Project Viability
Table of Contents

2.10 PROJECT VIABILITY 1

2.10.1 Economic Viability 1

1) Macro-Economic Impact 1

2) Project Economics 1

a) Tolls 1
b) Expected Revenues for Various Project Stakeholders 4
c) Netback Analysis 6
d) Fort Nelson Option Upside 7
e) Expansion Economics 7
f) State Revenues 9
g) Netback Sensitivity Analysis 10

3) Selection of Destination Markets 12

2.10.2 Technical Viability 13

1) Simulation Tool 13

2) Basic Design Premise 13

3) Design Selection 13

4) Design Assumptions 16

5) Design Parameters and Inputs 16

6) Design Outputs 19

7) Carbon Emissions 22

8) Engineering Challenges and Technology Solutions 22

2.10 PROJECT VIABILITY

2.10.1 Economic Viability

In determining the Project's economic viability and its impacts during the development and operations phases, TransCanada has relied on a number of assumptions. TransCanada has ensured that these assumptions are consistent with those prescribed in Section 3.2.1 of the RFA.

1) Macro-Economic Impact

The potential macro-economic benefits during the development and operating phases of the Project are attributable to the direct Project expenditures as well as indirect or induced benefits resulting from the direct expenditures. These benefits can be estimated through state, provincial/territorial and federal level Input-Output models.

While TransCanada has not yet estimated a dollar value for these aggregate impacts for the entire Project, TransCanada has in the past completed such an analysis for the Canada Section of the Project. Therefore, TransCanada is confident that the macro-economic impacts of the entire Project will be very significant given:

- the size of expenditures involved;
- the duration and magnitude of construction labor employment, during initial build and subsequent expansions;
- the use of advanced technology in materials and construction techniques to suit the adverse terrain and weather conditions;
- the stimulation of incremental exploration and production activities for hydrocarbons on the North Slope of Alaska and along the pipeline route; and
- the number of communities that the pipeline will traverse.

2) Project Economics

a) Tolls

One of the key variables in determining the economic viability of the Project is the toll. For the purposes of this Section 2.10.1, TransCanada has assumed that all Shippers would elect the Negotiated Rate option. Refer to Section 2.2.3.7 "Negotiated Rates" for the structure of the Negotiated Rates. In the determination of these Negotiated Rates, cost inflation has been incorporated using the U.S. EIA's annual Consumer All-Urban Price Index.

The table below summarizes the key assumptions underlying the estimated tariffs/tolls for the Alaskan Section, the Yukon-BC Section and the GTP based on receipt volumes into the pipeline at Prudhoe Bay:

	ALASKA SECTION	YUKON-BC SECTION	TOTAL PIPELINE	GTP
Initial Volumes (Bcf/d)	4.5	4.5		4.5
Pipe Diameter	48”	48”		
Gas Heat Content (Btu/cf)	1,118	1,118		
Fuel	0.94%	1.21%		4.40%
Debt/Equity %				
Pre start-up	70/30%	70/30%		70/30%
Post start-up	75/25%	75/25%		75/25%
Return on Equity	14.00%	14.00%		14.00%
Interest Rate (with U.S. Loan Guarantee)	4.70%	4.70%		4.70%
Interest Rate (without U.S. Loan Guarantee)	6.20%	6.20%		6.20%
Capital Cost (2007 US$ Million)	10,084	9,217	19,301	5,800
Cost Escalation	2,180	1,939	4,118	1,258
State Reimbursement	(253)	(154)	(406)	(94)
Property Tax During Construction	324	0	324	197
AFUDC	1,720	1,552	3,273	1,031
Total Project Cost (US$ Million)	**14,056**	**12,554**	**26,610**	**8,192**
Working Capital, incl. Line Pack	95	71	166	30
Initial Rate Base (US$ Million)	**14,151**	**12,625**	**26,776**	**8,222**
Opex (% of Capex)	0.67%	0.67%		2.00%
Property Tax (% of Net Book Value)	2.00%	1.15%		2.00%
Income Tax Rates	41.11%	33.50%		41.11%

For the purposes of calculating the indicative tariffs/tolls for the Alaska Section, the Yukon-BC Section and the GTP, 2018 is assumed as the first year of service.

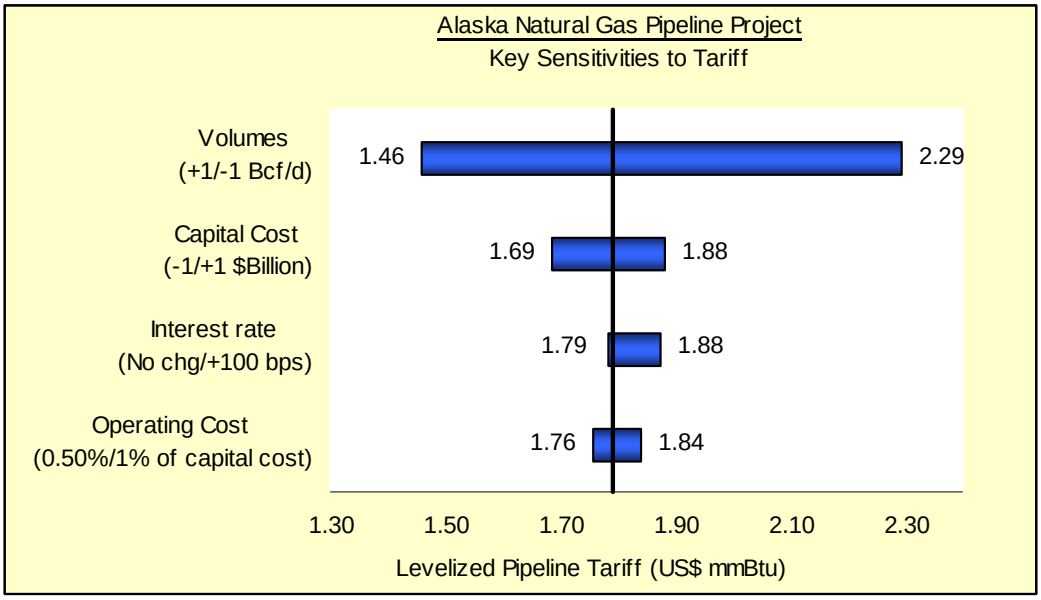
Annual depreciation rates for the Alaska Section, the Yukon-BC Section and the GTP can be found in Appendices K1, K2 and K3 respectively.

Using these assumptions, TransCanada’s estimate of the tariffs/tolls (excluding fuel) for the Alaska Section, the Yukon-BC Section and the GTP components of the Project is provided in the table below:

NOMINAL, US$/MMBTU	ALASKA SECTION	YUKON-BC SECTION	GTP
Levelized Toll	0.99	0.80	0.64

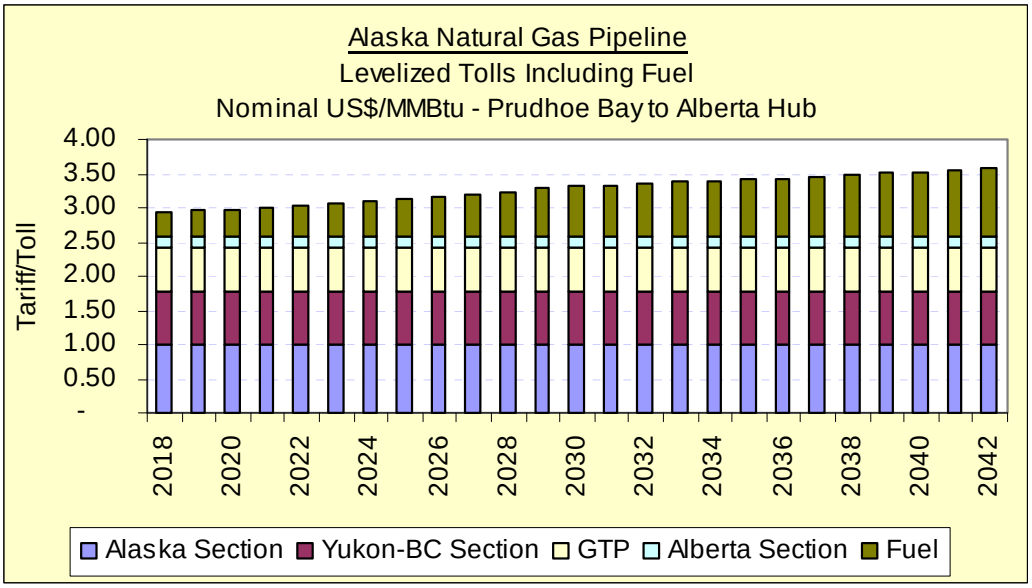
It is critical to understand that the tariffs/tolls in this Application are calculated based on information provided by the State, or TransCanada's estimates, of initial volumes, gas heat content, capital cost, financial parameters, tax rates, operating costs, inflation and exchange rates, and In-Service Date. A change in one or more of these factors (most of which are beyond the control of TransCanada) will also result in a change in these tariffs/tolls.

