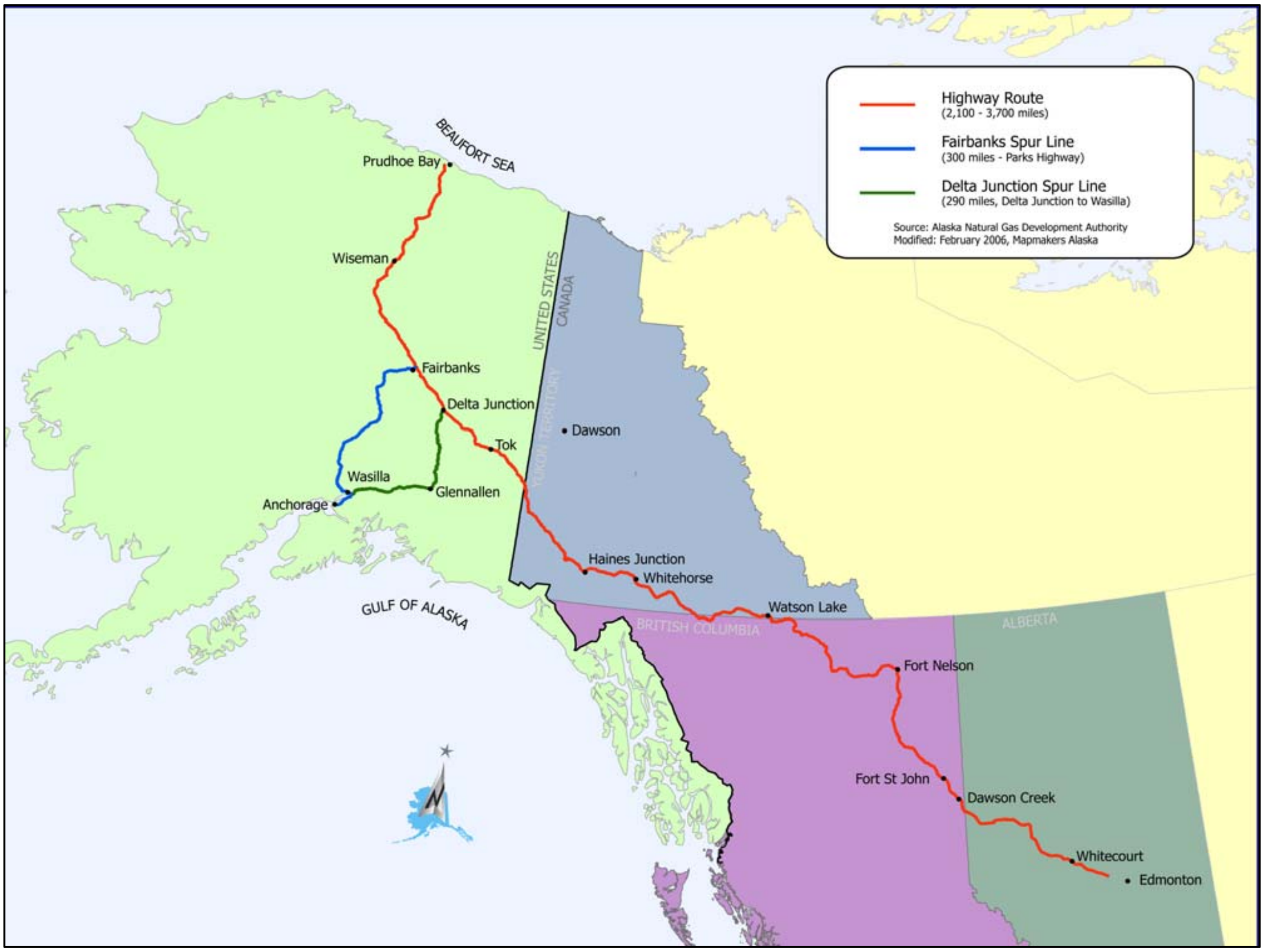
Alaska Natural Gas Needs and Market Assessment



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Disclaimer

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Advisory Committee

An Advisory Committee was formed to review the scope of work, monitor progress, and make suggestions for further work. The primary function of the committee was to make sure the most critical issues were addressed and to assist in obtaining critical data. The Advisory Committee met on September 28, 2005 and November 9, 2005. The committee members are listed below.

- Alaska Industrial Development and Export Authority: Ron Miller, Executive Director
- Alaska Governors Office: Michael Menge, Energy Advisor, Office of the Governor
- Alaska Natural Gas Development Authority: Harold Heinze, CEO
- Anchorage ML&P: James Posey, General Manager
- ASRC Constructors, Inc.: Marvin Swink, Sr. Vice President
- Chugach Electric Association: Lee Thibert, General Manager - Distribution Division
  Bradley Evans, General Manager – Generation and Transmission Division
- ENSTAR Natural Gas: Tony Izzo, President
- Fairbanks Natural Gas, LLC: Dan Britton, President
- Kenai Peninsula Borough: Bill Popp, Oil, Gas and Mining Liaison

In addition to their participation in the Advisory Committee, several members were interviewed by phone and in person, in some cases multiple times, regarding select opportunities. They graciously shared materials and estimates, and directed us to visit web sites and interview other agencies and developers involved in the industrial opportunities. SAIC is indebted to the assistance of the Advisory Group, in particular:

- Alaska Industrial Development and Export Authority
- Alaska Natural Gas Development Authority
- Chugach Electric Association
- ENSTAR
- Fairbanks Natural Gas
- Kenai Peninsula Borough

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Abstract

Study Objectives

The objective of the Alaska Natural Gas Needs and market Assessment is to estimate the potential demand for natural gas in South Central and other areas of Alaska directly associated with a potential spur pipeline connecting the proposed Alaska North Slope gas pipeline to the Cook Inlet pipeline infrastructure. This assessment is intended to provide an independent estimate of in-state natural gas demand and supply options for the years 2015 through 2035. Although other gas transportation projects have been proposed, this study assumes the gas pipeline from the North slope will roughly follow the oil pipeline right-of-way past Fairbanks to Delta Junction before following the Alaska Highway route into Canada.

Study Methodology

To develop an estimate of the potential requirement for natural gas in South Central (Anchorage/Wasilla/Kenai area) and Central Alaska (Fairbanks area), this study modeled the following demand sectors: residential/commercial; electric power generation; and various natural-gas-intensive industries including petrochemicals, ammonia and urea, liquefied petroleum gas (LPG), natural gas to liquids (GTL), and liquefied natural gas (LNG). Financial modeling provided the primary methodology to estimate the economically viable demand. Natural gas consumption from the power sector was determined using a commercial-grade power dispatch and capacity-build model. Residential/commercial demand was modeled using a combination of financial and econometric modeling. Smaller demand points such at the Yukon River crossing and along the spur pipeline routes were not modeled.

This study assumes a dense-phase line (capable of transporting methane with significant NGLs maintaining a gaseous phase), with a capacity of at least 4.5 billion cubic feet per day (Bcf/d), will be operating in 2015 to deliver North Slope natural gas to the lower-48 states (Lower 48); and that the majority of Alaska's demand will be supplied by a spur pipeline delivering natural gas to South Central Alaska with an off-take facility in Central Alaska to serve the Fairbanks area. With the exception of future supply from currently producing Cook Inlet gas fields, the study did not model any potential future production from drilling programs in the Cook Inlet, Nenana or Copper River Basins.

Natural gas prices are based on the DOE Energy Information Administration forecast for Lower 48 prices. North Slope wellhead prices are assumed to be Lower 48 prices less the estimated tariff for delivery to the Lower 48. The prices in Central and South Central Alaska are North Slope wellhead prices plus tariff to the takeoff point plus the estimated spur pipeline tariff.

Study Conclusions

The South Central Alaska yearly-average demand for residential/commercial and electric power generation is estimated to be 260 million cubic feet per day (MMcf/d) in 2015, increasing to 265 MMcf/d in 2025, and to 290 MMcf/d by 2035. Peak gas consumption in the winter season will be about 350 MMcf/d in 2015, 400 MMcf/d in 2025, and 430 MMcf/d by 2035. The residential/commercial and power generation demand in Central Alaska is estimated to increase from a yearly average of about 18 MMcf/d in 2015, to about 65 MMcf/d in 2025, and 75 MMcf/d in 2035. Hence, the total estimate for these two regions in Alaska, which will account

for most of the natural gas use in Alaska, will require a total of about 280 MMcf/d in 2015 increasing to over 500 MMcf/d by 2035.

While this study examines opportunities presented by a spur line, it is important to note that South Central Alaska demand can potentially be met by increasing natural gas reserves from the Cook Inlet basin through exploration and development. A total Cook Inlet gas resource endowment of 25 to 30 trillion cubic feet of original-gas-in-place, more than two times the amount already discovered was postulated to exist in a 2004 U.S. Department of Energy analysis. In the interim, Cook Inlet reserves have increased by an estimated 200 billion cubic feet as a result of exploration and development spurred by higher gas prices. However, continued reserves additions through drilling faces the risks inherent in any exploration activity as well as competition for investment capital by other opportunities around the world with potentially lower risks and higher rewards. The remaining options for South Central Alaska are a spur pipeline or importing LNG to meet basic demand. Central Alaska demand can be met by gas from a take off point from the North Slope pipeline near Fairbanks or other Central Alaska locations near the pipeline route and is not dependent on construction of a spur pipeline.

Under the base case assumptions, natural gas can be delivered to the South Central region by a spur pipeline for \$4.00 to \$5.00/MMBtu (2005\$) over the 2015 to 2035 time period. At these prices, only the residential/commercial and power sectors represent economical markets for the dry gas (utility-grade natural gas, predominately methane). Demand in these sectors could be satisfied with a 350 million cubic feet per day (MMcf/d) spur pipeline as long as it is coupled with natural gas storage capacity capable of delivering approximately 80 MMcf/d of additional utility natural gas to meet seasonal swings in demand.

A dense-phase (wet gas) spur pipeline containing sufficient quantities of natural gas liquids (NGLs) could potentially support a world class petrochemical and propane industry in South Central Alaska for the base case price assumptions. However, uncertainties in long-term product market prices and the additional technical and economic hurdles related to the amount of NGLs remaining in the gas delivered into Canada make this option more problematic. Demand for these sectors, and the sectors mentioned in the previous paragraph, could be satisfied with a 590 MMcf/d wet-gas line plus storage.

Finally, if a spur pipeline could deliver natural gas to South Central at prices lower than the base case prices (\$3.20/MMBtu compared to the \$4.00 to \$5.00/MMBtu base case range), the GTL and LNG sectors could add an additional 700 MMcf/d of dry gas demand. Under this scenario, a dry gas spur line would need a capacity of 1.0 Bcf/d. If NGLs are also included, the total wet gas pipeline capacity needed would be 1.3 Bcf/d. Such a large withdrawal could require design changes and cause significant economic hurdles for the Alaska North Slope pipeline.

The potential for locating a petrochemical industry in the Fairbanks area was not included in the initial objectives of this study. Although initial estimates of spur pipeline costs versus shipping petrochemical products by rail do not indicate a clear advantage for locating a petrochemical plant in South Central over Fairbanks, South Central was chosen as the site for a petrochemical plant analysis due to lower operating and capital costs and its proximity to export terminals and major trade routes.

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Abbreviations

2005$	U.S. Dollars in real 2005 dollars
AEO	Annual Energy Outlook
AECO	Alberta Energy Company, Alberta gas hub
AIDEA	Alaska Industrial Development and Export Authority
ANGDA	Alaska Natural Gas Development Authority
ANGTS	Alaska Natural Gas Transmission System
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
bbl	Barrels
bbl/d	Barrels per day
Btu	British thermal units
CH_4	Methane
DEG	Di ethylene glycol
EG	Ethylene glycol
EIA	U.S. Energy Information Administration
EO	ethylene oxide
EPS	Expanded polystyrene
Gal	Gallon
GEMS	Gas and Electric Modeling System (SAIC)
GTL	Gas to Liquids
HAGO	High Atmospheric Gasoil
HDPE	High density polyethylene
Mbbl/d	Thousand Barrels per Day
Kta	Thousand metric tonnes per annum (i.e., per year)
kWh	Kilowatt-hour
LDPE	Low density polyethylene
LLDPE	Linear low density polyethylene
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
MAPLE-C	Model for Analyzing Policies Linked to Energy – Canada
Mcf	Thousand cubic feet
MECS	Manufacturing Energy Consumption Survey
MEG	Mono ethylene glycol
MMBtu	Million British thermal unit
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MMTPA	Million metric tonnes per annum (i.e., per year)
MW	Megawatt
N_2	Nitrogen
ND	Northern Dynasty
NEMS	National Energy Modeling System

NG	natural gas
NGL	Natural gas liquid
NH_3	Anhydrous ammonia
NPV	Net present value
NRCAN	Natural Resources Canada
OGIP	Original Gas in Place
PE	Polyethylene
PET	Polyethylene Terephthalate
R/P	Reserves to Production Ratio
SAIC	Science Applications International Corporation
SEC	Securities and Exchange Commission
SPE	Society for Petroleum Engineers
TAPS	Trans Alaska Pipeline System
Tcf	Trillion cubic feet
TEG	Tri ethylene glycol
Tetra EG	Tetra ethylene glycol
Tonne	Metric Ton
US$	U.S. Dollar

Measures and Conversions

Fuel	Tonne	MMBtu	bbl	Dry Gas* Mcf
LNG	1	52.11	14.0	47.97
Ethane	1	49.24	17.65	48.88
propane	1	47.74	12.41	47.39
n-butane	1	46.96	10.73	46.62
i-butane	1	46.82	11.19	46.48

* Methane equivalent on a thermal basis

Equivalents to 1 Mcf Dry Gas

Fuel	Mcf	MMBtu	Bbl	Tonne
Dry gas	1.00	1.035	NA	NA
Methane	1.00	1.01	NA	NA
Ethane	1.00	1.77	0.64	0.04
propane	1.00	2.52	0.65	0.05
i-butane	1.00	3.25	0.75	0.07
n-butane	1.00	3.26	0.78	0.07

1 Barrel Diesel = 42 gallons = 5.825 MMBtu
1 Mcf of dry gas = 1.035 MMBtu
1 Metric Tonne = 2200 lbs

1.0 Executive Summary

1.1 Study Purpose

The objective of the South Central Alaska Natural Gas Needs Assessment (the Study) is to estimate the potential demand for natural gas in South Central and other areas of Alaska directly associated with a potential spur pipeline connecting the proposed Alaska North Slope gas pipeline to the Cook Inlet pipeline infrastructure. The Study provides forecasts of future natural gas consumption for existing natural gas uses, potential consumption from new markets and industries, and the anticipated requirements for natural gas storage for the years 2015 through 2035.

It is important to note that with completion of an Alaska Natural Gas Pipeline (ANGP) from the North Slope of Alaska to the Lower 48, Alaskan gas prices will become linked to Lower 48 prices. The impact of this linkage to the Lower 48 market has not been addressed in previous studies examining Alaska pipeline options.

1.2 Study Scope

The Study includes the assessment of potential dry gas and natural gas liquid (NGL) demand in the industrial, power generation, and residential/commercial sectors of South Central and Central Alaska. At least two potential routes for a spur pipeline are possible and are the subject of another U.S. Department of Energy (DOE) study.[1] The two routes under consideration are the Parks Highway route from Fairbanks to Wasilla, ultimately connecting to the existing ENSTAR system; and a pipeline with a take-off point near Delta Junction with a route to Glennallan along the Richardson Highway and then to Wasilla along the Glenn Highway. A preferred route has not been determined nor has specific routing for either option.

The two general options for a spur gas pipeline are a dry gas line and a dense-phase wet gas line. Either of these lines would support residential/commercial and power generation demand for natural gas. A dry gas line could support only methane intensive industries (i.e., LNG, ammonia-urea, and GTL), while a wet gas pipeline could serve methane intensive industries and NGL intensive industries (i.e., petrochemicals and LPG). The industrial analysis considers potential demand for natural gas components from both a dry and wet gas spur line. A wet gas spur pipeline to meet the requirements for a petrochemical industry would require that NGLs be separated from the natural gas in ANGP at a separation plant and added to the spur pipeline gas stream to enrich it to the required level.

It is assumed that a spur pipeline would serve only South Central Alaska, and that Central Alaska would be served directly by one or more takeoff points from ANGP. A lateral off the spur pipeline to serve Fairbanks is possible, if detailed design and economic analysis deem it to be

[1] The conceptual engineering study is being conducted by ASRC Constructors, Inc. and is scheduled for completion in the fall of 2006.

more desirable than a dedicated takeoff point. Estimates for future residential/commercial and electric power gas demand in Central Alaska are included in the Study.

Future natural gas demand will be a function of many variables, including the supply and price of natural gas. Therefore, the assessment includes natural gas supply from known reserves, natural gas storage, and projected natural gas prices.

The potential for Cook Inlet fields to provide additional supply above currently estimated proven reserves is not included in this assessment. However, the Cook Inlet remains a highly prospective natural gas basin. The 2004 DOE study[2] postulated a total Cook Inlet gas resource endowment of 25 to 30 trillion cubic feet (Tcf) of original-gas-in-place (OGIP). This is more than two times the 10 Tcf OGIP already discovered suggesting that the potential exists for an additional 13 to 17 Tcf of conventionally recoverable natural gas to be discovered in the Cook Inlet basin. Continued exploration and development in the Cook Inlet is important to state and regional economies; however, a comparison of drilling and development costs in the Cook Inlet verses the cost of building a spur pipeline is not included in the Study because the outcome of future drilling programs cannot be assured and the objective is to estimate the potential demand to support a spur pipeline.

The sections below summarize major Study assumptions, key findings, natural gas price forecasts, sector-specific demand for South Central Alaska, and a summary of Cook Inlet natural gas supplies. The expected prevailing natural gas price in 2015 to 2035 ultimately determines the estimated demand, which in turn dictates the throughput of a possible spur pipeline. This integration of supply, demand, and price is discussed in Section 1.7, followed by a brief discussion of Central Alaska gas demand in Section 1.8. Details of the analysis are in Chapters 2 through 7 and in Appendices A thru H.

1.2.1 Study Assumptions

Several basic assumptions are critical to understanding the scope and the uncertainties in the Study:

- The Study is market based and does not include analysis of gas price discounts or special incentives by the state to encourage in-state industrial development.

- The ANGP and spur pipeline become operational in 2015.

- Once ANGP connects North Slope gas to the Lower 48 markets, gas prices in Alaska are determined by Lower 48 gas prices.

- Lower 48 gas prices are based on the forecasts published by the U.S. DOE Energy Information Administration (EIA) in their *Annual Energy Outlook 2005 (AEO 2005)*. Uncertainties in price forecasts are especially critical in the long term analyses required

[2] Thomas, C.P., T.C. Doughty, D.D. Faulder, D.M. Hite: "South Central Alaska Natural Gas Study," U.S. Department of Energy, National Energy Technology Laboratory, June 2004.

in this study. Hence, sensitivity to price uncertainty is evaluated by performing the analyses at forecast prices plus and minus \$2.00/MMBtu (high and low price cases).[3]

- Oil price forecasts are taken from EIA's *AEO 2005* (High-B Case). The impact of changes in oil prices are also investigated because GTL market prices are tied to oil prices.

- All analyses are performed and reported using 2005\$, including gas and product prices and estimated tariffs unless specifically noted.

- North Slope gas, including NGLs, will be sold at the Lower 48 natural gas price *less* ANGP tariff.

- Pipeline tariffs estimated for the ANGP pipeline (North Slope to Chicago) are based on estimated capital costs that include the North Slope gas conditioning plant. The tariff estimates include an adjustment for gas offtake in Alaska (e.g., Fairbanks) so that gas transported to Chicago does not incur a penalty for gas or NGLs removed in Alaska. Final tariff structure for ANGP and for a spur pipeline has not been determined and will include many factors that are not currently defined.

- The price of natural gas delivered to South Central Alaska will be the North Slope gas price *plus* the ANGP tariff to the takeoff point near Fairbanks *plus* the tariff to South Central Alaska on the spur pipeline.

- Tariff calculations for the spur pipeline include capital costs for various pipeline sizes and volume throughput, compression, and NGL separation facilities. NGL separation plants will be required at each takeoff point from a wet gas, dense-phase line where utility grade gas or propane for local use is desired (Appendix B).

- It is assumed that natural gas used to meet future gas demand in the Fairbanks region (Central Alaska) will not be transported through the spur pipeline to South Central Alaska, but will involve a separate distribution system. This will definitely be the case for a spur pipeline with a takeoff point at Delta Junction. If the takeoff point is near Fairbanks the design and economics will determine if it is advantageous to have a front-end section in the spur pipeline that includes the Fairbanks volumes.

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[3] This assumption is based on market modeling and observations from other isolated markets that became integrated with Lower 48 markets once a pipeline was built. For example, spot gas price at the Opal and Cheyenne hubs in the Rockies were significantly discounted below average Lower 48 gas prices due to lack of pipeline takeaway capacity out of the area, rising gas production, and intense competition among producers for the limited pipeline capacity. The expansion of the Kern River pipeline to 1.8 Bcf/d in 2003 helped alleviate the pipeline congestion and prices in the Rockies rose closer to the Lower 48 average. As Rockies production continued to grow and pipelines became congested again, renewed downward pressure has mounted on Rockies gas prices. The completion of the 1.8 Bcf/d Rockies Express pipeline from northern Colorado to eastern Ohio by 2009 is expected to alleviate this growing downward pressure and raise Rockies prices. A similar example is provided by the Alliance pipeline, which brings natural gas and NGLs from Alberta to Chicago. Prior to completion of this pipeline, Canadian gas at Alberta usually traded at a significant discount to Lower 48 prices. Once the pipeline was built and Canadian gas could find new markets in the Lower 48, Canadian gas and U.S. gas prices approached parity.

- The analysis for industrial demand in South Central Alaska is designed to determine the maximum price at which dry natural gas, or NGLs, or both must be available at the plant gate to make the industry satisfy an assumed 12% discount rate, over a 20-yr project life.

- Dry natural gas as used in the Study is natural gas with a heating value of 1,035 Btu/standard cubic foot (scf), which is within the normal heating value range (990 to 1,050 Btu/scf) for utility grade gas for residential use. The composition is assumed to be composed of 90% or greater methane with small quantities of NGLs (ethane and propane) and inert gases such as carbon dioxide and nitrogen.[4]

- Wet gas refers to dry gas that has been spiked with NGLs. The amounts of NGLs that can be carried along with the methane depend on the pressure and temperature maintained in the pipeline.[5] Specific amounts of NGLs that will be in the natural gas transported from the North Slope in ANGP have not been determined and will depend on the raw gas source and content after processing on the North Slope to remove inert gases such as CO_2 and NGLs that can be transported in the Trans Alaska Pipeline System (TAPS).

- Removal of NGLs for local use in Alaska or for enriching a natural gas stream for transport of NGLs in a spur pipeline to a petrochemical plant will require a separation plant to remove the liquids and add them to the dry gas or raw gas stream in ANGP (Appendix B).

- For industrial NGL demand, spur pipeline gas will be enriched with NGLs to required levels. This could result in the gas delivered to Alberta being lower in NGLs than raw gas from the Prudhoe Bay Unit.

- South Central natural gas is currently supplied from existing Cook Inlet proven natural gas reserves. Even though exploration activity in the Cook Inlet continues, and is expected to increase given the recent increases in contract prices, estimating production impacts and timing of production resulting from such drilling is speculative and not included in this study.

- The potential for locating a petrochemical industry in the Fairbanks area was not included in the initial objectives of the Study. Although initial estimates of spur pipeline costs versus shipping petrochemical products by rail suggest there is no clear advantage for locating a petrochemical plant in South Central over Fairbanks, South Central was chosen as the site for a petrochemical plant due to expected lower operating and capital costs and its proximity to export terminals and major trade routes.

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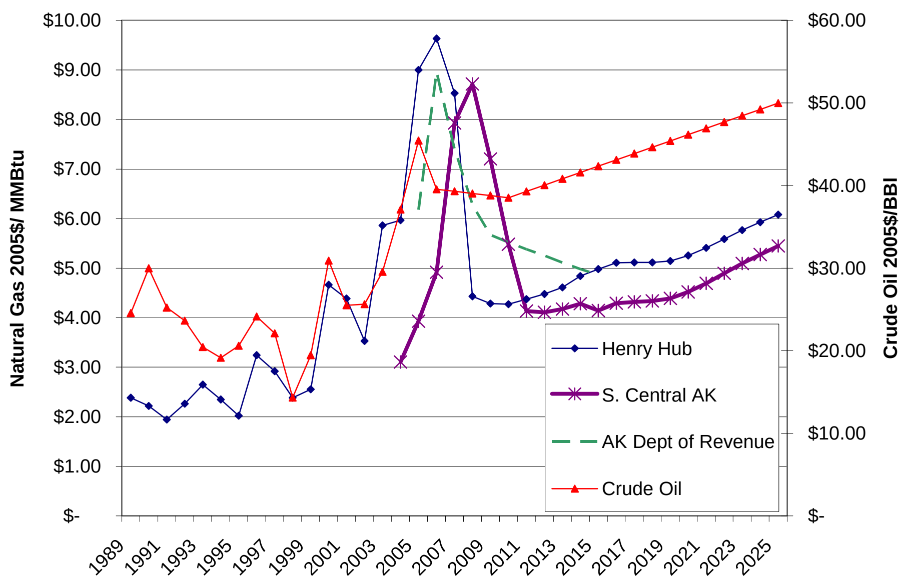
[4] Michael Baker, Jr., Inc., "Transport of North Slope natural Gas to Tidewater," Alaska natural Gas Development Authority, Aoril 2005, p. 3-2.

[5] Ibid.

1.3 Natural Gas Price Forecasts

Figure 1 presents the base case gas price forecasts for South Central Alaska, the Lower 48 states, and regional markets. The oil prices used to assess market demand for products such as GTL are also included. Prices used in the analysis, along with a description of the drivers, are provided in Section 3 and Appendix D. The base case price forecast of the Lower 48 prices (2005$) was derived from the EIA's *AEO 2005*.[6]

Figure 1: Base Case Natural Gas and Oil Price Forecasts (2005$



Source: Energy Information Administration, *AEO 2005 & Short Term Energy Outlook, January 10, 2006;* Alaska Department of Revenue; and SAIC analysis of market differentials

The Study considered several other gas and oil prices to assess demand sensitivity:

- High Gas Price Case: Base Gas Case plus $2.00/MMBtu
- Low Gas Price Case: Base Gas Case minus $2.00/MMBtu
- High Gas and Oil Price Case: Base Gas Case plus $2.00/MMBtu and Base Oil Price Forecast plus $11.60/bbl
- High Oil Price Case: Base Case Gas Case and Base Oil Price plus $11.60/bbl.

[6] EIA's AEO 2006 was not available when this analysis was conducted. Summary findings made available in the third week of December 2005 suggest no substantial changes to the analysis since EIA did not significantly change the base case gas price forecast.

Figure 1 shows that South Central Alaska natural gas prices are lower than Henry Hub prices,[7] but follow the trend. In the initial years (2005 to 2008), South Central Alaska prices are forecast to increase, while Henry Hub prices decline. This is due to the three-year lagged link between South Central gas prices and Henry Hub prices in recently approved purchase contracts. This link results in lower prices when Henry Hub prices are rising and higher prices when Henry Hub prices are declining. Once the spur pipeline and ANGP are completed in 2015, the link becomes market-based rather than contractually-based and the link between Lower 48 prices and South Central prices becomes established by relative pipeline tariffs along the ANGP and the spur pipeline. The gas price in South Central Alaska is equivalent to the gas price in the Lower 48 minus the tariff along ANGP back to ANS, plus the tariff from the ANS to South Central Alaska. Between 2015 and 2025, South Central Alaska gas prices rise at the rate of Lower 48 prices, increasing from $4.14/MMBtu to $5.45/MMBtu. Figure 1 also shows the Alaska Department of Revenue's Henry Hub price forecast published in the fall of 2005, which converges with EIA's view of Lower 48 natural gas prices by 2015.

The oil price forecast used for this analysis was derived from the *AEO 2005* (High-B Case) crude oil case. In this case, oil prices peak at over $50.00/bbl (2005$) by 2025. This is close to the *AEO 2006* base case oil price forecast released by EIA in February 2006, but higher than some oil analysts foresee.

