess water, the resultant increase in pore pressure may be sufficient to produce a loss of strength and a collapse of the inter-granular soil structure.

A liquefied soil offers little support or uplift resistance to buoyancy and the entire soil mass may move down slope on slopes greater than 2 percent or up to the ground surface as sand boils. Under such conditions, structures located in or on level ground will tend to float or sink depending on buoyancy considerations. Even on relatively flat slopes an unconfined soil mass and any structure supported by that mass will tend to slide or flow downhill. Liquefied soils quickly regain their strength once the shaking ceases and drainage occurs.

Seismic liquefaction is a naturally occurring phenomenon, but the potential for occurrence may be affected by pipeline construction and operation if natural drainage patterns are changed resulting in the saturation of sensitive soils. Drainage patterns may be changed by surface features such as road embankment or by subsurface features such as the pipeline ditch or constricting freeze bulb.

Many of the relatively common deposits of uniform silts and fine sandy silts along the route corridors lack cohesion. Due to a general lack of cohesion, they are susceptible to seismic liquefaction. The pipeline and ancillary structures will traverse areas where soils with low cohesion and high groundwater content may be exposed to strong seismic activity. Therefore, the liquefaction potential along the route is a significant geotechnical constraint to siting and design.

Areas identified as liquefaction prone will be avoided as much as possible by minor adjustments in the pipeline alignment and facilities siting. Because of the significant expense of stabilizing an area of potential liquefaction and/or constructing a pipeline segment capable of resisting adverse loading due to seismic liquefaction, a relatively high priority will be given to avoidance of potentially liquefiable areas.

5.9.8. Active Faults

All route corridors proposed cross active faults. Faults with suspected Holocene activity that cross or tend directly toward the route corridor will require extensive field investigation and characterization to determine location, return period, and sense and magnitude of movement for proper design of the pipeline. The following areas have been identified for further study before selecting final route selection.

Prudhoe Bay to Port Valdez Corridor

This route crosses an active fault at the Salcha River at approximately MP 490. This zone has shown consistent seismic activity but no surface expression has been found to date.

The route also crosses the Donnelly Dome Fault west of Donnelly Dome between MP 550 and 552. This fault crossing was documented during the original design of TAPS but no fault trace was found crossing the pipeline route.

The most important fault crossed by the corridor is the Denali Fault at MP 581. This fault has been extensively studied in 2003 and 2004 by an APSC team of seismic experts and by the USGS as a result of the November 2002 Denali Fault earthquake.

Prudhoe Bay to Nikiski /Palmer Corridors

This route crosses the Healy Creek Fault at approximately MP 521.5 and the Healy Fault at approximately MP 524.7.

It also crosses the Denali/Hines Creek Strand Fault at approximately MP 540.2 and the Denali/McKinley Strand Fault at approximately MP 557.8.

The Nikiski route crosses the Castle Mountain Fault at approximately MP 724.9.

The Palmer route crosses the Castle Mountain Fault at approximately MP 713.

5.10. Permitting and Environmental Challenges

5.10.1. Prudhoe Bay to Port Valdez Corridor

There are minimal permitting and environmental challenges associated with the Prudhoe Bay to Port Valdez corridor. There have been four environmental impact statements written for pipeline projects within this corridor in the last thirty years. Environmental baseline information has been updated by each subsequent project and there exists an extensive database of geotechnical conditions within the corridor. Permitting of a new pipeline route within the corridor is expected to be relatively straight forward and to require a minimal lead time.

5.10.2. Prudhoe Bay to Nikiski Corridor

Environmental and permitting challenges are expected to be minimal for the portion of this route that is within the existing TAPS corridor from Prudhoe Bay to TAPS Pump Station 7. The portion of this route from TAPS Pump Station 7 to Nikiski, however, has minimal environmental baseline data and little or no geotechnical data. The only environmental information that exists is the Denali Pipeline Project Environmental Assessment. The Denali Pipeline report covers only the portion of the Prudhoe Bay to Nikiski corridor from Nenana to the Susitna River crossing near Talkeetna. Extensive environmental baseline studies are expected to be required for this corridor south of TAPS Pump Station 7. Additionally, a detailed geotechnical assessment is needed to support both the environment impact statement and the permitting process.

The subsea crossing of Cook Inlet will require a special technical evaluation and marine study to determine feasibility and marine environment impacts before finalizing a pipeline location.

5.10.3. Prudhoe Bay to Palmer Corridors

Environmental and permitting challenges are expected to be minimal for the portion of this route that is within the existing TAPS corridor (Prudhoe Bay to TAPS Pump Station 7). The portion of this route from TAPS Pump

Station 7 to Palmer, however, has minimal environmental baseline data and little or no geotechnical data. The only environmental information that exists is the Denali Pipeline Project Environmental Assessment. The Denali Pipeline report covers only the portion of the corridor from Nenana to Houston. Extensive environmental baseline studies are expected to be required for this corridor south of TAPS Pump Station 7. Additionally, a detailed geotechnical assessment is needed to support both the environment impact statement and the permitting process. The permitting effort is expected to encounter significant difficultly with conflicts associated with private land ownership and population centers south of Willow.

Section 6. Project Management

The scope of work for this study addresses four of the five project alternatives identified by ANGDA in their 2004 Interim Feasibility Report. The fifth alternative is a spur line to Cook Inlet that is the subject of a separate work effort commissioned by ANGDA. The following are summary descriptions of the four alternative projects addressed in this study based on information contained in ANGDA's Interim Feasibility Report:

1) ANGDA stand-alone project with 2 Bscfd capacity

Project 1 consists of a stand-alone 36-inch pipeline starting on the North Slope and terminating at either Valdez or Cook Inlet depending on which location is selected for the liquefaction plant. A 24-inch spur line from Glennallen to Cook Inlet would be installed if the liquefaction plant is located in Valdez. Propane would be extracted from the gas at the terminus of the spur line in Cook Inlet for barging to coastal communities. NGL will be extracted from the gas in Valdez prior to liquefaction. The notional configuration of the LNG plant is based on the use of 5 MTA[3] trains at the Valdez facility and shipment of LNG to either or both Asia and the US West Coast. The configuration for the NGL extraction facilities in Glennallen, Cook Inlet or Valdez is undefined.

2) ANGDA stand-alone project with 1 Bscfd capacity

Project 2 is essentially the same as Project 1 except that a 30-inch diameter pipeline would be installed from the North Slope to carry 1 Bscfd of gas.

3) Take-off project from the Highway Project

Project 3 consists of a secondary project branching off of a 52-inch diameter pipeline from the North Slope to Alberta. A 30-inch diameter pipeline is used to transport 1.5 Bscfd of gas from Delta Junction to Glennallen at which the pipeline branches into two 24-inch pipelines terminating in Cook Inlet and Valdez respectively. The proposed disposition of the end products is the same as that of Projects 1 and 2. Project 3 reflects the "Y-line" concept and is based on a flow of 6 Bscfd from the North Slope to Delta Junction with 4.5 Bscfd of flow continuing through the pipeline to Alberta. Project 3 does not include the 52-inch pipeline.

4) Bullet line to Nikiski

Project 4 consists of a 30-inch diameter pipeline transporting 1 Bscfd of gas to Cook Inlet with the disposition of end products similar to that of Projects 1 and 2. ANGDA stated the following goal for Project 4:

> "The goal of the bullet line is to get North Slope gas to the existing industrial complex at Nikiski by the fastest, cheapest and most direct route thereby replenishing existing natural gas supplies from Cook Inlet which are projected to be unable to meet demand within ten years. The bullet line is geared more to satisfying Alaska needs, and particularly as a source of replacing dwindling Cook Inlet gas supplies, rather than being driven by LNG exports."

The scope of work included preparation of a number of deliverables for Projects 1 through 4. These deliverables specifically excluded the gas conditioning or treatment plant at Prudhoe Bay, LNG plant, LNG tankers, and the NGL plant. ANGDA required that the following minimum deliverables be provided:

- Recommended routes including a description of major engineering, construction and permitting challenges;
- Schedules showing major activities, manpower requirements, and cost estimates;

[3] MTA = million metric tons per annum. This is standard term used in the LNG industry to discuss LNG rates.

- List of other projects that will compete for the labor force and other resources required for project construction;

- Available resources to provide the required training for the Alaska work force; and

- Conceptual design for pipeline compressor stations, power requirements, and possible co-use of Alyeska facilities.