In order to illustrate how these tariffs/tolls could change, TransCanada has completed a number of sensitivities on the above levelized tariffs/tolls. The following chart shows the tariff/toll sensitivity for the combined Alaska Section and Yukon-BC Section by varying the shipping volume, capital cost, interest rate and operating cost.



South of Boundary Lake, the Alaska Shippers would pay the Alberta System receipt toll for access to the Alberta Hub. For the purposes of this economic viability analysis, TransCanada has assumed the Alberta System toll, exclusive of fuel, would remain at $0.15/mmBtu throughout the analysis period.

As shown in the chart below, the rates for the GTP, the Alaska Section and Yukon-BC Section are designed to remain constant over the life of the contract term. However, as described in Section 2.2.3.7 "Negotiated Rates", certain toll components such as operating and maintenance costs, income taxes, non-income related taxes, etc. are structured as flow-through items, therefore rates that Shippers would pay may be different than the above indicative rates to the extent that the actual amounts for one or more of these components vary from the estimate.



The table below summarizes the Year 1 tariffs/tolls for the various sections of the Project. The total cost for shipping Alaskan gas from Prudhoe Bay to the Alberta Hub, inclusive of GTP processing tariff and fuel charges, is estimated to be $2.95/mmBtu in Year 1 and gradually increases to $3.57/mmBtu by Year 25 as a result of the increase in fuel cost over the years (fuel cost is a function of the underlying gas prices assumption).

Year 1 Nominal, US$/mmBtu	Alaska Section	Yukon-BC Section	GTP	Alberta Section	Total
Levelized Toll	0.99	0.80	0.64	0.15	2.57
Fuel Cost	0.04	0.05	0.20	0.09	0.38
Toll including Fuel	1.03	0.85	0.84	0.24	2.95

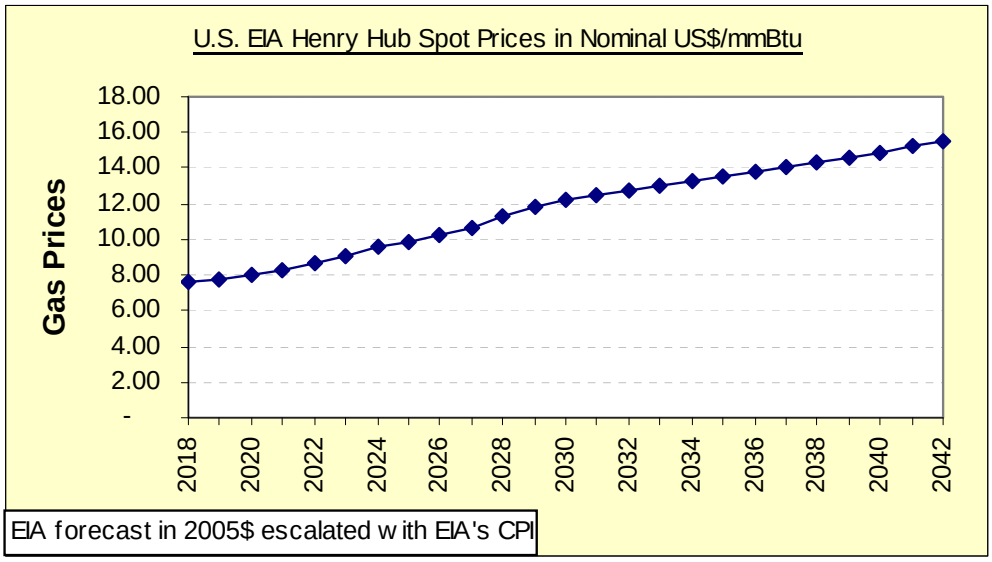
b) Expected Revenues for Various Project Stakeholders

Using the State's provided natural gas prices at the Henry Hub, adjusted for the basis differential to the Alberta Hub, TransCanada estimates that over the first 25-years of operation, the aggregate netback to Alaska Producers, after royalties and taxes but before assumed upstream costs (see discussion below on costs upstream of GTP), from the sale of Alaskan natural gas and natural gas liquids will amount to $207 billion if the pipeline operates at 100% load factor.

Refer to Appendix R "Economic Viability Analysis" for Project stakeholders' revenue assessment. This is also included in MS Excel format on the CDs enclosed with this Application.

This revenue figure is based on:

- Natural gas volume at the outlet of the GTP of 4.5 bcf/d;
- Heat content of 1,118 Btu/cf;
- The State provided the U.S. EIA gas price forecast for all RFA applicants to assess the project economic viability. The U.S. EIA forecasts for Henry Hub natural gas spot prices (see Appendix L "EIA Forecasts") are in constant 2005 dollars per mmBtu. TransCanada has inflated these forecasted prices by the U.S. EIA All-Urban Consumer Price Indices (see Appendix L "EIA Forecasts") to nominal dollars. In addition, since the U.S. EIA's gas price forecasts only cover up to year 2030, TransCanada has assumed the gas prices in constant 2005 dollars remain unchanged after 2030, and the annual inflation rate from 2031 to 2042 continues to be the same as that in 2030;
- A basis differential of US$0.75/mmBtu between the Henry Hub and Alberta Hub prices; and
- NGL value of approximately $0.20/mmBtu in 2007 dollars as described in Section 2.2.3.15(4) "NGL Value Estimate" and Appendix O "NGL Value Assessment".



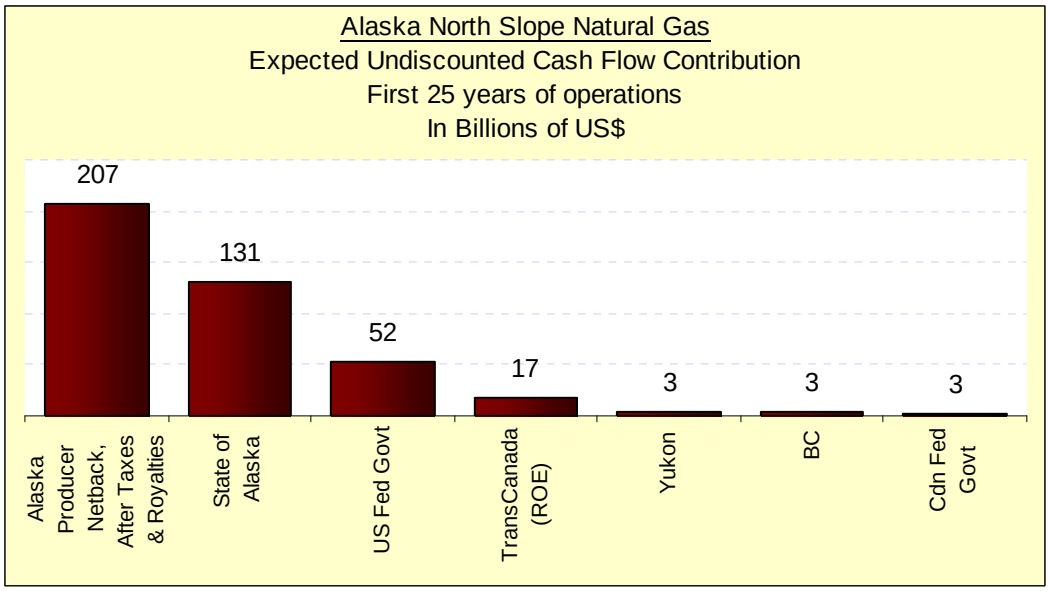
- Costs Upstream of GTP

  TransCanada does not have direct knowledge regarding Alaska producers' production costs for natural gas in their various reservoirs. In order to comply with the RFA requirements, it was necessary for TransCanada to make assumptions relating to the upstream natural gas production costs in order to calculate the total revenues to governments. TransCanada has assumed that the upstream production costs for natural gas would be in the range of $1.00 to $2.00/mmBtu. For the purposes of calculating government revenues, TransCanada has used the midpoint of that range ($1.50/mmBtu in 2007 dollars) as the assumed upstream natural gas production costs.