1.4 Key Findings

Table 1 provides an estimate of natural gas demand (including NGLs) for South Central Alaska using the base case gas price assumptions. If natural gas cannot be delivered at the maximum price indicated, demand from that sector is not expected to occur or could be significantly lower (e.g., power could switch to an alternative such as coal).

[7] Henry Hub is located in Louisiana and is the primary pricing point for natural gas in the United States. Natural gas futures and spot contracts traded on the NYMEX are based on gas prices at the Henry Hub.

Table 1: Potential Consumption and Prices by Sector for Natural Gas in South Central Alaska, 2025

Potential Demand	Sector	Maximum Price $/MMBtu*	Demand in 2025
Dry Gas Demand	Residential / Commercial	$8.50	134 MMcf/d methane
	Power	$5.20	131 MMcf/d methane
	Ammonia / Urea	$2.79	145 MMcf/d methane
	LNG	$3.20	212 MMcf/d methane
	GTL	$3.20	480 MMcf/d methane
Total Potential Demand for Dry Gas			**1,102 MMcf/d methane**
Additional Wet Gas Demand	Petrochemicals	$4.60	3 MMcf/d methane 75,000 bbl/d [118 MMcf/d] ethane
	LPG	$4.20	63,000 bbl/d [96 MMcf/d] butane and propane, and 15,000 bbl/d [20 MMcf/d] pentane
Total Potential Demand w/Wet Gas			**1,339 MMcf/d methane equivalent.**

*Average price between 2015 and 2025.
Source: SAIC

Using the **base case price assumptions**, the following key findings result from the Study:

- The expected supply price of natural gas in South Central Alaska will be between $4.00 and $5.00/MMBtu during the first several years of spur pipeline operation.

- The South Central Alaska market can likely support a dry gas spur pipeline with capacity of 350 MMcf/d. A pipeline of this capacity coupled with storage capable of delivering approximately 80 MMcf/d by 2035 should be able to meet seasonal load swings of 260 MMcf/d between the winter peak of 435 MMcf/d and the summer low of 175 MMcf/d.

- Most of the natural gas demand will be from the residential/commercial and electric generation sectors. Gas delivered to South Central Alaska will be too expensive to support large-scale methane-intensive industries.

- Petrochemicals and LPG pass the basic economic tests and are also a potential source of large increments of demand. They could provide an additional 153,000 barrels per day (bbl/d) of NGL consumption (237 MMcf/d equivalent).

- The current LNG facility located in Nikiski, Alaska (plant and export terminal) and a new-build GTL plant marginally fail the economic test under the base case price forecast. GTL would be the next most likely large gas-intensive industry to locate in South Central Alaska, if some of the inherent uncertainties surrounding this technology and long-term market prices for ultra-low sulfur diesel can be overcome. This could provide an additional 480 MMcf/d in gas demand.

- The fertilizer industry (ammonia/urea) fails to generate gas demand under the base case price assumptions.

- Smaller scale industries do not add significant gas demand to support the spur pipeline. However, they do add power demand that results in additional load for the power sector. For example, the proposed Pebble Mine would add 300 MW of power demand, which would be satisfied by gas-fired generation. This natural gas demand is included in the South Central demand forecast.

The Study results in four possible spur-pipeline scenarios. The first scenario is the only one that is viable based on the base case pricing assumptions, Cook Inlet supply assumptions, and technical and economic hurdles for a petrochemical industry in South Central Alaska. The other scenarios are ranked from most likely to least likely.

1. *A 350 MMcf/d Dry Gas Pipeline*. This scenario is based on the base case assumptions. The demand to support this pipeline will come from the South Central residential/commercial and electric generation sectors. The price of gas is too expensive to support large-scale gas intensive industries, and smaller-scale industries do not add significantly to gas demand. Natural gas storage with the capability to deliver 80 MMcf/d of gas is needed to allow high utilization of the spur pipelines and also to meet the seasonal variability of the power and residential/commercial sectors.

2. *A 590 MMcf/d Wet Gas Pipeline*. This scenario assumes the same dry gas demand as above from the power and residential/commercial sectors, with the addition of NGL demand to feed a petrochemical plant (75,000 bbl/d [118 MMcf/d] of ethane), an LPG industry (63,000 bbl/d [96 MMcf/d] of combined butane and propane), and pentane sales for gasoline blending (15,000 bbl/d [20 MMcf/d]). This scenario is viable based on gas prices, but is complicated by several factors: construction and operation of a wet gas pipeline; competition from the existing petrochemical industry in Alberta; and long-term price projections for propane, butane, and pentane.[8]

3. A *1,000 MMcf/d* Dry Gas Pipeline. This scenario includes the same dry gas demand as scenario #1 from the power and residential/commercial sectors, with an additional 212 MMcf/d from continued operation of the LNG facility at Kenai and 480 MMcf/d demand from a GTL complex. This scenario hinges on continued operation of the LNG facility until 2015 in the face of dwindling gas supplies from the Cook Inlet and expiration of the export license in 2009. Uncertainties in capital costs for GTL plants and the value of GTL plant products in West Coast and world markets in 2015 and beyond make this scenario even more unlikely than scenario #2. Current capital costs of about $45,000/daily barrel are far above stated industry goals of $20,000/daily barrel or less. However, the $20,000/daily barrel is used in the Study because a GTL plant cannot come online until 2015 and provides industry the opportunity to achieve its goal of reducing

[8] Location of a petrochemical operation in Fairbanks was not originally included in the scope of work for the Study but was raised during the reviews of the draft report. The Fairbanks option will require that the finished products be shipped by rail versus shipping natural gas and NGLs by pipeline. The total shipping costs are similar for these two options based on the information available. Capital costs and operating costs are generally higher in Fairbanks then in South Central Alaska (by at least 10%). Hence, considerations other than market economics may determine the most viable option for location of a petrochemical plant.

capital costs through technology innovations.[9,10] This configuration would also result in a significant drawdown of dry natural gas from ANGP and could negatively impact the economics of that project.

4. A *1,300 MMcf/d Wet Gas Pipeline.* This scenario assumes the same demand as scenario #2, with an additional 212 MMcf/d from continued operation of the LNG plant at Kenai and 480 MMcf/d of demand from a GTL complex. The drawdown this pipeline would have on dry natural gas and NGLs from ANGP is large and would impact the design and operation of the ANGP and could negatively impact the economics of that project.

1.5 South Central Alaska Natural Gas Demand

The Study estimates natural gas demand for South Central Alaska based on a sector-by-sector analysis of the industrial, electric power generation, and residential/commercial sectors. Analysis methods for all sectors include projections of production costs and market prices that become increasingly uncertain further in the future.

The industrial sector has the greatest maximum potential for natural gas demand; however, it is also the sector for which demand is most sensitive to price. The residential/commercial and electric power sectors are less sensitive to price. Figure 2 shows the sensitivity of the demand for dry gas mixed with NGLs at different price levels based on demand projected in 2025. As shown in the left bar, demand for about 1.3 Bcf/d of dry gas mixed with NGLs could occur at prices less than $3.00/MMBtu. In the second bar from the left, fertilizer demand drops out, leaving a total demand for about 1.2 Bcf/d of dry gas and NGLs. At prices above $4.00/MMBtu, potential dry gas demand drops off quickly. The fall-off in projected dry gas demand as prices rise above $3.00/MMBtu is due to the inability of the fertilizer industry to remain competitive on the world market with higher gas prices. Similarly, the LNG and GTL industries fail to remain competitive on the world market as gas prices rise above $3.20/MMBtu. The electric power sector demand for natural gas is projected to decrease precipitously if the price of gas exceeds $6.00/MMBtu due to more favorable economics for local coal-fired power generation. At prices greater than $6.00/MMBtu, only residential/commercial demand remains viable.

Potential NGL demand from petrochemical and LPG industries could occur at prices between $4.00 and $5.00/MMBtu. A world class petrochemical complex would require around 75,000 bbl/d of ethane as feedstock. An LPG export industry would have a demand based on the spur pipeline supply of propane and butane, which this Study assumed to be 63,000 bbl/d. The analysis in Appendix B indicates that 15,000 bbl/d of pentanes would also be available for sale, possibly for gasoline blending.

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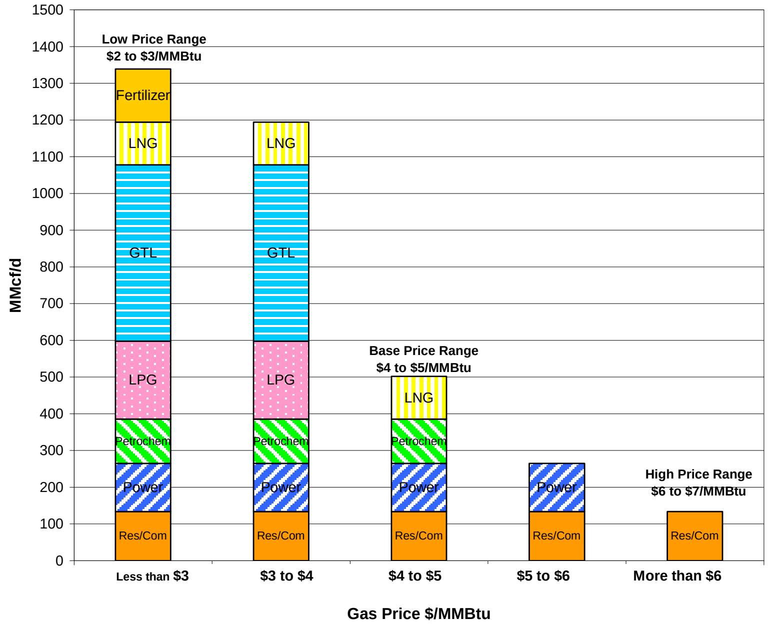
[9] Iraj Isaac Rahmim, "Stranded gas, diesel needs push GTL work," Oil and Gas Journal, March 14, 2005

[10] Jennie Stell, "Project plans respond to market demands for more, cleaner fuels," Oil and Gas journal, November 21, 2005.

Figure 2: Resulting Demand for Dry Gas and NGLs at various Price Levels (South Central Alaska) in 2025



Source: SAIC

1.5.1 South Central Alaska Industrial Demand

The two general options for a spur gas pipeline are a dry gas line and a dense-phase wet gas line. A dry gas line could support only methane (gas) intensive industries (i.e., LNG, ammonia-urea, and GTL) while a wet gas pipeline could serve methane intensive industries and NGL intensive industries (i.e., petrochemicals and LPG). The industrial analysis considers potential demand for natural gas components from both a dry and wet gas spur line.

Gas-intensive industries include those that are already present in South Central Alaska (i.e., fertilizer and LNG), and those for which interest has been expressed for Alaskan development (i.e., petrochemicals, GTL, and LPG). Non gas-intensive industries are also reviewed to assess their potential gas demand, which, with the exception of oil refining, are found to have minimal gas requirements.[11]

Currently, significant sources of industrial demand for natural gas include the ConocoPhillips /Marathon LNG plant and terminal, the Agrium fertilizer (ammonia and urea) plant, and the Tesoro refinery. All are located in Nikiski on the Kenai Peninsula. The LNG plant consumes approximately 212 MMcf/d; the ammonia and urea plant, which is currently operating at about half capacity, consumes 68 MMcf/d; and the refinery uses only 11 MMcf/d. The LNG plant will have to shut down by 2009 unless its export license is extended. The current license encountered significant opposition before it was extended in April 1999. Continuing concerns about the

[11] Other industries analyzed were more likely to use electricity, and were therefore incorporated into electric power demand estimates.

decline in proven reserves in the Cook Inlet is expected to play a significant role in deciding whether the operator will choose to request a license renewal. The Agrium fertilizer plant may shut down in October 2006 unless it can secure new reasonably priced feedstock supplies. Agrium is actively investigating coal gasification as an alternative gas supply for it operations. The Tesoro refinery is expected to continue operation, as long as petroleum feedstock supply lasts.

Potential gas demand from gas-intensive industries is based on the specifications of a world-class facility. Netback analysis is used to indicate the maximum price a facility could pay for gas while remaining economically viable in the world market. The netback analysis employs an investment model adapted to each industry. Input parameters include facility specifications (i.e., size, efficiency, etc.), production costs, and projected product prices on world markets. Model outputs include the net present value and the netback price of gas. As an example, the netback price for a fertilizer plant is calculated as the price of fertilizer on world markets minus transportation costs, minus the cost to convert Alaskan natural gas to a fertilizer.

Based on the assumptions of this analysis, key findings for dry gas and NGL consuming industries are:

- *Gas-to-Liquids Plant* -- A 50,000 bbl/d GTL plant would require approximately 480 MMcf/d of natural gas in feedstock and fuel. For the plant to be economically attractive, the maximum price this industry could pay for dry gas is approximately $3.20/MMBtu. Potential markets for GTL included rural and urban Alaska, the U.S. west coast, Japan, Korea, and China.

- *Liquefied Natural Gas* -- Continued operation of the 1.7 million tonnes per annum (MMTPA) LNG terminal at Kenai is the most likely scenario for maintaining Alaska's LNG exports. If its license is extended in 2009, the LNG terminal would consume approximately 212 MMcf/d of natural gas. For the terminal to be economically attractive, the maximum price this industry could pay for dry gas is approximately $3.20/MMBtu. Potential markets for LNG include the U.S. west coast, British Columbia, Baja Mexico, and Japan.

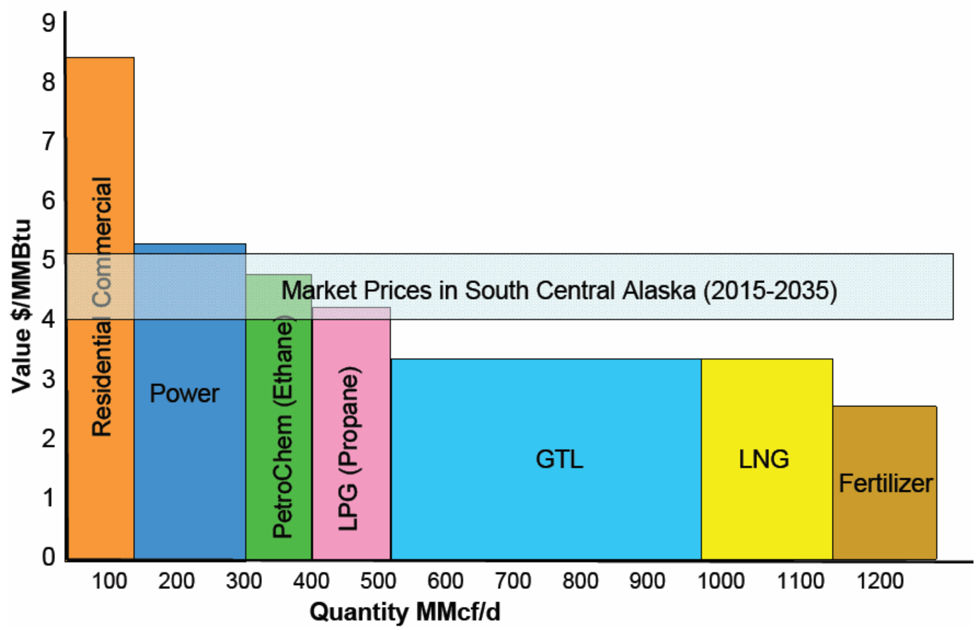
- *Fertilizer Plant* -- If the Agrium facility were mothballed and then refurbished for operations beginning in 2015, this industry would consume 145 MMcf/d of natural gas and 4 megawatts (MW) of electric power. To be economically attractive, the plant could accommodate a maximum dry gas price of $2.79/MMBtu. Current markets include the U.S. west coast and Asia.

- *Petrochemical Plant* -- A world-class petrochemical complex in South Central Alaska that manufactures polyethylene (PE) and monoethylene glycol (MEG) would consume 75,000 bbl/d of ethane feedstock, 3 MMcf/d of methane, and would require 100 MW of electric power. To be economically attractive, the petrochemical plant could accommodate a maximum price for ethane expressed as a thermal equivalent to dry gas of approximately $4.60/MMBtu. Potential markets include the U.S. and Canadian west coasts and Asia.

- *Liquid Petroleum Gas* – An LPG export industry supplying 63,000 bbl/d of LPG could accommodate a maximum price for propane and butane expressed as a thermal equivalent to dry gas of about $4.20/MMMBtu. Likely markets include rural and urban Alaska, Canada, the U.S. west coast, Japan, Korea, and China.

Figure 3 shows the gas and NGL volumes (NGLs are converted to dry gas equivalent on a thermal basis), and maximum prices for the residential/commercial and power sectors and each of the industries. The base case gas supply price band is also shown. If gas prices are higher than the maximum price 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 for Residential/Commercial, Power, and Candidate Industries for Dry Gas and NGLs (Methane equivalent units) in 2025 and the Gas Supply Price Band (2005$)



Source: SAIC

Based on this analysis, the industries that would require a wet gas spur pipeline to supply NGLs have the greatest potential for relatively low risk development with good chances of a favorable return on investment. However, issues outside the scope of this study relating to the quantity of NGLs remaining in ANGP when it reaches Canada's petrochemical complex may have impacts that cannot be quantified by economics alone. The relative investment appeal of various industry opportunities can be used to determine the industries for which the spur line gas composition should be tailored.

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.

1.5.2 South Central Alaska Electric Power Demand

Natural gas demand for power generation in South Central Alaska is driven by electricity demand, type of fuel used to generate electric power, relative fuel pricing, relative efficiency of the generators employed, and plant dispatch. Plant dispatch was simulated under varying gas price assumptions using a dispatch model that simulates the operation of the region's existing generation and makes economic decisions for what technology and fuel will be used in order to minimize system costs in the long-run.

There was a very small difference in gas demand between the Base and Low Natural Gas Price scenarios. In these two scenarios, natural gas dominates new generation unit construction. In contrast, the High Natural Gas Price Case triggers the construction of a number of new coal-fired electric generations units, which significantly displace not only new but existing natural gas fired electric generation.

Some general observations are:

- Natural gas is currently available for electric power generation throughout the interconnected electricity grid in Alaska, with the exception of Fairbanks. Traditionally, natural gas has been very inexpensive. However, the building of ANGP and the Spur pipeline will link prices in the Alaska gas market with the Lower 48. The harmonization and likely increase in South Central natural gas prices could make technologies using competing fuels such as coal more attractive (coal prices may not go up as much due to the isolation of Alaska, but coal plant capital cost could be a deterrent to rapid new coal capacity builds).

- The existing inventory of electric generating units in the interconnected portion of Alaska is generally older and significantly less efficient than new generating units that will replace them. As new generating units are introduced, they will generate the same quantity of electric power using less fuel. The average heat rate of natural gas-fired plants in Alaska is currently 11,000 Btu/kWh. Over time, as more efficient plants are built, heat rates could decrease to 7,000 Btu/kWh, which would diminish gas demand over what it would otherwise be.

Key findings for the electric sector are:

- Natural gas demand for power generation in South Central will grow significantly under base case price assumptions. Natural gas penetration in the power sector is substantial, and gas consumption could increase from 93 MMcf/d currently to 148 MMcf/d by 2035 due to increases in load. Mitigating factors that reduce potential growth are the increased efficiency of new generating units discussed above.

- Coal loses out to natural gas due to higher capital costs, but captures almost all new growth when natural gas prices are assumed to be $2.00/MMBtu higher than in the base case.

1.5.3 South Central Alaska Residential and Commercial Demand

New residential and commercial natural gas customers in the South Central Area will result from a combination of:

1) Increased penetration of ENSTAR into existing service areas; and

2) Expansion of ENSTAR service into new areas of South Central Alaska.

Major conclusions are:

- Natural gas demand from the residential/commercial sector is expected to be strong after North Slope pipeline gas becomes available. This is a result of favorable gas pricing compared to the primary alternative fuel, heating oil. The price of heating oil (adjusted for the amortized cost of appliance conversion and distribution lines) to the customer averages $8.50/MMBtu over the forecast period, well above the expected price of gas from the North Slope.

- Based on expected prices and population increases in the Anchorage region (a population growth rate of 2% is assumed), the demand for natural gas from the residential/commercial sector is forecast to grow from 96 MMcf/d currently to 118 MMcf/d by 2015, 134 MMcf/d by 2025, and 148 MMcf/d by 2035.

1.6 Natural Gas Supply

Cook Inlet: South Central Alaska's gas supply currently comes exclusively from the Cook Inlet basin and was described in detail in a 2004 DOE-NETL report.[12] Estimates of Cook Inlet proven gas reserves using the base case price forecast described in this Study (see Section 7.3) and the additional production data and discoveries since the 2004 DOE study indicate that approximately 200 Bcf of proven reserves have been added. These estimates are based on field-wide production rather than well-by-well analysis and may be conservative. Even including these additional reserves, gas production will decline to approximately 113 MMcf/d by 2015 from current production levels of about 550 MMcf/d, and will decrease to 15 MMcf/d by 2023 when the field will reach its economic limit based on the estimates and assumptions used. The widening gap between available supply from proven Cook Inlet reserves and anticipated demand is of significant concern for the region and is assumed in the Study to provide a market for the spur pipeline.

[12] Thomas, C.P., T.C. Doughty, D.D. Faulder, D.M. Hite: *South Central Alaska Natural Gas Study*, U.S. Department of Energy, National Energy Technology Laboratory, June 2004.

The estimated growth in proven reserves since the 2004 DOE report of approximately 200 Bcf is equal to the 2005 production from the Cook Inlet. This suggests that current price signals based on the Henry Hub index are encouraging reserves growth and aggressive reservoir management to improve recovery. Recently, Escopeta Oil announced plans to lease an offshore jack-up rig to drill several exploration prospects in the Cook Inlet, starting August 2006.[13] It is likely that renewed exploration focused on natural gas will result in discoveries of new reserves. Additionally, other operators have offshore exploration prospects that once an offshore drilling rig is in the Cook Inlet, additional exploration will likely occur. The 2004 DOE report noted that historical discoveries in the Cook Inlet have been structural plays. In analog basins, only about one-half the petroleum endowment is discovered in structural settings; the remaining discoveries are in stratigraphic plays. The Cook Inlet has not been explored for stratigraphic plays to date, indicating a large up-side potential. Both Marathon and Unocal have been successful in finding and developing natural gas in the Cook Inlet basin in the last few years, and with Chevron's recent announcement that they will keep the Unocal Cook Inlet assets acquired in the 2005 purchase of Unocal Corporation,[14] this activity can be expected to continue. Several independent companies have announced plans for exploration in the Cook Inlet as well.

Thus, while this report considered proven reserves only, the Cook Inlet is still a prospective natural gas basin. Additional natural gas will likely be discovered and reserves growth will continue, provided access to prospective areas is available and natural gas prices remain high enough to encourage exploration. Therefore, the proven reserves natural gas case is a conservative assessment of future production from the Cook Inlet.

Also, a spur pipeline connecting South Central Alaska to North Slope gas reserves would provide a ceiling price for gas in South Central Alaska that is expected to be lower than Henry Hub prices. This would potentially be a disincentive for Cook Inlet exploration in the long term unless industrial development does occur that provides a large and viable market for natural gas in South Central Alaska. However, it is technically feasible for a spur pipeline to be reversed to carry the natural gas produced from the Cook Inlet Basin to the ANGP pipeline for delivery to the Lower 48. Historically the Cook Inlet has been a closed market with only four gas markets, the local residential/commercial and power generation sectors, LNG export, and fertilizer manufacture and export. This possible sales option would offer explorers in the Cook Inlet the option to sell into the North American natural gas market as well as supply local consumption and industry.

North Slope: Spur pipeline gas will originate from the North Slope. North Slope producers believe they have, or will have through exploration, enough gas supply to support a 4.5 to 6.0 Bcf/d pipeline to the Lower 48. The Study indicates that North Slope natural gas can be delivered to South Central Alaska at prices between $4.00 and $5.00/MMBtu (2005$), as described in Section 1.7.

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[13] Petroleum News, "Jack-up Under Contract" Vol. 11 (9), February 26, 2006.

[14] Petroleum News, "Chevron to keep Cook Inlet assets," News Bulletin, Vol. 12 (14), March 1, 2006.

LNG Import: An alternative source of natural gas supply for the South Central region is LNG imports. It is estimated that the Kenai liquefaction and export terminal can be converted to a regasification terminal for about $60 million. This option could provide an alternative source of natural gas supply for South Central Alaska in addition to either North Slope gas delivered by a spur pipeline or Cook Inlet production. It is expected that the price of imported LNG in South Central Alaska will be $5.00 to $5.50/MMBtu because LNG suppliers can likely get this price by selling into the California or Mexico market. The Study results indicate that gas delivered by a spur line would be cheaper than imported LNG.

1.7 South Central Alaska Integrated Analysis and Results

This section integrates supply, demand, and price estimates to give a base case estimate of dry gas demand to support the Spur Pipeline.

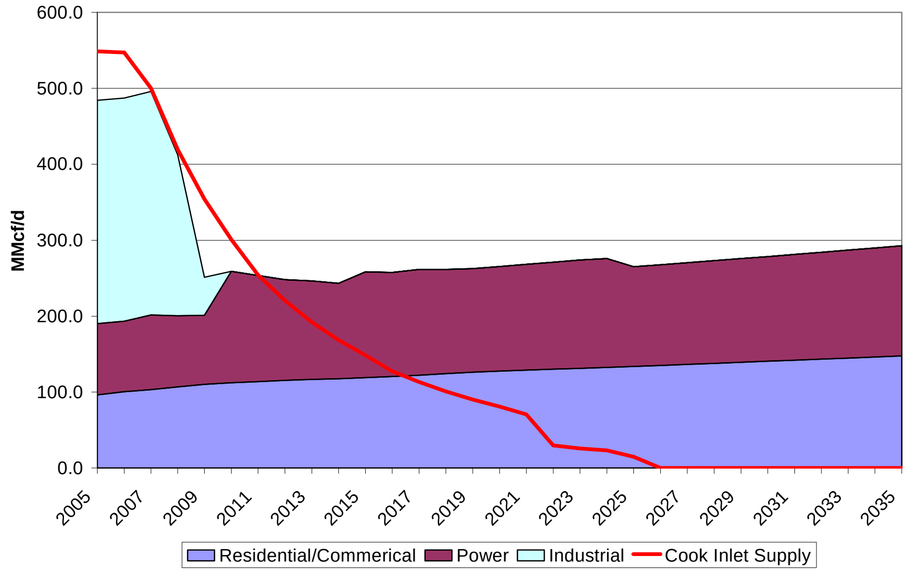
Based on EIA's *AEO 2005*, long term prices of natural gas in the Lower 48 are expected to be between $5.00 and $6.00/MMBtu (2005$). The estimated ANGP tariff is $2.30/MMBtu between the North Slope and Chicago (see Appendix C), implying that North Slope producers will expect to receive between $2.70/MMBtu and $3.70/MMBtu for their gas at the inlet to ANGP. The tariff for a 20-inch, 350 MMcf/d spur pipeline, plus the tariff along ANGP from the North Slope to Fairbanks, is estimated at $1.30/MMBtu.[15] This would result in a delivered price of gas to South Central Alaska of between $4.00 and $5.00/MMBtu over the time period from 2015 to 2035.

Given the range of delivered prices in South Central Alaska estimated in the Study and the maximum price each customer would be willing to pay for dry gas, only the residential/commercial and power sectors would be captured by North Slope producers, with the rest being sold into the Lower 48 market as shown in Figure 3. With a maximum price of $3.20/MMBtu, GTL and LNG fall just below the point of economic feasibility. GTL faces the most uncertainty in terms of price, costs, and technology, but could be considered a high demand case for the spur pipeline.

Figure 4 summarizes dry gas consumption and Cook Inlet supply for South Central Alaska between 2015 and 2035. This analysis suggests that the region could experience a shortfall in gas of 110 MMcf/d by 2015, 250 MMcf/d by 2025, and 300 MMcf/d by 2035.

[15] The conceptual engineering study of Alaska spur pipeline options that ASRC Constructors and partners are conducting for DOE will develop more refined tariff estimates based on more detailed information they will generate in that study.

Figure 4: Forecast for Proven Gas Reserves and Annual Gas Consumption for the Residential/ Commercial and Power Sector



Source: SAIC

Figure 5 shows the seasonality in gas consumption. Peak gas consumption is almost 350 MMcf/d by 2015 and 430 MMcf/d by 2035. The figure clearly shows the widening gap between available supply from Cook Inlet proven reserves, which by 2025 have decreased to about 50 MMcf/d, and demand, which has grown to 265 MMcf/d. This gap could be filled by a spur pipeline capable of delivering up to 350 MMcf/d, with access to about 80 MMcf/d of storage providing the optimal spur pipeline configuration for meeting South Central Alaska gas demand.