The first of the required deliverables pertained to a description of the various pipeline routes and is addressed in the previous Section 5. Most of the remaining deliverables pertained to issues that are common to all the routes and are described in Section 6.1. A few deliverables that were particular to individual project alternatives were identified and theses are addressed in Section 6.2.

6.1. Deliverables Common to All Projects 1 – 4

6.1.1. Schedules Showing Major Activities, Manpower Requirements, and Cost Estimates

Cost Estimates

Budget level cost estimates for the construction of 16-, 20-, 24-, 30- and 36-inch diameter pipelines and compressor stations are contained in Section 5.

Schedule Showing Major Activities

A general schedule of major activities associated with construction of an 800-mile long pipeline is shown in Figure 6.1. The information contained in this figure is based on the assumption that preliminary engineering has been completed and the basic configuration of the project has been established.

Initial activity will focus on detailed engineering and permitting, which must be done concurrently since these activities are interdependent with the results of one potentially having a significant impact on the other. Field surveys will be conducted during this phase to collect data for incorporation into the construction drawings, and detailed project planning will be initiated. Material specifications will be finalized and material procurement initiated with focus on the very long lead items such as turbine drivers for the compressors and specialized process equipment required for the liquefaction and/or gas conditioning trains.

A construction plan will be developed during detailed engineering to fully characterize the infrastructure required to support a remotely located construction project such as camp facilities, equipment maintenance shops and material lay-down areas. An extensive logistical plan will be required for material supply and the mobilization of construction equipment and temporary facilities.

Once sufficient detailed engineering has been completed pre-construction activities will commence and survey crews will be mobilized to establish a system of control points, elevation benchmarks, and reference points for grading limits, work pad locations, ditch centerline and elevation, valve locations, and final pipeline alignment. Surveys of gravel source sites will be done to determine the quantities available for removal and use for construction of temporary facilities and camps. These surveys will be followed closely by gravel mining and processing activities to allow for the timely installation of support facilities.

Construction materials such as line pipe, valves, compressors, etc., will be received at the port of entry and will be transported to designated lay-down areas where they will be stored for later use. A transportation plan will be developed to provide for economical transportation of heavy and/or oversized loads and will address road conditions, seasonal weight restrictions, traffic encountered during the summer months and weather conditions.

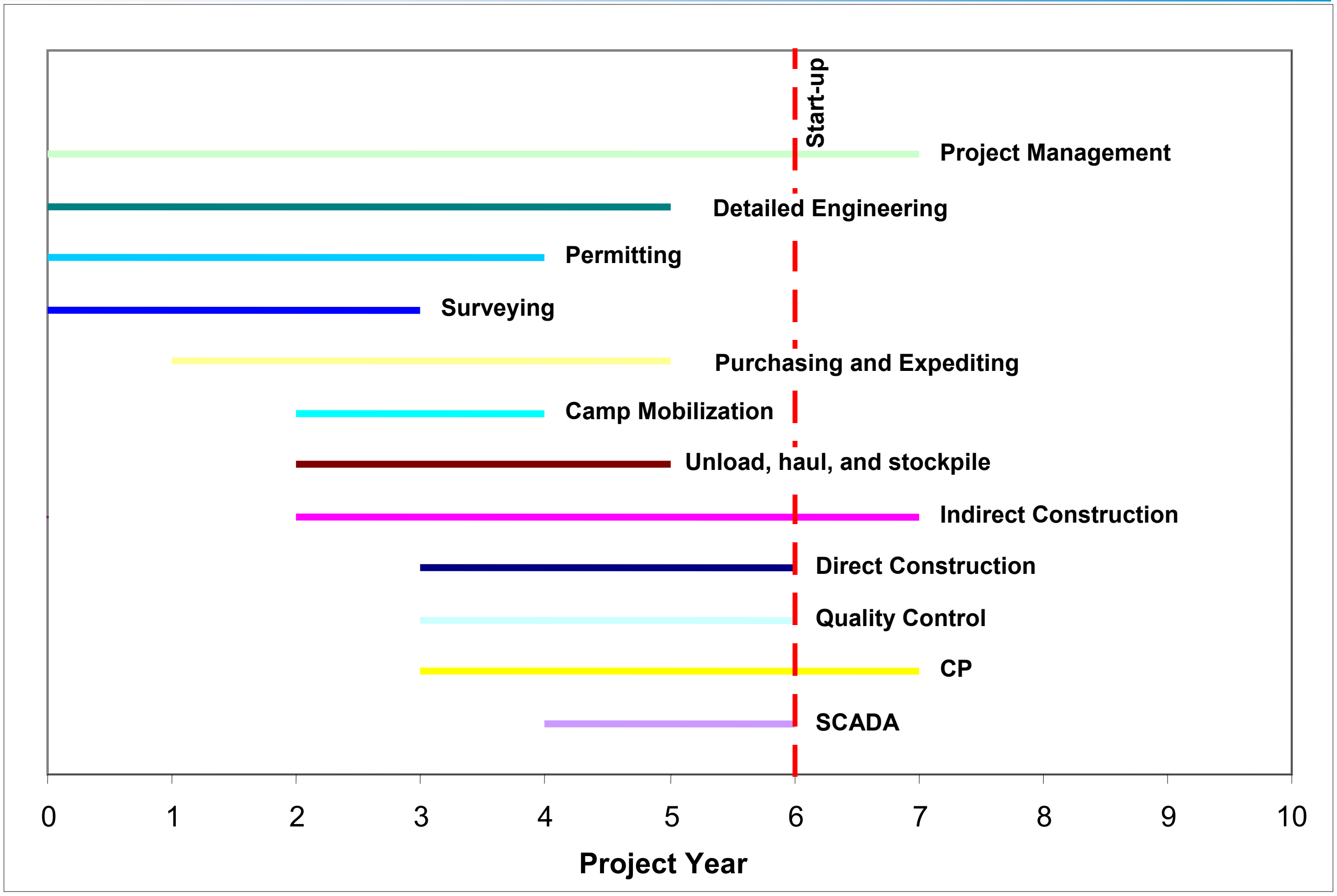


Figure 6.1: Schedule of Major Pipeline Construction Activities (30-inch Scenario)

Pipeline construction is essentially a production line operation with crews following each other down the right-of-way performing specific tasks. Once survey of the line has begun, the brush or trees within the right-of-way limits will be cleared and the right-of-way graded to remove high spots, rock out-crops and any extreme low points to provide a consistent working surface.

Ditching activities will begin once the right-of-way has been graded and the any work pad and access roads constructed. Spoil from the ditch will be placed on the opposite side of the ditch from the work pad for later use as backfill around the pipeline. Shortly after ditching, crews will string the line pipe beside the ditch, field bend the pipe as necessary to conform to the bottom profile of the ditch, and then weld the individual pipe joints together. Non-destructive examination of the welds (typically radiography and/or possibly ultrasonic testing) will be conducted to identify any anomalies and weld repairs made as necessary. Numerous other quality control activities will be employed regarding inspection of materials and processes throughout construction.

Depending on the quality of the spoil excavated from the ditch, it may be necessary to line the ditch with imported bedding material to support the pipeline and prevent damage to the external coating. The weld joints will be field coated and any damage to the pipe coating repaired prior to lowering the pipe into the ditch. The line will be lowered into the ditch in sections between designated line breaks such as changes in the direction of the right-of-way. Tie-in crews will weld these sections together in the ditch with the tie-in welds inspected and field coated prior to burial. Crews will also install cathodic protection and SCADA systems.

The ditch will be backfilled using ditch spoil with excess spoil mounded over the ditch to allow for consolidation of volume and future settling. Restoration of the right-of-way will include grading, removal of temporary bridges and structures, repair of existing property or structures damaged through the course of the work, and seeding.

The final phase of the pipeline construction will consist of cleaning, hydrostatic-testing, drying and final tie-in of the line. Selection of breaks between test sections will be done with consideration of the availability and sources of water and will be preferentially located at line disruptions such as valve stations and river/road crossings. Testing will be completed in accordance with all applicable regulations, codes and standards.

After completion of testing, drying and final tie-in, the project will be turned over to the operations team at which time construction crews will be demobilized, temporary camp and support infrastructure removed, and clean-up and remediation activity completed. As-built drawings reflecting final line configuration and location will be prepared and Quality Control documentation to include weld drawings, inspection and test reports, and inspection results will be organized and archived.

