Alaska Natural Gas Needs and Market Assessment: 2008 Update of the Industrial Sector

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1.0 Purpose

The objective of this report is to provide an updated assessment of the potential value of gas-intensive industries in South Central Alaska if a pipeline is constructed that provides Alaska North Slope (ANS) gas to this region. The original study, *Alaska Natural Gas Needs and Market Assessment*, was conducted for the US Department of Energy, National Energy Technology Laboratory, and released in April 2006. The 2006 Study addressed gas supply and demand from all sectors in Central and South Central Alaska, including residential, commercial, power, and industrial needs. Industrial demand included both gas-intensive industries (i.e., LNG, fertilizer, petrochemical, GTL, and LPG), and other industries for which demand is primarily for power. An investment model was applied to assess potential gas-intensive industries, which are particularly sensitive to their feedstock (i.e., gas) prices. Since 2006, oil, natural gas, and product prices have risen considerably, both domestically and internationally, requiring an update to the financial modeling previously performed for gas-intensive industries.

2.0 Key Findings

The results of this study suggest the following key findings:

- The recent rise in natural gas and product prices has improved feasibility of the assessed natural gas-intensive industries in South Central Alaska.
- Under base case price assumptions, petrochemicals and liquid petroleum gas (LPG) are potential sources of large increments of natural gas liquids (NGL) demand. They could provide an additional 127,000 barrels per day (bbl/d) of NGL consumption, 201 million cubic feet per day (MMcf/d) of gas equivalent.
- Both the current liquefied natural gas (LNG) export facility in Nikiski and a greenfield gas-to-liquids (GTL) plant may require sales contracts in premium markets for economic feasibility under the low price scenario. Natural gas demand from these industries is estimated at 375 MMcf/d and 464 MMcf/d for LNG and GTL, respectively.
- The investment climates for all assessed industries will remain highly uncertain given ongoing volatility in energy and product prices.
- The greatest uncertainty is associated with GTL due to the combination of evolving market, costs, and technology.

3.0 Scope and Assumptions

3.1 Gas Pipeline Operation

Natural gas and natural gas liquids (NGL) demand by industry is assessed based on the assumption of a dense-phase wet gas line that delivers ANS natural gas and NGL to South Central Alaska through a spur pipeline that branches off from the proposed Alaska Natural Gas Pipeline (ANGP) that would transport natural gas from the ANS to Canada and the Lower 48 States. The gas-intensive industries assessed in this report are assumed to be located in South Central Alaska due to expected lower operating and capital costs and proximity to export terminals and major trade routes.[1] As determined in the 2006 Study, an NGL-rich stream will generate the greatest level of industrial demand in Alaska.

The route of the pipeline to South Central Alaska is not determined in this update. However, for the purpose of modeling the pipeline tariff, it is assumed that the Alaska Natural Gas Pipeline (ANGP) from ANS to the Lower 48 States is constructed with the spur line branching off in Central Alaska (e.g., Delta Junction, or Fairbanks). As in the 2006 Study's largest wet gas pipeline scenario, pipeline capacity from the ANS to Central Alaska is at least 4.5 Bcfd, and the spur line capacity is approximately 1 Bcf/d, with operations commencing in 2015.

Also as in the 2006 Study, the wet gas spur line is assumed to be enriched with NGL extracted at a separator plant in Central Alaska. Surplus dry gas from the separator (i.e., in excess of South Central needs) is then re-injected into the ANGP for delivery to the Lower 48 States. The extracted NGL are assumed to be transported through a spur line to meet demand from two, new South Central industries: petrochemicals and LPG. The amount of enrichment in the spur line is adjusted based on the main line gas composition to meet the industrial demand for ethane (i.e., the petrochemical industry). In contrast, the LPG industry demand is adjusted based on the average gas composition in the ANGP from the ANS, and the resulting amount of propane and butane in the enriched mixture removed by the Central Alaska separator. Assumed gas composition at the separator inlet and outlet is described in Appendix A.