- Royalty and Taxes

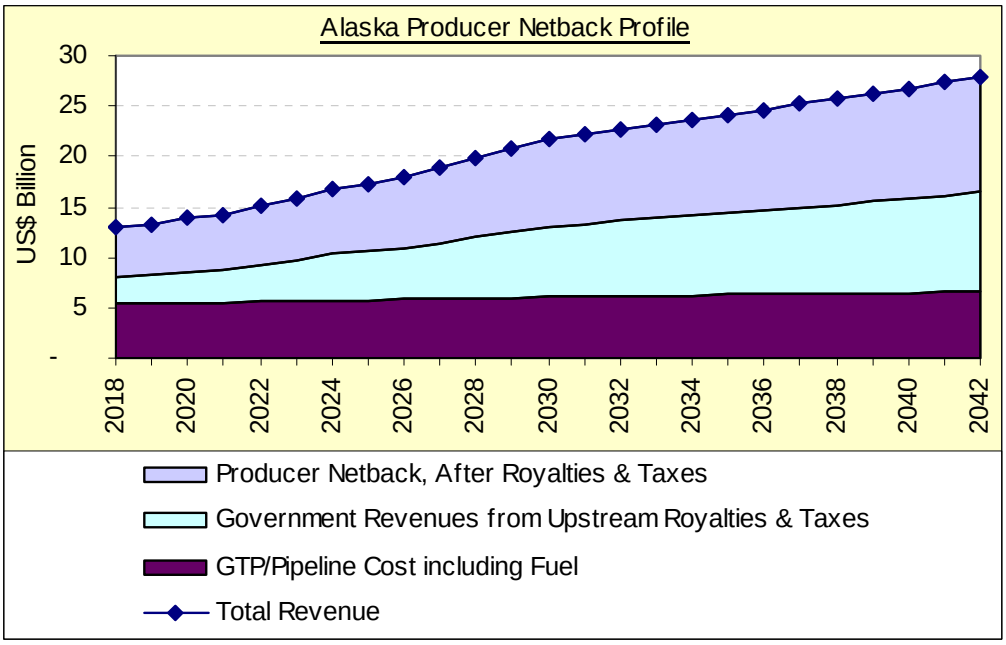
  This analysis utilizes the Alaska royalty rates, property tax and income tax rates as provided in the RFA document. Since the State did not provide a gas production tax rate, and TransCanada does not know how that will be set by the State in the future, TransCanada has used a simplified structure to complete this analysis. TransCanada has assumed a flat gas production tax rate of 25% for calculating the production tax revenues to the State. Also, given TransCanada does not have knowledge regarding the field operating costs and future upstream capital investments, TransCanada has taken a simple approach in estimating the production tax revenues to the State by multiplying the flat 25% tax rate by the netback value of the gas after subtracting the above assumed upstream production costs at the wellhead.

Based on the above assumptions, TransCanada has estimated the expected aggregate cash flows for the various Project stakeholders. This is shown in the following chart:



c) Netback Analysis

TransCanada has also completed a netback analysis using the assumptions mentioned above. Given the increase in natural gas prices forecasted by the U.S. EIA and the relatively flat nature of the tolls, TransCanada expects that the Alaska producers, the State and the U.S. and Canadian federal governments will see increasing levels of cash flow over the life of the project. The results of the analysis, which are captured in the following chart, illustrate the economic viability of the Project.



d) Fort Nelson Option Upside

In the event TransCanada is successful in commercially moving the receipt point that provided access to the Alberta Hub/NIT for the Alaska gas upstream to Fort Nelson from Boundary Lake, this would provide the Alaska Shippers a toll savings in the range of $0.15/mmBtu to $0.20/mmBtu or approximately $275 million to $370 million per year. This toll savings would produce a net increase in after-tax netback to the Alaska Shippers of approximately $2.6 billion to $3.4 billion, and an increase in Alaska's royalty and tax revenues of approximately $2.8 billion to $3.7 billion, over a 25-year contract term.

e) Expansion Economics

TransCanada believes that it has chosen the optimal design for the initial phase of the Project if 4.5 bcf/d of gas is committed in the initial Open Season. With the expected availability of higher volumes of natural gas in the future, TransCanada's design would permit inexpensive expansions of the Pipeline System. These inexpensive expansions, primarily relying on the addition of compression, would allow TransCanada to apply rolled-in toll treatment to the expansion costs, thereby further enhancing the long-term economics of the Pipeline System.

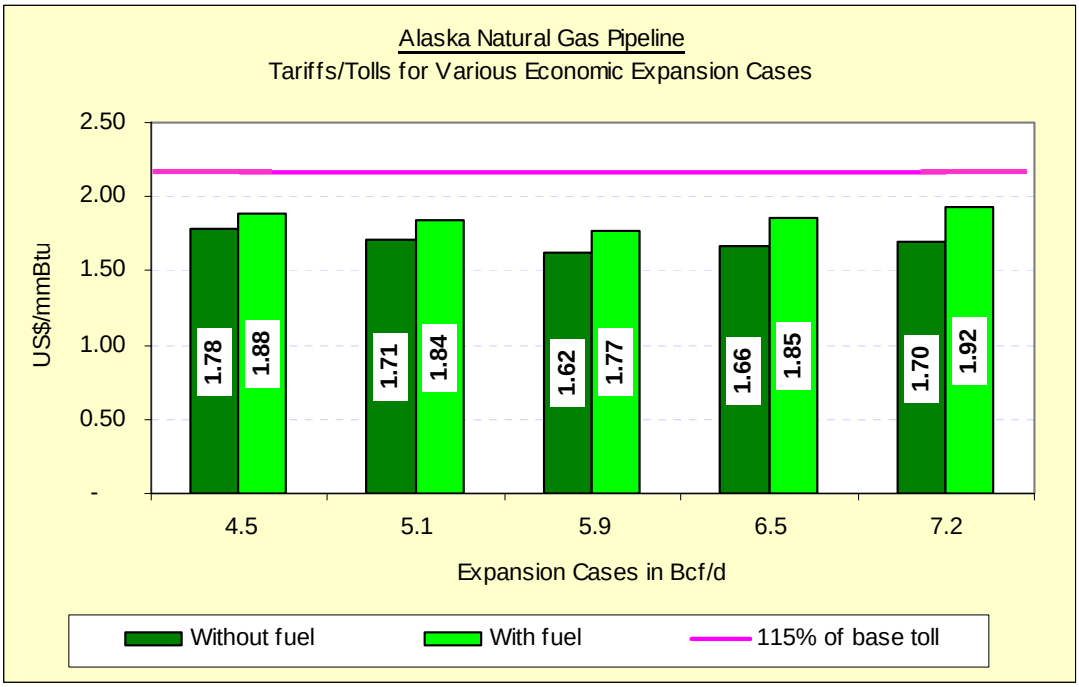
TransCanada's expansion case assumptions are based on the following capital cost (in 2007 dollars, net of state reimbursement, before cost escalation, property tax paid during construction and AFUDC) and fuel for the Alaska and Yukon-BC Sections of the Pipeline System:

PIPELINE CAPACITY BCF/D	ALASKA SECTION	YUKON-BC SECTION	TOTAL US$ BILLION	FUEL
4.50	9.8	9.1	18.9	2.2%
5.10	10.6	9.8	20.4	2.8%
5.90	11.4	10.4	21.9	3.4%
6.50	12.6	11.8	24.3	4.2%
7.20	13.9	13.1	27.0	5.1%