Construction Manpower Requirements

A rough estimate of manpower requirements for construction of a 30-inch 800-mile long pipeline was prepared based on the crew sheets developed for the budget level cost estimate. The 30-inch diameter pipeline was selected as the basis for reporting construction manpower requirements because ANGDA based Projects 2, 3, and 4 on this size pipe and a 30-inch diameter pipeline can be expanded to accommodate the 2 Bscfd rate specified by ANGDA for Project 1.

Manpower estimates for construction of the 30-inch pipeline were prepared by DEM Services under subcontract to Baker. Manpower estimates for the construction of a compressor station were developed by Willbros Engineers under subcontract to Baker and are contained in Appendix B.

Estimated peak annual manpower requirements for construction of a 30-inch diameter pipeline as described above are presented in Table 6.1. The values reported in this table refer to all disciplines including permitting and design, construction and supervision. Details regarding the construction labor are addressed in Section 6.1.3 and in Appendix F.

Table 6.1: Peak Manpower Requirements by Year, 30-inch Pipeline

Project Year	Peak Manpower Requirements
1	<500
2	<500
3	2,000
4	4,000
5	3,000
6	<500

6.1.2. Competition for Construction Labor – List of Other Projects

Research was conducted to identify pipeline projects that have been proposed within North America that might compete with the all-Alaska LNG project regarding construction labor, equipment and materials. While a definitive list could not be compiled, the list of pipeline projects currently being constructed, permitted or planned presented in Table 6.2 provides a reasonable representation of the number of projects that could coincide with construction of the all-Alaskan LNG Project. While not considered here, projects outside of North America could affect the worldwide demand for steel and therefore the costs of the all-Alaska project.

Table 6.2: North America Pipeline Projects

Owner	Project
Allegheny/Sempra	Desert Crossing
Colorado Interstate Gas Company	Raton Basin 2005 Expansion
Columbia Gas	Millennium Pipeline
Coronado Pipeline Company	Coronado Pipeline
Dominion Transportation, Inc.	Cove Point LNG Expansion
Dominion Transportation, Inc.	Greenbrier Pipeline
El Paso Natural Gas Company	Seafarer Pipeline System
El Paso Natural Gas Company	Piceance Basin Expansion
El Paso Natural Gas Company	Blue Atlantic Transmission
El Paso Natural Gas Company	All-American Pipeline
El Paso Natural Gas Company	All-American Pipeline (California Lateral)
Empire State Pipeline	Empire Connector
Entrega Gas Pipeline, Inc.	EnCana Project
Kern River Gas Transmission Company	Kern River Expansion
Kern River Gas Transmission Company	California Expansion
Kinder Morgan Interstate Gas Transmission, LLC	Advantage Southern Pipeline
Kinder Morgan Interstate Gas Transmission, LLC	West Texas Pipeline
Kinder Morgan Interstate Gas Transmission, LLC	Piceance Pipeline
Kinder Morgan Interstate Gas Transmission, LLC	Silver Canyon Pipeline
Kinder Morgan Interstate Gas Transmission, LLC	Wheatland Expansion
MacKenzie Gas Project	Mackenzie Valley Natural Gas Pipeline
Maritimes & Northeast Pipeline, LLC	Maritimes Phase IV
Mill River Pipeline LLC	Mill River Pipeline
Midwestern Gas Transmission Company	MGT Eastern Extension
National Fuel Gas Company TransCanada Pipe Lines Limited	Northwinds Pipeline
Northern Border Pipeline Company	Bison Pipeline
Northern Border Pipeline Company	Chicago Expansion III
Northern Border Pipeline Company	Eastern Extension/MGT Pipeline
Pacific Texas Pipeline Company	Picacho Pipeline
Panhandle Eastern Pipeline Company, LLC	Muncie Lateral
Petal Gas Storage, LLC	
Questar Pipeline Company	Southern System Expansion
Questar Pipeline Company	Southern Trails Pipeline
Questar Pipeline Company	Wamsutter Pipeline
Southern Star Central Gas Pipeline, Inc.	Western Frontier Pipeline
Tennessee Gas Pipeline Company	Freedom Trail Expansion
Terasan	Bison Pipeline
Texas Eastern	Logan Lateral Pipeline
Trailblazer Pipeline Company	Trailblazer Expansion
TransColorado Gas Transmission Corp.	TransColorado Extension
Transcontinental Gas Pipeline Corporation	
Transwestern Pipeline Company	San Juan Lateral Expansion
Transwestern Pipeline Company	Sun Devil Project/Phoenix Lateral
Vector Pipeline LP	Mainline Expansion

6.1.3. Training for the Alaska Work Force – Available Resources

Northern Economics was subcontracted to prepare a narrative describing the work force available within Alaska for construction of the pipeline portion of the all-Alaska project, and the resources available to train the work force for the specific skills required for the project. Northern Economics prepared labor assessments based on the manpower estimates completed by DEM Services for construction of a 30-inch 800-mile pipeline and by Willbros Engineers for construction of a compressor station. It was assumed that three compressor stations would be required for the initial commissioning of the pipeline. The report completed by Northern Economics is contained in Appendix F.

6.2. Issues Particular to a Specific Project 1 – 4

This section contains brief qualitative descriptions of issues that are particular to individual Projects 1 through 4.

6.2.1. Liquefaction Capacity and Extended End Flash

Natural gas is liquefied by first using a refrigeration system to condense the gas while under pressure, and then reducing the pressure of the cryogenic liquid to atmospheric pressure. A portion of the liquid vaporizes during the pressure reduction and the temperature of the LNG drops to that of the final product pumped to storage. The word “***flash***” is an industry term commonly applied to a process that results in vaporization of a portion of a hydrocarbon stream. The flash vapors are compressed and used as facility fuel.

The throughput capacity of a liquefaction process is limited by the amount of refrigerant horsepower and surface area of the installed heat exchangers. Due to these process constraints, the amount of flash vapors will vary inversely with the feed rate to the liquefaction process. Typically, the feed rate is adjusted as necessary so that the flash vapors just meet the facility fuel demand.

An ***extended end flash*** refers to a scenario in which the feed to the facility is increased so that the flash vapors exceed the facility fuel demand with the excess gas compressed for consumption by a second party. An extended end flash benefits the liquefaction process because is results in increased LNG production from the facility.

An LNG facility located in Cook Inlet could benefit from extended end flash with the excess vapors consumed as residential heating, power generation, or industrial fuel. The amount of increase in LNG production is limited and depends on the size of the LNG project relative to the local utility gas demand.

The value of extended end flash to a Cook Inlet LNG project can be approximated using the “six tenth” rule of thumb for estimating capital costs. This established industry rule of thumb is based on the premise that the capital costs for one facility can be approximated by multiplying the cost of a similar facility by the ratio of relative capacities raised to the 0.6 power. *For example*, assume that the cost of a 5 MTA LNG train is $400 million and that an extended end flash can increase the capacity by 10 percent. According to the rule of thumb the cost of a 5.5 MTA facility would be approximately $424 million (400 * 1.1^0.6), thus subject to this scenario the benefits from an extended end flash would be equivalent to an incremental capital outlay of $24 million. It is recommended that ANGDA complete a similar analysis if ANGDA needs to compare LNG projects located in Port Valdez and Cook Inlet.

It is important to consider that the benefits of extended end flash pertain only to the liquefaction trains and cannot be achieved without adding capital to increase the capacity of the rest of the project including the gas conditioning plant, pipeline and stations, LNG storage tanks and LNG tankers. *Although a benefit to a facility located at Cook Inlet, the magnitude of the this benefit will be dwarfed by the overall cost of a multi-billion dollar project and extended end flash will likely not be a key leveraging issue driving the selection of the pipeline route and location of the LNG facility at tidewater in south-central Alaska.* Other issues, such as avoiding the cost of a spur line from a project to Valdez, permitting and the target date for project start-up, may be more leveraging regarding selection of a configuration of the all-Alaska project.