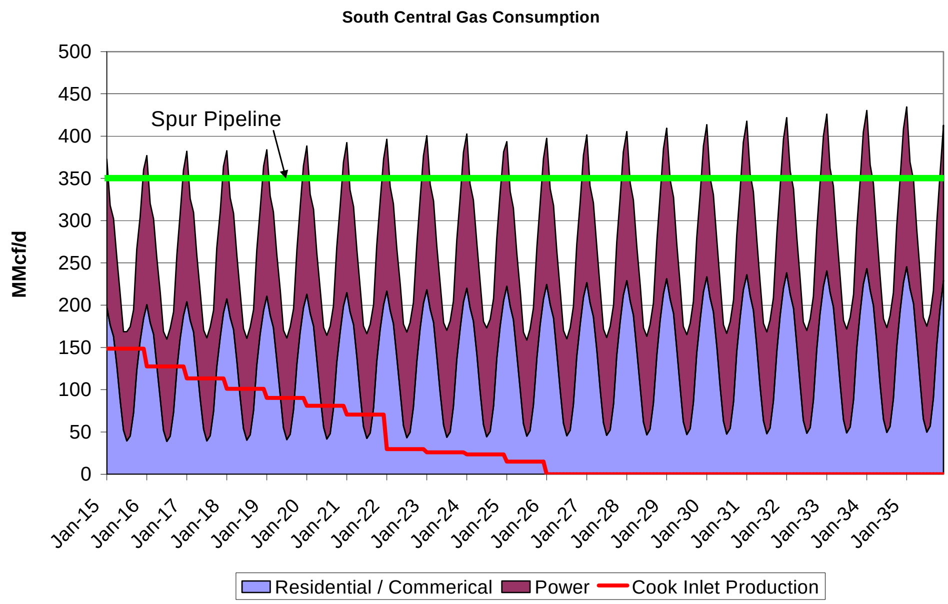
1.8 Central Alaska Gas Demand

Future Central Alaska gas demand is estimated for the period 2015 to 2035, but these estimates were not used to determine the spur pipeline capacity. Key findings for Central Alaska gas demand are:

- The Fairbanks area currently does not have access to natural gas via pipeline.[16] The introduction of Alaska North Slope gas into Central Alaska would reduce the cost of gas to Fairbanks and surrounding areas, resulting in rapid demand growth. Demand from the residential/commercial sector is expected to reach 24 MMcf/d (yearly average) by 2025. Monthly demand is expected to range from a high of 41 MMcf/d in January 2025 to a low of 11 MMcf/d in July 2025.

[16] LNG is currently trucked to Fairbanks from Wasilla.

Figure 5: Monthly Supply Demand Balance in South Central Alaska



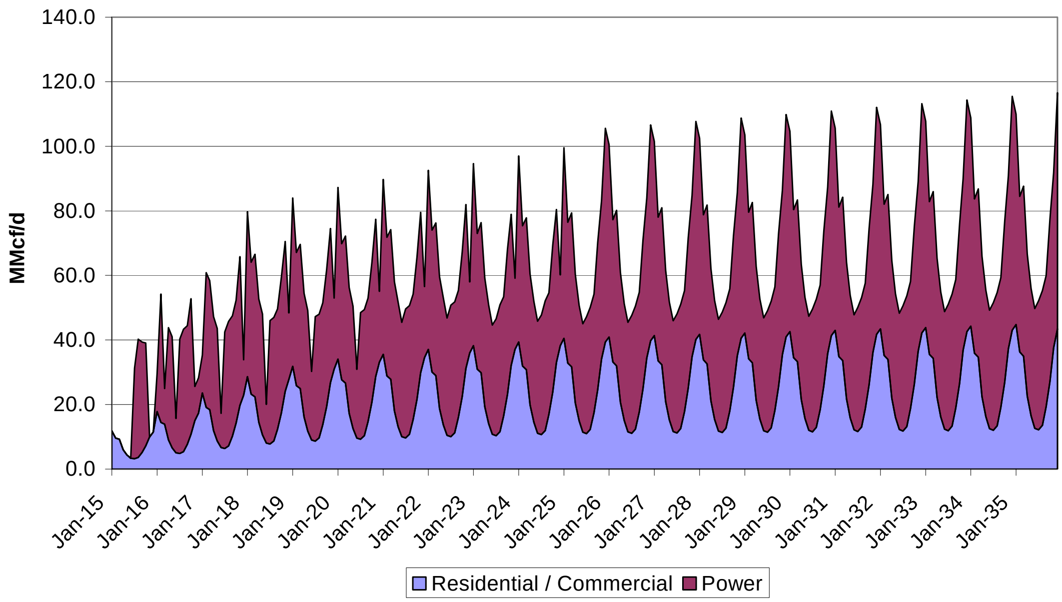
Source: SAIC

- Fairbanks Natural Gas has not achieved significant penetration in the Fairbanks Area. Current residential accounts represent about 2% of the Fairbanks-North Pole urban area housing units and 1% of the Fairbanks North Star Borough total. It is assumed that the introduction of relatively low cost gas (compared to trucked LNG) would result in rapid conversion of homes to natural gas heating.

- There is no gas-fired generation currently in the Fairbanks region; however, power modeling runs suggest that with the introduction of natural gas, more than 250 MW of gas generation would be added, requiring 42 MMcf/d of gas by 2025.

- Figure 6 shows potential natural gas demand in Central Alaska between 2015 and 2035. Overall, natural gas consumption could grow from about 18 MMcf/d in 2015 to almost 70 MMcf/d by 2025. Peak demand could be greater than 115 MMcf/d.

Figure 6: Monthly Gas Consumption in Central Alaska



Source: SAIC

1.9 Alaska Gas Demand Sensitivities

The study performed is a market-based analysis predicated on a set of base case conditions and assumptions. As such, alteration to those base case conditions would generate a modified resultant natural gas demand. A cost-benefit analysis comparing the potential spur pipeline with other sources of natural gas supply - such as new finds in the Cook Inlet, coal gasification, and a possible conversion of the Kenai LNG export terminal into an import terminal - was not conducted as a part of this study.

Some of the conditions that could increase or decrease gas demand over the base case estimates are as follows:

- **High Prices.** High oil and gas prices tend to raise global product prices for LPG, petrochemicals, GTL, and LNG, making these products more attractive. On balance, however, high oil and gas prices reduce potential gas demand in South Central Alaska, impacting the core residential/commercial sector, and making coal a more attractive alternative in the power sector. High oil and gas prices also raise the price of gas feedstock to gas intensive industries, diminishing the benefits of higher product prices. These cases are discussed in Section 3.3.

- **Low Prices.** Low oil and gas prices do not have a significant effect on consumption for the core residential/commercial and power sectors, although consumption is likely to rise slightly. If only gas prices are lower and oil prices remain at base case levels, then all the gas intensive industries, other than LNG, look attractive. If oil prices are also lower, this would adversely impact the viability of GTL. Under the low price scenario there is a potential that ANGP might not be built at all. These cases are discussed in Section 3.3.

- **Increased Cook Inlet Gas Supply.** The study assumes that production from existing Cook Inlet reserves is sustained, but that no new reserves are added. Any new reserves and subsequent increase in Cook Inlet supply would likely satisfy local South Central gas demand first, reducing the requirement for the spur pipeline.

- **Coal Gasification and LNG imports**. The presence of coal gasification and LNG regasification facilities would increase South Central gas supply, lessening the need for the spur pipeline as long as the facility development costs are lower than those for the spur pipeline alternative. Initial findings suggest that if imported LNG prices are based on world LNG prices, the price of spur pipeline gas may be lower. However, this is highly dependent on the commercial arrangements made between a potential LNG import terminal and nearby exporter.

- **GTL on North Slope**. Development of GTL on the North Slope would likely impact the development of GTL in South Central Alaska. However, initial analysis indicates that development of GTL in South Central Alaska would be a lower-cost option, adjusting for the relative tariffs along TAPS and the Spur Pipeline (See Section 5.6.6).

- **Industry Incentives.** The Study was performed without consideration of possible state incentives. Depending on the incentive, a source of consumption that is currently not viable could possibly be made viable. More detailed analysis would be required to determine the viability of such options and overall costs to state and local governments.

- **Technology Advances**. Current technology and costs were used in this study. Technological advances, particularly in processes such as GTL and LNG, could improve the economics of any or all consumption sources investigated and increase potential gas consumption.

- **Petrochemical Complex and LPG processing at Fairbanks.** The primary disadvantage of locating a petrochemical complex near Fairbanks is the assumed higher construction and shipping costs associated with transporting goods from a location farther from tidewater. Based on data from the Alaska Railroad, shipping LPG and styrene pellets from Fairbanks to Anchorage would be roughly equivalent on a Btu basis to shipping natural gas through the spur pipeline. Therefore, a South Central Alaska location was assumed for this study because of the lower capital costs and proximity to export terminal and major trade routes. Development of a complex in Central Alaska would impact the type and size of the spur pipeline.

2.0 Introduction

The objective of the Alaska Natural Gas Needs Assessment is to estimate the potential demand for natural gas in South Central and other areas of Alaska directly associated with a potential spur pipeline connecting the proposed Alaska North Slope gas pipeline to the Cook Inlet pipeline infrastructure. This assessment is intended to provide an independent estimate of in-state natural gas demand and supply options for the years 2015 through 2035. Although other gas transportation projects have been proposed, this study assumes the gas pipeline from the North slope will roughly follow the oil pipeline right-of-way past Fairbanks to Delta Junction before following the Alaska Highway route into Canada.

FERC Order 2005[17] requires applicants desiring to build the Alaska natural gas pipeline project to conduct a study to determine in-state natural gas needs prior to holding an Open Season. The study results are to be shared during the Open Season to ensure sufficient pipeline capacity.

The Study provides support for a separate Alaska Spur Pipeline conceptual engineering/socio-economic impact study, which will incorporate the information generated under this effort in the identification of permitting needs, engineering, project estimating, right of way, public outreach, and social and economic impact of the project on adjacent communities.[18] The collective objective of the engineering/socio-economic impact study and this Study is to provide an objective comparison of the benefits, challenges, costs and issues associated with potential routes for a natural gas spur pipeline between the ANGP and Central and South Central Alaska.

Two routes have been proposed for the spur pipeline. One route follows the Parks Highway and interconnects with Alaska Natural Gas Pipeline (ANGP) at Fairbanks, eventually interconnecting with ENSTAR's natural gas system at Wasilla just north of Anchorage and is approximately 300 miles long. The other route is 290 miles long and would interconnect with ANGP at Delta Junction and with ENSTAR's system near Wasilla. Figure 7 shows these pipeline routes.

2.1 Study Objectives

The objective of this study is to provide a reasonable estimate of future natural gas demand for South Central and Central Alaska for the period of 2015 to 2035. It assumes that gas would be supplied to South Central Alaska through a spur pipeline linked to the ANGP line at Fairbanks or Glenallen. It is anticipated that ANGP will transport at least 4.5 Bcf/d of North Slope natural gas to markets in Alberta and the Lower 48. Because price affects demand, a prerequisite for determining demand is to determine the maximum price that each sector in Central and South Central Alaska can pay while retaining market viability.

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[17] FERC Order No. 2005, "Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects," February 9, 2005.
[18] The conceptual engineering study is being performed by ASRC Constructors, Inc. and will be completed in the Fall of 2006.

Figure 7 Major Proposed Pipeline Routes in Alaska

Source: Modified from Alaska Natural Gas Development Authority (ANGDA)

2.2 Study Scope

The scope of the Study includes the assessment of potential dry gas and NGL demand in the industrial, power generation, and residential/commercial sector of South Central and Central Alaska. The spur pipeline will serve South Central Alaska, while Central Alaska could be served directly from an interconnection with ANGP or a lateral off the spur pipeline, if this is determined to be advantageous in the final design. The Study assumes that the spur pipeline will solely serve South Central Alaska.[19]

Future natural gas demand will be function of many variables, including the supply and price of natural gas. Therefore the Study also considers natural gas supply, related storage, and natural gas prices. The potential for the discovery and development of new gas reserves in the Cook Inlet and regional coal gasification is not included in the Study. However, the Cook Inlet is still a highly prospective natural gas basin as described in a 2004 DOE study.[20] Continued

[19] However, estimates for future residential/commercial and electric power gas demand in Central Alaska power are provided.

[20] Thomas, C.P., T.C. Doughty, D.D. Faulder, D.M. Hite: "South Central Alaska Natural Gas Study," U.S. Department of Energy, National Energy Technology Laboratory, June 2004.

exploration and development of natural gas in the Cook Inlet is important to state and regional economies but exploration success is not assured. An assessment of this potential and the costs of exploration and production compared to spur pipeline costs were not included in the objectives for the Study. Therefore, the potential for Cook Inlet to provide supply other than currently estimated proven reserves is not included in this assessment. Also, the potential for regional coal gasification is not included.

2.3 Primary Drivers of Natural Gas Demand by Sector

Three primary factors affect the economic feasibility and related demand for delivering North Slope gas to South Central Alaska.

1. The price that North Slope producers expect to sell gas for delivery to the South Central market.

2. The market price on world markets of industrial products produced from natural gas, such as LNG, GTL, and petrochemicals.

3. The price of competing fuels in the residential/commercial and power sectors.

In South Central Alaska, the residential/commercial sector attaches a high value to natural gas because the competing fuels (i.e., heating oil, diesel oil, LPG, etc.) are relatively high priced. Depending largely on the distance that competing fuels must be transported, the power sector may also attach a relatively high value to natural gas. When natural gas is priced economically compared to other regional fuel choices, demand growth in the residential/commercial and power sectors is limited by population growth. Conversely, the value of natural gas to the industrial sector usually reflects the price at which it can sell its product in the global marketplace.

2.4 Demand Growth Potential

When natural gas prices are competitive with other fuels, residential/commercial and power sector demand growth is substantially linked to regional population growth. Thus, population growth estimates for South Central Alaska are a critical component of natural gas demand projections for these sectors. In contrast, industrial sector growth in South Central is not likely to be substantially affected by population growth, but by costs and product prices.

Therefore, modest population growth projections for South Central between 2015 and 2035 suggest that the industrial sector has the most potential to provide a large increase in natural gas demand. Within the industrial sector, the potential for growth depends on the world market price for each industry's products, and the price of natural gas in South Central Alaska.

2.5 Potential Industries

Natural gas intensive industries that were considered for South Central Alaska include industries that use dry natural gas (composed primarily of methane), and those that use the heavier hydrocarbon components of wet natural gas. These heavier hydrocarbons include the NGLs: ethane, propane, butane, and pentane.

Industries with large demand for dry gas or methane that are assessed in this report include:

- Fertilizer Industry – uses methane as a feedstock to produce ammonia and urea, most of which is exported.

- Liquefied Natural Gas Industry – liquefies dry natural gas to reduce storage space for later local use and/or for transport to distant markets.

- Gas to Liquids (GTL) Industry – uses methane as a feedstock to produce low sulfur, higher energy liquid fuels such as gasoline, diesel fuel, and jet fuel.

Industries with large demand for NGLs that are assessed in this report include:

- Petrochemical Industry – produces polyethylene and ethylene glycol most efficiently from ethane feedstock, but may use other NGLs as feedstock depending on relative prices.

- Liquefied Petroleum Gas (LPG) Industry – liquefies propane and butane to reduce storage space for later local use and/or for transport to distant markets.

If the spur line is a dry gas line, none of the industries with NGL demand will be developed. However, if NGL components can be sold in South Central at a high price compared to methane and dry gas on a thermal basis, it may be economically favorable for the South Central spur line to contain wet gas. Including enough NGLs to support a major petrochemical industry in South Central may require spiking the NGL content in the spur line to a higher level than the rich gas being transported in ANGP, which will reduce the NGL content going to Canada for existing petrochemical-based industries. (This same issue will exist for petrochemical industries in Fairbanks.) This option could result in difficult negotiations with Canadian interests, price competition for the NGLs, and impacts to ANGP economics. Without the premium that may be charged on propane and butane, substantial industrial use of natural gas in South Central Alaska from 2015 to 2035 is unlikely without substantial government incentives.

Regardless of whether the spur line contains wet or dry gas, it will need to be sized according to the step-wise demand increases from industrial plants, which must be world-class size facilities running at or near full capacity to be economically efficient. Of the industries listed above, the only industry that does not require large step changes in demand is the LPG industry, where propane and butane demand can change in relatively small increments based on storage capacity and the frequency and volume of shipments.

2.6 Capacity of the Spur Pipeline

At a minimum, the spur pipeline should have sufficient capacity to meet the projected dry gas demand for residential/commercial and power sectors assuming the price of gas delivered to South Central is favorable compared to other competing fuels. In 2015, industrial dry gas demand will be minimal because the existing large industrial uses (i.e., the Agrium fertilizer plant and LNG liquefaction facility) will have shut down due to a lack of gas supply based on estimated remaining proven Cook Inlet reserves. New NGL intensive industries, such as petrochemicals and LPG, and GTL, could provide new sources of economically viable industrial demand; therefore, two spur line scenarios are considered in this report.

1. Dry Gas Spur Line. The size of this line would be a function of the minimum average natural gas price that can be charged by the producers; the competitiveness of natural gas prices to other regional fuels in the residential/commercial and power sectors; and the maximum natural gas price each industry could pay while still being able to produce products competitive in the world market.

2. Wet Gas (Dense Phase) Spur Line. The impetus for a wet gas spur line is to deliver NGLs to market at more competitive costs (or higher profit) as a result of the lower tariff costs associated with NGL transport to South Central compared to Alberta and the Lower 48. The size of this line would be determined from the proportion of methane and specific NGLs within the spur line; the demand estimated above for dry gas; the step increases associated with industrial natural gas use of methane (i.e., fertilizer plant, GTL plant, LNG liquefaction facility) and ethane (i.e., petrochemical plant); and reasonable maximum amounts of propane and butane that can be transported by the spur line.

2.7 Minimum Average Natural Gas Price from the Producer's Perspective

Because ANGP will be delivering natural gas to the Lower 48, North Slope producers' interest in the South Central spur line will depend on their ability to sell gas into South Central markets at net prices that are at least equivalent to net prices in the Lower 48 on an average thermal basis. The EIA *AEO 2005* gas price forecast is used as the baseline gas price forecast for the Study. The EIA forecast is generally consistent with the price trajectory used by the Alaska Department of Revenue.

EIA's long-term price of natural gas in the Lower 48 and Alberta is between $5.00 and $6.00/MMBtu ($2005) from 2015 to 2035.[21] The tariff along ANGP is estimated to be $2.30/MMBtu for a 4.5 Bcf/d pipeline between the North Slope and Chicago (See Appendix C for details). As shown in Table 2, this implies that North Slope producers will expect to receive between $2.70/MMBtu and $3.70/MMBtu for their gas over this time period. The estimate for a tariff along the spur pipeline, plus the tariff along ANGP from North Slope to Fairbanks, varies from about $1.30/MMBtu for a 20-inch, 350 MMcf/d pipeline (estimated size needed to meet the most-likely demand for a dry-gas line) to about $1.50/MMBtu for a 30-inch, 1.3 Bcf/d pipeline (maximum estimated capacity needed to meet the highest demand for a wet gas line). This yields a delivered price to South Central Alaska between 2015 and 2025 of $4.00 to $5.00/MMBtu for a 350 MMcf/d line and $4.20 to $5.20/MMBtu for a 1.3 Bcf/d line. An increase in the flow rate in ANGP to 5.8 Bcf/d to maintain the flow rate at 4.5 Bcf/d for delivery to Canadian and Lower 48 markets would reduce the tariff for delivery to South Central Alaska to $1.40/MMBtu (see Appendix C).

[21] EIA Annual Energy Outlook 2005. All prices have been converted to 2005$. http://www.eia.doe.gov/oiaf/archive/aeo05/index.html

Table 2: Minimum Average Natural Gas Price ($2005)

Gas Price in Chicago, 2015 - 2035 ($/MMBtu)	North Slope Gas Price* ($/MMBtu)	South Central Alaska Gas Price with tariffs ($/MMBtu)	
		350 MMcf/d Spur Line	1.3 Bcf/d Spur Line
$5.00 - $6.00	$2.70 - $3.70	$4.00 - $5.00	$4.20 - $5.20
* Based on projected price of ANGP gas in Chicago minus tariffs.			

The tariff calculation methodology described in Appendix C was also used to investigate what the impact would be on the price of gas delivered to South Central Alaska if capital costs were to increase significantly for ANGP as a result of increased steel prices and escalating construction costs. It was assumed that the capital costs would increase by 25% for ANGP. It was also assumed that the same cost increases would impact the spur pipeline resulting in 25% increase its capital costs. This increase in capital costs results in an increase in the ANGP tariff of $0.59/MMBtu for the 4.5 Bcf/d rate, resulting in a lower ANS wellhead price. The tariff for delivery from ANS to Fairbanks and the spur pipeline tariff also increases by $0.53/MMBtu for the 4.5 Bcf/d rate and the 20-in., 350 MMcf/d spur pipeline rate. Hence, the assumed increase in capital costs would result in a small decrease of less than $0.06/MMBtu in the cost for gas delivered to South Central Alaska. Therefore, the impact from a cost over run on pipeline construction costs is a lower ANS producer wellhead price but no significant improvement for gas delivered to South Central Alaska. Also, the state of Alaska would receive a lower value for the state's royalty gas and lower production taxes.

2.8 Study Methodology

The Study estimated natural gas demand during the 2015 to 2035 time frame based on the breakeven price at which gas consumption would be expected to occur. The breakeven price, also referred to as the netback price of natural gas, is the price at which the use category achieves a breakeven net present value (NPV).

For the residential/commercial sectors, the netback price for new demand accounts for the cost of serving new customers with new gas distribution lines, and the price of the next best alternative fuel (usually heating oil) plus the cost associated with converting from the alternative to natural gas. Thus the netback price allows for increased penetration of natural gas in the residential/commercial markets. An econometric approach (see Section 4.2.1) was used to assess growth from existing natural gas customers for the South Central and Central Alaskan utilities, ENSTAR (serving Anchorage and surrounding areas) and Fairbanks Natural Gas (serving the Fairbanks area).

For the power sector, the Study used a power dispatch model (MarketPower) to project plant dispatch, new capacity builds, and conversions over the forecast period.[22] The model determined the fuel price (netback) at which gas displaces most alternative fuels.

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[22] MarketPower is a product of NewEnergy Associates.

For the natural gas intensive industries, an investment model allows the user to set the projected world price of the industrial product, and then determine the netback price of natural gas or natural gas equivalent (i.e., feedstock price at which the facility achieves a breakeven NPV).

Assumptions common to all industries include:

- 20-year project operating life

- 12% discount rate for NPV determinations

- Turnkey projects with equity financing, paid in full at start of operations

Variants of the general investment model were developed for each industry (LNG, LPG, petrochemicals, GTL, and ammonia-urea) using appropriate capital costs, operations and maintenance costs, product yield, and product world-market sale prices. These variables were estimated for the project time frame from industry sources when available, and otherwise were developed from secondary sources. When necessary, data were adjusted to reflect the project's technical (e.g., size), performance (e.g., yield), and economic (e.g., cost) parameters, as described in the project-specific sections of Chapter 3. Whenever possible, industry experts were asked to review and comment on the validity of assumptions.

A number of smaller-scale industries were investigated and modeled. None of the leading smaller scale industries required natural gas as a feedstock and all four industries could survive on electricity alone. The four industries considered include:

- Internet Server Farm
- Pebble Mine
- Insulated Wallboard
- Rolled Steel/Pipe Forming

Other industrial opportunities were investigated but not modeled, due to lack of reliable data:

- Seafood Processing
- Value-Added Wood Products
- Donlin Creek Mine
- Copper Smelter
- Autoclave Aerated Concrete

2.9 Report Structure

The following chapters address the major natural gas (or NGL) consuming sectors, natural gas supply, and integration of supply and demand along with sensitivities to price. The integrated market analysis is discussed in Chapter 3. Projected gas demand for the residential/commercial, industrial, and power sectors is discussed in Chapters 4, 5, and 6, respectively. Chapter 7 discusses the supply outlook for the Cook Inlet, including production costs and the build up of supply curves that are used in the integrated modeling. The Appendices describe many of the assumptions used in the analysis that are not covered in the individual chapters.

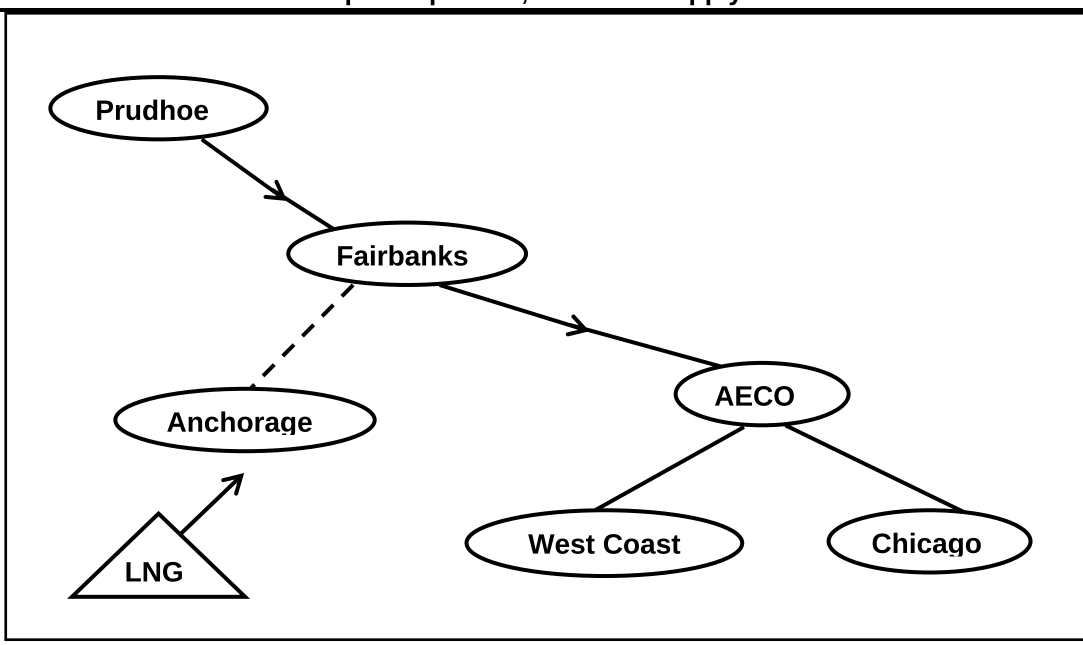
3.0 Integrated Market Modeling

This chapter provides overall estimates of South Central gas demand for a base case and five side cases, integrating the supply, demand (residential, commercial, electric power, and industry), and price forecasts provided in Chapters 4, 5, 6, and 7. It also provides an initial estimated capacity for the spur pipeline and estimated requirements for natural gas storage in the South Central Alaska region.

The integrated analysis was performed using a regional natural gas market model that simulates the flow and value of natural gas to producers, pipelines, and consumers under varying scenarios of consumption, production, and prices. The model was integrated with EIA's National Energy Modeling System (NEMS) and Natural Resources Canada's Model for Analyzing Policies Linked to Energy – Canada (Maple-C), which provides estimates for Lower 48 and Canadian gas demand and prices, to ensure that gas flows to the Lower 48 and Canada are consistently modeled. The modeling methodology is further discussed in Appendix F.

The model solves for the optimal flow of gas along a transportation network and is composed of nodes and arcs. The nodes represent areas of supply or demand, while the arcs represent transportation links between the nodes. As well as the optimal flow, the model also calculates the optimal amount of storage and pipeline capacity required to meet seasonal variation in demand. Figure 8 shows a simplified version of the gas transportation model developed for this study.

Figure 8: Potential Alaska and Export Pipelines, with Gas Supply and Demand Nodes



Source: SAIC

Inputs to the model include the dry gas demand curves for Alaska developed in this study, gas supply curves and costs developed for Cook Inlet and Alaska North Slope production in previous Alaska studies, and EIA and Natural Resources Canada (NRCAN) forecasts of gas demand and prices in the Lower 48 and Canadian markets. The premise of the model is that natural gas will flow to the highest value markets. The model can easily be run under varying input assumptions to determine different outcomes.