For the purposes of expansion tolling, TransCanada has assumed changes to the following variables leaving all other parameters unchanged:

Expansion Assumptions		
Debt/Equity %	60/40%	No U.S. Loan Guarantee
Cost of Debt	6.20%	No U.S. Loan Guarantee
Expansion Operating Cost	1.00%	of Incremental Capital Cost

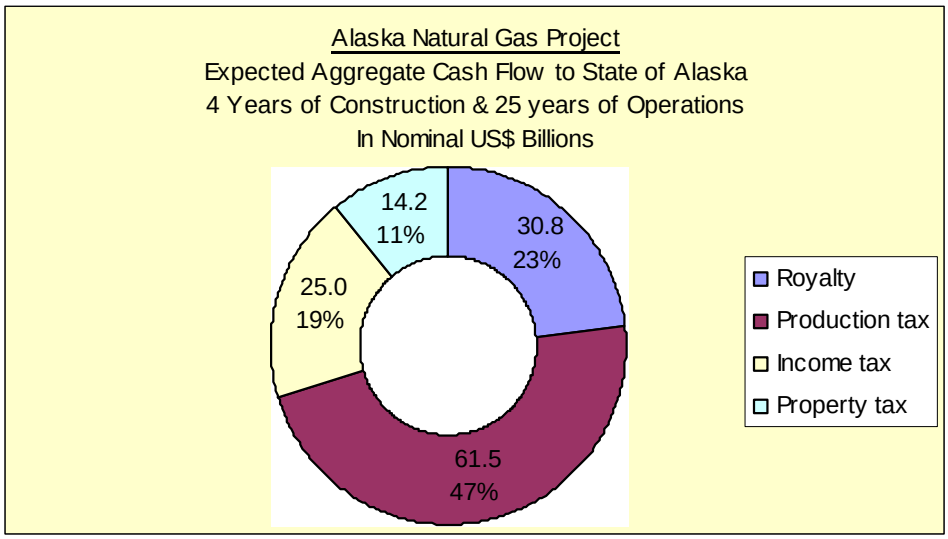
As shown in the chart below, tariffs/tolls, including fuel, for expansions of up to 7.2 bcf/d are expected to fall below 115% of the initial 4.5 bcf/d tariff/toll. Since the timing of expansions are unknown at this time, for simplification purposes, these expansion cases assume the timing of these expansions are the same as the initial build.



TARIFF/TOLL OF EXPANSION CASES AS A PERCENTAGE OF INITIAL 4.5 BCF/D TARIFF/TOLL		
Pipeline Capacity	Without Fuel	With Fuel
4.5 bcf/d	100%	100%
5.1 bcf/d	96%	98%
5.9 bcf/d	91%	94%
6.5 bcf/d	93%	98%
7.2 bcf/d	95%	102%

f) State Revenues

Based on a 4.5 bcf/d case, TransCanada's analysis suggests that royalty and production taxes would contribute over 70% of the expected cash flow of the State's revenues from the Project:



- Based on the above projection for a 4.5 bcf/d Project, the average annual revenue that the State would receive from the Project is approximately $4.5 billion, in nominal dollars. This is equivalent to the same amount of the oil and gas revenues that the State collected in 2006. (Note: State of Alaska's Spring 2007 Revenue Sources Book shows the total oil and gas revenues collected by the State in the year of 2006 was $4,358.9 million.)
- Using the various discount rates provided in AS 43.90.170, TransCanada has calculated the present value of anticipated cash flows to the State of Alaska. The amounts presented in the table below confirm the significant direct economic value of the Project to the State:

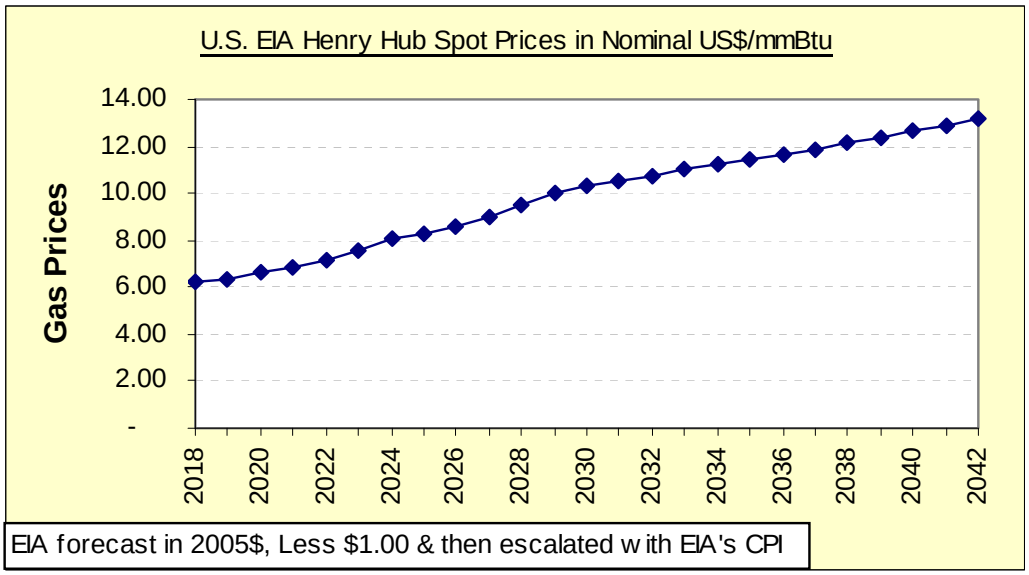
DISCOUNT RATE	US$ BILLIONS	
	DISCOUNTED TO 1/1/2008	DISCOUNTED TO 1/1/2018
2%	$81	$98
5%	$41	$66
6%	$33	$59
8%	$22	$47

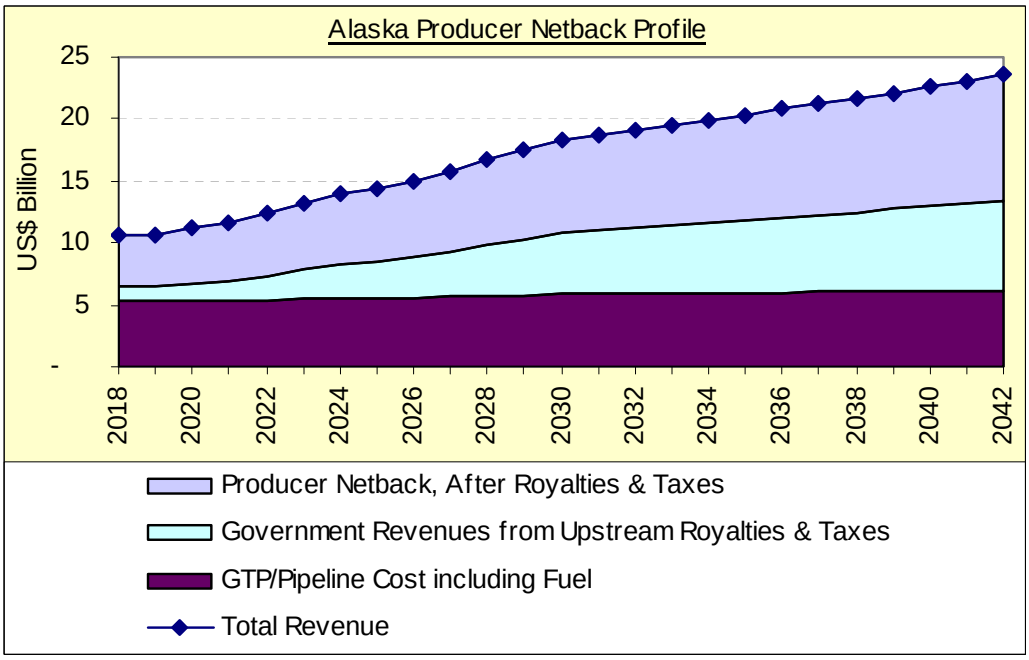
- Using the same assumptions as stated in Section 2.10.1(2)(b) "Expected Revenues for Various Project Stakeholders" and the timing of expansion the same as the initial build, TransCanada has completed a sensitivity on the expected revenues for various project stakeholders on the selected expansion cases, as tabled below:

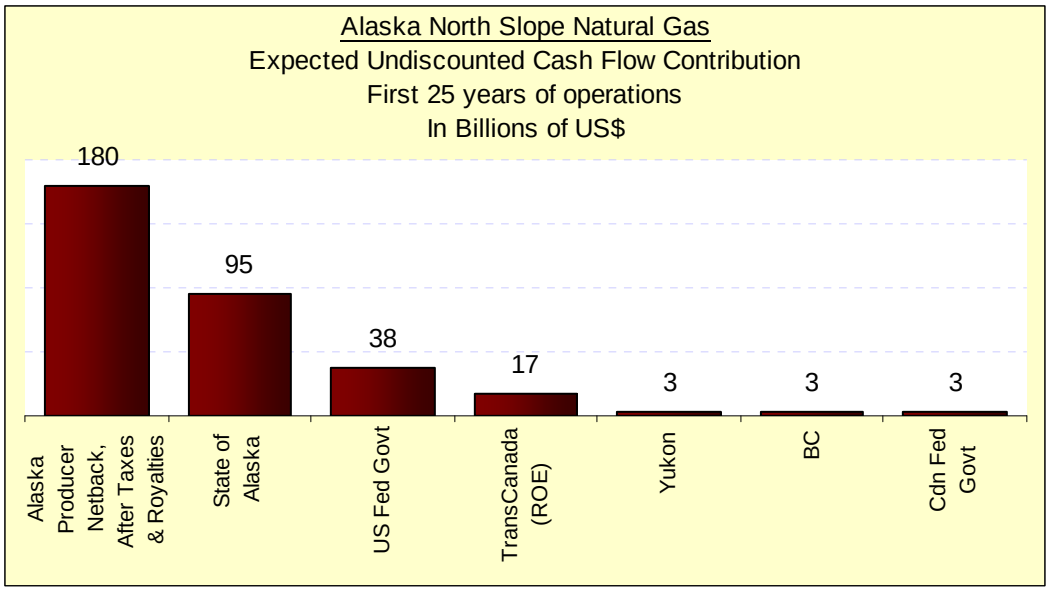
VOLUME	ALASKA PRODUCERS NETBACK, AFTER TAXES & ROYALTIES	STATE OF ALASKA	US FED GOV'T	TRANSCANADA (ROE)	CANADIAN FEDERAL, PROVINCIAL. TERRITORIAL GOV'T
	US$ BILLIONS				
4.5 bcf/d	207	131	52	17	9
5.9 bcf/d	276	174	70	20	10
7.2 bcf/d	333	207	83	26	14

g) Netback Sensitivity Analysis

The U.S. EIA projects natural gas prices at Henry hub in constant 2005 dollars. For its base netback analysis, TransCanada applied the U.S. EIA's annual All-Urban Consumer Price Index (the "CPI") to inflate the U.S. EIA's forecasted gas prices to nominal dollars and then deducted pipeline and GTP tolls (also in nominal dollars) to calculate the netback before royalty and taxes. Because natural gas prices are volatile and forecasts could change, TransCanada has completed a sensitivity analysis on the netback by reducing the U.S. EIA forecasted 2005 constant dollars Henry Hub natural gas spot prices by one dollar across the entire forecast period. The adjusted gas prices were then inflated with CPI to nominal dollars for netback sensitivity analysis. The charts below show the natural gas prices that TransCanada used for the netback sensitivity analysis and the results of the sensitivity analysis with respect to expected undiscounted cash flows to various Project stakeholders.


U.S. EIA Henry Hub Spot Prices in Nominal US$/mmBtu
Gas Prices
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
EIA forecast in 2005$, Less $1.00 & then escalated with EIA's CPI


Alaska Producer Netback Profile
US$ Billion
25
20
15
10
5
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Producer Netback, After Royalties & Taxes
Government Revenues from Upstream Royalties & Taxes
GTP/Pipeline Cost including Fuel
Total Revenue



3) Selection of Destination Markets

TransCanada has selected the Alberta Hub as the gas market for the purposes of determining the economics of the Project. TransCanada believes that connecting to the Alberta Hub would provide the best economics for Alaska gas, from both a natural gas and natural gas liquids perspective. The key advantages of integration with the Alberta System are both economic and the ability to reduce risk. Given the long-lead time of the Project and the uncertainties of market demand for natural gas over time, the flexibility of this integrated solution offers many advantages:

- Highest netback for Alaska gas;
- lowest transportation toll to the Alberta Hub;
- easy access to:
  - the most liquid market for natural gas and one of the most liquid market for NGLs; and
  - multiple export pipelines from Alberta to North American markets;
- the value of market-based NGLs through several options as described in Section 2.2.3.15 “Plan for Gas Processing and NGL Markets”;
- mitigates risk of capital overruns by:
  - integration with existing facilities;
  - staged construction, shorter lead-times; and
  - taking advantage of existing spare capacity;
- minimizes firm transportation commitments by utilizing available capacity; and
- provides integration benefits to all stakeholders, Alaska Shippers and WCSB shippers.

2.10.2 Technical Viability

The platform chosen as the design basis for this Application was developed as a result of analysis performed to determine the optimum design for the flow assumptions made. The analysis was performed using TransCanada's proprietary in-house simulator and associated tools.

1) Simulation Tool

For the specific purpose of supporting the transportation of Arctic gas, Foothills developed a hydraulic steady state simulator, TempFlo, which has been used and validated for over 25 years. TempFlo has continuously served as Foothills' simulator and been used for both design and operations support. It has been used to provide the basis for justifying the need for the initial Foothills Pre-Build facilities and subsequent expansion facilities as approved by the Northern Pipeline Agency.

As a mature working model, TempFlo has continually evolved since its inception to add functionality and accuracy. TempFlo incorporates the conservation of energy equation as part of its node to node calculations which provides good gas temperature prediction, an important factor in the modeling of northern pipelines. Additional features applicable to northern pipeline simulation include:

- the AGA-8 Equation of State to perform accurate density calculations at higher pressures;
- after compression cooling of the gas routines for either a propane refrigeration chilling cycle or aerial coolers; and
- heater station and pressure regulator routines.

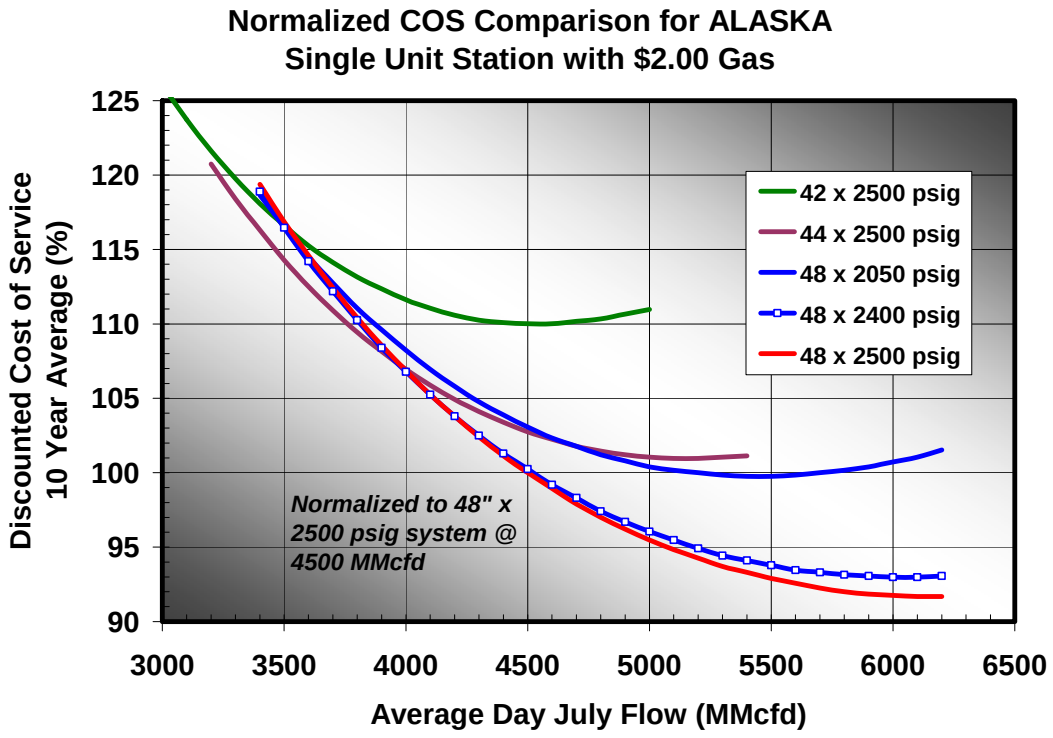
Heat transfer between the pipe and surrounding soil for the Alaska Section is estimated using the Kennelly equation.