3.2 Industrial Demand

The potential industries represented in this update are the same as those in the original study's largest wet gas spur line scenario, which calculates petrochemical and GTL demand based on sizing and siting "World Class" facilities. In this study, the GTL complex was sized to a 50,000 bpd capacity, which demand 464 MMcfd. LNG industrial demand is based on retrofit of the current, nearly 40-year old plant in Nikiski and expansion to 3.0 MMTPA, demanding 375 MMcfd. Fertilizer industry demand is based on renovation of the 40-year old Agrium-owned facility in Kenai, and would demand 145 MMscfd. The Agrium facility is currently mothballed due to dwindling supply from the Cook Inlet and associated high feedstock prices. LPG industry

[1] The 2006 Study considered industry at Fairbanks and the North Slope, but found that locating industry in South Central Alaska to be the most economically viable. Residential and commercial gas demand growth were the strongest and anchor customers such as the ConocoPhillips LNG terminal and the Agrium fertilizer plant on the Kenai Peninsular were then operational, providing a ready source of demand.

demand is calculated as the amount of extra propane and butane in the wet gas line, which is determined by the spur line volume and liquids content.

Table 1 shows the gas and NGL capacity and demand for the potential industries considered in this update report. Only the LPG industry capacity and demand differs from the 2006 Study. This Study updates ANS gas composition and reflects the "Rich Gas Case" composition described in the Alaska Gasline Inducement Act (AGIA) Request for Applications (RFA), released in July, 2007.

Table 1: Potential Industry Capacity and Demand for Natural Gas and NGL

Industry	Capacity	Demand as MMcf/d methane equivalent (NGL feedstock)
Fertilizer *	1.25 MMTPA ammonia, 1 MMTPA urea	145
LNG **	3.0 MMTPA	212
GTL	50,000 bpd low sulfur diesel	480
Petrochemical	1.27 MMTPA ethylene	122 (76,000 bpd ethane)
LPG	50,000 bpd LPG	78*** (41,000 bpd propane, 9,000 bpd butane)
	Total Potential Demands	**1,041.**

* Assumes upgrade of the existing fertilizer plant
** Assumed expansion of the existing LNG facility at Nikiski
*** Under the "Lean Gas Case" composition described in the AGIA RFA, LPG capacity and demand would be reduced to approximately 24,000 bpd propane and 4,800 bpd butane, which is equivalent to 45 MMcf/d methane.

In both the 2006 Study and this update, it is recognized that pentanes will also be in the spur line gas stream, and will be separated out in South Central Alaska. Pentanes can likely be readily sold for blending into local gasoline, however their quantity and associated total value is quite small compared to the other gas stream components (i.e., approximately 1,400 bpd pentanes versus over 50,000 bpd LPG), thus pentanes are not further considered in this assessment.

3.3 Financial Assumptions

As in the 2006 Study, this update of industrial gas needs is market based and does not include analysis of gas price discounts or special incentives by the state to encourage in-state industrial development. Also as in the 2006 Study, it is assumed that, as a result of the integration of the South Central gas market with Canadian and Lower 48 gas markets, Alaskan gas prices will be based on Lower 48 gas prices adjusted for tariff. Thus, the price of natural gas in South Central Alaska is determined as the market price for natural gas at Henry Hub[2], minus the difference in estimated tariff rates between Henry Hub and South Central Alaska. In this update report, these

[2] This is the pricing point for North American natural gas futures on the New York Mercantile exchange. It is located in Erath, Louisiana.

differences are estimated to be $2.51 and $3.12 in the "Low" and "High" case scenarios, respectively.

All results presented in this update report are in 2007$ unless specified otherwise. As in the original study, the financial analysis assumes the following for each industry:

- *Project Life* – 20 years. This is a common industrial project life.
- *Discount Rate* – 12% rate. This varies among industries and projects, and may be relatively low for industries with higher risk (e.g., GTL).
- *Federal and state taxes* – were assumed at the rates of 35% and 4.5% of taxable income, respectively.
- *Cost Adjustment* – to adjust for the higher costs in Alaska compared to the Lower 48, construction and operations costs were multiplied by 1.3 for South Central Alaska.
- *Cost of Capital (during construction)* – 6%.
- *Financing* – all projects were assumed to be equity financed as turn-key projects.

The financial analysis of each industry is designed to determine the netback value of the feedstock (i.e., dry natural gas, ethane, or propane) to each industry. Netback value represents the maximum price for natural gas and NGL that each industry can afford to pay given global price for products, transportation costs, capital and operating costs, discount rate, and taxes.

The industry-specific inputs to the financial analysis for capital and operating costs, and shipping costs are the same values used in the 2006 Study after adjustments based on changes in Producer Price Indices from 2005 to 2007, as published by the Bureau of Labor Statistics. Table 2, below, displays the updated cost assumption for each industry assessed – these costs were held constant in both the high and low market price scenarios.