3.1 Base Case Model Results - Dry Gas pipeline

A basic premise of the Study is that North Slope producers will want to maximize profits and sell to the highest value market, whether in Alaska, Canada, or the Lower 48. EIA's *AEO 2005* forecasts the long-term price of natural gas in the Lower 48 at $5.00 to $6.00/MMBtu (2005$), from 2015 to 2025. The estimated ANGP tariff along ANGP is $2.30/MMBtu (2005$) between the North Slope and Chicago (See Appendix C). This implies that North Slope producers should expect to receive between $2.70 and $3.70/MMBtu (2005$) for their gas at the wellhead. The draft estimate[23] of a tariff along the spur pipeline, plus the tariff along ANGP from the North Slope to Fairbanks, is $1.30/MMBtu for a 20-inch, 350 MMcf/d pipeline. This would provide a delivered price of gas to South Central Alaska of $4.00 to $5.00/MMBtu (2005$) between 2015 and 2025. This supply price, coupled with supply and prices for Cook Inlet gas production, will determine the expected level of demand for gas from the spur pipeline

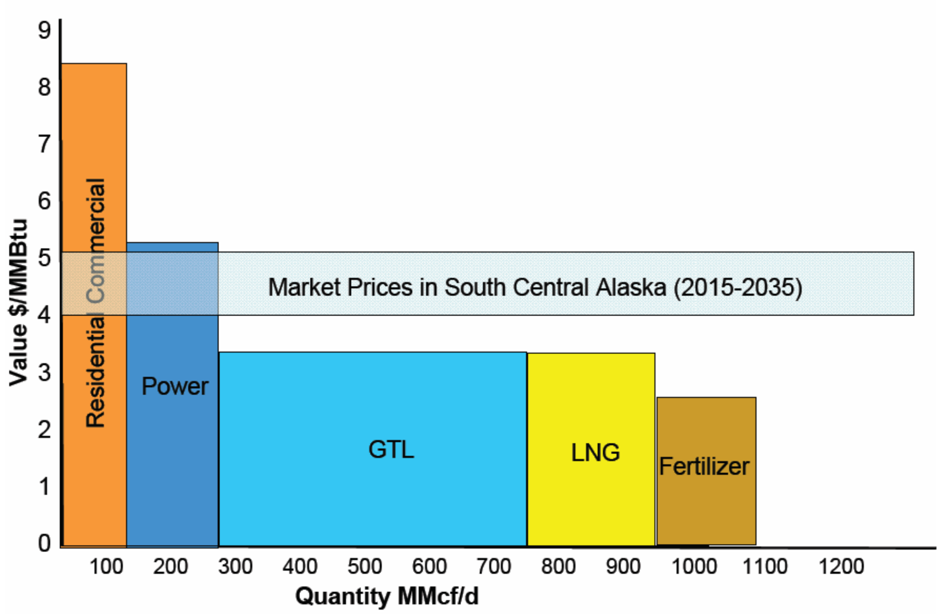
Figure 9 shows the South Central Alaska dry gas demand curve for the year 2025. Volumes of dry gas demand by each major sector are plotted on the x axis against the maximum price of dry gas each sector would be willing to pay on the y axis. If gas prices are higher than the maximum price shown for a particular sector, then gas consumption from that sector would likely be severely curtailed or not develop. With a maximum price of $3.20/MMBtu, LNG and GTL fall just below the point of economic feasibility. While GTL faces the most uncertainty in terms of price, costs, and technology, it could be considered a high demand case for the spur pipeline.

Given the range of delivered prices in South Central Alaska and the maximum price each customer would be willing to pay, only the residential/commercial and power sectors would be captured by North Slope supply, with the rest of the North Slope gas production being sold into the Lower 48 market.

Figure 10 provides a summary forecast of dry gas consumption and Cook Inlet supply from estimated remaining reserves for South Central Alaska between 2015 and 2035. This analysis suggests that the region will experience a gas shortfall of 110 MMcf/d by 2015, 250 MMcf/d by 2025, and about 300 MMcf/d by 2035. The jump in gas demand from the power sector in 2010 is due to additional load of 300 MW from the Pebble Mine, assuming it becomes operational around this time.

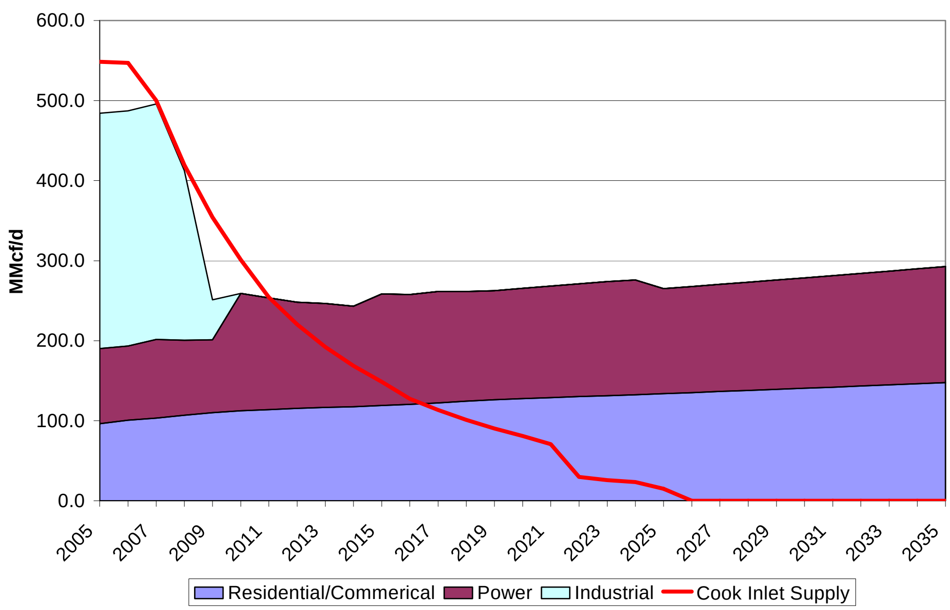
[23] This tariff estimate is termed a draft estimate because it is anticipated that tariffs calculated in the conceptual engineering study being performed by ASRC Constructors, Inc. will be based on more definitive design criteria and routing.

Figure 9: Dry Gas Demand Curve for 2025 and Gas Supply Price Band



Source: SAIC

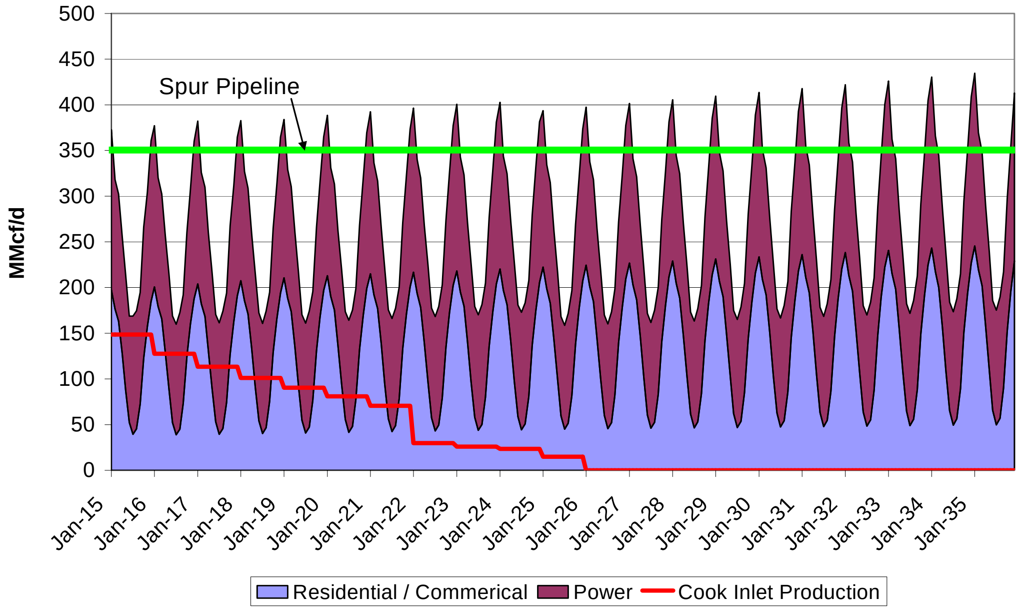
Figure 10: Forecast of Annual Dry Gas Consumption for the Residential/Commercial and Power Sectors



Source: SAIC

Figure 11 shows the seasonality in South Central gas consumption. Peak gas consumption is almost 400 MMcf/d by 2025 and 430 MMcf/d by 2035. The figure clearly shows the widening gap between available supply from proven reserves, which by 2025 has dwindled to only 15 MMcf/d, and demand, which has grown to a yearly average of 265 MMcf/d by 2025. This gap could be filled by a spur line capable of delivering up to 350 MMcf/d, with access to 80 MMcf/d of storage, which would provide the optimal configuration for meeting South Central gas demand in 2035.

Figure 11: Monthly Supply Demand Balance in South Central Alaska (350 MMcf/d)



Source: SAIC

If the potential demand for dry gas for continued LNG at 212 MMcf/d and GTL at 480 MMcf/d are combined with the 350 MMcf/d for residential/commercial and power demand the total is 1,042 MMcf/d or about a 1.0 Bcf/d dry gas spur pipeline.

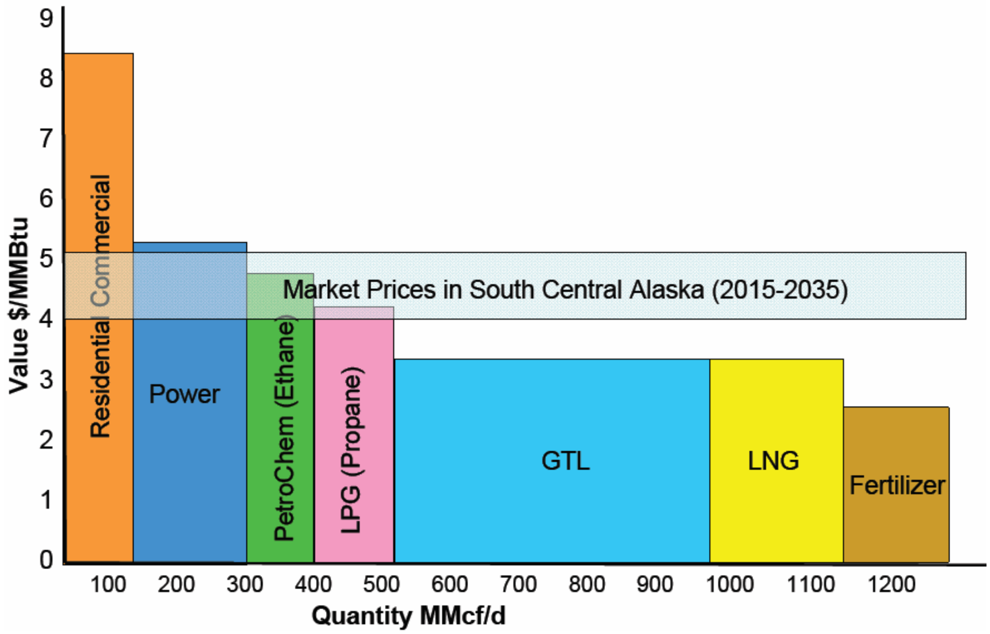
3.2 Base Case Model Results - Wet Gas pipeline

Figure 12 shows the South Central Alaska dry gas demand and NGL curve developed for the year 2025. In this instance, petrochemical and propane industry demand could develop under the price and cost assumptions detailed in Chapter 5.

This results in seasonal gas demand shown in Figure 13, with monthly consumption peaking in 2035 at 627 MMcf/d. A total of 350 MMcf/d of dry gas coupled with 80 MMcf/d of storage and NGLs of 234 MMcf/d based on Btu equivalents, suggest a pipeline capable of carrying dry gas and liquids of 590 MMcf/d capacity.

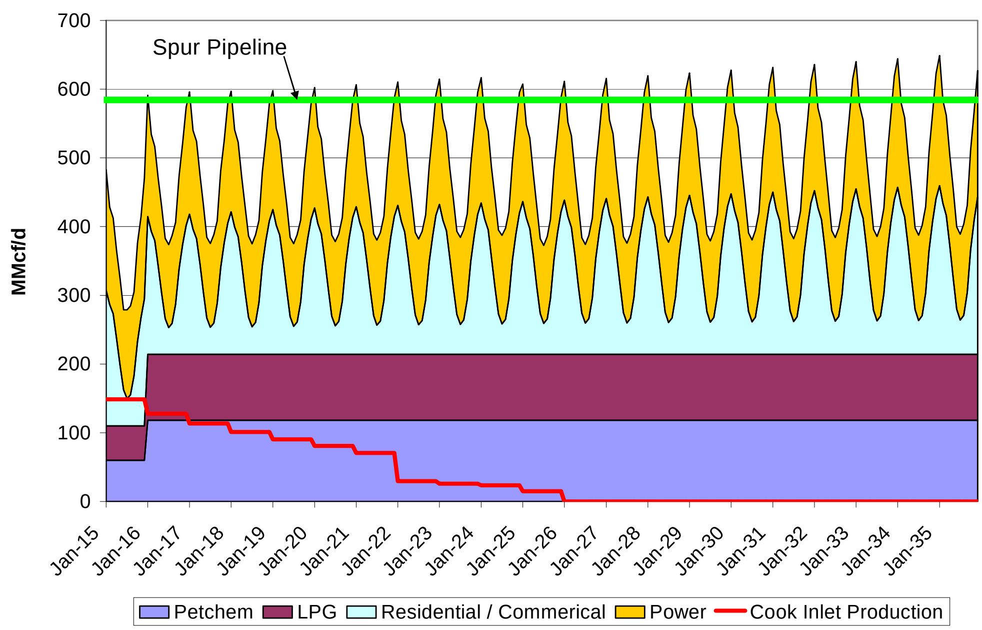
If the NGLs of 234 MMcf/d in this case are coupled with the upside dry gas case of 1.0 Bcf/d a wet gas pipeline capable of carrying about 1.3 Bcf/d would be required.

Figure 12: Dry Gas and NGL Demand Curve for 2025 and Gas Supply Price Band



Source: SAIC

Figure 13: Monthly Supply Demand Balance in South Central Alaska (590 MMcf/d)



Source: SAIC

3.3 Side Cases

Five side case scenarios were constructed to provide sensitivities around the base case. The side cases include (all 2005$):

- High Gas Price Case: Base Gas Case plus $2.00/MMBtu = South Central Gas Supply Price of $6.00 to $7.00/MMBtu.

- Low Gas Price Case: Base Gas Case minus $2.00/MMBtu = South Central Gas Supply Price of $2.00 to $3.00/MMBtu.

- High Gas and Oil Price Case: Base Gas Case plus $2.00/MMBtu = South Central Gas Supply Price of $6.00 to $7.00/MMBtu. Base Oil Price Forecast plus $11.60/bbl.

- High Oil Price Case: Base Case Gas Case and Base Oil Price Forecast plus $11.60/bbl.

- Without South Central Spur Pipeline, and LNG imports through Kenai

3.3.1 High Gas Price Case

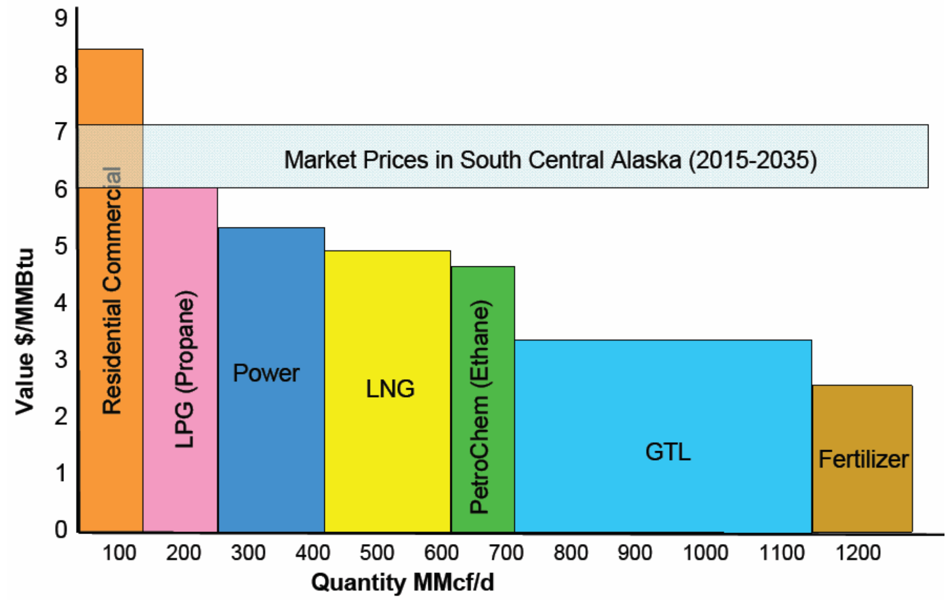
Under the high gas price case, the price of natural gas in the Lower 48 is assumed to rise to between $7.00 and $8.00/MMBtu (Base Case + $2.00/MMBtu). The resulting impact on the demand curve is that the netback price of LNG rises to $4.50/MMBtu due to a $2.00/MMBtu price rise in Southern California prices and LNG has a higher value than GTL. The value of LPG also rises to just under $6.00/MMBtu. However, the price that North Slope producers expect to sell their gas for also rises by $2.00/MMBtu and the delivered price in South Central Alaska rises to between $6.00 to $7.00/MMBtu. Figure 14 shows that only residential/commercial demand survives under the high price case, with the power sector moving to coal fired generation. This scenario estimates approximately 134 MMcf/d of gas demand in 2025 and 148 MMcf/d in 2035. Under these circumstances the market could likely be served by a small 170 MMcf/d pipeline.

3.3.2 Low Gas Price Case

Under the low gas price case, the price of natural gas in the Lower 48 is between $3.00 and $4.00/MMBtu (Base Case minus $2.00/MMBtu). The resulting impact on the demand curve is that the netback price of LNG falls to $1.00/MMBtu due to a $2.00/MMBtu price decrease in Southern California prices and the netback price of LPG falls to $3.74/MMBtu. The price that North Slope producers expect to sell their gas also falls by $2.00/MMBtu and the delivered price in South Central Alaska declines to between $2.00 and $3.00/MMBtu.

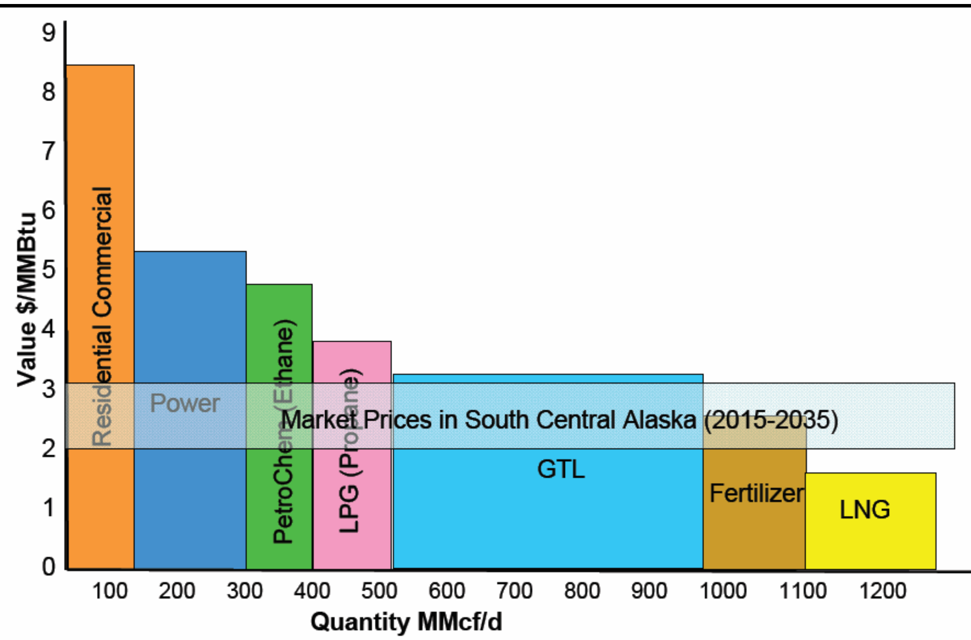
Figure 15 shows that under low gas prices, residential/commercial, power, GTL, fertilizer, LPG, and petrochemicals survive, providing approximately 1.1 Bcf/d of dry gas and NGL demand in 2025. Under these circumstances the market could likely be served by at least a 1.1 Bcf/d wet gas pipeline.

Figure 14: Demand Curve – High Gas Price Case



Source: SAIC

Figure 15: Demand Curve – Low Gas Price Case



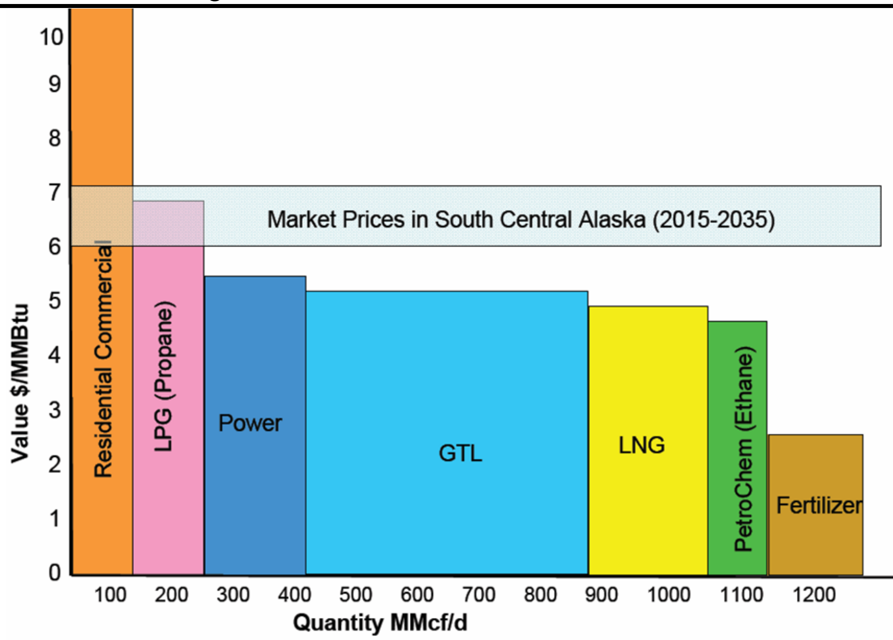
Source: SAIC

3.3.3 High Gas and High Oil Price Case

Under the high gas and high oil price case, $2.00/MMBtu was added to the base price of gas and $11.70/bbl was added to the base price of oil. The $11.70/bbl represents a similar order of magnitude rise in the oil price as the gas price; i.e., a $2.00/MMBtu equivalent rise. The netback prices for LNG, GTL, and propane – products closely tied to oil and gas prices – all rise, as shown in Figure 16. Compared to the base case, the netback price of propane rises from $4.20/MMBtu to almost $7.00/MMBtu, GTL rises from $3.20/MMBtu to almost $5.00/MMBtu, and LNG rises from $3.20/MMBtu to almost $5.00/MMBtu. The netback price of natural gas use in the residential/commercial sector also rises due to the higher price of the substitute fuel oil.

The market price in South Central Alaska also rises by approximately $2.00/MMBtu, leaving only residential/commercial demand and propane to make the economic cut and providing approximately 230 MMcf/d average daily demand.

Figure 16: Demand Curve – High Gas and Oil Price Case



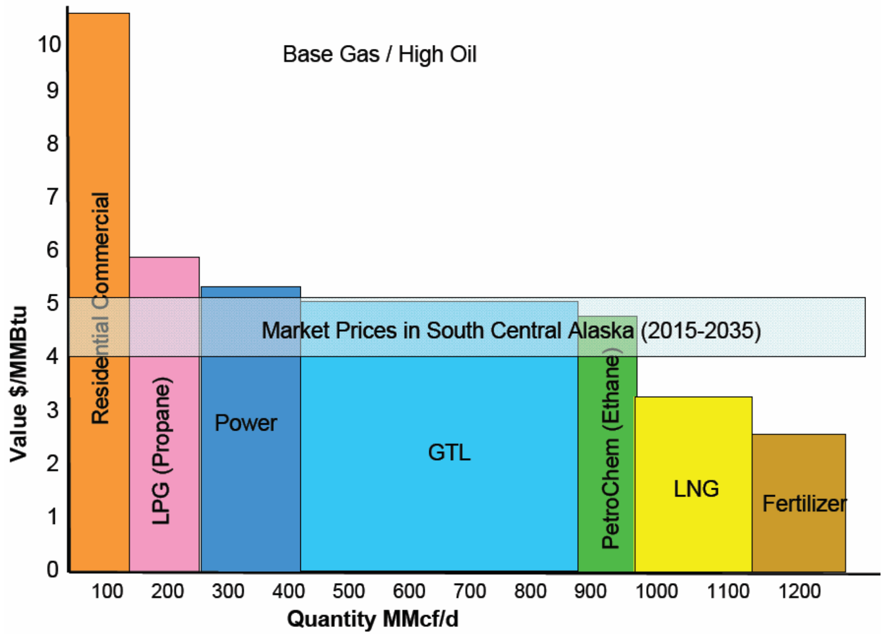
Source: SAIC

3.3.4 High Oil Price Case

Under the high oil price case, gas prices remain unchanged from the base case, while $2.00/MMBtu was added to the oil price, equivalent to $11.70/bbl. In this case, the netback price for propane (often a close substitute for fuel oil) rises to $5.75/MMBtu. The price of GTL is directly related to oil prices and the netback price rises to just under $5.00/MMBtu, well within the economic range. The value of gas to the residential/commercial sector also rises.

The market price of natural gas in South Central Alaska is the same as the base case; however, as shown in Figure 17, more industries become economic at these price levels, providing almost 980 MMcf/d of average daily demand.

Figure 17: Demand Curve - High Oil Price Case



Source: SAIC

3.3.5 Without South Central Spur Pipeline / LNG Imports through Kenai

A final side case was run in which a spur pipeline is not built. In this case, it is assumed that natural gas is obtained by converting the Kenai terminal into an LNG import terminal capable of importing approximately 280 MMcf/d, which is relatively small by today's regasification standards.[24] It is assumed that LNG would be supplied from a Pacific Basin supplier at a similar price to the price paid in Southern California, approximately $5.00 to $5.50/MMBtu. Under these circumstances, only dry gas consumption from the residential/commercial and power sectors survives (see Figure 9).

[24] Most LNG regasification terminals in the US are currently being sized at around 1.0 Bcf/d capacity and higher.

4.0 Residential and Commercial Sector Gas Demand

4.1 Introduction to Residential and Commercial Demand

This section projects natural gas demand for the residential/commercial sector in portions of Alaska. The Study reviewed projected demand for the Anchorage, or South Central Area, and the Fairbanks, or Central Area. Natural gas is used primarily for space heating in Alaska's residential/commercial sector and heating oil is the primary competing fuel.

4.1.1 Current South Central Alaska Demand

The gas utility servicing South Central Alaska, ENSTAR, has approximately 108,000 residential and 13,000 commercial accounts. Based on census data for total housing units in the service area, this represents a 78% penetration of natural gas in the South Central Alaskan residential market.[25]

4.1.2 Current Central Alaska Demand

Approximately half of the residential units in Central Alaska are in the Fairbanks-North Pole metropolitan area, while the remaining residences are in the greater rural area of the Fairbanks North Star Borough. Fairbanks Natural Gas began natural gas service to this area in 1998 through truck transport of LNG from Wasilla to Fairbanks, a distance of approximately 300 miles. Lack of ready access to natural gas and the expense of trucking LNG have contributed to the relatively slow conversion of Central Alaska residential properties to natural gas. In 2005, only 2% of the 11,481 housing units in Fairbanks were using natural gas. In contrast, natural gas penetration in the commercial sector is nearly 50% of the estimated 1,277 commercial units.[26] Higher fuel use in the commercial sector reduces the time needed to recover conversion costs, and has helped increase this sector's conversion rate.

4.1.3 Drivers of Natural Gas Demand

Natural gas demand from the residential/commercial sector is driven by the long-term price of gas relative to alternative fuels (i.e., heating oil), population size and growth, and heating degree days. Deciding to convert to natural gas from another fuel already in use requires an evaluation of fuel prices and equipment conversion costs.

4.1.4 Scenarios

The Study modeled residential/commercial sector gas demand using a five-year amortization period and three price scenarios for the primary competing fuel (heating oil). The base case assumed heating oil prices based on forecasts in the EIA *AEO 2005 (High-B case)*. The two alternative heating oil price scenarios were a high price case, designated as a \$2.00/MMBtu premium to base heating oil prices, and a low price case, designated as a \$2.00/MMBtu discount to base heating oil prices.