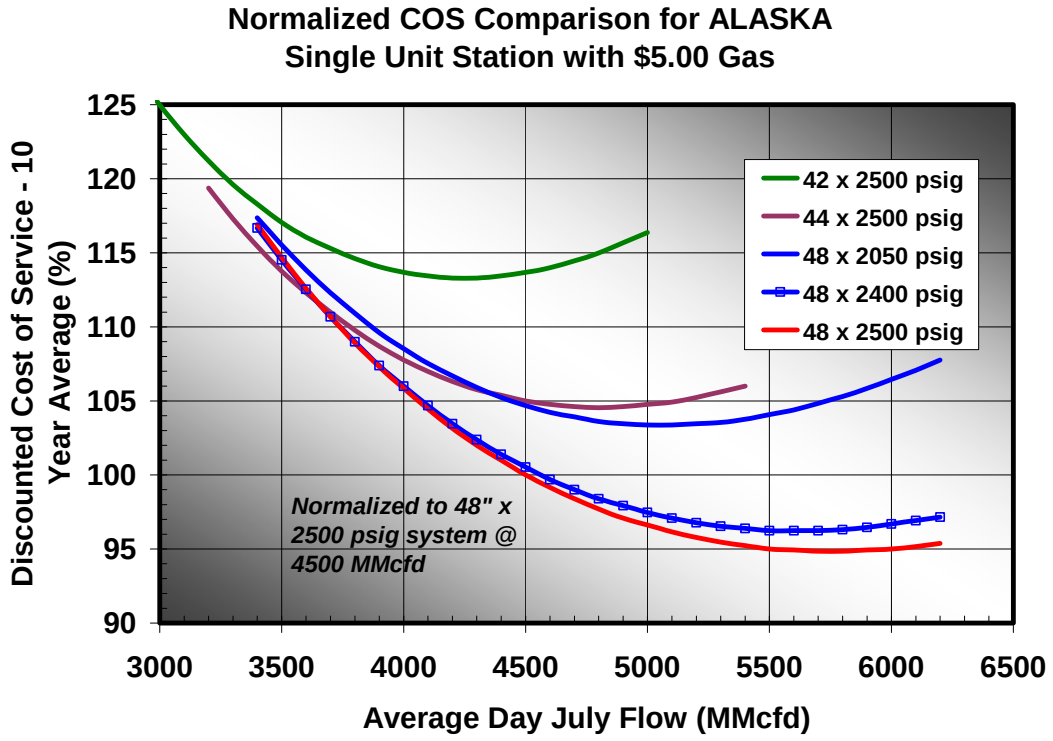
2) Basic Design Premise

The basic design premise was to develop a system with an initial capacity of 4.5 bcfd with some low cost expansion potential. The facilities are designed to allow for reduced capability during periods of higher than normal ambient temperatures and for make-up provision resulting from flow reductions during scheduled and unscheduled station outages.

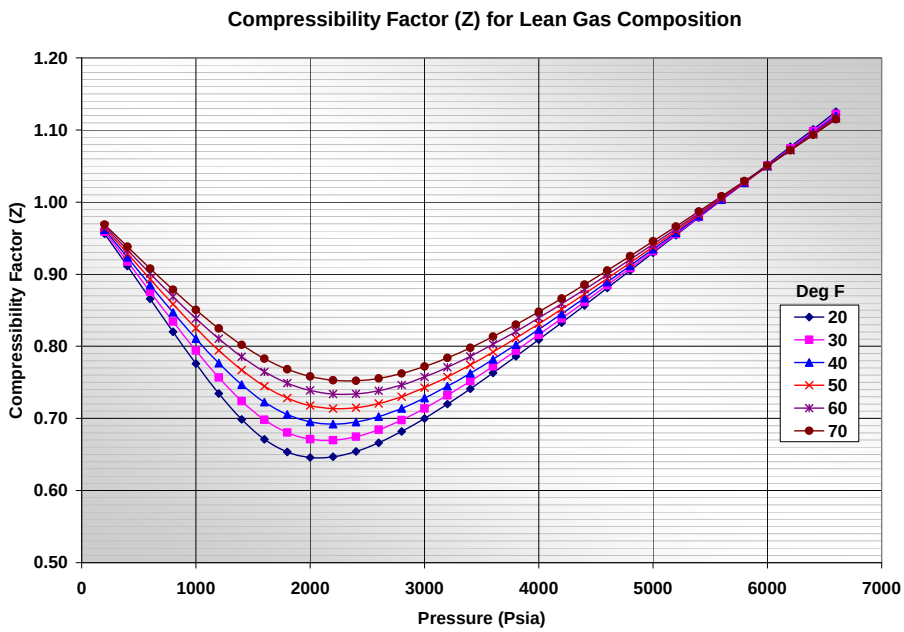
3) Design Selection

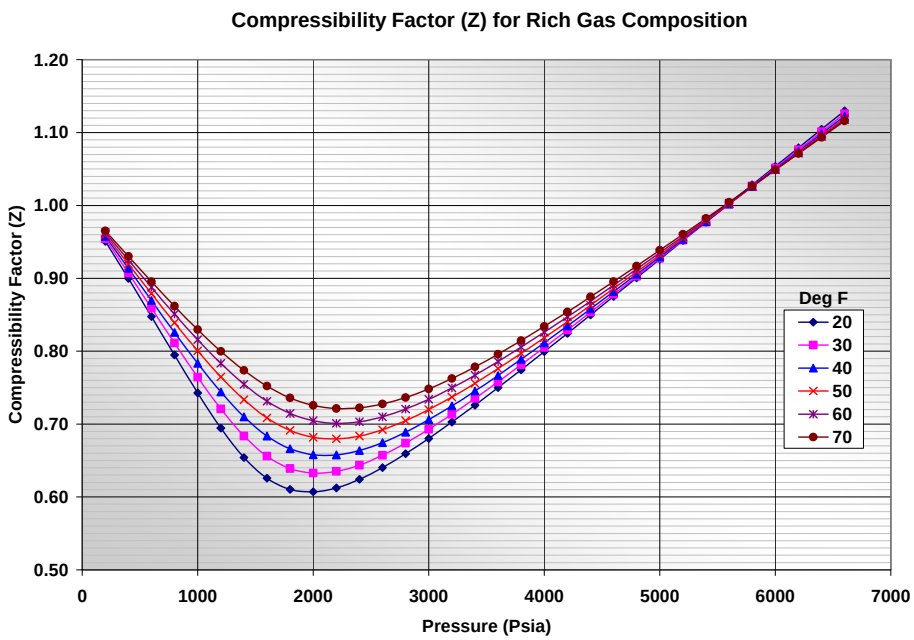
The design platform was selected from the results of a theoretical cost of service vs. flow analysis. The 48" x 2500 psig platform has been identified as being optimal for the volume flow range being considered. The following normalized J-Curves show the relative relationships to other platforms for cases where the cost per mcf for fuel gas is specified at both $2.00 and $5.00.