Table 2: Cost Assumptions for Potential Industries ($ millions)

Industry	Capital Costs	Low Price Scenario		High Price Scenario	
		Operating Costs	Shipping Costs	Operating Costs	Shipping Costs
Fertilizer *	$257	$316	$55	$589	$57
LNG **	$880	$642	$128	$1,271	$135
GTL	$3,112	$772	$103	$1,504	$108
Petrochemical	$2,993	$722	$80	$1,046	$82
LPG	$844	$440	$66	$740	$69

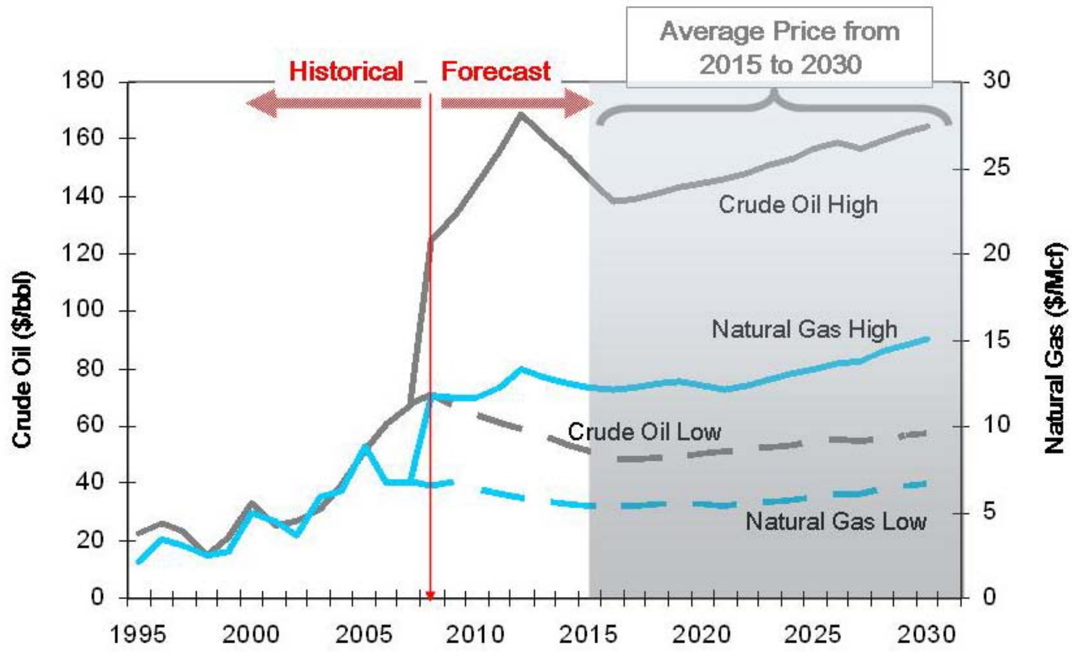
* Assumes upgrade of the existing fertilizer plant
** Assumed expansion of the existing LNG facility at Nikiski

4.0 Methodology

This analysis employs the same investment model adapted to each industry that was used in the 2006 Study. Input parameters include facility specifications (i.e., size, efficiency, etc.), production costs, and projected product prices on world markets. Model outputs include the netback value of gas to each industry. As an example, the value of gas to a fertilizer plant is calculated as the average annual price of fertilizer on the world market minus the average annual cost of transportation, and present value of combined capital and operating costs to convert Alaskan natural gas to a fertilizer.

For this update, model input parameters were changed to reflect increases in forecasted gas and oil prices, and related increases is the price of industrial products that would be produced from the modeled industries. Forecast natural gas and oil prices are based on the Energy Information Administration (EIA) forecasts published in the *Annual Energy Outlook 2008* as the "reference" case for Lower 48 prices. The EIA forecast prices for gas and oil are viewed by many energy analysts as conservative, thus this forecast is used as the "low" price scenario in this report. The June 3, 2008 futures prices of natural gas and crude oil on NYMEX for 2012 were used to represent a high price scenario in 2012, with the subsequent high-price scenario forecast through 2030, following the same annual percentage change as in the low price scenario. Historical and forecast prices of Lower-48 natural gas and crude oil are shown in Figure 1.