6.2.2. Marine Infrastructure

The three most likely locations for the terminus of a major gas pipeline in south-central Alaska are Port Valdez, North Cook Inlet or south of the Cook Inlet forelands near Nikiski. ANGDA is considering placement of marine facilities in North Cook Inlet near Point McKenzie. *Marine considerations could be an important leveraging issue with regard to the all-Alaska LNG Project and it is recommended that ANGDA complete a comprehensive marine infrastructure and operability assessment of the Cook Inlet port options as part of the project feasibility studies.*

Port Valdez is an ice-free port with an established marine infrastructure including tanker escort vessels. Port Valdez is clearly the most preferable of the three locations based solely on marine considerations. The Anderson Bay location in Port Valdez has been thoroughly vetted through an EIS process and was found satisfactory by regulatory agencies.

Large hydrocarbon containing vessels have successfully serviced the LNG and oil refinery facilities located in **Nikiski** for many years. Although tidal currents are much stronger in Nikiski than in Port Valdez, history has shown that these currents have not had a materially adverse impact on marine operations. Operations for the berthing of LNG tankers at the Nikiski facility are scheduled to use the tidal currents to assist with mooring of the vessels.

North Cook Inlet is characterized by strong tidal currents throughout the year and large amounts of floating ice during the winter months. The hulls of the tankers can be strengthened and the sea chests modified to allow large vessels to traverse North Cook Inlet; however, berthing operations may be adversely impacted by the combination of currents and ice and should be thoroughly evaluated by ANGDA.

The first vessel to use the new dock at Port McKenzie in upper Cook Inlet, the Keoyang Magesty, terminated loading operations and left the dock because, in the captain's opinion, the heavy ice at the dock made keeping the ship at port dangerous (Anchorage Daily News, February 5, 2005). A marine study should assess the potential for encountering periods during which vessels may similarly not be able to access a marine facility in north Cook Inlet.

The marine study should also address the potential impact on facility storage and project operation should vessels not be able to access the marine terminal. This would be particularly important if a spur line or take-off project from a large diameter pipeline would require the use of a marine terminal. An operability review of the entire project, including the large diameter pipeline, should be done to determine whether adverse operation at the marine terminal could result in a cascade of problems throughout the system.

For example, ANGDA is considering a spur line project to south-central Alaska from which propane is to be extracted for sale as LPG via marine infrastructure. Depending on the quantities of propane extracted from the major pipeline project as feed to the spur line, the portion of the major pipeline project downstream of the spur line take-off point may be configured based on the predictable removal of propane. A prolonged shut-down of the marine terminal at the terminus of the spur line could have a severe adverse impact on the operation of the major pipeline project depending on whether this system is designed to accommodate swings in the propane content. A potential solution to such a problem would be to increase the amount of propane storage at the marine terminal with the associated additional capital costs.

ANGDA is considering marine transport of LNG, LPG, and products from a petrochemical plant. Marine issues will be compounded by the number of vessels required to export multiple products from the marine terminal.

6.2.3. Y-line (Project 3) Marketing Issues

Project 3 as described by AGENDA in the 2004 Interim Feasibility Report consists of a 6 Bscfd pipeline from the North Slope to Delta Junction at which 1.5 Bscfd will be removed for an Alaska pipeline system with the remaining 4.5 Bscfd transported to Alberta. ANGDA identified various risks regarding the Y-line project in their Interim Feasibility Report that were associated with hydrocarbon reserves, permitting, project costs, and project economics that will not be repeated herein. The Interim Feasibility Report did not address potential complications associated with the marketing of the products from the Y-line.

The Y-line concept is based on the premise that project economics will be enhanced by achieving economies of scale with a very large pipeline from the North Slope to Delta Junction. The Y-line concept, however, compounds the marketing issues of the project to Alberta and the project to south-central Alaska. In order for the Y-line concept to work, all products from both projects must be placed in their respective markets simultaneously. This approach represents a significant complication to project marketing, and potentially project viability, as compared to either a stand-alone Highway project to Alberta or a stand-alone project within Alaska.

Section 7. Enriched Gas Small Pipeline to Cook Inlet

7.1. Introduction

ANGDA stated in their RFP that a primary goal of the contract was to encourage the contractor to advise ANGDA of concepts and issues that ANGDA has not studied and to discuss their applicability to the all-Alaska LNG project. ANGDA encouraged the contractor to review ANGDA's Interim Feasibility Report issued in September of 2004 regarding the issues that ANGDA had addressed.

The potential for sale of LPG to coastal communities within Alaska by barge is identified in the Interim Feasibility Report, but the report contains no mention of the sale of LPG to Asian Pacific Rim markets. The LPG market in Asia has been very robust historically and represents a potentially significant market for an Alaska project.

Project 4, as described in the Interim Feasibility Report, consists of a 30-inch diameter bullet line transporting 1 Bscfd of gas from the North Slope to Nikiski. ANGDA states the following regarding the bullet line:

> "The goal of the bullet line is to get North Slope gas to the existing industrial complex at Nikiski by the fastest, cheapest and most direct route thereby replenishing existing natural gas supplies from Cook Inlet which are projected to be unable to meet demand within ten years. The bullet line is geared more to satisfying Alaska needs, and particularly as a source of replacing dwindling Cook Inlet gas supplies, rather than being driven by LNG exports."

A project alternative similar to ANGDA's bullet line exists that, to the best of Baker's knowledge, has not been studied previously, and may provide for economic replacement of Cook Inlet natural gas supplies. This alternative was referred to as Project A in the work proposal to differentiate it from ANGDA's Projects 1 through 4. Project A is referred to as the ***Enriched Gas Small Pipeline (EGSP) Project*** throughout this report.

The EGSP project differs from ANGDA's bullet line concept in two significant ways: 1) a smaller 24-inch diameter pipeline is specified to target a smaller initial gas volume delivered to Cook Inlet than what would otherwise be required to justify installation of a 30-inch diameter pipeline, and 2) the pipeline gas is enriched with large amounts of propane for extraction and sale as LPG to Asian markets.

Discussions of gas enrichment and pipeline economies of scale are contained in Section 3 and Section 4. ***The EGSP project differs from the other larger proposed North Slope gas projects in that the pipeline cost of service on a thermal, or btu basis is reduced by transporting a highly enriched gas stream instead of increasing the size of the project to achieve economies of scale***. The EGSP project is based on the use of a small quantity of methane as a medium to transport large quantities of non-methane hydrocarbons via a dense phase pipeline. The revenues obtained from the sale of the non-methane hydrocarbons subsidize the delivery of North Slope natural gas, i.e., the methane transport medium, to Cook Inlet.

The capacity of the EGSP project is expandable to approximately 1 Bscfd, but is not large enough, nor intended, to market the vast quantities of natural gas that exist on the North Slope. ***The EGSP project is configured to deliver natural gas from the North Slope to Cook Inlet without being contingent on the installation of one of the larger gas projects that have been proposed. The purpose of investigating the economic viability of the EGSP project was to determine if this or a similar project merits further consideration by ANGDA.***

7.2. EGSP Project Configuration

7.2.1. Overall Block Flow Diagram

A block flow diagram of the overall EGSP project configuration is shown in Figure 7.1.