Normalized COS Comparison for ALASKA
Single Unit Station with $2.00 Gas
Discounted Cost of Service
10 Year Average (%)
125
120
115
110
105
100
95
90
3000
3500
4000
4500
5000
5500
6000
6500
Average Day July Flow (MMcfd)
42 x 2500 psig
44 x 2500 psig
48 x 2050 psig
48 x 2400 psig
48 x 2500 psig
Normalized to 48" x
2500 psig system @
4500 MMcfd


Normalized COS Comparison for ALASKA
Single Unit Station with $5.00 Gas
Discounted Cost of Service - 10
Year Average (%)
125
120
115
110
105
100
95
90
3000
3500
4000
4500
5000
5500
6000
6500
Average Day July Flow (MMcfd)
42 x 2500 psig
44 x 2500 psig
48 x 2050 psig
48 x 2400 psig
48 x 2500 psig
Normalized to 48" x
2500 psig system @
4500 MMcfd

The pressure operating range of the proposed platform (nominally between 2000 and 2500 psig) provides good efficiencies for the hydraulic calculations as the compressibility of the gas is located within the optimal range. The compressibility of both the lean and rich compositions is shown in the following charts.





While maintaining the same pipe diameter in the Yukon-BC section, the maximum operating pressure is increased to 2600 psig to maximize throughput capability while staying within expected design limitations.

4) Design Assumptions

The design assumptions used for the system are listed below:

- Design is based on average monthly July and January ambient conditions.
- X80 pipe material is assumed, which results in a wall thickness of 1.042 inches in the Alaska Section and 0.975 inches in the Yukon-BC Section.
- Intra-Alaska deliveries can be readily accommodated into the system design when demand levels are defined.
- The pipeline will operate below freezing upstream of Kluane Lake in the Yukon, and generally operate above freezing downstream of this location.
- Single unit compressor stations using large aero derivative DLE equipped gas turbines having a nominal power in the order of 45,000 hp with centrifugal compressors are used for mainline compression.
- Modular propane refrigeration trains powered by smaller gas turbines (6,000 to 15,000 hp) are used for after compression chilling upstream of Kluane Lake.
- Aerial cooling is used for after compression cooling downstream of Kluane Lake.
- Additional compression power for outage protection is used only at critical locations (upstream of Kluane Lake and at the end of the Yukon-BC Section).
- The station locations, which are determined using a station spacing routine, are assumed fixed for all flow level designs.

It should be noted that the design assumptions would be revisited during FEED and are subject to change when pipeline volumes are established though shipper commitments during the Open Season or as other new information becomes available.

5) Design Parameters and Inputs

- **Base Conditions**
  - Pressure: 14.73 psia
  - Temperature: 60°F
- **Equation of State**
  - Density for natural gas: AGA8
  - All other applications: BWRS
- **Gas Composition by Mole Percent**

  Hydraulic designs were based on the lean gas composition as specified in the RFA. The designs were confirmed to also be fully suitable for the rich gas composition. The specific compositions used in the simulations are shown in the table below:

	LEAN GAS	RICH GAS
N_2	0.7	0.6
CO_2	1.5	1.5
CH_4	89.9	86.4
C_2H_6	5.8	7.1
C_3H_8	1.7	3.6
iC_4H_{10}	0.1	0.3
nC_4H_{10}	0.2	0.4
iC_5H_{12}	0.04	0.04
nC_5H_{12}	0.04	0.04
C_6H_{14}	0.02	0.02

- **Btu Content per standard cubic foot (as per the RFA specification)**
  - Lean: 1067
  - Rich: 1118
- **Receipt Conditions @ Prudhoe Bay**
  - Pressure: 2500 psig
  - Temperature: 30°F
- **Delivery Conditions @ British Columbia/Alberta Border**
  - Pressure: 1225 psig
  - Temperature: 26°F minimum
- **Ambient Temperatures**

  Monthly data was taken from weather stations located in close proximity to the pipeline alignment. Temperatures located between the weather stations have been determined using milepost interpolation.

- **Ground Temperatures/Soil Conductivities**

  As previously noted, the heat flux between the pipe and the surrounding soil for the Alaska Section has been determined using the Kennelly equation**.**

  For the Yukon/BC Section, ground conditions including temperatures and soil properties are not specified as an input for the simulation. Heat transfer between the pipe and surrounding soil is determined from pre-generated look-up tables created using a 2-D geothermal model for relatively homogenous segments along the pipeline alignment. Individual soil sections within each segment are formulated to provide a composite soil for the segment from which the tables are based.

- **Flow Equations**

  The AGA rough-pipe / smooth-pipe equations have been used in the simulations. The pipe is assumed to be internally coated with a roughness of 300 micro-inches for calculations performed by the fully turbulent flow equation. A drag factor of 0.96 for partially turbulent flow is specified in the model, but is not a significant factor at the design flow levels.

- **Elevation Profile**

  A detailed profile has been used for the Alaska and Yukon-BC Sections in Canada. Compressor station elevations have been approximated by milepost interpolation between nodes.

- **Compressor Efficiency**
  - 85% for mainline compressors
  - 80% for propane chiller compressors
- **Compression Mechanical Efficiency**
  - 96.5% which includes a partial allowance for unit degradation between overhauls.
- **Driver Duct Losses (at full load)**
  - Intake: 3 inches H_2O
  - Exhaust: 4 inches H_2O
- **Compression Auxiliary Loads**
  - 5.0%
- **Compressor Station Losses**
  - Compressor inlet piping Equivalent length: 1175 ft
  - Compressor outlet piping Equivalent length: 988 ft
  - Station outlet piping Equivalent length: 495 ft
  - Station scrubber 4 psi
  - Chiller or aerial cooler 8 psi
- **Compressor Maximum Power Calculation**

  For simulation purposes, the mainline unit power is based on the performance of vendor units suitable for the application with empirical corrections for elevation, ambient temperature, duct losses, and mechanical and auxiliary losses.

  Propane chiller train power is similarly calculated based on a specific vendor unit as the driver.

- **Compression Fuel**

  Fuel calculations are also based on vendor performance data. Unit heat rates are determined by an empirically fitted detailed equation correcting for shaft power, turbine speed, and ambient temperature.

- **Compressor Station Maximum Discharge Temperature**
  - 30°F in chilled zone

  - Highest of 60°F or a value resulting from a specified approach temperature for aerial coolers in warm flow zone. The approach temperatures are normally 15 to 20 degrees depending on system requirements.
- **Pipeline Minimum Temperature**
  - Approximately 26°F for warm flow zone

6) Design Outputs

Summaries of simulation results for the 4.5 bcf/d and 5.9 bcf/d cases are shown on the following charts:

Summary of Simulation Results for 4.5 Bcfd Case
July Ambient Conditions

	Cumulative Milepost	Discharge Flow (mmcfd)	Station Pressure (psig)		Unit Pressure (psig)		Station Temperature (°F)			Station Power (HP)		Station Fuel (mmcfd)	
			Inlet	Outlet	Inlet	Outlet	Suction	Unit Discharge	Discharge	Available	Used	Mainline	Chillers
GTP Receipt	0.00	4500.000		2500					30.0				
Alaska Sta 1	53.84												
Alaska Sta 2	101.38	4491.562	1948	2498	1942	2507	15.1	40.6	30.0	41330	38759	6.215	2.223
Alaska Sta 3	140.67												
Alaska Sta 4	207.00	4482.592	1993	2500	1987	2509	21.3	45.2	30.0	40789	36403	5.907	3.064
Alaska Sta 5	266.57												
Alaska Sta 6	317.78	4473.729	2030	2500	2025	2509	23.2	45.1	30.0	39282	33548	5.559	3.304
Alaska Sta 7	380.67												
Alaska Sta 8	431.57	4464.197	2024	2500	2019	2509	25.1	47.6	30.0	41315	34376	5.668	3.864
Alaska Sta 9	493.01												
Alaska Sta 10	543.32	4454.841	2010	2495	2004	2504	24.4	47.5	30.0	41662	34989	5.743	3.613
Alaska Sta 11	597.95												
Alaska Sta 12	651.48	4444.826	1987	2500	1982	2509	24.7	49.4	30.0	41396	37235	6.038	3.977
Alaska Sta 13	704.77												
Yukon Sta 1	747.14	4434.485	2049	2600	2044	2609	25.5	50.8	30.0	40975	38769	6.240	4.100
Yukon Sta 2	803.53												
Yukon Sta 3	877.18	4430.314	1981	2300	1976	2301	20.6	36.0	36.0	38289	22835	4.171	
Yukon Sta 3a	877.22	4426.501	2300	2592	2295	2594	36.0	48.6	48.5	38297	19863	3.813	
Yukon Sta 4	934.24												
Yukon Sta 5	979.99	4421.378	2180	2600	2175	2601	42.2	61.8	61.8	39104	30322	5.123	
Yukon Sta 6	1027.90												
Yukon Sta 7	1062.66	4416.449	2175	2550	2170	2559	49.4	68.1	68.1	38400	28803	4.929	
Yukon Sta 8	1106.77												
Yukon Sta 9	1146.47	4410.920	2129	2550	2124	2560	53.5	75.3	75.0	38154	33370	5.529	
Yukon Sta 10	1183.66												
Yukon Sta 11	1229.91	4405.235	2122	2550	2117	2560	57.5	80.1	75.4	37917	34537	5.685	
BC Sta 1	1277.27												
BC Sta 2	1320.03	4400.260	2144	2500	2139	2510	59.8	78.9	78.3	38255	29090	4.975	
BC Sta 3	1371.38												
BC Sta 4	1406.86	4395.172	2049	2400	2044	2410	59.3	79.3	79.2	37851	29932	5.089	
BC Sta 5	1457.12												
BC Sta 6	1499.14	4389.712	1937	2300	1932	2310	59.5	81.7	81.6	38051	32705	5.459	
BC Sta 7	1544.92												
BC Sta 8	1584.44	4384.429	1790	2117	1785	2119	58.8	80.5	80.5	38317	31444	5.284	
Delivery to Alberta	1709.11	4384.429	1225				39.0						