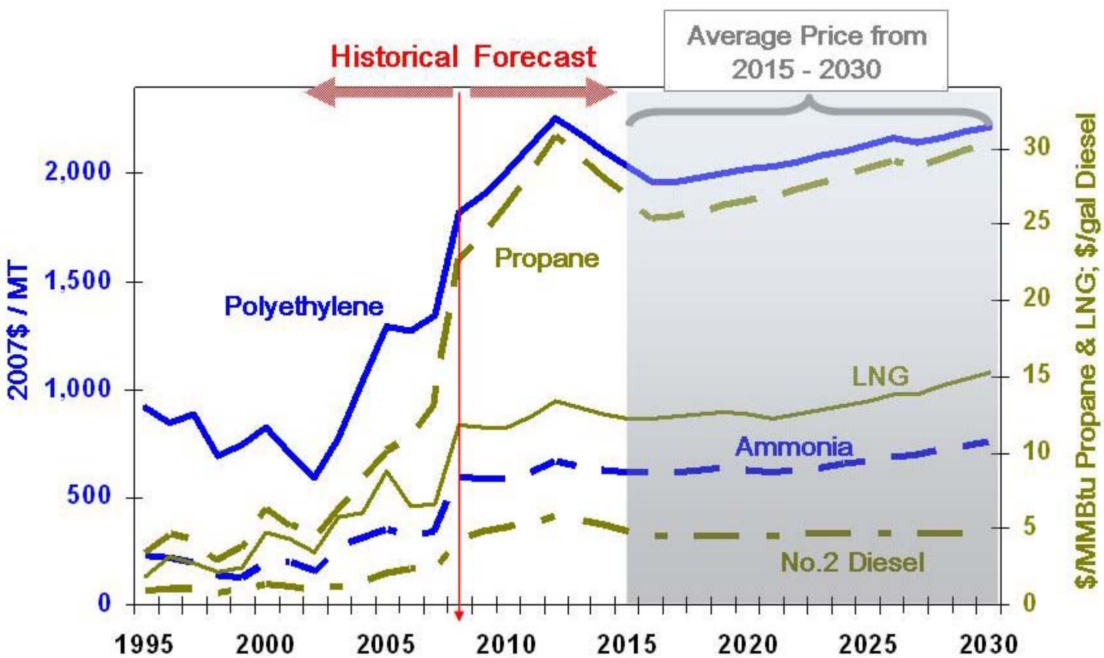
Figure 1: Lower-48 Crude Oil and Natural Gas Prices: Historical and High and Low Forecast Scenarios (2007$)



As described in the assumptions discussed above, the price of natural gas in South Central Alaska was determined as the market price for natural gas at Henry Hub, minus the difference in estimated tariff rates between Henry Hub and South Central Alaska..

Forecast product prices for each of the modeled industries are based on their historical relationship with natural gas and crude. Historical natural gas prices have a tighter relationship with ammonia and LNG, thus high and low natural gas price forecasts are the basis of the ammonia and LNG price forecasts. Historical crude prices have a tighter relationship with polyethylene, propane, and diesel; thus high and low crude price forecasts are the basis of the product forecasts for petrochemical, LPG, and GTL industries. Figure 2 shows the high scenario forecast of product prices.

Figure 2: High Scenario Product Price Forecast for LNG, LPG, Polyethylene, Ammonia. and Diesel (2007$)



The average low and high forecast product price from 2015 to 2030 is used in the investment model, a summary of these prices is provided in Table 3. Unless specified otherwise, prices in Table 3 represent average world prices -- in general, market locations are specified for prices representing products that may be sold to regions that are expected to have consistent price premiums.

Table 3: Average Forecast Prices (Model Input): 2015-2030

Commodity	Low Price	High Price
Natural Gas, Henry Hub ($/MMBtu)	$6.44	$13.52
Natural Gas, SC Alaska ($/MMBtu)	$3.93	$10.41
Crude Oil Price ($/Bbl)	$52.26	$150.69
LPG ($/ton)	$453	$1,305
Diesel, North America ($/MMBtu)	$11.47	$33.08
Diesel, Japan ($/MMBtu)	$14.14 [a]	$35.75 [a]
LNG, Southern California ($/MMBtu)	$6.09	$13.17
LNG, Japan ($/MMBtu)	$7.05	$16.74
Ammonia ($/ton)	$322	$676
Polyethylene ($/ton)	$1,097	$2,081

a Based on the world crude oil forecast plus a $0.37/gal premium in Japan based on average prices in 2007.

5.0 Industry Investment Analysis Results

5.1 Product Markets

Product markets were re-assessed for this update. Japan is identified as a potentially highly desirable market for Alaskan LNG, diesel from the GTL complex, and LPG. These products have been sold at a significant premium in Japan in recent years. Shipping costs from Alaska to Japan are roughly equivalent to, or less than other suppliers competing for the Japanese market. Potential markets assessed in this study are shown in Table 4 for each assessed product.