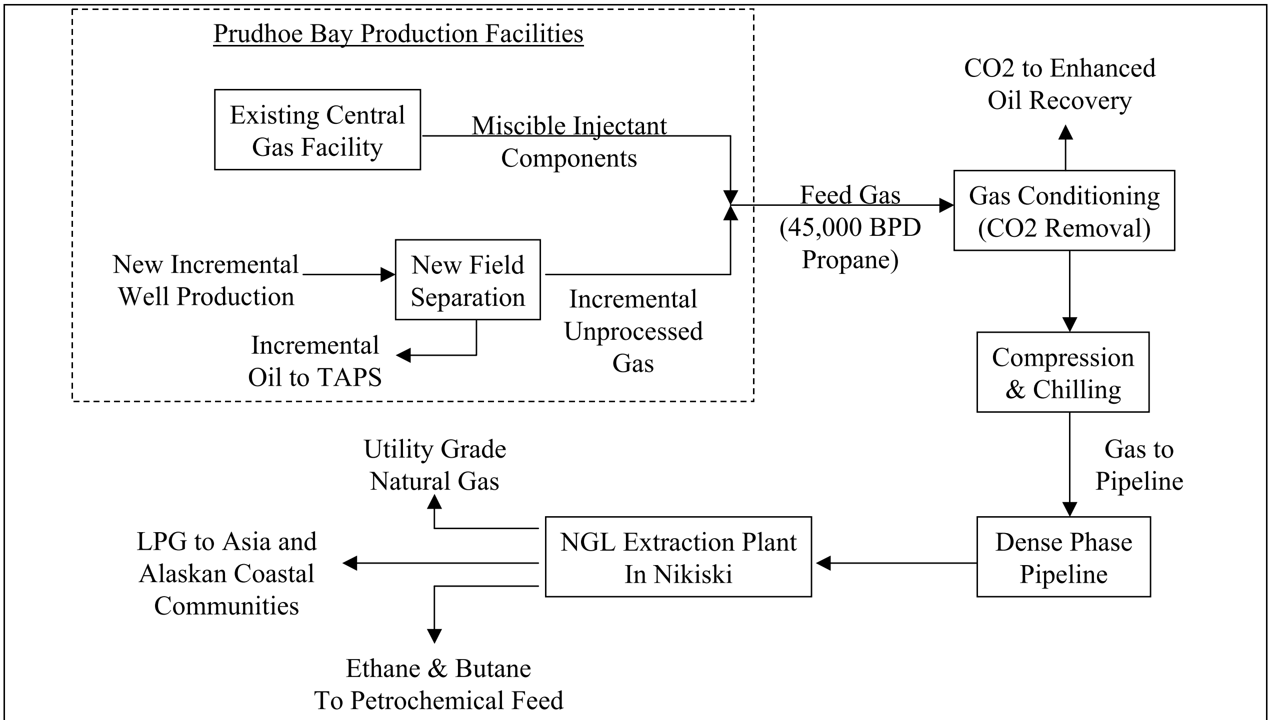


Figure 7.1: EGSP Project, Overall Block Flow Diagram

The EGSP project is based on the assumption that a finite amount of non-methane hydrocarbons contained in the MI from Prudhoe Bay would be available for blending into unprocessed gas from Prudhoe Bay as needed to achieve a liquid equivalent of 45,000 barrels per day of propane in the feed to the project. The term ***liquid equivalent*** refers to the amount of liquid propane that would be produced if the propane content of the gas stream were condensed.

A discussion of the major streams at, and operation of, the Prudhoe Bay CGF is contained in Section 3.The EGSP project is based on the premise that MI components would be available for spiking into the project by start-up in 2011 regardless of whether these components were obtained by operating the CGF to produce more MI or a portion of the current MI stream would be diverted to the EGSP feed. Removal of 45,000 barrels per day of propane from the Prudhoe Bay field equates to 411 million barrels of propane over the 25-year life assumed for the EGSP project model. A discussion of the potential hydrocarbon reserves potentially available from the Prudhoe Bay field is contained in Section 3.2. A 411 million barrel recoverable propane reserve was considered as a reasonable estimate to support the screening quality economic analysis of the EGSP project. It is recommended that ANGDA obtain estimates of the recoverable hydrocarbon reserves from the Prudhoe Bay field.

It was assumed that a gas conditioning plant would be installed on the North Slope to reduce the carbon dioxide to a concentration of 1.50 mole percent prior to the gas entering the pipeline with the carbon dioxide re-injected into the reservoir. The hydrocarbon composition of the feed gas would not be adjusted on the North Slope.

7.2.2. Basic Premises

The EGSP project is based on the installation of a 24-inch diameter pipeline with a 2,500 psig MOP from Prudhoe Bay to Nikiski following the route down the west side of the Susitna Valley as described in Section 5 of this document. A NGL extraction plant would be located in Nikiski to remove and separate ethane, propane, and butane and heavier components (butane+) such that the residue gas from the facility would be utility grade with a HHV of approximately 1,030 btu/scf. It was assumed that the ethane and butane+ would be sold as feed to a petrochemical facility located in Nikiski although other options may exist for the disposition of these components. The project is configured to separate and store propane as LPG in Nikiski for subsequent delivery to markets both within Alaska and along the Pacific Rim in Asia. The overall configuration of the EGSP project is shown in Figure 7.2.

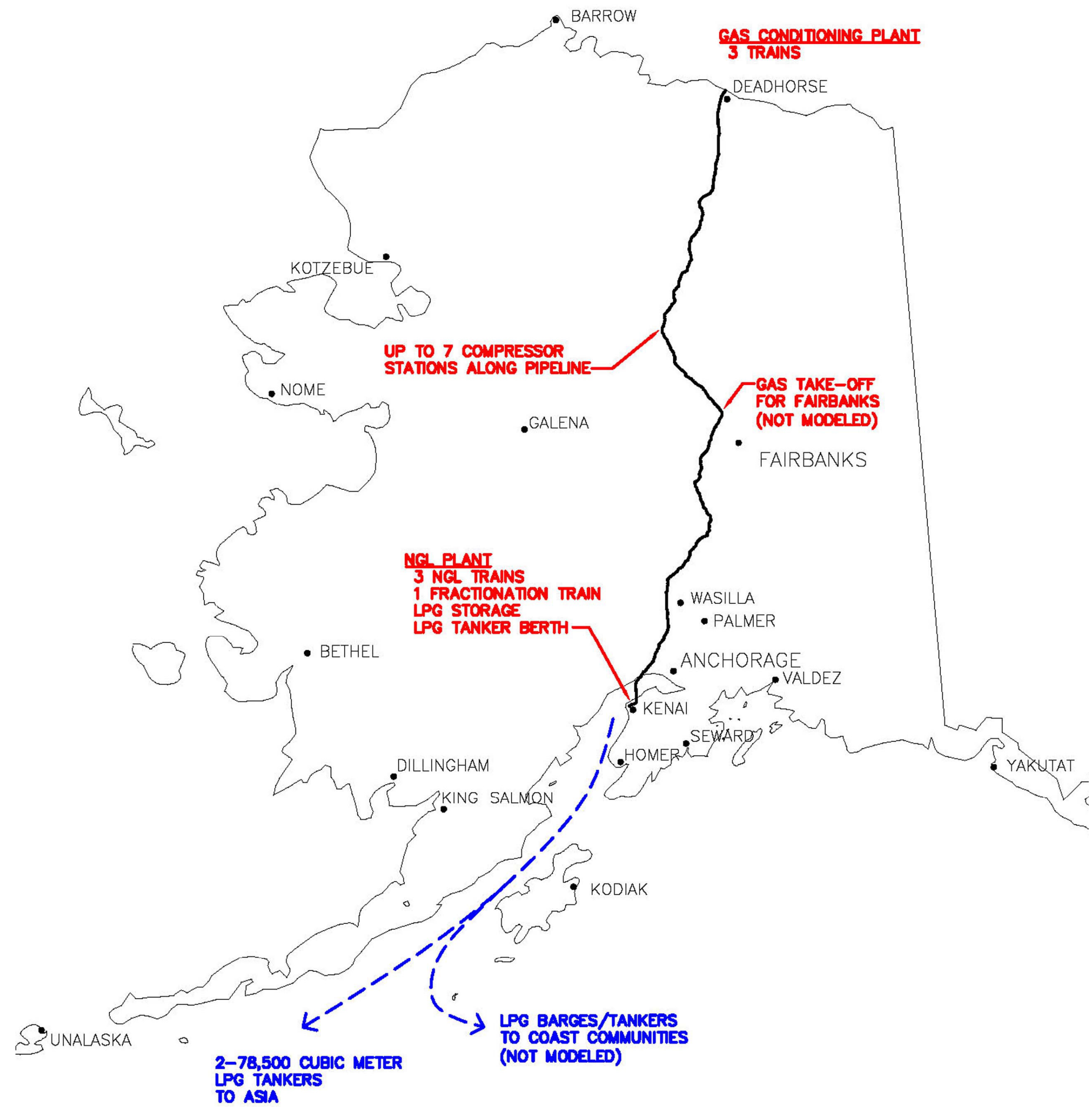


Figure 7.2: Overall Configuration of the EGSP Project

To complete the study evaluation within the time and scope allotted, the simplifying assumption was made to base project revenues only on the sale of utility gas within Cook Inlet, petrochemical feed to a facility in Nikiski, and LPG sales to Asia. The economic model for the project does not address the extraction of either utility grade gas or propane upstream of Nikiski for use in the interior of Alaska, nor revenues from the sale of LPG to coastal communities. These are not oversights and the project could certainly serve Alaska markets other than those modeled.