[25] Correspondence with Andrew White, ENSTAR, 10/7/05

[26] Fairbanks Natural Gas estimate for 2001. The residential natural gas estimate is less than census data would indicate. The 2002 census data indicate 17,511 residential units in the Fairbanks-College-North Pole areas.

4.2 Methodology

4.2.1 Econometric Analysis

Natural gas demand for current ENSTAR customers in South Central Alaska is based on econometric analysis, while gas demand for new customers is based on the statistical approaches described below. In the case of South Central Alaska, future demand from current (2004) customers is determined by econometric analysis and added to this is estimated demand from new account growth.

In developing the econometric analysis to determine "base" residential load, demand for residential/commercial natural gas (RES_CONS) was assumed to be a function of the price of natural gas relative to the price of its closest competitor, distillate fuel oil (RELPRICE), weather as proxied by heating degree days (HDD), and the size of the market as proxied by the number of households. The demand equation was constructed to estimate elasticities of demand. Mathematically, the equation was written as:

$$LN\_RES\_CONS = \beta_0 + \beta_1 LN\_RELPRICE + \beta_2 LN\_HDD + \beta_3 LN\_HH + \varepsilon$$

LN_RES_CONS	=	Logarithm of residential consumption
LN_RELPRICE	=	Logarithm of the relative price of natural gas to fuel oil.
LN_HDD	=	Logarithm of Heating Degree Days
LN_HH	=	Logarithm of the number of households
β_0	=	Constant
β_1	=	elasticity of demand with respect to the relative price of natural gas to fuel oil.
β_2	=	elasticity of gas consumption with respect to heating degree days
β_3	=	elasticity of gas consumption with respect to number of households
ε	=	the random error term.

The equation was estimated with a correction for first order serial correlation using monthly data from January 1989 through December 2004.

The overall performance of the estimated equation was good. Over 93% of the variation in the monthly residential consumption of natural gas was explained by the variation in relative price, weather, and market size. Importantly, all estimated coefficients had the expected signs and all were statistically significant at standard levels. More specifically, the results indicate that:

- A 10% increase (decrease) in the relative price of natural gas, all other factors constant, will cause a 5.4% decrease (increase) in residential gas consumption;

- A 10% increase (decrease) in the number of heating degree days per month, all other factors constant, will cause a 6.7% increase (decrease) in residential gas consumption; and

- A 10% increase (decrease) in the number of household, all other factors constant, will cause a 10.8% increase (decrease) in residential gas consumption.

Appendix E contains a detailed reporting of all results and regression diagnostics.

In the following section we describe the approach taken for calculating growth in new customers based in South Central Alaska and Fairbanks.

4.2.2 Netback Analysis

A netback analysis was used to determine price points at which potential customers would choose either to install new appliances or convert existing appliances to natural gas. The netback is calculated as the cost of the next best alternative fuel (usually heating oil) adjusted for the cost of converting to gas and the marginal cost of distribution lines per customer. The netback price is expressed in $/MMBtu and represents the price at which new conversions will occur. The lower the actual price of gas is below the netback price, the faster conversions are likely to occur.

South Central Alaska

New natural gas customers in the South Central Area will result from a combination of:

1) Increased penetration in existing ENSTAR service areas; and

2) Expansion of ENSTAR service into new areas in South Central Alaska.

ENSTAR has already developed projections for both of these factors and they form the basis for the projections in this study. Given the high rate of natural gas penetration in South Central Alaska and ENSTAR's history in tracking current accounts and forecasting future accounts, the ENSTAR projections are judged to be more reliable for future planning than a new demand forecast methodology.

ENSTAR has divided their service area into ten geographical service areas, eight of which have established service as of 2005. One new area is planned for 2006 (Homer) and one for 2014 (Anchor Point). ENSTAR has a forecast for each new or existing service area through 2015. Beyond 2015, projections are extrapolated with the same formulae used in the ENSTAR service area forecasts through 2015.

Using this methodology for new residential/commercial accounts in the South Central Area, this study then adds the projected volumes for new accounts to the base gas demand for existing accounts. The base gas demand is determined from the econometric approach described above.

Fairbanks Area

Unlike the South Central Area, the Fairbanks Area has little historical information on customer accounts, growth, and natural gas volumes. The methodology used, therefore, relies on census data and population growth projections in the Fairbanks Borough to estimate the number of housing units that could potentially receive gas. It is assumed that pipeline gas becomes available in the year 2015.

Because 50% of the housing units in the Fairbanks Area lie outside the Fairbanks-North Pole urban area, the study methodology uses a gradual ramp up in residential uptake over the first ten years after pipeline gas is available – rising to a 70% overall penetration by the tenth year.

Higher distribution line costs per account result from the longer distances in the rural settings and will moderate the overall penetration rate.

Using the above methodology for residential/commercial accounts in Central Alaska, overall demand is projected after pipeline gas becomes available (assumed 2015). Further details on the methodology and results are in the following sections.

4.3 Assumptions

4.3.1 Population Growth

It is assumed that the historical 2% population growth rate for South Central Alaska continues over the forecast period. In South Central Alaska, the annual population growth rate has maintained at the 2% level since 2001 according to census data and ENSTAR statistics.

According to U.S. Census data, Fairbanks North Star Borough grew 3.7% between April 2000 and July 2004, which is an annual growth rate of 0.9%. A 1% growth rate is used for future projections of household units for Central Alaska through the forecast period.

A concern raised in one of the Advisory Committee meetings was the possibility of a significant number of workers relocating to Alaska for the construction of ANGP. This trend was observed during the construction of TAPS in the 1970s and acutely strained all services in the area. To address the possible additional demand from workers who migrate to the area, the Municipal Impact Analysis conducted by Information Insights Inc. in November 2004 is used. The Impact Analysis determined that 9,400 to 10,400 out-of-state workers can be expected to remain as permanent residents after the construction is completed. For this analysis it is assumed that all these workers (10,400) will remain in Central Alaska, although the Impact Analysis does not specify where in Alaska they might remain. A large number of temporary resident workers are also expected, but only those that settle permanently should affect long term residential demand.

4.3.2 Natural Gas Penetration Rates

Natural gas penetration in the South Central residential/commercial sector is currently very high, and there is limited ability to increase this market share. In South Central Alaska, ENSTAR will slowly increase their overall penetration to 82% of existing households by 2015 and continue to provide service to new customers at a similar penetration rate. By 2015, some 136,000 housing units will be serviced by natural gas as well as 14,700 commercial accounts.

Average annual residential demand per household is assumed to be 175 MCF based on ENSTAR data. New small and large commercial accounts are assumed to have average annual natural gas demands of 389 MCF and 5,529 MCF, respectively, based on ENSTAR data

In Central Alaska, by 2015, residential demand is conservatively estimated to be 15% of residences in Fairbanks North Star Borough (5,718 units). This is a combination of existing residences served by natural gas and conversions that could occur between 2005 and 2015. With the introduction of North Slope gas and favorable netback pricing, it is then assumed that the Central Alaskan residential sector will see 70% overall penetration by natural gas within 10 years and 80% within 20 years. Average annual residential demand per household is assumed to be 190 MCF based on existing data from Fairbanks Natural Gas.

In the Central Alaskan commercial sector, the rate of natural gas market penetration from 2005 to 2015 is expected to be greater than in the residential sector due to the higher volumes used by those accounts, allowing faster amortization of conversion costs. Commercial accounts are conservatively set at 60% in the first year of pipeline gas availability, reaching 90% by the fifth year. It is assumed that small and large commercial accounts have average annual natural gas demands of 389 MCF and 4,435 MCF, respectively, based on ENSTAR data. The large commercial account volume is slightly different than in South Central Alaska because ENSTAR estimates a higher percentage of their future commercial growth in South Central Alaska will come from the so-called commercial transport accounts. These are higher volume accounts that can negotiate directly with the gas producers in the Cook Inlet and are often bundled accounts with multiple commercial users.

4.3.3 Conversion Costs

Estimated costs to convert existing residential oil boilers to gas are $1,400 when the burner can be changed out and $3,000 when the entire unit needs to be replaced. Although certain oil heater burners can be converted to gas without replacing the entire unit, this study used a full replacement cost in the netback analysis. The conversion costs were provided by ENSTAR and were double checked against other sources such as the Fairbanks NG web site.

4.3.4 Distribution System Costs

For new accounts in both South Central and Central Alaska, an average of 500 feet of distribution line would be required. This represents the length required for an average new rural account; in contrast, new urban accounts typically require only 200 feet of new distribution line.

For South Central Alaska, main distribution line construction costs are about $9.79/foot (less highway crossings), as stated in ENSTAR's Tariff Advice Letter 128-4 dated March 26, 2004. However, a recent correspondence with ENSTAR indicated that construction costs are currently $8.80/foot. This lower cost was used in the netback analyses. Current operating and maintenance (O&M) charges for the South Central Alaskan distribution system are estimated at $1.64/MCF. This figure is derived from average residential/commercial (small and large) margin data and is judged to be a conservative (slightly high) estimate of the actual O&M cost.

For Central Alaska, the Fairbanks Natural Gas distribution system is small and located only in Fairbanks. Current distribution line cost data for this area, therefore, likely won't accurately reflect costs in 2015 and beyond when an extensive system is required for both urban and rural areas. ENSTAR's distribution line construction cost data were used for the netback analysis in Central Alaska. For Central Alaskan distribution line O&M costs, correspondence with Fairbanks NG indicates that ENSTAR's current O&M charges are too low for use in years when the Central Alaskan system will be rapidly expanding in response to pipeline gas availability. Amortization costs during this early period will be higher due to increased capital spending spread over a relatively small customer base. The colder operating conditions in the Fairbanks area will also create some additional costs. The Study used a conservative O&M value of $3.00/MCF in the netback analysis for Central Alaska (compared to $1.64/Mcf in South Central Alaska) to ensure the growth projections are not overly optimistic.

4.3.5 Alternative Fuel Prices

To analyze fuel alternatives to natural gas, the price of the alternatives was converted into equivalent heating units. For example, heating oil prices in Alaska were projected at the same rate as the crude oil forecast in the *EIA AEO 2005* (High B Case). This projects out to an average heating oil price over the 2015 to 2025 period of $18.50/MMBtu (2005$), which is equivalent to $2.55/gallon (2005$) and close to the current (October 2005) Alaska market survey heating oil price of $2.52/gallon.

4.4 Residential/Commercial Sector Assessment Results

4.4.1 Netback Results

Based on the assumptions discussed above, the netback price (the price at which new conversion to natural gas from alternatives such as heating oil will occur) of natural gas in both South Central and Central Alaska is substantially higher than projected South Central natural gas supply prices. This suggests a fairly healthy increase in gas penetration rate, particularly in Central Alaska.

As summarized in Table 3, in South Central Alaska, netback prices of natural gas for low, base, and high heating oil price scenarios are $6.74/MMBtu, $8.74/MMBtu, and $10.74/MMBtu, respectively. In Central Alaska, the netback prices of natural gas for low, base, and high heating oil price scenarios are $6.08/MMBtu, $8.08/MMBtu, and $10.08/MMBtu, respectively. The expected supply price is between $3.84 and $4.84/MMBtu in South Central Alaska and potentially cheaper in Central Alaska, assuming it will not pay a spur pipeline tariff between Fairbanks and Anchorage of $1.30/MMBtu.

Table 3: Demand, Cost Assumptions, and Netback for Residential/commercial Sectors (2005$).

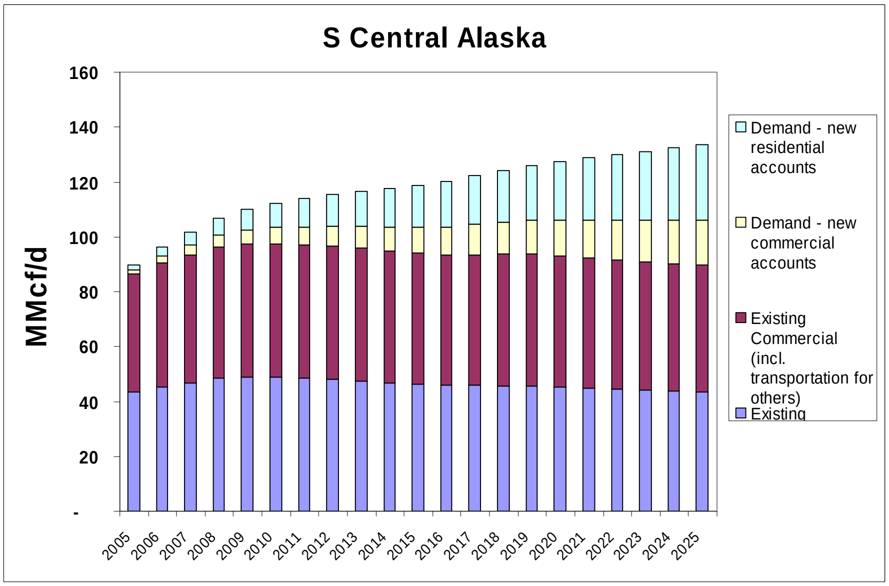
	SCENARIOS					
	Low Heating Oil Price		Base Heating Oil Price		High Heating Oil Price	
	South Central	Central	South Central	Central	South Central	Central
Demand (in 2025)	**MMcf/d**	**MMcf/d**	**MMcf/d**	**MMcf/d**	**MMcf/d**	**MMcf/d**
Natural Gas	134	32	134	32	134	32
Cost/ Price Assumptions						
Heating Oil Price ($/MMBtu)	16.50	16.50	18.50	18.50	20.50	20.50
Replacement Cost/ Unit ($)	3,000	3,000	3,000	3,000	3,000	3,000
Distribution Line Costs (500 ft) ($)	4,400	4,400	4,400	4,400	4,400	4,400
System O&M Cost ($/Mcf)	1.64	3.00	1.64	3.00	1.64	3.00
Netback	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**
Price below which conversions to natural gas occur	6.74	6.08	8.74	8.08	10.74	10.08

Source: SAIC

4.4.2 Demand Projections

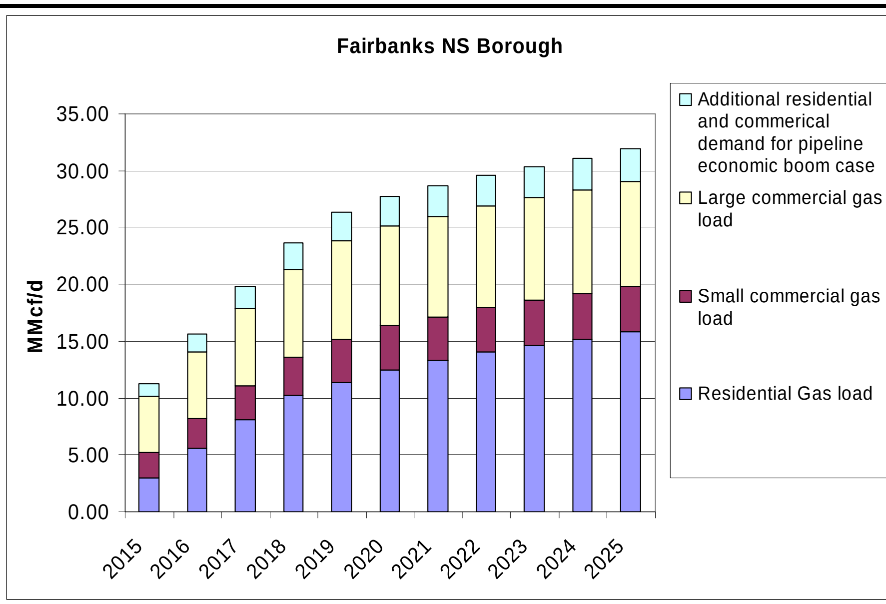
Demand from the South Central Alaskan residential/commercial sector is expected to reach 134 MMcf/d (yearly average) by 2025. Monthly demand in South Central Alaska is expected to range from a high of 222 MMcf/d in January to a low of 45 MMcf/d in July 2025. Demand from the Central Alaskan residential/commercial sector is expected to reach 32 MMcf/d (yearly average) by 2025. Monthly demand is expected to range from a high of 40 MMcf/d in January to a low of 11 MMcf/d in July 2025. Annual growth in demand in the residential/commercial sector from 2015 to 2025 is summarized in Figure 18 and Figure 19 for South Central and Central Alaska, respectively.

Figure 18: Residential and Commercial Demand Growth in South Central Alaska



Source: SAIC

Figure 19: Residential and Commercial Demand Growth in Central Alaska



Source: SAIC

It is projected that the residential/commercial sector demand in Central and South Central Alaska will not be substantially affected by the three fuel oil price scenarios considered in this analysis (i.e., base EIA forecasts, and plus and minus $2.00/MMBtu for high and low price scenarios, respectively). This is because natural gas competes very favorably with fuel oil, even under the low fuel oil price scenario. It should be noted that there has been a very low rate of residential market penetration in Central Alaska under the current high natural gas prices in this region (i.e., currently about $7.00/MMBtu more than in South Central). This current price difference puts the average residence just out of the range of an economical conversion. The \$4.00/MMBtu difference in price between the low and high price scenarios of this study is substantially less than \$7.00/MMBtu, and economical residential conversions will occur in all cases.

5.0 Potential Gas Demand in the Industrial Sector

5.1 Introduction

Major gas intensive industries include export oriented industries such as LNG, GTL, petrochemicals, LPG, and ammonia and urea. They provide potential "anchor" customers that could underwrite a spur pipeline. Non gas intensive industries would not provide sufficient gas demand to underwrite a pipeline, but would provide some additional load once the major customers are established.

This chapter provides estimates of potential demand for dry gas and NGLs (i.e., ethane, propane, and butane) for use in the industrial sector. It is assumed that significant industrial gas demand will only occur in South Central Alaska due to access to nearby ports. LNG, ammonia, and urea manufacturing is already present in South Central Alaska; however, both of these industries may be forced to close before the proposed in-service date for the spur pipeline unless successful exploration and production in the Cook Inlet is able to reverse the current decline in natural gas reserves.

Gas-intensive industries considered include:

- Liquefied Natural Gas (LNG)
- Fertilizer production, specifically ammonia and urea production
- Gas-to-Liquids (GTL) processing, specifically, ultra low-sulfur diesel fuel production
- petrochemical manufacture, specifically polyethylene and ethylene glycol production
- Liquefied Petroleum Gas (LPG) for export

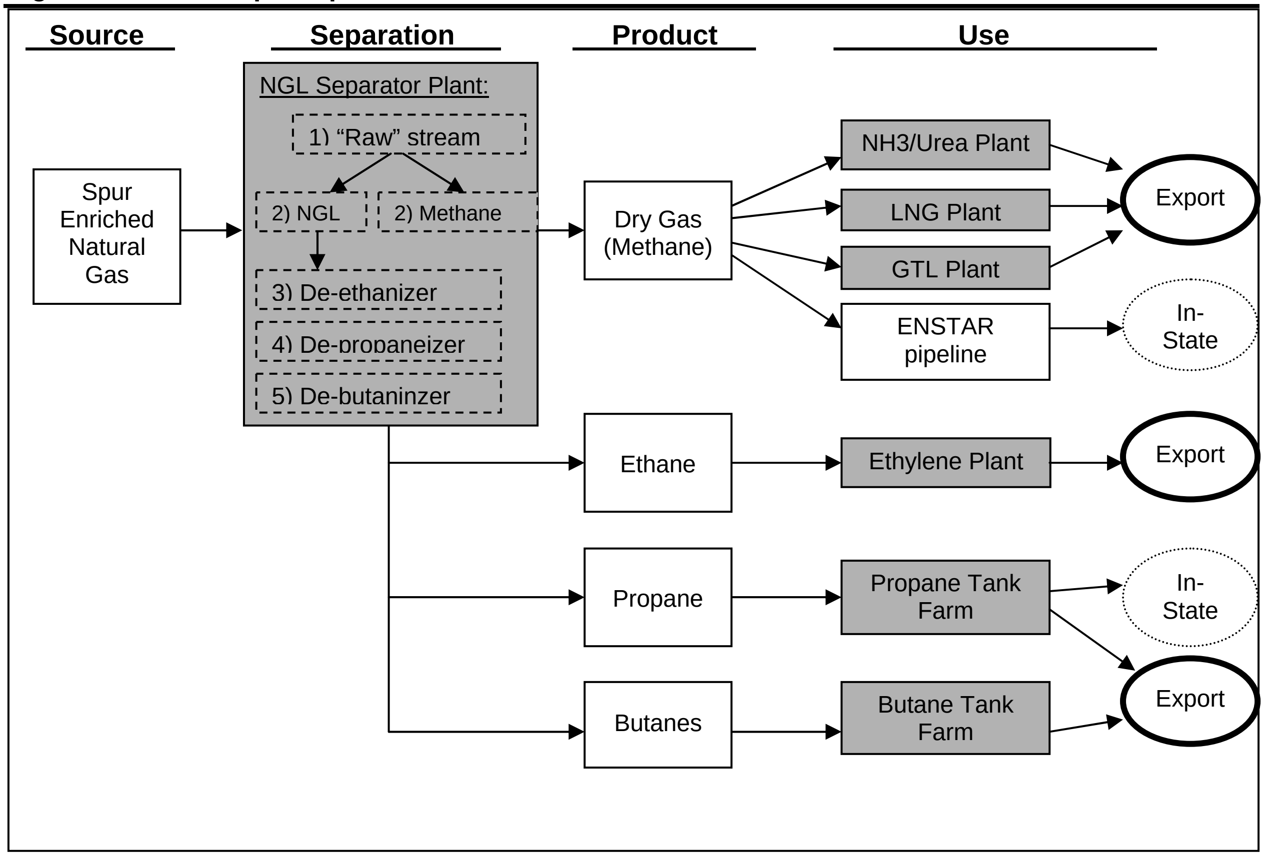
A number of non-gas-intensive industries were also considered, including:

- Gold-Copper-Molybdenum Mine
- Oil Refinery
- Internet Server Facility
- Insulated Wallboard Manufacturing
- Rolled Steel/Pipe Forming

Major factors affecting the location and economic viability of gas consuming industries include the price of gas used as a fuel or a feedstock and the market value of their products on world markets. For many industries, product prices cycle from periods of low prices to periods of high prices over the course of several years. Timing new capacity to come on line during a period of high product prices is essential for investment success and could impact the schedule of the pipeline.

The two options for a spur pipeline are a dry gas line and a dense phase wet gas line. A dry gas line can support only methane intensive industries (i.e., LNG, ammonia-urea, and GTL), while a wet gas pipeline can serve methane intensive industries in addition to NGL intensive industries. The gas components of a wet gas line are summarized in Figure 20 along with the potential gas-intensive industry that may use these gas components.

Figure 20: Alaska Spur Pipeline Potential Products and Uses



5.2 Methodology

Since the spur pipeline will not be operational until 2015, all cost and market analysis were performed for the period 2015 to 2035 using 2005 dollars (2005$). An investment model was developed for the assessment and comparison of potential gas-intensive industries. Model outputs are net present value and netback price.

Assumptions that are the same for all industries modeled include:

- *Project Life* – 20 years. This is a common industrial project life.
- *Discount Rate* – 12% rate. This varies among industries and projects. It may be relatively low for some industries (e.g., GTL, due to risks).

- *Federal and state taxes* – were assumed at the rates of 35% and 4.5% of taxable income, respectively. These rates may vary depending on public policy for industrial development.

- *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 and 1.4 for Central Alaska.

- *Cost of Capital (during construction)* – 6%.

- *Financing* – all projects were assumed to be equity financed as turn-key projects.

Model inputs that are industry specific include capital and operating costs, shipping costs, and the market price of industry products. These industry-specific assumptions are discussed in the subsections below for LNG, ammonia-urea, GTL, petrochemical, and LPG industries.

5.3 Summary Conclusions

Based on the assumptions of this analysis, summary conclusions for dry gas and NGL consuming industries are:

- *Gas-to-Liquids Plant* – A 50,000 barrel per day GTL plant would require approximately 480 MMcf/d of natural gas in feedstock and fuel. For the plant to be economically attractive with base case assumptions, the maximum price this industry could pay for dry gas is approximately $3.20/MMBtu.

- *Liquefied Natural Gas* – Continued operation of the 1.7 million tonnes per annum (MMTPA) LNG terminal at Kenai is the most likely scenario for maintaining Alaska's LNG exports. The LNG terminal would consume approximately 212 MMcf/d of natural gas. For the terminal to be economically attractive, the maximum price this industry could pay for dry gas is approximately $3.20/MMBtu.

- *Fertilizer Plant* – If the Agrium facility were mothballed and then refurbished for operations beginning in 2015, this industry would consume 145 MMcf/d of natural gas and 4 megawatts (MW) of electric power. For the plant to be economically attractive, the maximum price this industry could pay for dry gas is approximately $2.79/MMBtu.

- *Petrochemical Plant* – A world class petrochemical complex in South Central Alaska that manufactures polyethylene (PE) and monoethylene glycol (MEG) would consume 75,000 bbl/d of ethane feedstock, 3 MMcf/d of methane, and would require 50 MW of electric power. For the plant to be economically attractive, the maximum price this industry could pay for ethane, expressed as a thermal equivalent to dry gas, is approximately $4.60MMBtu.

- *Liquid Petroleum Gas* – If an LPG export industry were established with a supply of 70,000 bbl/d LPG, to be economically attractive, the maximum price this industry could pay for propane and butane, expressed as a thermal equivalent to dry gas, is around \$4.20/MMMBtu.

Based on this analysis, the industries that would require a wet gas spur pipeline to supply NGLs have the greatest potential for relatively low risk development with good chances of a favorable return on investment. The relative investment appeal of various industry opportunities can be used to determine the industries for which the spur line gas composition should be tailored.

5.4 Liquefied Natural Gas (LNG)

5.4.1 LNG Background

The LNG industry liquefies natural gas by chilling it to minus 160 degrees centigrade, which effectively reduces its volume 600 times. The LNG is then stored and shipped to other countries on specialized LNG tankers. The LNG is offloaded from the tanker and stored and converted back to natural gas at a regasification terminal, before being sent to final customers.

Alaska currently has one operating LNG liquefaction plant located in Nikiski on the Kenai Peninsula. The liquefaction plant was placed into service in 1969, with an initial capacity of 173 MMcf/d (1.2 MMTPA). The facility has been expanded twice to a present capacity of 220 MMcf/d (1.7 MMTPA). This is a relatively small plant by contemporary standards, with many new world class plants having capacities of 730 MMcf/d to 3.0 Bcf/d (5 to 20 MMTPA). LNG terminal operators generally expect to run the terminal at high capacity rates, year round.

LNG at Kenai is stored in three single containment storage tanks prior to loading on ships for export.[27] Each tank has a capacity of 36,000 cubic meters, relatively small compared to today's LNG storage tanks that typically have capacities of at least 165,000 cubic meters.

ConocoPhillips has a 70% ownership in the project and is the plant operator, while Marathon has the remaining 30% interest and is responsible for operation of the two LNG carriers that transport the LNG to Japan. The port at Kenai can only accept LNG ships up to a capacity of 88,000 cubic meters.[28]

The original sales contract with Japanese LNG buyers expired in 1989. The subsequent contract expired in 2004, but was extended through the first quarter of 2009. Further extension of the contract requires securing adequate volumes of gas at relatively low prices beyond 2009 and a new export license.

5.4.2 LNG Project and Scenarios

The Study analyzed LNG export potential from South Central Alaska for three scenarios:

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[27] The single containment tank comprises a steel outer tank and an aluminum inner tank. Approximately three feet of insulation is provided between the inner and outer tanks.

[28] Gas Technology Institute, World LNG Source Book 2001.

1. *Continued operation of the ConocoPhillips LNG Plant* – In this scenario, exports from the current 1.7 MMTPA LNG plant at Kenai are maintained, which will require substantial refurbishment because many components are reaching the end of their useful lives.

2. *Expansion of the ConocoPhillips Plant* – This includes refurbishment of the current 1.7 MMTPA facility at Kenai and capacity expansion to 3.0 MMTPA.

3. *Greenfield Plant at Kenai* – A new plant with capacity of 7.5 MMTPA would be constructed at or near the site of the current ConocoPhillips LNG plant. This new plant would use the latest technology and attain higher efficiencies.