Table 4: Potential Markets for Alaskan Industrial Products

Product	Modeled Markets
Fertilizer	US West Coast, China, Japan
LNG	Japan, British Colombia, US / Mexico West Coast, China, Korea
GTL (ULSD)	US West Coast, BC, Japan
Petrochemical	US Gulf, Korea, China
LPG	US West Coast, China, Japan

The previous markets for Alaskan fertilizer, the US west coast and Asia, are good candidates for future markets. As indicated by the netback analysis shown below, Alaskan fertilizer, petrochemical and LPG industries value natural gas well-within, or above the range of forecasted natural gas market prices in South Central. This suggests favorable economics for these industries, with flexibility in the regions their product may be sold. China and Korea are viewed as likely markets for petrochemical products, both of which are projected to have increasing demand. Price premiums in Japan make it a very desirable market for LPG. Combined with the relatively larger expected growth in LPG demand in China, the Asian market is viewed as a likely market for Alaskan LPG.

Based on the assumptions used in this analysis, Alaskan GTL and LNG industries may be relatively more sensitive to product prices than the other modeled industries. Under the "low" price scenario and associated assumptions, products from Alaskan GTL and LNG industries may require that sales be to regions that place relatively high premiums on their products (i.e., Japan), or their operation may cease to be economically favorable.

The relatively high capital investment required for the modeled GTL complex in conjunction with its relatively high sensitivity to market prices, and the greater risk associated with this less common technology, may make the development of this industry less desirable than some of the other industrial options.

5.2 Netback Results

Based on the assumptions of this updated analysis, the maximum value of natural gas for each of the assessed industries is shown in Table 5. Netback prices that are below the forecast range of South Central natural gas (i.e., the average forecast price for each scenario plus or minus $0.50) suggest particularly risky investments based on the assumptions applied in this study.

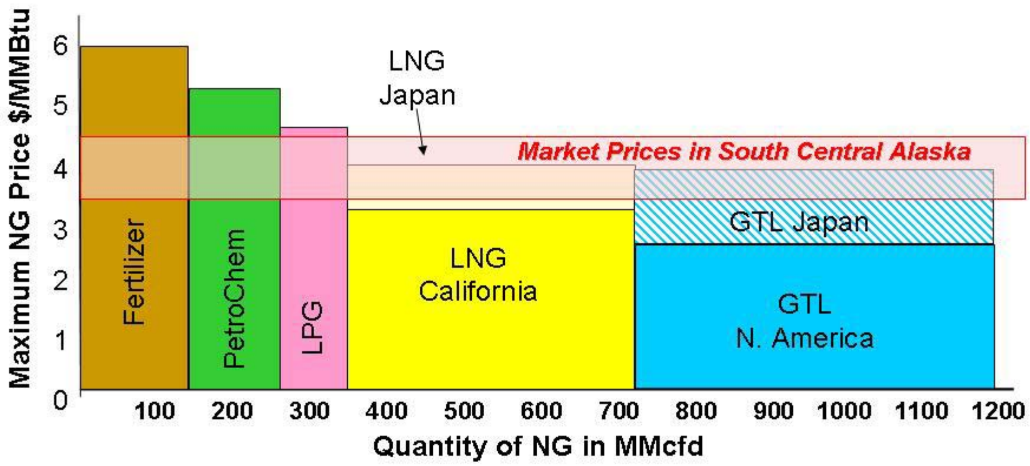
Table 5: Netback price of Natural Gas and Associated Product Prices: 2015-2030

Industry	Low Price Scenario (SC NG Market Price: $3.43 to $4.43/MMBtu)		High Price Scenario (SC NG Market Price: $7.76 to $8.76/MMBtu)	
	Product Price	Netback ($/MMBtu)	Product Price	Netback ($/MMBtu)
Fertilizer *(Ammonia)	$322 ton	$5.87	$676/ ton	$13.45
LNG , Southern California	$6.09/ MMBtu	$3.24	$13.17	$9.63
LNG, Japans	$7.05/ MMBtu	$4.11	$16.74/ MMBtu	$12.87
GTL (Diesel), N. America	$11.47/ MMBtu	$2.45	$33.08/ MMBtu	$14.89
GTL (Diesel), Japan	$14.14/ MMBtu	$3.99	$35.75/ MMBtu	$16.43
Petrochemical	$1,097/ ton	$5.19	$2,081. ton	$20.72
LPG	$453/ ton	$4.65	$1,305/ MMBtu	$19.92

The two industries that have the lowest increase in netback under the high price scenario (i.e., LNG and fertilizer) have product price forecasts that are based on natural gas prices (which increase less in the high scenario than crude prices), in addition to relatively low capital investment. In general, when market prices are relatively high, industries with greater capital investment benefit disproportionately more than industries with lower capital investment.