Material balances for the EGSP project were completed for operation at low flow (400 MMscfd), medium flow (800 MMscfd) and high flow (1,150 MMscfd). The low flow scenario is based on the assumption that the project would start at 400 MMscfd and the capacity would never increase past this rate. The medium flow scenario is based on operation at 400 MMscfd in the first year of operation, expanding to 800 MMscfd in the second year, but never expanding past this rate. Similarly, the high flow scenario is based on rates of 400, 800 and 1,150 MMscfd in years 1, 2 and 3 respectively with the flow remaining at 1,150 MMscfd for all years thereafter. The overall material balances for the three scenarios are shown in Table 7.1. Material balances with compositional details are contained in Appendices I, J, and K.

The low flow scenario results in the most enriched pipeline gas of the three scenarios because the 45,000 barrels per day of propane equivalent, and associated ethane and butane, are contained in the smallest volume of pipeline gas. The relative amounts of unprocessed gas and MI in the feed vary depending on the project capacity with less MI is required to obtain 45,000 barrels per day of propane equivalent as project throughput increases.

Consideration was given to use of residue gas from the CGF as the primary feed to the EGSP project. Unprocessed gas from Prudhoe Bay was selected for the feed because: 1) the unprocessed gas has a higher propane content than the residue gas, thus less MI would be required to achieve 45,000 barrels per day of propane; 2) use of unprocessed gas may benefit oil production from the Prudhoe Bay Pool; and 3) this was requested by ANGDA.

After consideration of various stream compositional changes along the project, about 45,000 barrels per day of propane product can be extracted at the NGL facility in Nikiski for subsequent transport to Asian LPG markets using two 78,500 cubic meter tankers. LPG tankers of 78,500 cubic meters were selected for the economic screening studies simply because information on these tankers was available and this capacity coincidently matched the approximate LPG sales rate envisioned for the project.

The screening quality economic analyses of the EGSP project do not include any revenues from the sale of propane to communities within Alaska although this clearly could be a part of the project. Propane for sale in-state can be obtained by simply increasing the amount of propane spiked into the feed on the North Slope. *For example*, assume that 3,000 barrels per day of propane is required for extraction in Nikiski for sale to coastal communities throughout Alaska. The amount of MI spiked into the project feed on the North Slope could be increased from 45,000 to 48,000 barrels per day. The NGL extraction facilities in Nikiski would have to be configured to accommodate the increased amount of propane.

Table 7.1: Overall Material and Energy Balances for the EGSP Project Scenarios

	Volume, MMscfd				Thermal, Tbtu/yr				Heating Value, btu/scf		
	Low	Medium	High		Low	Medium	High		Low	Medium	High
Gas Conditioning Plant (GCP)											
Raw Gas	233.0	757.0	1,217.0		87.4	284.0	456.5		1,028	1,028	1,028
Miscible injectant	253.0	187.0	129.0		127.4	94.2	65.0		1,380	1,380	1,380
Combined feed	486.0	944.0	1,346.0		214.8	378.2	521.5		1,211	1,098	1,062
Re-injected	72.0	116.0	154.6		0.0	0.0	0.0		0	0	0
NGL	0.0	0.0	0.0		0.0	0.0	0.0		0	0	0
Fuel	13.4	28.2	41.2		5.3	10.7	15.4		1,091	1,040	1,027
Pipeline											
Inlet	**400.5**	**799.9**	**1,150.2**		209.5	367.5	506.1		1,433	1,259	1,205
Fuel	0.9	10.9	38.7		0.4	4.2	14.5		1,093	1,041	1,028
NGL Plant											
Inlet	399.7	788.9	1,111.5		209.1	363.3	491.5		1,434	1,262	1,212
Utility gas	253.6	623.9	929.7		95.3	234.7	349.5		1,030	1,031	1,030
Ethane product *	56.2	57.5	59.7		34.3	33.6	34.2		1,670	1,602	1,568
Propane product	69.1	69.2	68.8		63.4	63.5	63.1		2,515	2,514	2,512
Butane+ product	9.6	18.9	27.2		11.9	24.2	35.0		3,400	3,495	3,524
Fuel	11.1	19.3	26.2		4.2	7.3	9.8		1,030	1,031	1,030

* The ethane product contains significant amounts of carbon dioxide.

7.3. Economic Results

The low, medium, and high flow scenarios result in utility gas rates of 254, 624 and 930 MMscfd respectively in Nikiski with the remainder of the flow attributable to NGL. Economic analyses were completed to determine the wholesale price of utility gas in Cook Inlet required to justify the EGSP project assuming that the collective gas demand along the Rail Belt could absorb these rates. Project viability was assessed by completing screening quality economic analyses assuming that the project would be privately financed. The threshold of economic viability was assumed as 13.5 percent return-on-equity (ROE). The economics are based on purchase of all hydrocarbons on the North Slope at $1.00/MMbtu. The sales price of propane sold as LPG and ethane/butane sold as petrochemical feedstock were held constant at $5.60/MMbtu and $2.50/MMbtu respectively.. The prices of utility gas in Nikiski required to achieve the 13.5 percent ROE threshold of economic viability for the three flow scenarios of the EGSP project are shown in Figure 7.3

EDWARDS CAPITAL MARKETS

Summary of Private Finance Model
30% Equity / 70% Taxable Debt

	400 MMscfd	800 MMscfd	1150 MMscfd
Gas Price (/ mmbtu) [a]	$3.59	$2.54	$2.28
Internal Rate of Return (IRR)	13.5%	13.5%	13.5%
Years Debt Ammortized	15 years	15 years	15 years
Minimum DSCR	1.44x	1.49x	1.52x
Average DSCR	1.78x	1.86x	1.91x

[a] Minimum gas price needed to achieve a 13.5% internal rate of return.

Figure 7.3: EGSP Project, Price of Utility Gas in Nikiski

The economic results in Figure 7.3 show that a project consisting of a small diameter pipeline transporting a gas heavily enriched with non-methane hydrocarbons merits further investigation regarding whether such a project can deliver natural gas to the Rail Belt of Alaska at acceptable prices. Demand along the Rail Belt will have to be consolidated and utility gas preferentially purchased from the EGSP project in order to achieve the sale rate shown for the low flow scenario. Consolidation of utility and industrial demand, such as that of the Agrium and LNG facilities in Nikiski, would increase the overall throughput of the EGSP project resulting in a lower wholesale gas price for all the end consumers. Development of new gas demand along the Rail Belt could benefit all consumers by lowering the price of the utility gas.

7.4. Alternative Configurations

To simplify the analyses, the economics for the EGSP project are based on installation of a single NGL facility in Nikiski with all hydrocarbons marketed from Cook Inlet. Other viable configurations exist for this project and should be evaluated by ANGDA.

7.4.1. Process Facilities in Fairbanks

Utility gas and/or propane can be extracted from the EGSP project for use in the Fairbanks area. NGL extraction facilities similar to those described for Cook Inlet could be installed with fractionation facilities configured depending upon the local demand for the non-methane hydrocarbons.

7.4.2. Split NGL Plant to Provide Gas in North Cook Inlet versus Nikiski

The various processing services of an NGL extraction plant are shown in Figure 3.15. Many NGL plants in the Lower 48 produce a utility grade natural gas and a de-methanized NGL product that is sold via pipeline. The option exists to install the NGL plant on the north side of Cook Inlet and ship a methane free NGL product to Nikiski via a subsea pipeline. NGL fractionation facilities could be installed in Nikiski to produce propane for sale as LPG and ethane and butane for use as petrochemical feed stock.

This alternative configuration may have advantages over installing all the gas processing facilities in Nikiski depending upon how the relatively large quantities of utility gas from the EGSP project can best be accommodated by the Enstar gas distribution system around Cook Inlet. Installation of the NGL extraction plant on the north side of Cook Inlet west of the Susitna River would allow the utility gas from the EGSP project to flow into Enstar's 20-inch pipeline traversing the north side of Cook Inlet. Gas from the EGSP project could then flow either east to the Wasilla-Palmer area, southwest to the Beluga area, or both.

North Cook Inlet is characterized by strong tidal currents with significant amounts of ice during the winter months, which are less-than-optimum conditions for routine operation of a marine facility (see Section 6.2.2). A subsea pipeline from an NGL extraction facility in North Cook Inlet to a fractionation facility with marine terminal in Nikiski would avoid the need for installation of marine facilities in North Cook Inlet.