5.4.3 LNG Market and Prices

The global LNG market in 2015 will look very different than it does today, with markets for Alaska LNG opening up on the west coast of the United States, Canada, and Mexico, and with new LNG sources from other Pacific Basin and Middle East countries being developed.

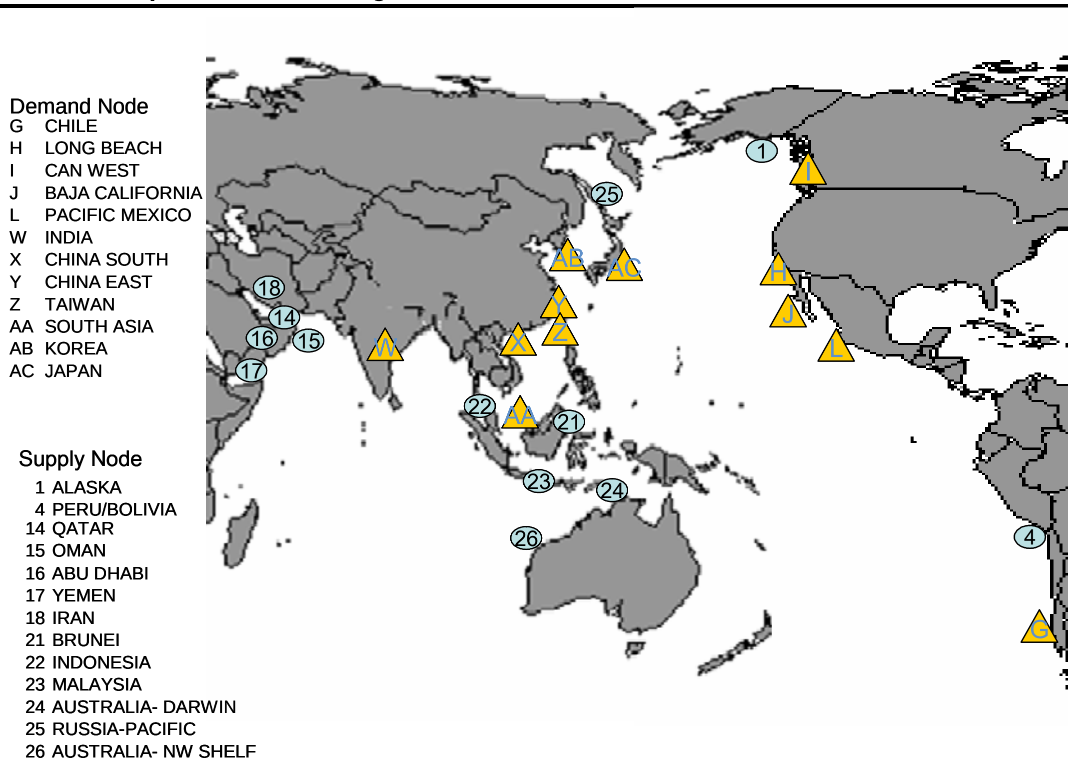
Markets for Alaskan LNG

Figure 21 shows likely liquefaction and regasification terminals in 2015 based on published announcements. Pacific basin markets are currently served by 99 MMTPA of liquefaction terminals, predominantly located in Asia and the Middle East. Regasification capacity in the Pacific Basin is currently 256 MMTPA, which is over twice the liquefaction capacity. About three-fourths of the regasification capacity is accounted for by 24 terminals in Japan.

Given Alaska's geographic location and its relationship to competing Pacific Basin and Middle East liquefaction projects, the most likely markets for future Alaska LNG exports would be British Columbia (Kitimat), Southern California (Long Beach or Cabrillo Point), or Baja Mexico (Costa Azul). If one regasification terminal is built at each of these locations, it would provide approximately 21 MMTPA (2.8 Bcf/d) of capacity for receiving product from world suppliers including Alaska.

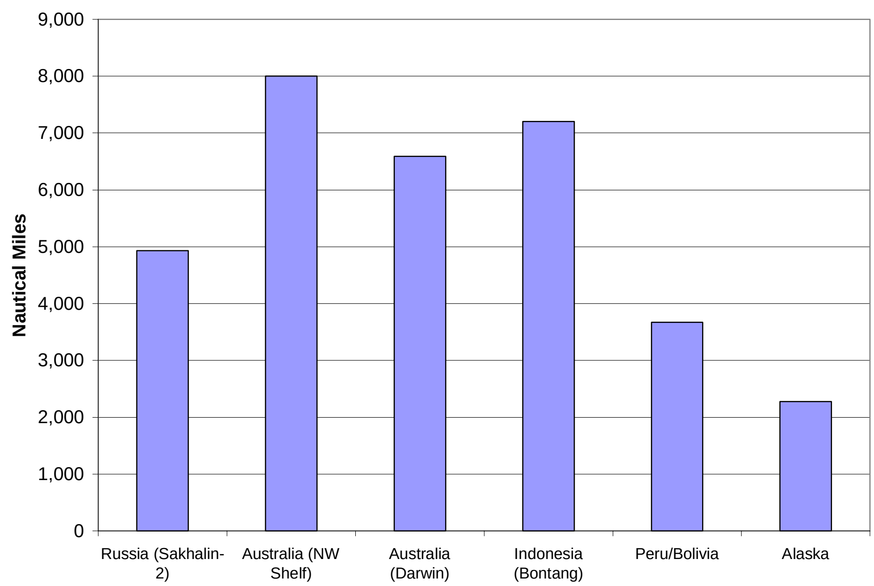
Although Alaska has a distance advantage for sales to the west coast (Figure 22), Alaska will likely have a higher cost of natural gas feedstock and possibly higher liquefaction costs than Middle Eastern suppliers. New, larger liquefaction facilities in the Pacific Basin will have lower costs and will provide competition for LNG sales to California. Additionally, Alaska exporters would face higher shipping costs when shipping to U.S. west coast markets due to the restrictions of the Jones Act that require U.S. built ships to be used for interstate shipping.

Figure 21: LNG Liquefaction and Regasification Terminals in the Pacific Basin



Source: SAIC & GTI

Figure 22: Distances to Southern California from Competing Liquefaction Projects



Source: SAIC

LNG Sale Prices

During 2005, LNG prices averaged $6.00 to $7.00/MMBtu, reflecting relatively tight supply conditions and high gas prices in North America and Europe. Because LNG imported into North America competes with local natural gas production, SAIC expects that the North American gas price will set the price of imported LNG. Based on EIA's *AEO 2005* gas price forecast, the price of natural gas at the Henry Hub will average $5.41/MMBtu (2005$) between 2015 and 2025. Based on historical spreads between the Henry Hub and western trading points, this suggests prices of $5.72/MMBtu in Southern California, $5.68/MMBtu in Baja Mexico, and $5.27/MMBtu in British Columbia.

5.4.4 LNG Assumptions

One basic assumption common to all three LNG plant scenarios is that LNG facilities will be run at 95% capacity. Also, shipping and regasification costs are kept the same for all three scenarios. Capital and operating costs varied among the LNG project scenarios, and are described for each scenario, below.

1. *Continued Operation of the ConocoPhillips LNG Plant*

   Although capital costs are fully depreciated for the Kenai terminal, many components are reaching the end of their useful lives and need replacing. Stone & Webster concluded that the remaining useful life of the Kenai LNG Plant is of the order of six years without significant investments to modernize key elements of the plant. Assuming this is the case, and that other parts of the plant need upgrading, it is assumed that a capital cost investment of $370 million ($218/tonne of capacity) is required to keep the terminal operating. Operating costs are estimated at approximately $21 million per year. It is assumed that the LNG port and loading facilities are not upgraded, which continues to limit the size of LNG carriers to 88,000 cubic meters. Assuming a carrier lease cost of $70,000 per day (underway) and $40,000 per day in port, and an 11-day round trip to Southern California/Baja Mexico, the total cost is approximately $1 million per round trip voyage, or $0.50/MMBtu.

2. *Expansion of the ConocoPhillips Plant to 3.0 MMTPA*

   The cost of expanding an LNG terminal is usually much less than building a new facility because of the sharing of utilities, land, and port facilities, etc. For example, the cost of Trinidad Trains 2 and 3 has been estimated at $165/tonne, North West Shelf Train 4 at $209/tonne, and Ras Laffan Trains 3 at $125/tonne. Consequently, it is assumed that the Kenai facility could be expanded at $280/tonne (accounting for a geographic cost adjustment for the Anchorage Area of 1.4 times the equivalent U.S. Gulf Coast), or $420 million. Along with the capital cost to keep the existing plant functioning, this results in a total capital outlay of $789 million.

   It is assumed that operating costs for the expanded facility would be $68 million per year. This yields an average liquefaction cost of $1.25/MMBtu, which is within the realm of international standards.

3. *New Greenfield Plant with Capacity of 7.5 MMTPA*

   It is assumed that if a new Greenfield plant is constructed, it would use the existing LNG port facilities. This would allow substantial cost savings by enabling a new plant to be constructed at a capital cost rate similar to the plant expansion capital cost rate discussed in the scenario above, i.e., $280/tonne. Thus, a new Greenfield plant of 7.5 MMTPA would require a total capital outlay of about $2.1 billion. Operating costs are estimated as 8% of capital costs, or $161 million per year. This results in overall liquefaction costs of $0.86/MMBtu.

The cost and price information for the three scenarios is summarized in Table 4 in terms of 2005$.

Table 4: Price and Cost Assumptions for LNG Scenarios (2005$). Shaded column is the most favorable scenario.

Cost Item	SCENARIOS		
	Continued Operation of Current Plant	Expansion of Current Plant	New Greenfield Plant
LNG Price (S. California cif)	$4.90/MMBtu	$4.90/MMBtu	$4.90/MMBtu
Capital Costs	$370 Million	$789 Million	$2,100 Million
Operating Costs	$21 Million/Yr	$68 Million/Yr	$161 Million/Yr
Shipping Cost	$36 Million/Yr	$63 Million/Yr	$157 Million/Yr

Source: SAIC

5.4.5 LNG Industry Assessment Results

Based on the size and operating assumptions of the LNG project scenarios, dry gas demand is estimated to be 212 MMcf/d for continued operation of the current 1.7 MMTPA LNG plant; 375 MMcf/d for an expansion to 3.0 MMTPA; and 986 MMcf/d for a new 7.5 MMTPA plant.

At an average LNG market price in Southern California/Baja Mexico of $4.90/MMBtu (2005$), the investment model calculated the netback price (maximum price the plant can afford to pay) at approximately $3.20/MMBtu for the case involving continued operation of the current 1.7 MMTPA LNG plant. Table 5 summarizes the demand and netback price of dry gas for the LNG scenarios.

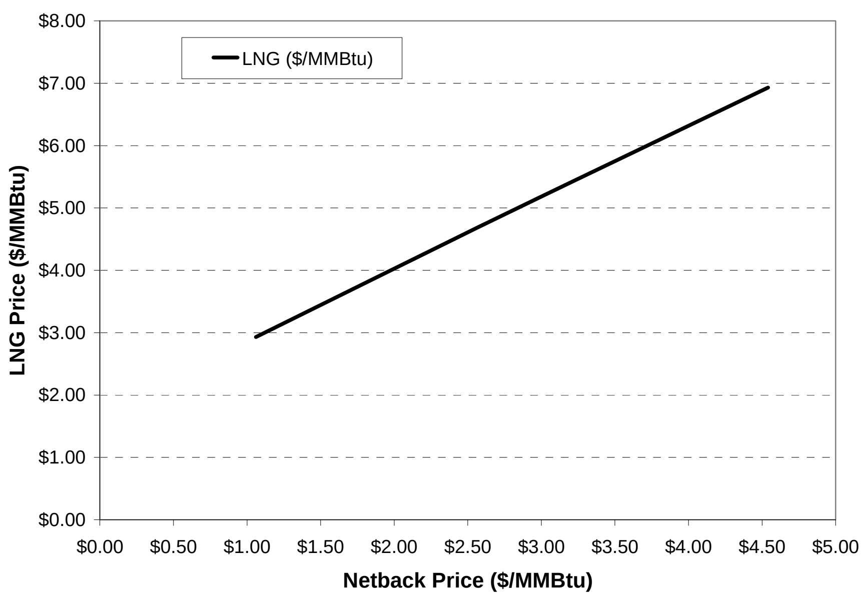
Table 5: Demand and Netback for LNG Scenarios (2005$). Shaded column is the most favorable scenario.

	SCENARIOS		
	Continued Operation of Current Plant	Expansion of Current Plant	New Greenfield Plant
Demand Estimate	**MMcf/d**	**MMcf/d**	**MMcf/d**
Natural Gas	212	375	986
Netback	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**
Before Taxes	$3.46	$3.11	$3.10
Taxes	$0.23	$0.28	$0.30
After Taxes	$3.23	$2.83	$2.80

Source: SAIC

Figure 23 provides a diagram of the sensitivity of gas prices at the LNG plant gate to LNG prices in Southern California. This exemplifies the sensitivity of netback price to the projected market price of LNG.

Figure 23: Comparison of LNG Market Price to Netback Gas Price at Kenai



Source: SAIC

5.5 Ammonia/Urea Manufacturing

5.5.1 Ammonia/Urea Background

Ammonia and urea typically are co-produced at an integrated facility because the feedstocks for the latter are the products of the former. Anhydrous ammonia (NH_3) is a gas that is liquefied and handled under pressure. It is manufactured from the nitrogen (N_2) in the air, methane (CH_4), high temperature steam, and a reaction catalyst. The by-product is carbon dioxide, the majority of which is consumed in the urea manufacturing process. Urea, a dry granular product with no special handling requirements, is manufactured by reacting anhydrous ammonia and carbon dioxide. Ammonia and urea manufacturers adjust production of ammonia versus urea; i.e., the volumes of ammonia it sells to market versus that which it uses as input to urea, based on the relative market prices of the two products.

Agrium U.S., Inc. operates a world class ammonia and urea production facility in South Central Alaska, at Kenai. At full capacity, the plant produces 1.25 million gross tonnes of anhydrous ammonia and 1 million tonnes of urea annually, which it sells to world markets and domestic customers. The original Kenai plant was completed in 1968. Over the years, it has been expanded and major equipment replaced as necessary to maintain continued operations without additional major capital outlay. Dwindling Cook Inlet natural gas supplies have forced Agrium to operate at half capacity while it seeks alternatives to its anticipated closure in 2006 from lack of feedstock.

Agrium is considering several options for the Kenai facility. If it is forced to close, Agrium could dismantle, remove, and remediate the plant site, in which case it may not be worth the investment to rebuild the plant if new gas supply becomes available later. Agrium reports that it may mothball the facility rather than permanently closing it. A third option is developing coal gasification for feedstock. Under the proposed coal gasification scenario, it is assumed that the existing plant will close as anticipated in October 2006, then reopen in five years when the gasification plant is complete. Preliminary plans are to barge Beluga coal from across the Cook Inlet to provide feedstock for gasification and fuel to generate 350 MW of electric power, up to 250 MW of which would be sold back to the Railbelt electricity grid. The coal gasification feasibility study is ongoing, and the option appears promising.[29] The draft timeline for coal gasification to become a reality includes a decision point by mid-year 2006, and if pursued, completion as early as 2011.[30]

5.5.2 Ammonia and Urea Project Scenarios

The Study analyzed urea and ammonia manufacturing in South Central Alaska for three scenarios:

1. *Current Operation of the Agrium Facility* – This scenario estimates gas demand based on current Agrium facility operations at full capacity. This scenario does not provide a likely case for the 2015 to 2035 forecast period because the facility would need major refurbishment for operations throughout this period.

2. *Renovation of the Agrium Facility* – Renovation of the Agrium facility after having been mothballed due to insufficient feedstock and subsequently refurbished for turnkey

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[29] In addition to the internal Agrium feasibility study, NETL has commissioned a Beluga Coal Gasification Study to analyze coal gasification options in Alaska.

[30] Tom Kizzia, "Agrium looks at supplying Nikiski plant with gas" Anchorage Daily News, November 16, 2005, http://www.adn.com/news/alaska/story/7211202p-7123601c.html.

operations beginning in 2015. Refurbishments would be needed to sustain a 20-year operating life.

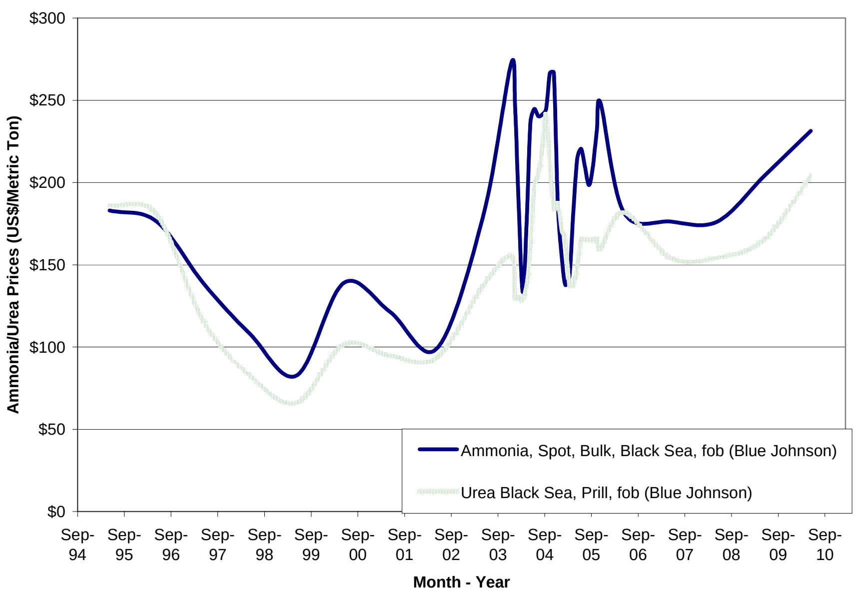
3. *New World Class Ammonia/Urea Facility* -- Closure of the existing unit and replacement by a new world scale unit of the same capacity built with the latest technology and efficiency improvements, ready as a turnkey plant in 2015.

5.5.3 Ammonia and Urea Markets and Prices

Markets for Alaskan Ammonia and Urea

The fertilizer market is a global $70 billion industry[31] that experiences the large cyclical swings characteristic of commodity chemical markets. The chemical industry cycle averages seven years in duration. Figure 24 represents observed and projected ammonia and urea industry cycles. Recent cycle swings include a low period during the late 1980s into the early 1990s, followed by a run-up to a relative high around 1995 to 1996. Fertilizer companies endured a subsequent downturn around 1999 to 2001, from which time prices have been recovering until the most recent record highs in late 2005.

Figure 24: Observed and Projected Ammonia and Urea Industry Cycles



Source: SAIC

When investing in new capacity, fertilizer companies attempt to time new plant entry into the market as product prices begin to rise. The aggregate impact of these closely timed investments results in overcapacity as millions of tonnes of new capacity enter the market within a short time period, which drives up world supply relative to demand. The cycle downturn occurs when the

[31] Yara Capital Markets Day, presentation, November 19, 2004, http://www.hydrogas.dk/library/attachments/en/investor_relations/cmd_2004/YARA_CMD_04_hel.pdf

market corrects itself and product prices drop until the marginal producers cut back production. The cycle then repeats. If the average seven-year cycle holds, the ideal time to bring a refurbished or new facility on-line may be a year or two after the proposed completion of the spur line in 2015.

Ammonia and urea products manufactured in Alaska will compete with existing world class plants in Russia, Ukraine, and the Middle East, and with new capacity in places with very inexpensive feedstock (e.g., the Middle East).[32] In this competitive world market, very low natural gas prices are essential to enable sales to Asian consumers at competitive product prices.[33]

Some North American producers are not competitive in the export market as a result of significantly higher natural gas prices. However, the Kenai Agrium facility has maintained viable margins as a result of relatively low Cook Inlet gas costs. Although some of the product manufactured in Alaska will likely be shipped to the U.S. West Coast, the majority of product is expected to be exported to other Pacific Rim countries. For this assessment, Korea is the assumed destination for ammonia, as most of Agrium's current product is sold there. Mexico (west coast port) is the assumed destination for urea.

Ammonia and Urea Sale Prices

Historic ammonia market prices over the past decade have ranged from $75 to $300/ tonne, with prices spiking to $400/tonne during late 2005, corresponding with high oil and gas prices. Historic urea prices have ranged from $60/tonne in 1999, to $170/tonne in 1995, and recent prices above $200/tonne.[34]

One fertilizer manufacturer suggests that future market values will be pushed higher than the historic product average prices: "[T]he main determinants of competitiveness of a fertilizer plant are input costs (gas for an upstream plant, ammonia for a downstream plant), logistics costs (distance to end customers) and technology/energy efficiency. In a holistic perspective, this puts the profitability of plants in the Middle East ahead of the rest while Chinese and Russian plants on average compete unfavorably with European plants and the best plants in the US. Nevertheless, the capital cost of building new plants in the Middle East is so high that fertilizer prices need to stay at a level above historical average prices for new projects to be viable."[35] Another industry analyst predicts that higher product prices in correlation with energy prices will not continue: "[A]s capacity continues to shrink in [the United States and Europe], and continues to grow where gas prices are low and relatively predictable, the logic for a [nitrogen] price tie to

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[32] British Sulphur Consultants, personal communication, 2005.

[33] Possible reform of the Russian internal gas market could result in a rise in domestic Russian gas prices to global levels over the next ten years.

[34] Blue, Johnson Associates, Inc.. "The Sheet 2/05" January 6, 2005.

[35] Yara Capital Markets Day, presentation, November 19, 2004, http://www.hydrogas.dk/library/attachments/en/investor_relations/cmd_2004/YARA_CMD_04_hel.pdf

higher-cost energy locales will progressively weaken, and international supply-demand relationships will reign."[36]

The highly cyclical ammonia and urea markets complicate long-term price forecasting. To address this concern, this analysis uses an average price approach. The average prices for fertilizer products used in this analysis are based on estimates of the FOB Black Sea market prices of $224/tonne for ammonia and $185/tonne for urea, adjusted to include shipping costs to Asia.

5.5.4 Ammonia and Urea Assumptions

When operating at full capacity, the Kenai plant consumes approximately 53 Bcf/yr of natural gas for feedstock and fuel. It is assumed that a new facility would achieve 5% efficiency improvement over the existing facility (i.e., gas consumption would remain the same while product output would increase). Assumptions for capital, operating, and shipping costs are discussed below.

Capital and Operating Costs

Capital costs are estimated for the three scenarios based on industry sources and literature. For Scenario 1, continued operation of the Agrium facility in its current configuration, there are no initial capital costs, but the existing plant would require $4 million (2005$) in recurring annual capital expenditures to maintain operations. For scenario 2, renovation of the Agrium facility, the major capital costs for facility renovation include $10 million for mothballing the current facility from 2006 to 2015, $180 million for the manufacturing plant (including ammonia and urea), $4 million for loading and marine facilities, and $10 million for power generation. The total depreciable capital cost for scenario 2 is estimated to be $232 million. Capital costs for a new ammonia-urea facility total $1.35 billion, which includes $800 million for the ammonia plant, $325 million for the urea plant, power generation, and loading and marine facilities.

Non-fuel operating costs include fixed and variable cost components, such as annual maintenance, labor, utilities, and purchased electricity. Costs are assumed to reflect a reasonable industry average and were developed based on industry sources and literature.[37] Operating costs are escalated for scenarios 1 and 2 at 1% per year, and for scenario 3, at 0.5% per year to reflect increasing maintenance requirements over time, and lower maintenance requirements for a new facility relative to the existing one. The utilization factors for the existing plant in scenarios 1 and 2 for ammonia and urea are assumed to be 93 and 95%, respectively. For scenario 3, the utilization factors for new ammonia and urea plants are assumed to be 95 and 96%, respectively, but other operating costs would remain the same.

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[36] Blue, Johnson Associates, Inc.. "The Sheet 2/05" January 6, 2005.

[37] ICF Resources, Inc., "A Market Analysis of Natural Gas Resources Offshore Newfoundland," Final Report, prepared for Newfoundland Ocean Industries Association, December 22, 2000.

Shipping Costs

Alaska's location adjacent to the well traveled shipping channels of the "Great Circle Route" makes it easy for South Central manufacturers to secure charter vessels to Asian ports. Shipping costs are representative of bulk solid rates and ammonia-specific rates from Alaska to East Asia. Ammonia is shipped as a liquid under pressure, so associated costs are higher than for dry products, and are similar to those for LPG. Shipping rates to Korea and Mexico are estimated from several sources including shipping companies,[38] Alaskan and Canadian exporters, industry literature,[39] and consultants.[40] Shipping costs for liquid ammonia bound for Korea (4,000 miles) were estimated at $0.011/tonne/mile. Shipping costs for solid bulk urea bound for Mexico (3,000 miles) were estimated at $0.009/tonne/mile.

Table 6 summarizes product price, capital, operating, and shipping costs for the ammonia-urea scenarios.

Table 6: Price and Cost Assumptions for Ammonia-Urea Scenarios (2005$). Shaded column is the most likely scenario.

Cost Item	SCENARIOS		
	Operation of Current Plant	Renovation of Current Plant	Construct New Plant
Ammonia Price Urea Price	$224/Tonne $184/Tonne	$224/Tonne $184/Tonne	$224/Tonne $184/Tonne
Capital Costs	$4 Million/Yr	$232 Million	$1,350 Million
Operating Costs	$67 Million/Yr	$67 Million/Yr	$67 Million/Yr
Shipping Cost	$55 Million/Yr	$55 Million/Yr	$57 Million/Yr

Source: SAIC

5.5.5 Ammonia/Urea Industry Assessment Results

If the existing Agrium facility can maintain operations without incurring major capital expenditures, and the expected average product price for ammonia and urea as $224/tonne and $184/tonne, respectively, then Agrium could pay as much as $3.52/MMBtu and achieve a 12% discount rate, over a 20-yr project life. In the more likely scenario in which the Kenai facility would be mothballed and then refurbished for operations beginning in 2015, the plant would be economically viable with gas prices at or below $2.79/MMBtu. The third scenario, building a new plant, has a netback price that is less than zero, suggesting it is not economically viable regardless of the price of gas. Summary gas demand and netback price results for the ammonia and urea plant are provided in Table 7.

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[38] Mark Conley, Glacier Northwest, personal communication, December 2, 2005.

[39] Buckland, A., 2004. *The Drewry Annual LPG Market Review and Forecast 2004/05*. Drewry Shipping Consultants Ltd., London, UK.

[40] Andrew Buckland, Editor Drewry LPG Forecaster, personal communication, December 1, 2005.

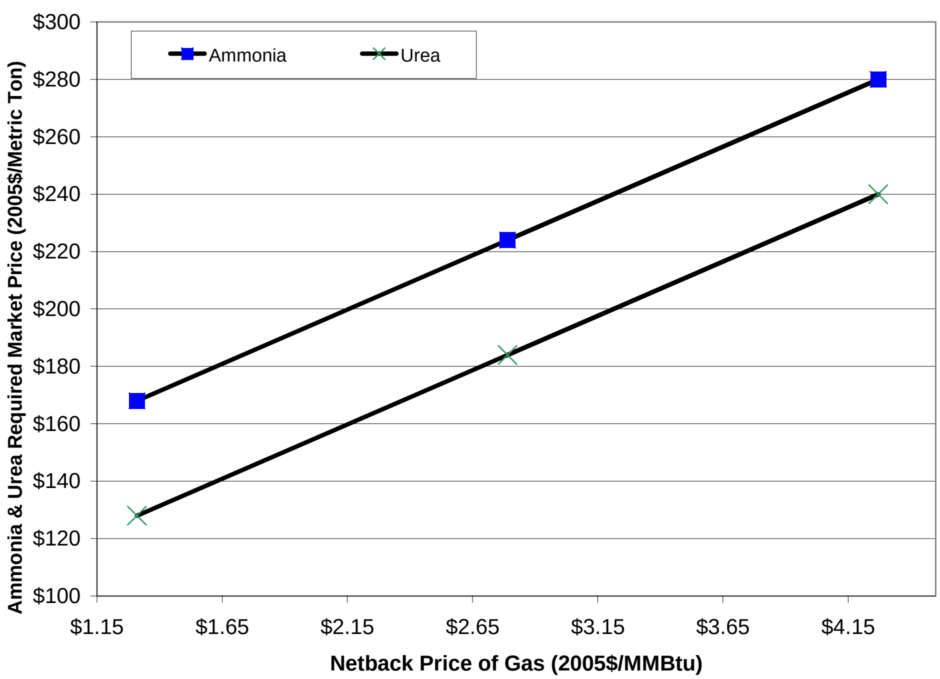
Figure 25 shows the relationship between product prices and the netback price. In general, a $40/tonne increase in market price corresponds with a roughly $1/MMBtu increase in the breakeven, netback gas price.