Figure 3 shows gas and NGL volumes as dry gas equivalents on a thermal basis on the x-axis, and the netback price on the y-axis, where netback price is maximum price of dry gas each of the assessed industries can pay while remaining economically viable under the modeled assumptions. The horizontal bar in Figure 3 represents the expected price range of South Central dry gas (i.e., the average low forecast price of $3.93/MMBtu, plus or minus $0.50). If South Central gas prices are higher than the maximum (i.e., netback) value for gas shown for a particular industry, then gas consumption from that industry will likely be severely curtailed, or may never develop.

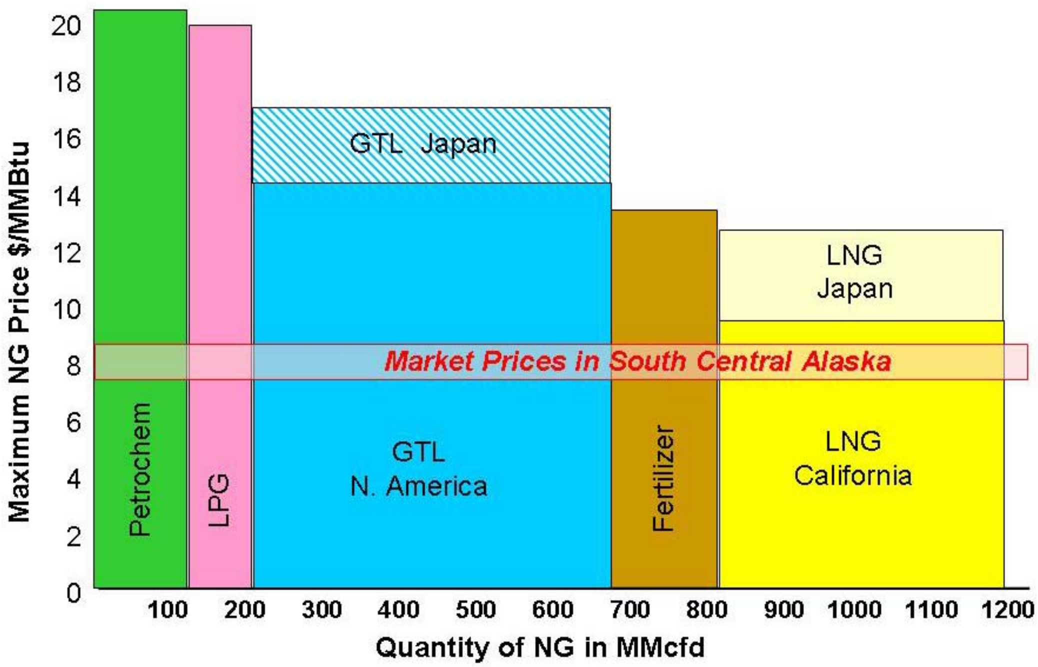
Figure 3: Estimated Maximum Prices Under Low Product Price Scenarios and Demand for Potential Industries for Dry Gas and NGL (Methane equivalent units) and the South Central Alaska Gas Market Price Band.



Source: SAIC

Figure 4 shows a similar graph the high market price scenario. In this case, the horizontal bar represents the expected price range of South Central dry gas with the average high forecast price of $8.26/MMBtu, plus or minus $0.50.

Figure 4: Estimated Maximum Prices Under High Product Price Scenarios and Demand for Potential Industries for Dry Gas and NGL (Methane equivalent units) and the South Central Alaska Gas Market Price Band.



Source: SAIC

In comparing netback values under the low and high price scenarios, the industries with the greatest increase in netback value under the high price scenario versus the low price scenario are those with products that have price forecasts based on the forecasted price of crude oil (i.e., GTL, petrochemical, and LPG). This is in part, a result of the greater difference between low and high forecasts prices for crude than for natural gas, i.e., high scenario natural gas prices are 2.1 times greater than low scenario prices, while high forecast prices of crude oil are 2.88 times greater than low forecast prices, as shown in Figure 1.