7.4.3. Use of a Pipeline with a Diameter Smaller than 24-inches

The J-curves produced for a 300-mile spur line (Figure 4.7) show that the COS of 20-inch pipeline is less than that of a 24-inch pipeline at the 400 MMscfd rate of the low flow scenario of the EGSP project. Installation of a 24-inch pipeline would provide for project expansion to a larger ultimate rate than what could be achieved with a 20-inch pipeline, but with the downside of adversely affecting the economics of the low flow scenario.

Selection of the optimum pipeline diameter will depend on the volume targeted for the project. Installation of a smaller diameter pipeline may be preferable if the primary goal is to provide lowest priced gas to Cook Inlet at lower flow rates, but at the expense of future expansion.

The J-curve for the 20-inch pipeline is based generally on the route of a spur line from Delta Junction to Palmer. The J-curve for the 24-inch pipeline was extrapolated from the costs for an 800-mile pipeline from Prudhoe Bay to Valdez. The difference between the J-curves of a 20- and 24-inch pipeline may decrease once placed on a common basis. It is recommended that ANGDA fully investigate the merits of pipeline diameters other than 24-inch if they choose to pursue the EGSP project.

7.5. Economic Assumptions and Evaluation Methods

Schedules of annual capital outlays, revenues, operating expenses, and gas purchase expenses were generated in the same general manner as those used to develop the economics for the J-curve and ROI analyses presented in Section 4 of this report. An in-house model was used to generate estimates of property tax and cumulative capital outlays by year of start-up for depreciation calculations. The summary sheets for the three flow scenarios are contained in Appendices I, J, and K.

Economic information generated for the three flow scenarios was provided to AG Edwards for calculation of the project economics. The information prepared by AG Edwards is also contained in Appendices I, J, and K.

The sales prices for ethane, propane and butane+ were held constant over the life of the project except for adjustment for inflation. Similarly, the purchase price of the hydrocarbons on the North Slope was adjusted annually only to reflect nominal yearly dollars after consideration of inflation. It was assumed that all hydrocarbons, whether obtained in the form of unprocessed field gas or as MI components, would be purchased on the North Slope for $1.00/MMbtu.

7.5.1. Private (Corporate) Economic Model

The economic model for private financing was based on the same assumptions as those used to generate the J-curves and ROI analyses described in Section 4 of this report, except for the following:

- 13.5 percent return-on-equity was assumed as the threshold of economic viability;
- 30 percent equity and 70 percent long term debt financed over 15 years;
- Fixed-rate financing at 1.5x coverage;
- 6 percent taxable borrowing rate;
- Tax depreciation schedules: 7-year for the gas conditioning plant, 15-year for the pipeline, compressor stations and NGL extraction plant, and 18-year straight line for the LPG tankers;
- Property tax of 20 Mills;
- State corporate tax of 9.4%;
- Federal corporate tax of 35%;
- No capitalized interest;
- Three to four tranches of debt;
- Minimum cash balance after start-up of $250 million; and
- 2 percent escalation for inflation.

7.5.2. Depreciation

The United States government passed a bill in October 2004 providing seven-year depreciation and loan guarantee incentives to a pipeline project from the North Slope to Alberta. Federal legislation was passed at end of 2004 extending these incentives to an Alaska LNG project. It is unknown if the federal incentives would apply to the EGSP project since this project is not configured for the delivery of natural gas to the Lower 48. The economics for the EGSP project are not based on the federal seven-year depreciation incentive even though this would result in a lower price for utility gas and propane delivered to Alaskans.

7.5.3. Tax-Exempt Debt

Under current tax law there are specific instances with regard to the project scope for which tax-exempt financing might be utilized. The opportunity to use tax-exempt debt will lower the overall cost of capital and will most likely decrease the purchase price of gas derived to achieve a ROE of 13.5%. *The amount of savings generated by the use of tax-exempt borrowing merits further investigation by tax counsel.*

7.6. Capital and Operating Cost Estimates

Capital and operating cost estimates for the project components were developed based on engineering judgment, experience, and information available in the public record. The rough estimates were developed for the sole purposes of completing screening quality economic analyses of the EGSP project.

7.6.1. Gas Conditioning Plant

BP, ExxonMobil, and Phillips Petroleum presented information regarding their proposed large diameter pipeline project from Prudhoe Bay to Alberta to the Alaska Legislature in April of 2002. The information contained data on the proposed "Gas Treatment Plant (GTP)," which was based on a peak output of 4.7 Bscfd producing a 2,500 psi pipeline gas at 30 deg F with a carbon dioxide concentration of 1.50 mole percent. The overall project was based on an initial rate of 4.5 Bscfd with potential expansion to 5.6 Bscfd.

The producers' GTP is based on the use of an amine process, however, details regarding composition of the process feed gas could not be found. Information was found regarding the configuration of an amine plant specified during work commissioned by the Alaska North Slope LNG Project in 1999 to 2000 and is provided in Appendix H. It was assumed that the amine plant for which the producers provided information in 2002 was configured generally the same as the amine plant developed by the producers in 2000, except that the specification for carbon dioxide removal was relaxed to 1.50 mole percent. The following information was extracted from the producers' information:

- Average annual design rate = 4.5 Bscfd
- Estimate cost = $2.6 billion expressed in 2002 dollars
- Annual non-fuel operating expense = $56 million expressed in 2002 dollars
- Fuel = 150 MMscfd
- GTP plant includes
  - Dehydration of the conditioned gas
  - Gas compression to pipeline conditions
  - Gas chilling
- 4 process trains
  - Capacity per train = 1125 MMscfd (4.5 Bscfd / 4)
  - Capital cost per train = $650 million ($2.6 billion / 4)
  - Annual operating cost per train = $14 million (56 / 4)
- Assumption: feed consisted of CGF residue gas and the re-injection compressors would be reconfigured to compress gas to pipeline inlet conditions

Use of a single 1,125 MMscfd train for the gas conditioning plant of the EGSP project would mean that the flow through the EGSP project would stop if this single train were to shut down. It was assumed that two 575 MMscfd would be installed for the EGSP in order to ensure at least 50 percent flow if a train was to shut down.

The capital costs and operating cost estimates for the gas conditioning plant for the EGSP project were developed as follows:

- Train size = 575 MMscfd
- Capital and operating costs per 575 MMscfd train based on the "0.6 rule" (see Section 6.2.1)
  - $650 million per train: re-wheeling of re-injection compressors that would not be done if unprocessed gas were used; a gas enriched with MI would result in handling relative more carbon dioxide per volume of conditioned gas
  - Capital for 575 MMscfd train = $650 million * (575/1125)^0.6 = $435 million
  - Capital escalated from 2002 to 2005 based on GDP deflator indices (1.037 from 2002 to 2004 plus 1.02 from 2004 to 2005) = $435 * 1.037 * 1.02 = $460 million in 2005 dollars
  - Annual operating = $14 million * (575/1125)^0.6 = $9.4 million
  - Annual operating costs escalated from 2002 to 2005 = $9.4 * 1.037 * 1.02 = $10 million in 2005 dollars
- Additional costs for residue gas compression due to the use of unprocessed gas
  - Operating horsepower based on HYSYS process models
  - Installed costs for compression horsepower were estimated based on same methodology used to estimate compressor station costs for the J-curve and ROI analyses
  - Compression costs do not include gas chilling which is included in the factored cost for the conditioning train
- Fuel based on 150 MMscfd for 4.5 Bscfd gas to pipeline
  - Assume fuel HHV = 1,100 btu/scf
  - (150 MMscfd fuel / 4500 MMscfd feed) * (1,000,000 scf/MMscf) * (1100 btu/scf) * (MMbtu / 1,000,000 btu) = 36.7 MMbtu / MMscf to pipeline

Table 7.2: Gas Conditioning Plant, Capital, & Operating Cost Estimates

Scenario	MMscfd	400	800	1,150
Stage 1 GCP compression	BHp	18,140	36,800	52,710
Stage 2 GCP compression	BHp	8,654	23,550	36,790
Sub-total	BHp	26,794	60,350	89,500
Gas compression costs				
Installed Hp (+10%)		29,473	66,385	98,450
Horsepower cost factors	$/Hp	531	531	531
Gas compression, all stations	$million	15	35	52
General station infrastructure costs				
Number of compressor stations		1	1	1
$/station	$million	22.5	22.5	22.5
General station, all stations	$million	23	23	23
Total Compression Costs	$million	38	57	74
Train Costs	$million	460	920	920
Total GCP Capital Costs	$million	498	977	994
Capital Cost by Increment of Flow	**$million**	**498**	**479**	**17**
Annual Operating Expense	$million	10	20	20
Operating Cost by Increment of Flow	**$million**	**10**	**10**	**0**