Note: Station Locations are theoretical only and have not been researched for geotechnical, environmental, or social suitability.

Summary of Simulation Results for 5.9 Bcfd Case
July Ambient Conditions

	Cumulative Milepost	Discharge Flow (mmcfd)	Station Pressure (psig)		Unit Pressure (psig)		Station Temperature (°F)			Station Power (HP)		Station Fuel (mmcfd)	
								Unit					
			Inlet	Outlet	Inlet	Outlet	Suction	Discharge	Discharge	Available	Used	Mainline	Chillers
GTP Receipt	0.00	5900.000		2500					30.0				
Alaska Sta 1	53.84	5891.471	2063	2500	2057	2510	18.6	38.1	30.0	42665	39840	6.356	2.172
Alaska Sta 2	101.38	5883.220	2073	2498	2067	2509	18.6	37.5	30.0	41330	38657	6.201	2.050
Alaska Sta 3	140.67	5875.321	2076	2500	2070	2510	18.0	36.8	30.0	40148	38317	6.139	1.760
Alaska Sta 4	207.00	5866.471	2112	2500	2106	2510	24.0	41.6	30.0	40789	35803	5.827	3.023
Alaska Sta 5	266.57	5857.424	2100	2500	2094	2510	22.5	40.6	30.0	39871	36727	5.977	3.069
Alaska Sta 6	317.78	5848.471	2095	2500	2089	2510	21.7	39.9	30.0	39282	36984	6.015	2.938
Alaska Sta 7	380.67	5838.929	2093	2500	2087	2510	23.9	42.5	30.0	42178	37563	6.088	3.453
Alaska Sta 8	431.57	5829.758	2088	2500	2082	2510	21.8	40.4	30.0	41315	37557	6.092	3.079
Alaska Sta 9	493.01	5820.259	2092	2500	2086	2510	23.7	42.3	30.0	42229	37482	6.078	3.421
Alaska Sta 10	543.32	5811.130	2083	2499	2077	2510	21.5	40.3	30.0	41662	37815	6.120	3.010
Alaska Sta 11	597.95	5801.830	2090	2500	2084	2510	22.9	41.6	30.0	41615	37477	6.072	3.228
Alaska Sta 12	651.48	5792.599	2091	2500	2085	2510	22.9	41.5	30.0	41396	37290	6.046	3.185
Alaska Sta 13	704.77	5783.423	2095	2500	2089	2510	23.0	41.4	30.0	40941	36835	5.988	3.188
Yukon Sta 1	747.14	5774.046	2179	2600	2174	2610	24.6	42.7	30.0	40975	37068	6.014	3.363
Yukon Sta 2	803.53	5765.259	2184	2600	2178	2610	22.7	40.4	30.0	38820	36184	5.899	2.889
Yukon Sta 3	877.18	5760.932	2035	2300	2030	2302	18.5	30.8	30.8	38289	24088	4.327	
Yukon Sta 3a	877.22	5756.398	2300	2598	2294	2600	30.8	43.2	43.2	38297	25733	4.533	
Yukon Sta 4	934.24	5750.609	2217	2600	2211	2610	36.0	53.5	53.4	38952	35380	5.789	
Yukon Sta 5	979.99	5745.283	2261	2600	2255	2602	46.4	62.1	62.0	39104	31871	5.326	
Yukon Sta 6	1027.90	5739.374	2190	2550	2184	2561	50.8	68.9	68.8	38643	36264	5.910	
Yukon Sta 7	1062.66	5733.619	2257	2600	2251	2611	59.7	77.0	70.0	38400	35080	5.754	
Yukon Sta 8	1106.77	5727.842	2255	2600	2249	2611	59.8	77.2	71.3	38447	35231	5.777	
Yukon Sta 9	1146.47	5722.007	2251	2600	2245	2611	60.2	77.8	70.0	38154	35683	5.835	
Yukon Sta 10	1183.66	5716.344	2261	2600	2254	2610	58.7	75.7	68.0	37695	34404	5.663	
Yukon Sta 11	1229.91	5710.755	2265	2600	2259	2610	58.2	74.9	70.3	37917	33807	5.588	
BC Sta 1	1277.27	5705.113	2265	2600	2259	2611	60.7	77.6	74.1	38143	34150	5.642	
BC Sta 2	1320.03	5699.186	2248	2600	2242	2611	63.1	81.2	73.3	38255	36319	5.927	
BC Sta 3	1371.38	5693.202	2244	2600	2238	2611	63.1	81.3	73.3	39446	36777	5.984	
BC Sta 4	1406.86	5687.243	2243	2600	2237	2611	61.1	79.3	74.3	37851	36526	5.959	
BC Sta 5	1457.12	5681.277	2246	2600	2240	2611	63.9	82.1	75.8	38615	36567	5.966	
BC Sta 6	1499.14	5675.244	2242	2600	2236	2611	64.1	82.5	77.0	38051	37029	6.032	
BC Sta 7	1544.92	5669.798	2240	2600	2234	2561	65.5	81.9	75.4	38628	32654	5.446	
BC Sta 8	1584.44	5664.104	2187	2520	2180	2522	63.4	80.9	80.8	38317	34556	5.695	Heater
Heater Sta	1695.00	5663.847					38.3		39.3				0.257
Delivery to Alberta	1709.11	5663.847	1225				30.0						

Note: Station Locations are theoretical only and have not been researched for geotechnical, environmental, or social suitability.

7) Carbon Emissions

TransCanada commits to incorporating practices for controlling carbon emissions from natural gas systems as established by the United States Environmental Protection Agency in the final design.

Direct emissions reductions programs, as well as the development of new technologies and practices, are key components of TransCanada's comprehensive climate change strategy (see Appendix S "Climate Change and Air Issues Policy, Principles and Strategy").

TransCanada has been actively involved in the U.S. EPA Gas Star program for many years. Through the program, EPA works with natural gas production, processing, transmission and distribution companies to identify and promote the implementation of cost-effective technologies and practices that will reduce emissions of methane, a potent greenhouse gas. TransCanada closely follows programs such as the Gas Star Lessons Learned Studies and Partner Reported Opportunities in order to continuously improve its efforts related to emission reduction. Current TransCanada programs and procedures, applicable to its facilities, generally meet or exceed Gas Star Best Management Practices.

8) Engineering Challenges and Technology Solutions

TransCanada's Application includes a plan that identifies and incorporates emerging technological solutions to meet the extraordinary challenges of the Project. This is discussed in Section 2.2.1(5) "Pipeline Design Methodology" and Section 2.2.1(6) "Emerging Technologies". TransCanada continues to support research into technological improvements to manage and minimize emissions resulting from the transmission of natural gas.