Because these analyses were conducted using assumptions that are inherently uncertain (i.e., projections of average market prices), none of the maximum price values should be considered accurate. However, the *relative* ranking of the industrial netback values in the South Central Alaska locations is not likely to change with modest assumption adjustments, with the possible exception of GTL. GTL is more sensitive to assumption modifications due to the larger gas demand and the higher uncertainty over project costs. The assumptions used in the GTL industry assessment are considerably more speculative than in other industries as a result of the uncertainty surrounding newer GTL technology and the still-emerging ultra-low-sulfur diesel fuel market.

6.0 Recommendations

There are many options and combinations of options that may have potential for Alaska with the development of ANGP and a spur pipeline. The relative merits of the options are complex and the long-term price forecasts for natural gas and oil and petroleum products on the world market always have a significant degree of uncertainty. Potential industries could be assessed on more detailed levels, with probabilistic analyses that account for cost and market risk to help provide additional insight into the complex interactions of options and economic benefits. Ultimately, these detailed analyses will likely be performed by serious investors. However, some over-reaching concepts are applicable to multiple industries and their integration, and thus may be best studied at an integrated level. Recommended integrated studies, include the following:

- A large-capacity spur pipeline will impact the design and operation of ANGP and could have significant economic impacts on that project. These issues were not analyzed in this study and could be more fully understood by running sensitivities to determine the impact of different-capacity spur pipelines on the value of ANGP.

- The uncertainties surrounding the completion of ANGP and consequently the spur pipeline are well understood. Alternative supply options exist, such as a smaller capacity bullet line from the ANS to Central Alaska. A comparative assessment of the alternative supply options would determine the costs and benefits of each supply option and help identify the optimal strategy for meeting natural gas demand.

- The potential location of various industries at North Slope or Central Alaska (e.g., GTL or petrochemical) may affect the desirability of further industry development in South Central. If industrial development at North Slope or Central Alaska is pursued further, the effects of industries located closer to the wellhead on state-wide industrial development may warrant further assessment.

- The results of this study suggest that the state of Alaska should explore the level of industry interest in investing in Alaska.

Appendix A: Gas Composition of a Dense Phase, Wet Spur Line

The spur line will provide a means to deliver a portion of the stranded natural gas at Alaska North Slope to a market. While the primary component of this gas is methane, it also contains a significant amount of natural gas liquids (NGL), i.e., ethane, propane, butane, and pentane. The economics of sending the stranded Alaska North Slope natural gas to market may depend on the inclusion of NGL because these components have a higher value per volume than methane.[3] A non-traditional, high-pressure pipeline allows transport of NGL without development of a separate liquid phase in the line, avoiding the slug flows that occur when a low pressure line includes more NGL than found in dry gas. The pressure of a wet gas line is set based on the NGL composition.

The composition of natural gas components in a wet gas line can vary greatly depending on:

- ***Gas source.*** There are several different potential sources of natural gas at Alaska North Slope, each source has a different proportion of methane and NGL.
- ***Volume of wet gas from which NGL are separated.*** The recovered NGL are used to enrich the South Central Spur line.
- ***Percent recovery of NGL.*** This is determined by the separation technology used for enriching the Spur and used to remove NGL at the end of the Spur (i.e., Anchorage/ Nikiski).

This update assesses each of the two gas compositions described in the Alaska Gasline Inducement Act (AGIA) Request for Applications (RFA), released in July, 2007. Separation efficiency assumptions are based on straddle separator plant efficiencies for recently designed plants in Canada, which have 95% separation efficiencies of ethane, and essentially 100% separation efficiencies of all other NGL. Based on recent designs, extraction of individual NGL from the liquid stream is assumed to be 100%.

The volume of gas from which NGL are separated is assumed to be the volume from which sufficient ethane would be removed to enrich the spur line with enough ethane to meet the demand of a world-class ethylene plant that uses ethane as a sole feedstock (i.e., 70,000 to 80,000 bpd ethane). The volume of raw gas that is transferred to the spur pipeline without processing by the straddle separator is assumed to be the volume that would allow the final spur line methane output to meet the projected dry gas demand for residential, commercial, and power sectors in addition to an industrial GTL complex. The propane and butane associated with the gas needed to meet the ethane and methane demand is the supply available for an LPG industry.