Table 7.3: Gas Conditioning Plant, Fuel Calculations

Scenario	MMscfd	400	800	1,150
Conditioned gas before fuel				
Volumetric flow	MMscfd	414	828	1,191
Higher heating value (HHV)	(btu/scf)	1,422	1,251	1,199
Thermal flow	MMbtu/d	588,708	1,035,820	1,428,009
Fuel rate based on GTP	MMbtu/MMscf	36.7	36.7	36.7
Gas to pipeline	MMscfd	400	800	1,150
Fuel HHV	MMbtu/d	14,680	29,360	42,205
Fuel, percent of pipeline inlet	Thermal Pct	2.49	2.83	2.96

7.6.2. Pipeline and Compressor Stations

The length of the route from Prudhoe Bay to Nikiski is approximately 800-miles. It was assumed for the purposes of the EGSP screening analyses that the capital costs of a 24-inch diameter pipeline from Prudhoe Bay to Nikiski would cost the same as the 24-inch pipeline from Prudhoe Bay to Valdez estimated for the J-curve and ROI analyses (Section 4.2.1). The $2,483 million cost estimate for the 800-mile 24-inch pipeline shown in Table 4.2 was used for the economic analysis. A $25 million annual operating expense was assumed for monitoring of the pipeline.

The capital cost for the compressor stations for the EGSP project was estimated in the same manner as the compressor cost estimates used for the J-curve and ROI analyses (see Section 4). The capital cost estimates for the compressor stations of the EGSP project are shown in the following table.

Table 7.4: Compressor Stations, Capital Cost Estimate

Scenario	**MMscfd**	**400**	**800**	**1,150**
Number of Stations		1	4	9
Total Station Costs	$million	29	158	441
Incremental Station Costs	**$million**	**29**	**128**	**284**
Annual Operating Costs (3.5% of CapEx)	$million	1	5	15
Incremental Operating Costs	**$million**	**1**	**4**	**10**
Fuel, Thermal Percent of Inlet	**Percent**	**0.17**	**1.13**	**2.87**

7.6.3. NGL Plant

Provisions were made for Linde BOC Process Plants to prepare a cost estimate for the Nikiski NGL plant and this option was offered to ANGDA as a separate fee item in the work proposal. ANGDA elected to not pursue this cost estimate work. A rough order of magnitude estimate for capital and operating costs for the NGL facility was prepared based on information provided by the gas producers in 2002 and engineering judgment.

The North Slope gas producers estimated the cost of NGL extraction facilities for a 4.5 Bscfd project at $0.6 billion. Escalating this to 2005 dollars yields a cost of approximately $0.64 billion. Based on the producers' estimate and considering that the maximum size of the EGSP project is approximately one fourth the size, the assumption was made that the maximum cost of NGL facilities in Nikiski, including bulk propane storage and a LPG tanker loading berth, would be no more than $425 million.

The capital and operating costs for the NGL facilities at Nikiski were estimated as follows:

- Cryogenic NGL separation facility = $75 million for each 400 MMscfd increment of gas flow
    - $75 million for 400 MMscfd
    - $150 million for 800 MMscfd
    - $225 million for 1125 MMscfd
- Two atmospheric propane storage tanks and single LPG loading berth = $125 million
- NGL fractionation train = $75 million
- Fuel including recompression = 2 percent of inlet on a thermal basis
- Non-fuel operating cost
    - $15 million for 400 MMscfd
    - $5 million incremental for expansion to 800 MMscfd
    - $5 million incremental for expansion to 1125 MMscfd

7.6.4. LPG Tankers

The capital and operating cost estimates for the LPG tankers are based on a 78,500 cubic meter vessel. Particulars of this tanker design are contained in Appendix I.

It was assumed that the LPG would be exported to Asian markets and that the tankers would be foreign built. Price quotes were not solicited and a capital cost of $150 million per tanker was assumed based on verbal communications with persons in the shipping industry. It was assumed that the tankers could be constructed over a three year period with a capital outlay schedule of 20, 40 and 40 percent of the total price expended 3, 2 and 1 years before delivery respectively.

The annual crew costs were assumed to be $10 million per tanker per year. The specifications for LPG tankers show a fuel consumption rate of 59.0 metric tons of fuel oil per day. The cost of fuel oil was assumed to be $200 per metric ton, which equates to $4.3 million per year per tanker.

7.6.5. Other Costs

An annual operating cost of $30 million was included to cover home office costs for administration of the project during operations.

7.6.6. Summary of Capital Outlays

A summary of the overall capital outlays for the three flow scenarios of the EGSP project are shown in Table 7.5.

Table 7.5: Capital Outlays by Flow Scenario Expressed in 2005 dollars

Scenario, MMscfd	400	800	1,150
Gas Conditioning Plant	498	977	994
Pipeline	2,483	2,483	2,483
Pipeline & Stations	29	158	441
Gas Plants	275	350	425
LPG Tankers	300	300	300
Total	**3,585**	**4,268**	**4,643**

Annual distributions of the capital outlays for each project components were estimated and input into the economic model. The schedules of capital outlays were referenced to the start-up of each component and are shown in Table 7.6.

Table 7.6: Percent of Capital Outlay by Year Prior to Start-up

	Year 1	Year 2	Year 3	Year 4	Year 5		
						Start-up	**Total**
Gas Conditioning Plant		5	30	38	25	2	100
Pipeline	1.9	2.8	34.1	42.2	18.6	0.4	100
Compressor Station				40	60		100
NGL Plant		5	30	38	25	2	100
LPG Tankers			20	40	40		100

7.7. Pricing Assumptions

7.7.1. Gas purchase price

The EGSP project is based on the assumption that all hydrocarbons will be purchased on the North Slope at a single price regardless of the source. Natural gas is routinely purchased and sold on a thermal basis as opposed to a volumetric basis since the commodity of interest is energy. Use of a single purchase price for all hydrocarbon components acquired from Prudhoe Bay is consistent with industry practice.

The appropriate price for natural gas stranded on the North Slope has received much scrutiny in recent years. Prices discussed by various parties have ranged from a low of $0.50/MMbtu to as high as $1.35/MMbtu. A price of $1.00/MMbtu was arbitrarily selected for this study.

The gas purchase price has sometimes been expressed in terms of $/Mscf. The gas purchase prices on a volumetric basis corresponding to $1.00/MMbtu are shown in Table 7.7.

Table 7.7: Gas Purchase Price, $/Mscf equivalent to $1.00/MMbtu

	HHV (btu/scf)	$/Mscf
EGSP Project cases, purchased gas before fuel		
Low flow (400 MMscfd)	1,422	1.42
Medium flow (800 MMscfd)	1,251	1.25
High flow (1,150 MMscfd)	1,199	1.19
By component		
Methane	1010	1.01
Ethane	1,769.6	1.77
Propane	2,516.1	2.52
I-butane	3,251.9	3.25
N-butane	3,262.3	3.26
N-pentane	4,008.9	4.01

7.7.2. Sales Price – Ethane and Butane+

The ethane and butane must be disposed of in Nikiski in order to produce a utility grade natural gas with a heating value within allowable limits. It was assumed that ethane and butane+ would be sold as feedstock to a new petrochemical industry although other markets may exist. It was assumed that a sales price of $2.50/MMbtu for both ethane and butane+ would ensure the economic viability of the petrochemical plant and, therefore, a long term means to dispose of these products in Nikiski. It was assumed that costs for bulk storage of the ethane and butane+ would be born by the petrochemical plant.

7.7.3. Sales Price – Propane

Propane sold as LPG in Asian Pacific Rim markets has historically commanded a higher price than LNG on a thermal basis. ANGDA acquired information from Mitsubishi showing that the price of LPG on a thermal basis was approximately 40 percent greater than LNG over the years 1998 through 2002.

A LPG price of $5.60/MMbtu was assumed based on a 40 percent premium over an average long term LNG price of $4.00/MMbtu. Currently, the price of LNG and LPG are much higher than these values.

7.7.4. Wholesale Price – Utility Gas in Nikiski

The wholesale price of the utility gas sold in Nikiski was adjusted in order to achieve prescribed economic threshold criteria.

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