Table 7. Demand and Netback for Ammonia-Urea Scenarios (2005$). Shaded column is the most likely scenario.

	SCENARIOS		
	Operation of Current Plant	Renovation and Operation of Current Plant	Construct New Plant
Demand Estimate	**MMcf/d**	**MMcf/d**	**MMcf/d**
Natural Gas	145	145	145
Netback	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**
Before Taxes	3.50	2.98	0.65
Taxes	-0.02	0.19	1.24
After Taxes	3.52	2.79	-0.59

Source: SAIC

Figure 25: Relationship between International Ammonia and Urea Prices, and Netback Natural Gas for a Fertilizer Plant



Source: SAIC

5.6 Gas to Liquids (GTL)

5.6.1 GTL Background

The conversion of natural gas to liquids (GTL) represents another way to monetize stranded natural gas. GTL technology uses the Fisher-Tropsch (F-T) process to convert hydrocarbon gases, such as natural gas, to longer chain hydrocarbons. These "distillates" may include a variety of products such as naphtha, which is blended into gasoline, and kerosene and diesel distillates, which are blended into jet fuel and diesel fuel, or used to directly produce ultra-low-sulfur diesel fuel.

The advantage of GTL-produced liquid fuels is that they are substantially cheaper to store and transport than gaseous fuels, and since they contain virtually no sulfur, nitrogen, or metals, they burn cleanly. Over the next few years, as new regulations for cleaner diesel fuel are implemented in the United States and Asia, sulfur levels in diesel fuel will fall from the current range of 350 to 500 ppm, to less than to 50 ppm. In the United States, new ultra-low-sulfur-diesel highway rules will require 15 ppm to be phased in between 2006 and 2010. These diesel fuel sulfur limits are expected to spur substantial demand for GTL diesel compared to other possible GTL products.

GTL conversion chemistry was discovered in Germany in the 1920s, but until the early 1990s focused principally on the production of hydrocarbon liquids from coal via the intermediate step of coal gasification. The first commercial scale GTL plant was developed by South Africa's SASOL as a means to secure petroleum products during apartheid, when economic sanctions were in place. In recent years, GTL development efforts have switched to using natural gas rather than coal as the primary feedstock. While the two GTL plants constructed in the 1990s yielded poor returns on investment, technology improvements have been incorporated into the next generation of GTL plants, which are beginning to come on-line. The lack of commercial experience with GTL technology, particularly with natural gas feedstock, adds an extra layer of investor risk.

5.6.2 GTL Project Scenario

With only three GTL plants currently in operation worldwide, there is no "typical" world-class plant on which to base a scenario for a GTL project. However, based on industry reports of under-construction and proposed GTL plants, it is assumed that a South Central Alaska GTL plant would have the following operating specifications:

- Plant Size 50,000 b/d
- Conversion 7.75 Mcf/bbl
- Feed Gas 369 MMcf/d
- Gas used in process 30% (110 MMcf/d)
- Feed gas required 479 MMcf/d

The Study assessed a similar sized plant at the North Slope to compare the economics of transporting GTL liquid products from the North Slope with the economics of transporting the gas along a spur pipeline for GTL processing at Anchorage.

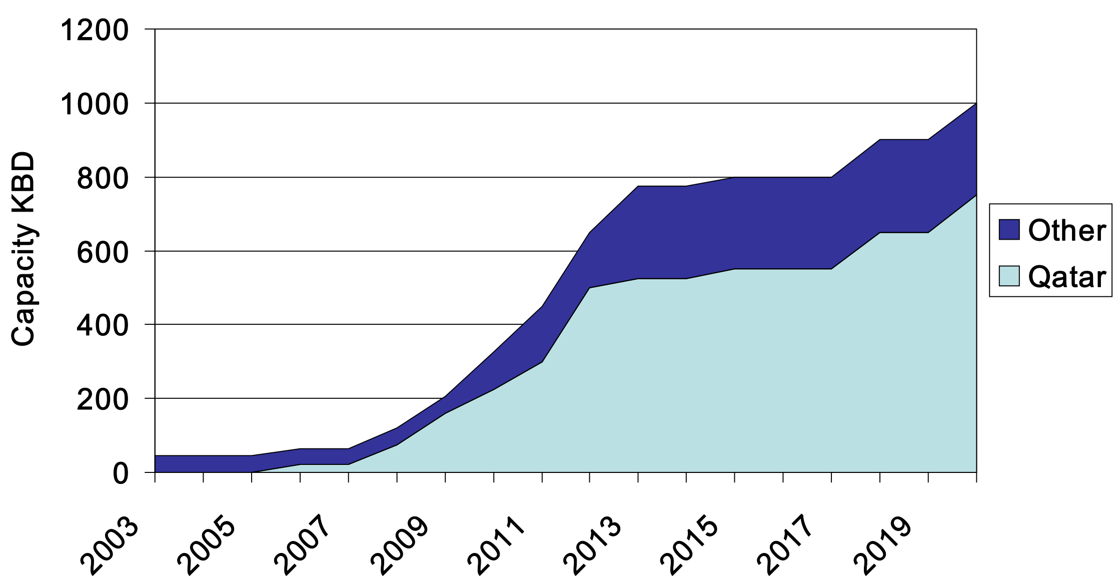
5.6.3 GTL Markets and Prices

GTL Distillate Market

Primary markets for sale of GTL distillates are petroleum refiners (for blending into gasoline, diesel fuel, and jet fuel), direct sale on the low-sulfur diesel market, and sale to the petrochemical industry as a feedstock. The implementation of new U.S. and Asian regulations for low-sulfur diesel has the potential to create a very favorable market for GTL diesel. Ultimately, it is estimated that GTL diesel products will represent about 7% of the North American and European ultra-low-sulfur diesel market.

Many analysts expect that total GTL capacity could grow from approximately 45,000 bbl/d presently to 1 million bbl/d by 2020 (10% of the global diesel market) as shown in Figure 26. Most of this capacity will likely be built in countries with access to low cost gas reserves, such as Qatar and Nigeria, but there will likely be opportunities for other niche producers to play a role in the GTL industry, depending on their proximity to markets.

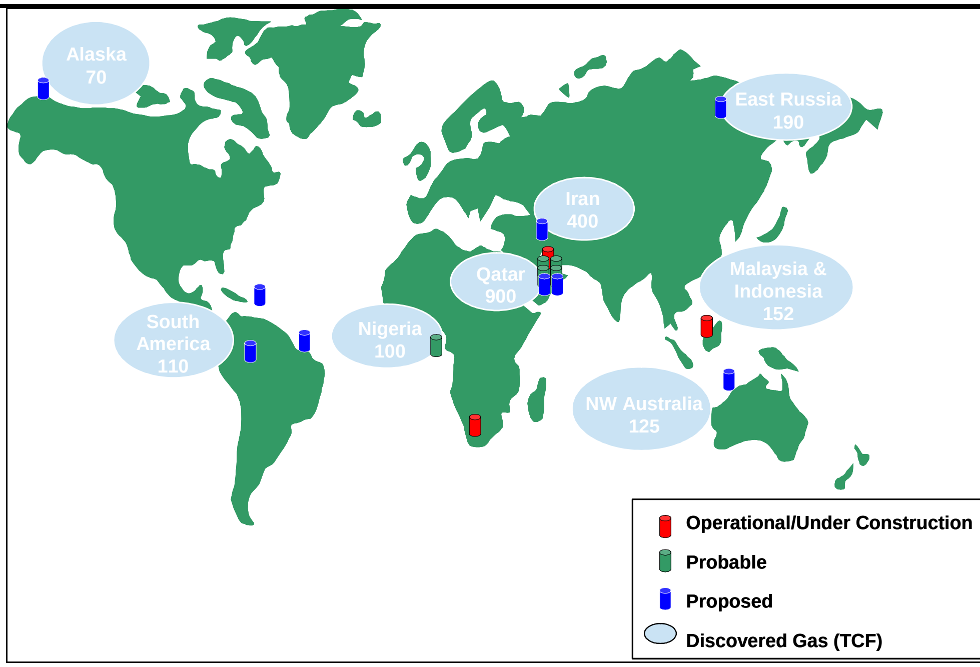
Figure 26: Growth in Global GTL Capacity



Source: ExxonMobil

Figure 27 shows the location of the operating and proposed GTL plants around the world and the magnitude of stranded gas reserves. Qatar has over 900 Tcf in stranded gas reserves and is seeking to monetize them through GTL and LNG development. If all proposed projects were to be implemented, Qatar would account for almost 700,000 bbl/d of global GTL capacity.

Figure 27: Location of GTL Plants



Source: ExxonMobil

GTL Distillate Prices

The GTL price is based on the price of low-sulfur diesel in California. The forecasted price is based on *AEO 2005* (High B Case) projections of U.S. light sweet crude oil prices, plus a price differential between light sweet crude and West Coast #2 distillate of $7.00/bbl, plus a $1/bbl price premium for high quality GTL diesel. These assumptions result in an average low-sulfur distillate price of $9.15/MMBtu (2005$) or $1.87/gallon between 2015 and 2025. These price forecasts are uncertain because the prices for low sulfur diesel resulting from the Environmental Protection Agency (EPA) rule requiring that 15 ppm highway diesel be phased in between 2006 and 2010 is just coming into effect and the long-term impacts on prices is not known. By 2015 when an Alaska GTL plant based on spur pipeline gas could come on line West Coast refiners will have had to upgrade refineries to make the low sulfur diesel or established sources for ultra-low-sulfur diesel for blending to meet the requirements. The sensitivity to distillate prices is illustrated in more detail Section 5.6.5.

5.6.4 GTL Cost Assumptions

A world class 50,000 bbl/d GTL plant would require approximately 500 MMcf/d of natural gas. Currently GTL plant capital costs are about $45,000/daily barrel in Trinidad and Tobago and in Qatar.[41] Stated industry goals remain at $20,000/daily barrel (2005$) or less suggesting that $20,000/daily barrel may be realistic by 2015.[42] Therefore, for the purposes of this study, $20,000/daily barrel was assumed. At a unit capital cost of $24,000/daily barrel (a factor of 1.2 is applied to a U.S. Gulf coast price of $20,000/daily barrel to account for higher costs in South

[41] Jennie Stell, "Project plans respond to market demands for more, cleaner fuels," Oil and Gas journal, November 21, 2005.

[42] Iraj Isaac Rahmim, "Stranded gas, diesel needs push GTL work," Oil and Gas Journal, March 14, 2005.

Central Alaska), total capital cost is $1.2 billion (including cost of capital during construction), and at unit operating costs (excluding feedstock and gas used in operations) of $6.00/bbl yields, annual operating cost is $104 million per year. The analysis assumes that GTL diesel can be shipped from Alaska on conventional petroleum product tankers (that meet Jones Act requirements) to the U.S. west coast at $20/tonne, for a total of $47 million per year. Table 8 summarizes price and cost assumptions for the GTL scenario for these base cost assumptions.

Table 8. Price and Cost Assumptions for GTL (2005$).

Price/Cost Assumptions	
Cost Item	**GTL Production**
Ultra Low Sulfur Diesel Price	$9.15/MMBtu
Capital Costs	$1,200 Million
Operating Costs	$104 Million/Yr
Shipping Costs	$47 Million/Yr

Source: SAIC

5.6.5 GTL Industry Assessment Results

The GTL plant in this scenario would require 479 MMcf/d of dry natural gas. Based on an average market price of $9.15/MMBtu for ultra-low-sulfur diesel and the cost assumptions listed above, the after-tax netback price for an Alaskan GTL plant is $3.18/MMBtu. Natural gas demand and netback prices are summarized in Table 9.

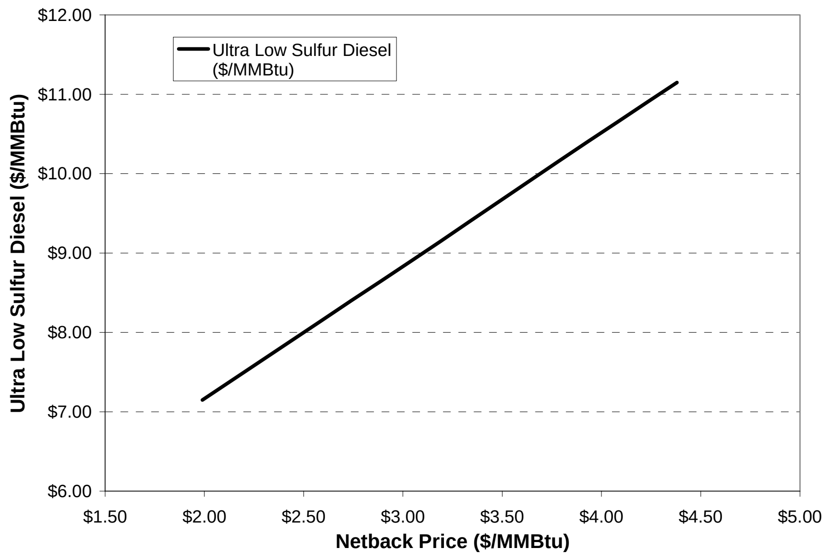
Table 9: Demand and Netback for GTL (2005$)

	GTL Complex
Demand Estimate	**MMcf/d**
Natural Gas	479
Netback	**$/MMBtu**
Before Taxes	3.75
Taxes	0.57
After Taxes	3.18

Source: SAIC

Figure 28 shows the sensitivity of the required natural gas netback price at a South Central plant location to the price of low-sulfur diesel. These results illustrate that small changes in per gallon ultra-low-sulfur diesel prices can cause very significant changes in the netback price for a GTL plant; e.g., a $0.20/gal [$1.44/MMBtu] change results in almost a $1.00/MMBtu change in the netback price.

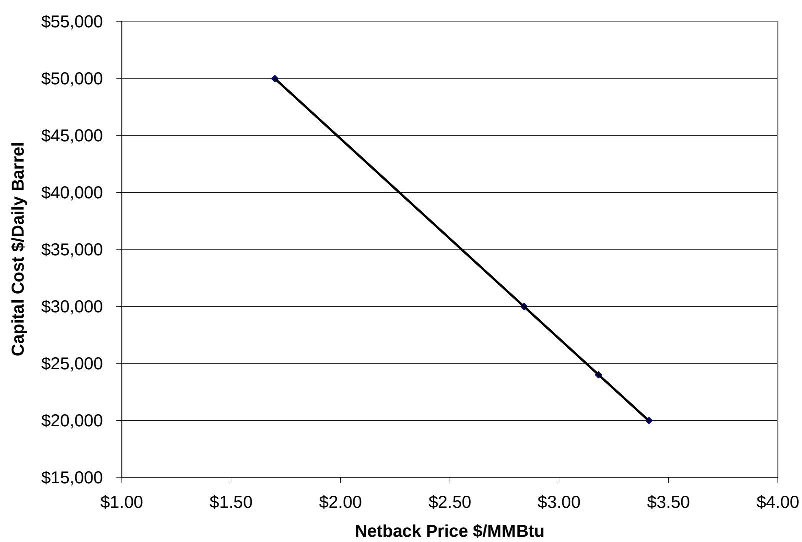
Figure 28: Sensitivity of Netback Price to Ultra Low Sulfur Diesel Price



Source: SAIC

Figure 29 shows the sensitivity of the required natural gas netback price to the capital cost assumptions used. A capital cost of $20,000/daily barrel of GTL increases the netback price to $3.40/MMBtu, while a capital cost of $30,000/daily barrel reduces the netback to $2.80/MMBtu, and a $45,000/daily barrel reduces it under $2.00/MMBtu. Hence, if industry cannot meet the stated goals of $20,000/daily barrel (2005$) or less by 2015, GTL is not a viable industry for the spur pipeline gas.

Figure 29: Sensitivity of Gas Price to Capital Costs for a GTL Plant



Source: SAIC

5.6.6 GTL Plant Located at North Slope Versus South Central

Table 10 compares the costs and value of GTL development in South Central Alaska with that of the Alaska North Slope (ANS). In the South Central analysis, all costs were multiplied by a factor of 1.2, while at ANS a cost factor of 1.5 was applied. This assumption results in a capital cost of $24,000/daily barrel in South Central Alaska compared to a cost of $30,000/daily barrel at the ANS. At $7.50/bbl, operating costs at the ANS are $1.50 higher than operating costs in South Central. The higher capital and operating costs at the ANS results in a netback price of gas of $2.70/MMBtu at the ANS compared to $3.20/MMBtu in South Central Alaska.

If these costs are further adjusted for pipeline tariffs, assuming GTL is transported through TAPS, while the spur pipeline brings gas from the ANS to South Central, the netback to ANS producers falls to $1.68/MMBtu for the ANS GTL option and to $1.90/MMBtu for the South Central option. Therefore, transporting gas to South Central provides a $0.22/MMBtu advantage over GTL manufacture at the ANS. Given the uncertainty in the cost estimates, this difference is not significant. However, transportation of GTL products in TAPS means that either the products have to be mixed with crude oil or transported in slugs. Both options have drawbacks that include losing the value of the GLT product when mixed with crude oil or increased operating complexity required to transport slugs of different products in TAPS.

Table 10: Competitiveness of GTL Development in South Central versus ANS

Location	Anchorage	ANS
Cost factor	1.2	1.5
Capital cost per daily barrel	$24,000	$30,000
Operating cost/bbl	$6.00	$7.50
Netback price at coast	$3.20	$2.70
Pipeline tariff ($/MMBtu)	$1.30 (Spur Pipeline)	$1.02 (TAPS)
Netback price equivalent at ANS	$1.90 /MMBtu	$1.68 /MMBtu

Source: SAIC

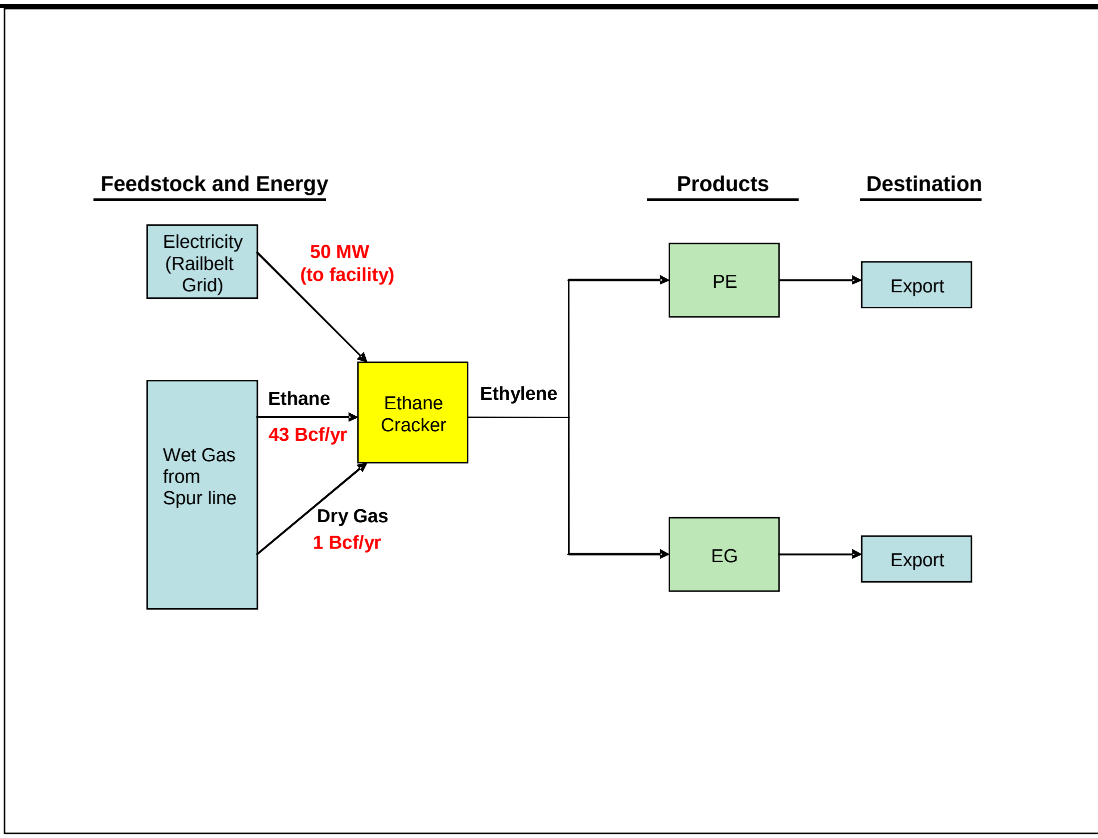
5.7 Petrochemicals

5.7.1 Petrochemical Background

The analysis of a proposed petrochemical manufacturing plant in South Central Alaska was conducted based on a world class facility that uses ethane feedstock to manufacture ethylene for the production of polyethylene (PE) and ethylene glycol (EG).

Figure 30 illustrates the feedstock and product flows through the system. Ethylene is a gas at ambient temperature and pressure. The need for pressurized, refrigerated vessels makes it relatively expensive to transport; therefore, ethylene is often used to manufacture other products in the same petrochemical complex where it is manufactured.

Figure 30: Petrochemical Plant Process Flows



Source: SAIC

Ethylene can be manufactured from a variety of feedstocks, including ethane, propane, butane, naphtha, and gas oil.[43] A pure ethane feedstock produces a higher ethylene yield and fewer by-products than any other feed.[43,44] However, the choice of a dual-feedstock cracker, for example using ethane and propane, reduces the long-term risk associated with future feedstock cost and derivative product prices.

Ethylene derivatives include a wide array of products. Two of the major products are Polyethylene (PE) and ethylene glycol (EG). PE, the world's most widely used plastic, is a thermoplastic manufactured through the polymerization of ethylene. Various high- or low-pressure, multi-staged process options are used to produce this dry solid product in the form of high density, low density, and linear low density polyethylene (HDPE, LDPE, and LLDPE).

EG is a liquid with a low freezing point and can be shipped by barge or tanker with no special handling requirements. EG is the main ingredient in commercial antifreeze, and is also used as a monomer in making Polyethylene Terephthalate (PET), which is formed into plastic drink

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[43] Burdick, Donald and William Leffler (2001). *Petrochemicals in Non Technical Language*. Third Edition. PennWell Publishing Company.

[44] Nexant's ChemSystems Process Evaluation/Research Planning (PERP) program, "Ethylene," October 2005. http://www.chemsystems.com/newsletters/perp/Oct05_N04-7.cfm

bottles, and polyester polymers, used for polyester. Globally, recent robust growth in demand for EG has been driven by polyester demand.[45] The simplest form of EG is mono-EG (MEG). When MEG is the intended primary commodity, it can be manufactured in the same plant as ethylene, with a small amount of marketable byproducts (i.e., di-EG (DEG)). The process produces approximately 1.67 tonnes of MEG/tonne of ethylene.

5.7.2 Petrochemical Project Scenario

The proposed petrochemical plant would be constructed at a tidewater location on the Cook Inlet, exporting to East Asian and Western U.S. markets. The assumed feedstock stream is 75,000 bbl/d ethane. While a dual feedstock stream of ethane and propane could be used, the lack of a local merchant market for the greater volume of by-product chemicals resulting from propane feedstock favors ethane as a sole feedstock.

The Study identified PE and EG as the most likely products from an Alaskan facility because these products are major commodities that can be manufactured in standard grades from ethylene and exported in bulk. Furthermore, the relatively isolated plant location means no nearby merchant markets for minor volumes of specialty derivative products, and no nearby sources for additional chemicals consumed in the production of other ethylene derivatives (e.g., benzene for styrene production).

Based on ethylene yields of 0.82 lb ethylene per lb ethane,[46] the ethylene production capacity is sized at 1.27 MMTPA. The assumed utilization factor of the ethylene unit is 95%, which means 1.2 MMTPA ethylene will be available as input to derivative products. The ethylene would then be allocated to PE and EG plants in a 70% to 30% split, based on the ethylene input volumes of standard world class PE and EG units. The EG unit was sized at 622 Kta, based on a 0.58 tonne ethylene per tonne MEG ratio.[46] The volume of marketable byproducts was assumed to be the industry standard of 0.07 to 0.08 tonne per tonne MEG.[46] The PE plant includes one HDPE, one LDPE, and one LLDPE unit sized at 280 Kta each. However, the analysis did not draw a distinction among these products, and considered only the general PE category.

5.7.3 Petrochemical Markets and Prices

Petrochemical Market

The petrochemical industry is large, global, and has periodic price swings typical of the chemical industry cycle. After experiencing strong profitability in 1994 to 1996, and relatively high product prices in the late 1990s, the chemical industry entered a low point of the cycle beginning in 2001. The most recent peak in the cycle, which included strong prices during 2004 and 2005, was compounded by record-high oil and gas prices, which drives the cost of feedstocks. Recent market prices in late 2005 have exceeded record highs. The next market downturn is expected in 2006 or 2007.[47] When investing in new capacity, petrochemical companies attempt to time the

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[45] CMAI, World Ethylene Oxide/Ethylene Glycol Analysis, http://www.cmaiglobal.com/apps/WorldAnalysis/pdf/WEOEGAMoreInfo.pdf

[46] Industry sources, 2005.

[47] Rick Cornelius, Director, Single Client Group, CMAI, personal communication, December 8, 2005.

market so that new plants will start production as product prices begin to peak. The timing of new capacity investment is a critical determinant of economic feasibility.

World scale ethylene units are concentrated in the U.S. Gulf Coast; Alberta, Canada; Western Europe; the Middle East, predominantly Saudi Arabia and more recently Iran; and East Asia, notably Japan and most recently China. Total global capacity is approximately 130 MMTPA. Main consuming regions for ethylene derivatives include Asia, the United States, and to a lesser extent, Western Europe. Demand growth for petrochemicals is closely related to gross domestic product. For most petrochemical products, including PE and EG, Asia will lead world demand growth in the coming decades, while consumption is expected to increase at lesser rates in most other regions.

Petrochemical manufacturing centers have been shifting from the U.S. gulf region and Canada to locations of plentiful low-cost gas, including the Middle and Far East, and this trend is expected to continue. In PE and EG, the Middle East has developed a dominant world trade position based on its feedstock cost advantage. A facility located in Alaska would have to compete with Middle East exporters in Asian markets and with producers in Alberta, the U.S. gulf coast, and increasingly the Middle East, for U.S. and Asian customers.[47]

Many North American producers are no longer competitive in the export market due to higher natural gas prices and thus are producing primarily for domestic consumers. Alberta petrochemical companies also face high gas prices relative to the Middle East, but may have a slight advantage over U.S. producers based on proximity to feedstock supply and associated cost savings in tariffs. Some Alberta producers have shifted their export volumes from Asia, where they are less competitive, into the U.S. market, which puts further pressure on U.S. gulf coast producers. These market forces have driven several petrochemical plants in the U.S. gulf coast region to permanently shut down during the past few years. Relative to a plant in Alberta or the U.S. gulf coast, a new petrochemical facility in Alaska would benefit from a more strategic location for exports to Asia, and theoretically lower feedstock costs based on shorter distance from North Slope supply.

PE and MEG Prices

Within a 20-year period, petrochemical commodity prices can reflect a four-fold difference between the highest and lowest price points. For example, since 2000, MEG prices have ranged from just over $300/tonne to nearly $1,400/tonne in late 2005.[48,49,50,51,52] Exhibiting similarly large swings, PE prices, which at a low point in 2001 had been less than $500 per tonne,[49]

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[48] Industry sources, 2005.

[49] Roger Newenham, Jacobs Consultancy, "Petrochemical and Fertilizer Projects in the Gulf, a short, medium, and long term perspective, 1st International Conference, Development of Gas Markets in the Gulf, March 2002.

[50] The Plastics Exchange, Public Research, Market Update, various editions, http://www.theplasticsexchange.com/Public/Public_Research.aspx

[51] Jim Bryan and Doug Rightler, "Petrochemical Insights: MEG," Chemical Market Reporter: Vol 263, No. 12, March 24, 2003.

[52] Old World Industries I Ltd., Product List Prices, October 12, 2005.

declined by roughly $300/tonne, or 20%, during the first quarter of 2005, then jumped more than 40% between June and November, reaching approximately $1,800/tonne. [53,54]

5.7.4 Petrochemical Cost Assumptions

The petrochemical plant analysis relied on various assumptions regarding capital, operating, and shipping costs, as discussed below.