Calculations of spur pipeline composition are provided for both the “Rich” and “Lean” gas cases delineated in the AGIA RFA. Assumed demand includes South Central residential, commercial,

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[3] Michael Baker, Jr., Inc. 2005. Transport of North Slope Natural Gas to Tidewater. Submitted to the Alaska Natural Gas Development Authority (ANGDA), April, 2005.

and power sectors (a combined demand estimated to be 0.26 Bscfd), in addition to continued demand from the Agrium fertilizer plant, expansion of the ConocoPhillips LNG facility, and new development of GTL, petrochemicals, and LPG industries (a combined demand estimated to be 1.18 Bscfd.

Table A1 shows calculations of spur pipeline composition under the Lean Gas Case, in which 930 MMscfd is processed by a straddle plant separator with an ethane removal efficiency of 95%, and 100% removal efficiency of other NGL. Separated NGL are added as enrichment to a 1.4 Bcfd gas spur pipeline. This entire stream is processed by a second straddle separator in Anchorage/Kenai with efficiencies that are the same as those of the first straddle plant.

Table D1: Lean Gas Case, Spur line gas composition and volume.[1] *(Assumes ideal gas behavior at 60 F and 14 psia)*

Raw Gas Compone nt	Raw Gas* Mole %	1st Straddle Input (930 MMscfd)		1st Straddle NGL Output to Spur		Total Spur Input**		2nd Straddle NGL Output	
		MMscfd	bpd	MMscfd	Bpd	MMscfd	bpd	MMscfd	Bpd
Methane	89.90	836	NA	NA	NA	1,169	NA	0	NA
Ethane	5.80	54	60,666	51	32,150	127	79,457	120	75,484
Propane	1.70	16	26,019	16	10,038	38	24,070	38	24,070
n-Butane	0.10	1	2,254	1	608	2	1,459	2	1,459
i-Butane	0.20	3	4,713	2	1,387	4	3,325	4	3,325
Pentanes	0.10	1	3,189	1	723	2	1,733	2	1,733

* Raw gas mole % based on AGIA RFA, 2007.
** Total spur pipeline input calculated as 1st straddle output plus 1.30 Bcfd gas directly from the main pipeline.

These spur line inputs and straddle plant efficiencies yield roughly 75,000 bpd ethane, meeting the needs of a world class ethylene plant. This line would also supply roughly 25,500 bpd of propane and butane for an LPG industry, and 1,700 bpd pentanes for sale to other users, i.e., for blending into gasoline.[4] In addition, the spur line would yield approximately 1.2 Bcfd dry gas to meet the dry gas demand of the South Alaskan residential, commercial, power and industrial sectors.

Table A2 shows calculation of spur pipeline composition under the Rich Gas Case scenario, in which 450 MMcfd is processed by a straddle plant separator with an ethane removal efficiency of 95%, and 100% removal efficiency of other NGL. Separated NGL are added as enrichment to a 1.4 Bcfd spur pipeline. This entire stream is processed by a second straddle separator in Anchorage/Kenai with efficiencies that are the same as those of the first straddle plant.

[4] Pentane is also referred to as "natural gasoline" because it is a major component of gasoline.

Table A2: Rich Gas Case, Spur line gas composition and volume.[1] *(Assumes ideal gas behavior at 60 F and 14 psia)*

Raw Gas Component	Raw Gas* Mole %	1st Straddle Input (450 MMscfd)		1st Straddle Output to Spur		Total Spur Input**		2nd Straddle NGL Output	
		MMscfd	bpd	MMscfd	Bpd	MMscfd	bpd	MMscfd	Bpd
Methane	86.40	389	NA	0	NA	1,175	NA	0	NA
Ethane	7.10	32	20,046	30	19,043	127	79,626	121	75,645
Propane	3.60	16	10,286	16	10,286	65	41,373	65	41,373
n-Butane	0.30	1	883	1	883	5	3,552	5	3,552
i-Butane	0.40	2	1,342	2	1,342	7	5,397	7	5,397
Pentanes	0.10	0	350	0	350	2	1,406	2	1,406

* Raw gas mole % based on AGAI RFA, 2007.
** Total spur pipeline input calculated as 1st straddle output plus 1.36 Bcfd raw gas.

These spur line inputs and straddle plant efficiencies yield roughly 76,000 bpd ethane, meeting the needs of a world class ethylene plant. This line would also supply roughly 50,000 bpd of propane and butane for an LPG industry, and 1,400 bpd pentanes for sale to other users, i.e., for blending into gasoline.[5] In addition to the NGL streams, the spur line would yield approximately 1.2 Bcfd dry gas to meet the demand for the South Central Alaskan residential, commercial, power, and industrial sectors.

[5] Pentane is also referred to as “natural gasoline” because it is a major component of gasoline.