Capital Costs

The Study estimated capital costs based on new comparable plants, as documented in industry literature[55] with input from industry experts. The NGL extraction plants in Fairbanks and Anchorage area are assumed to cost $230 million each (before application of Alaska construction factors), and the on-site fractionator costs an additional $150 million. This analysis assumes that all capital costs associated with the NGL extraction plants and fractionator are shared by spur line NGL customers on a thermal basis.

The steam cracker and associated plant utilities and infrastructure in total are estimated to cost $450 million, while the PE and MEG units are estimated to cost $260 million and $325 million, respectively (not including Alaska construction factors).

Operating Costs

The cost to operate the NGL extraction plants and fractionator is estimated at $0.50/bbl. The analysis assumes that the NGL extraction plants and fractionator consume 0.5 MMBtu/bbl of the gas that they process. Operating costs for the PE and MEG units were calculated based on l Lower 48 cost estimates, adjusted by the relevant Alaska cost factors (Fairbanks = 1.4; Anchorage = 1.3). The analyses include the operating costs associated with the production of ethylene, running the NGL extraction plants in Fairbanks and Anchorage, and running the fractionator in Anchorage. The later costs are assigned to the liquids users on thermal content basis (normally, these costs are made part of the tariff and are part of the delivered cost of the liquids). The total operating cost per tonne is about $390 for PE and $330 for MEG, for a total of $413 million per year.

Costs, prices, and natural gas demand of the petrochemical plant are summarized in Table 11. Salvage value is the scrap value of the plant minus site reclamation costs. Cash flow is the after-tax net income plus the effects of depreciation.

Shipping Costs

The petrochemical products will likely be sold into multiple markets including China, Thailand, Vietnam, and the U.S. However, the majority of product is assumed to be exported to Korea and

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[53] Alexander Tullo, “Spotlight on Polymers,” Chemical & Engineering News, September 12, 2005.

[54] The Plastics Exchange, Public Research, Market Update, various editions, http://www.theplasticsexchange.com/Public/Public_Research.aspx

[55] Peter Fairley, “Canadian Chemicals: Running on Empty,” *Chemical Week*, July 19, 2000, http://members.shaw.ca/pfairley/mmclips_files/CW20000719.htm

China. Shipping costs are estimated as $0.010/tonne/mile and $0.011/tonne/mile for PE and MEG, respectively. These costs are based on projected costs for the shipment of bulk solid and liquid petrochemical products bound for Korea and China (i.e., 4,500 miles).

Summary price and cost assumptions are shown in Table 11.

Table 11: Price, and Cost Assumptions for Petrochemical Project (2005$)

Price/Cost Assumptions	
Cost Item	**PE and MEG Manufacture**
PE Price MEG Price	$1,065/Tonne $656/Tonne
Capital Costs*	$2,700 Million
Operating Costs*	$413 Million/Yr
Shipping Costs	$73 Million/Yr

*Includes cost of capital and operating costs for product separation in Fairbanks and Anchorage.
Source: SAIC

5.7.5 Petrochemical Industry Assessment Results

A 75,000 bbl/d petrochemical plant would require 1 Bcf/yr of dry gas and 50 MW of electric power, supplied by the Railbelt electricity grid. This power demand is included in the analysis of the electric power sector.

Based on the petrochemical plant size, costs, and PE and MEG market prices discussed above, the netback price for ethane is equivalent to $4.63/MMBtu of dry gas on a thermal basis. Summary demand and netback price results are provided in Table 12.

Table 12: Demand and Netback for Petrochemical Project (2005$)

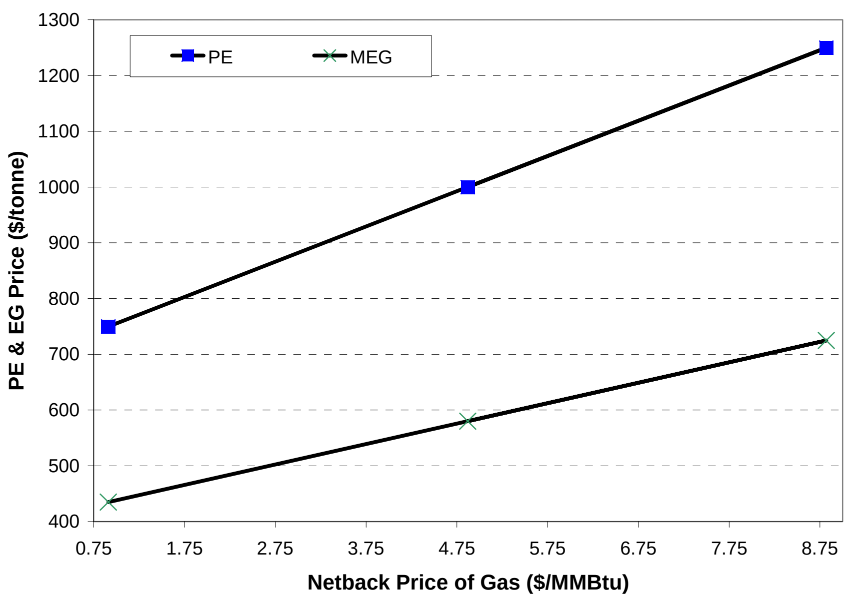
	PE and MEG Manufacture
Demand Estimate	**MMcf/d**
Natural Gas	3
Ethane	111
Netback	**$/MMBtu**
Before Taxes	6.07
Taxes	1.44
After Taxes	4.63

* Equivalent methane MMcf/d on a thermal basis.

Source: SAIC

Figure 31 shows the relationship between product prices and the required netback price.

Figure 31: Relationship between International PE and EG prices, and Netback Natural Gas for a Petrochemical Plant



Source: SAIC

5.8 Liquid Petroleum Gas (LPG)

5.8.1 LPG Background

Liquefied petroleum gas (LPG) contains primarily propane and butane, which are gases at atmospheric pressure and temperatures above 0ºC (32ºF). LPG is stored as a liquid under pressure, refrigeration, or both, to reduce storage capacity requirements.

The ratio of propane and butane in LPG varies considerably depending on both the source and the demand application.[56] Nearly half of global LPG use is by the residential sector as heating and cooking fuel, and the acceptable ratios of propane to butane in this sector depend on ambient temperatures in the user's region. In Alaska, the residential/commercial LPG market requires virtually all butane to be removed.

The chemical industry consumes about 25% of global LPG production as a feedstock. In regions with mature LPG markets, such as North America, Europe, Japan, and the Middle East, growth in the demand for LPG is largely the result of growth in the chemical sector.

5.8.2 LPG Project Scenario

The LPG supply is limited by the spur pipeline size and gas composition. An export oriented LPG industry in South Central Alaska could provide enough demand for all the propane and butane in the ANGP pipeline. Because this industry does not require large step increases in demand for optimized use of a processing plant, it is likely that the size of the spur line will be determined by demands for other components (i.e., methane and ethane).

For the LPG scenario, the LPG supply is based on a dense phase line sized to meet petrochemical industry ethane demand. Available LPG will be sold to meet in-state needs, and the remainder will be exported for sale on the world market. For simplicity in the supply estimate calculation, North Slope raw gas serves as input to the ANGP pipeline after conditioning to reduce carbon dioxide. NGLs are separated from the ANGP line and spiked into a 1 Bcf/d spur line. Assuming 100% separation efficiencies for propane and butane, and using gas composition estimates reported by Baker,[57] spur line supply of LPG supply is estimated to be around 48,000 bbl/d propane and 25,000 bbl/d butane. Appendix B further discusses spur line composition calculations.

5.8.3 LPG Markets and Prices

Alaskan LPG Market

PND Inc. assessed the feasibility of expanded propane use and distribution in Alaska and this report is the primary reference for in-state LPG market discussion and Alaska LPG terminal and storage costs.[58] Alaskan communities that are not connected to natural gas pipelines (as in the South Central Cook Inlet area) typically rely on coal or high atmospheric gas oil (HAGO) for electric power generation and on fuel oil for space heating. These are relatively expensive, and thus represent markets that may change to propane if it were available at a competitive price. The current demand for propane in Alaska is about 1,000 bbl/d, and about half of this demand is from the South Central area. The Tesoro refinery supplies LPG for roughly half of the current propane demand, and the remainder is imported from Canada.

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[56] Buckland, A., 2004. *The Drewry Annual LPG Market Review and Forecast 2004/05*. Drewry Shipping Consultants, Ltd., London, UK.

[57] Baker, M. (2005). *Transport of North Slope Natural Gas to Tidewater. Leveraging Issues, Configuration Descriptions & Issues, New Project Concept*. Prepared for ANGDA (133 pp).

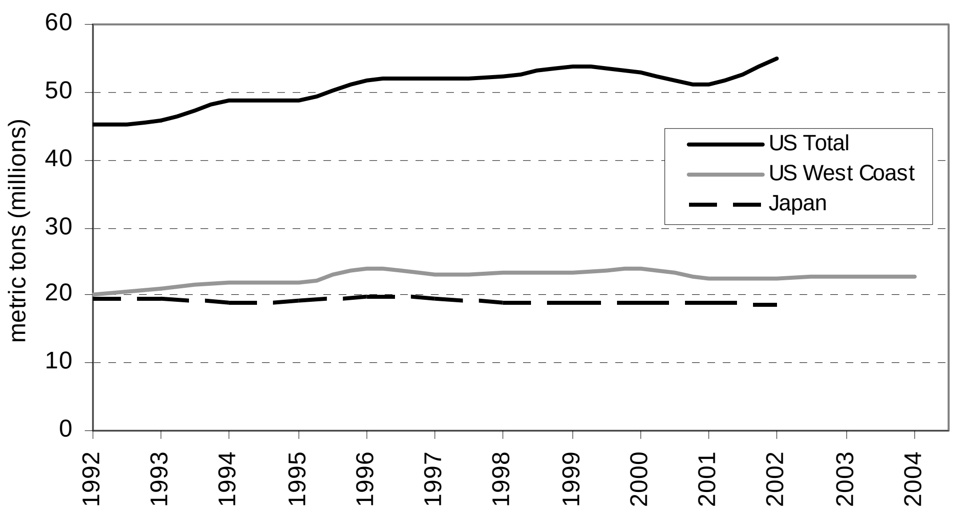
[58] PND, Inc., Anchorage, AK. Feasibility study of propane distribution throughout coastal Alaska, Augusta, 2005. Conducted for Alaska Natural Gas Development Authority (ANGDA).

The PND projections of propane penetration in the Alaskan market were based on lower spur line gas costs than assumed in this analysis. Thus, PND projections of in-state propane demand from the spur line are viewed as upper-end estimates. Within the first 10 years, PND estimates that Alaska's in-state demand for propane would be approximately, 2.761 million bbl/year (7,500 bbl/d), with summer transport of 15,000 to 20,000 bbl/d to replenish communities with a limited shipping season.

Lower-48 LPG Market

U.S. LPG consumption is expected to continue its recent growth rate of 1 to 2% per year.[59] Figure 32 displays propane demand for the entire United States and for the U.S. West Coast, the latter of which is similar in magnitude to the LPG demand in Japan. These regions represent mature LPG markets. Currently, the United States produces 85% of the LPG it consumes, with most of the remainder imported over land from Canada.

Figure 32: Propane Demand Growth for the US, US West Coast, and Japan



Source: SAIC

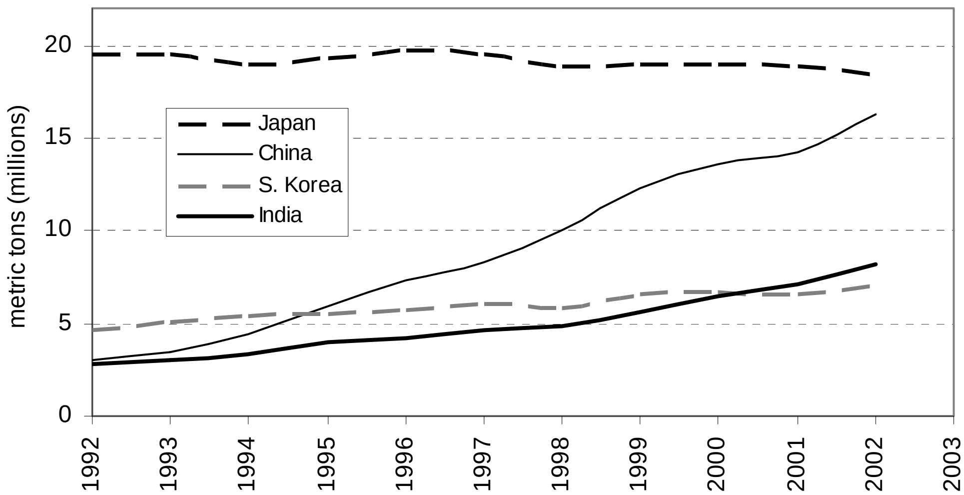
LPG Export Market

China, India, South Korea, and Japan are all net LPG importers. The Middle East provides approximately one-third of the LPG consumed in Asia, and most of the sea-borne trade in LPG moves from the Middle East to the Far East (primarily China, Japan, and South Korea).[60] China and India have had double digit growth in annual LPG consumption (Figure 33), and while annual demand growth is likely to fall below 10% over the next decade, these two countries are expected to continue high growth in LPG demand beyond 2015.

[59] Grist, Ronald L, Purvin & Gertz, 2005. Winter outlook for the US propane market. Presented at DOE-NASEO 2005-2006 Winter Fuels Conference, October 12, 2005.

[60] Buckland, A, 2004.

Figure 33: Propane Demand Growth for Japan, China, South Korea, and India.



Source: The Drewry Annual LPG Market Review and Forecast 2004/05 and EIA.

Middle East LPG production is expected to increase up to and beyond 2015, while both Middle East and U.S. LPG costs will remain similar to those of today. However, LPG consumption in the Middle East is growing at a higher rate than production increases due to growth in LPG use as a petrochemical feedstock. Thus, given continued Asian demand growth for LPG, and increased local markets for Middle Eastern LPG, there may be a relative reduction of Middle East LPG delivered to Asia over the next decade. Some of the increasing Asian demand will be met by net LPG exporters within Asia (e.g., Indonesia, Malaysia, and Thailand).[61]

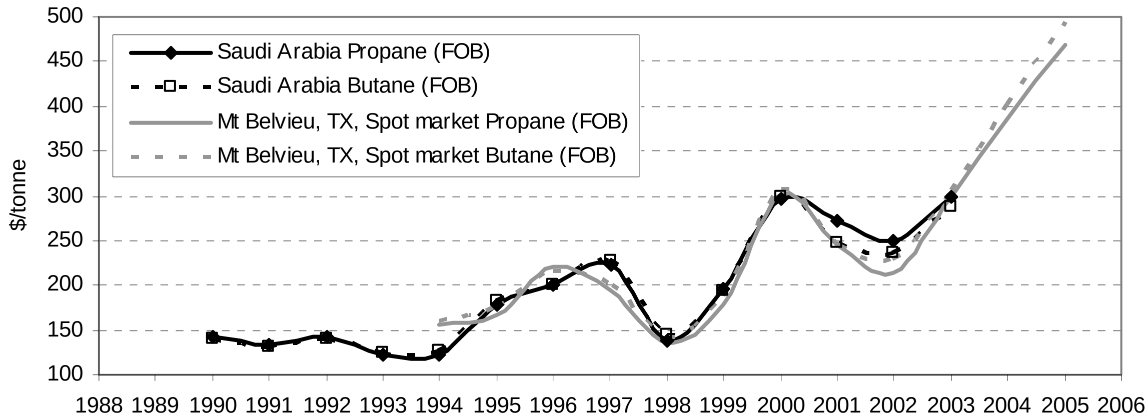
The year 2005 was the first year in which LPG consumption in China exceeded that of Japan. The size of the Chinese market in conjunction with its projected continuous strong growth in demand beyond 2015 suggests that China may also be a feasible market for Alaskan LPG.

LPG Prices

Based on published sources, average propane and butane prices in Japan are not substantially different from prices in Saudi Arabia or the U.S. Gulf Coast, and the price of propane is essentially the same as the cost of butane. Historical prices of propane and butane from Saudi Arabia and from Mount Belvieu, TX are shown in Figure 34. For this analysis, the selling price of LPG on the world market was estimated as $300/tonne for both propane and butane. This is based on the relative annual average price of natural gas over the last 10 years (from EIA), and the annual average price of propane at Mount Belvieu, TX.

[61] Ibid.

Figure 34: Propane and Butane Prices in Saudi Arabia and Mount Belvieu, TX (FOB: not including freight)



Source: SAIC

5.8.4 LPG Cost Assumptions

As discussed above, the selling price on the world market is estimated as $290/tonne for propane and butane, including shipping. Capital costs and shipping assumptions are discussed below.

Capital and Operating Costs

Assumed capital investment costs for LPG export to Pacific Rim markets include a portion of the NGL extractors ($440 million), Cook Inlet Tank farm ($270 million), terminal piping, loading system, and security and safety upgrades ($32 million). Additional costs that would be needed to substantially expand delivery of LPG to in-state markets include coastal LPG barges, Alaska destination port upgrades and storage, and community storage. Coastal barge purchases for in-state deliveries are included in this study ($13 million for two barges, each with a 20,000 bbl capacity), while in-state destination port upgrades and construction are not (these are provided in the PND report).

The Study assumes that LPG operations costs are 3% of the capital investment. Operating costs of the LPG units were calculated based on $5 million fixed and $8 million variable costs and include cost factor adjustments for Anchorage (1.2). The analyses include the operating costs associated with the production of propane and butane -- running the NGL extraction plants in Fairbanks and Anchorage, and running the fractionator in Anchorage. These costs are assigned to the liquids users on thermal content basis and are assumed to be shared with the users of ethane (this assumes the existence of a petrochemical plant in the vicinity). (Normally, these costs are made part of the tariff and are part of the delivered cost of the liquids.) The total operating cost for LPG were calculated to be $144 million per year

Shipping

LPG carriers are commonly designed specifically for transporting LPG, but there is often some flexibility in cargo type, particularly for shipping ammonia and LPG. Thus, shipping costs for ammonia and LPG generally follow similar patterns. A recent boom in tanker shipping rates allowed fleet owners to invest in new LPG and ammonia carriers.[62] The world LPG carrier fleet is expected to increase its total capacity more than 25% by the end of 2008 based on orders placed in 2005, during a period of high shipbuilding prices. High shipbuilding prices for this new capacity will contribute to higher LPG shipping costs,[63] and suggest that relative shipping costs will be higher in 2015 than in 2005.

Thus, export shipping costs were assumed to be $0.013/tonne/mile for 4,000 miles to the Pacific Rim. In contrast, a shipping rate of $0.011/tonne/mile was assumed for ammonia shipments of similar distance, which was based on historical costs and an older fleet. Costs for in-state shipping were not included in this assessment because they are very small relative to the other cost estimates, and are not significant at the level of precision used in this analysis.

Table 13 summarizes price and cost assumptions for the LPG scenario.

Table 13: Price and Cost Assumptions for LPG Distributed Over 20-Years (2005$)

Price/Cost Assumptions	
Cost Item	**LPG**
Propane and Butane Price (FOB)	$290/Tonne
Capital Costs *	$630 Million
Operating Costs*	$144 Million/Yr
Shipping Cost	$105 Million/Yr

*Includes cost of capital and operating costs for product separation in Fairbanks and Anchorage.
Source: SAIC

5.8.5 LPG Industry Assessment Results

Under the supply scenario and assumptions used in this analysis, the netback price for LPG is $4.78 before taxes and $4.20 after taxes. Netback model results and summary demand, cost, and price assumptions are shown in Table 14.

[62] Poten & Partners, A Global LPG Outlook, Nov. 4, 2005. http://www.poten.com/%5Ctankeroptions%5C110405.pdf.
[63] Growth Expected in LPG fleet rates. Oil & Gas Journal, Nov. 7, 2005, pg. 59.

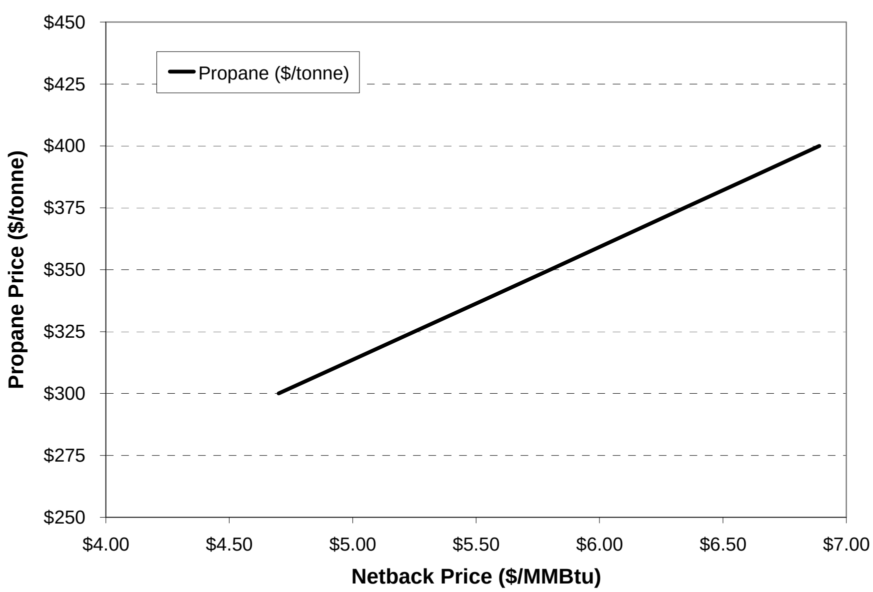
Table 14: Demand and Netback for LPG Distributed Over 20-Years (2005$)

	LPG
Demand Estimate	**bbl/day**
Propane and butane	63,000
Netback	**$/MMBtu**
Before Taxes	$4.78
Taxes	$0.58
After Taxes	$4.20

Source: SAIC

Figure 35 shows the sensitivity of netback price to the price of propane. This suggests that a $45/tonne change in the market price of propane causes a $1/MMBtu change in the netback price.

Figure 35: Sensitivity of Gas Price to Propane Price



Source: SAIC

5.9 Non-Gas-Intensive Industries

In addition to the gas-intensive industrial opportunities discussed above, the Study also assessed potential demand from several non-gas-intensive industries. This assessment included identification of major existing industries and those which had been previously proposed for South Central Alaska; possible industrial opportunities that made sense for the region and/or that complemented existing businesses; and industries that could operate within the constraints of regional transportation and infrastructure. Among these, five were considered to have sufficient gas or electric power demand for further analysis:

- Gold-Copper-Molybdenum Mine
- Oil Refinery
- Internet Server Facility
- Insulated Wallboard Manufacturing
- Rolled Steel/Pipe Forming

These industries are further described below, and when appropriate, electric power demand was added to the power analysis section of this report. Additional industries were investigated but were not modeled in this analysis either because the industry was not a major gas or electricity consumer, or because there was a lack of data. These industries include the following:

- Seafood Processing
- Wood Products
- Copper Smelting
- Concrete Manufacturing

Appendix A provides summary descriptions of these industries.

5.9.1 Gold-Copper-Molybdenum Mine

The mining company Northern Dynasty is investigating the Pebble site for a gold-copper-molybdenum Mine. The Pebble site, more than 200 miles southwest of Anchorage, currently has no access to Alaska's transportation or electric power infrastructure. Figure 36 illustrates the remote location of the Pebble Project. Northern Dynasty is planning a large-scale open pit mining operation to extract gold, copper, and molybdenum. As of September 2005, Pebble was projected to be a 200,000 to 250,000 metric tons/day operation that could produce 31.3 million ounces of gold, 18.8 billion pounds of copper, and 993 million pounds of molybdenum.[64] The mine developers are preparing a feasibility study, expected to be complete in 2006. If a decision is made to move forward, the earliest construction would begin would be 2009, and production would not begin until 2013.[65] The mine developers face objections from various organizations, including environmental and fishing interests, which assert that operations would adversely impact the environmentally sensitive region of the mineral deposit.[66] Through 2005, Northern Dynasty has invested more than $50 million in this proposed project and claims that "the Pebble project has made the important transition from exploration to mine planning and permitting"[67]

[64] The Resource Development Council for Alaska, Inc., "The Pebble Project," *Resource Review*, September 2005, http://www.akrdc.org/newsletters/2005/september.pdf.

[65] John Wood, AIDEA, personal communication, August 25, 2005.

[66] Wesley Loy, "Pebble gold mine nets fishermen's ire," *Anchorage Daily News*, December 14, 2005.

[67] Northern Dynasty, http://www.northerndynastyminerals.com/ndm

Figure 36: Remote Location of Pebble Mine Project

Source: Northern Dynasty, http://www.northerndynastyminerals.com/ndm.

The electric power sector analysis included 300 MW in projected power demand from the Pebble mine. It is assumed that the feasibility of the mine is not dependent on spur pipeline natural gas supply. The mine would not consume natural gas directly, but would be a major electricity consumer. Power could be produced from coal (e.g., Beluga) or natural gas (e.g., spur line or new gas development in Cook Inlet or Bristol Bay), and the choice would be based on permitting and price.[68] If gas is selected as the power source, approximately 20 to 30 Bcf/yr would be needed to supply a 200 to 300 MW power plant.[69] Northern Dynasty signed a Memorandum of Understanding with Homer Electric Association to supply power by a new transmission line to the mine site, which would be either 210 miles of overland transmission line, or 45 miles of submarine cable across Cook Inlet and 65 miles of overland transmission line.[70,71]

In addition to the Pebble Mine, the proposed Donlin Creek Mine project, which is a deposit of gold and possibly diamonds, was investigated for this analysis. Donlin Creek could conceivably draw power from the Railbelt electricity grid via a connection with the Pebble project. However, because this industrial opportunity is considered speculative at this point, the Study did not incorporate any potential gas or electrical demands associated with the Donlin Creek Mine.

[68] Rick Eckert, Homer Electric Association, personal communication, September 22, 2005.

[69] Bill Popp, Kenai Peninsula Borough, personal communication, September 16, 2005.

[70] Rick Eckert, Homer Electric Association, personal communication, September 22, 2005.

[71] Northern Dynasty, "Northern Dynasty and Homer Electric Launch Joint Power Review for the Pebble Project," Press release, January 11, 2005.

5.9.2 Oil Refining

Located in Kenai, Alaska, the Tesoro Refinery processes crude oil from the Kenai Peninsula and Cook Inlet oil fields. The facility, which opened in 1969, produces distillates, such as jet fuel, diesel fuel and heating oil, as well as gasoline, LPG, heavy oils, bunker fuels, and liquid asphalt.[72] The predominant customer is the Anchorage International Airport, which consumes approximately 30% of Tesoro's output as jet fuel.[73] With its strategic location within nine hours of 95% of the industrialized world, the Anchorage airport ranks second in landed cargo weight in the United States and third overall. Tesoro is linked to the airport, 70 miles away, by a 40,000 bbl/d pipeline. In addition, Tesoro serves the Alaskan home heating oil and transportation fuels market, supplying ultra low-sulfur gasoline and low-sulfur diesel fuel. Tesoro exports only a small amount of its products, including heavy fuel oil. For feedstock, Tesoro purchases 100% of Cook Inlet crude production, and supplements it with foreign crude and Alaska North Slope crude from Valdez.[73] Tesoro's rated crude oil capacity is 72,000 bbl/d,[72] and it operates at roughly 65,000 bbl/d on average over the year.[73]

The Tesoro Refinery maximum natural gas demand is 18 MMcf/d, and its current consumption level is 11 MMcf/d, 10 MMcf/d for fuel energy and 1 MMcf/d for feedstock to its hydrogen plant. The facility cogenerates roughly half its electricity needs, purchasing the other half from the Homer Electric Association. The refinery reported no plans to expand operations during the analysis period of 2015 to 2035.[73]

5.9.3 Internet Server Facility

Sequestered Solutions Alaska LLC operates an internet server facility in Anchorage, employing 11 people for secure, toll-quality data storage. As of October 2005, the facility hosted approximately 50 servers, each with its own 30-minute storage, offering contracts for servers at a rate of $17 per day. The five-year business plan reflects growth to a facility of 20,000 Blade servers and software, which cost approximately $1,500 each. The current space could hold up to 3,000 servers.[74] Sequestered Solutions purchases electric power from the Railbelt electricity grid, and receives an industrial/economic development rate in the current tariffs of both ML&P and Chugach Electric; however, the benefit declines progressively over four years, ending in year five. The proprietors have not considered generating their own electricity, but may analyze such an option when demand approaches 1 MW. The planned full load of 20,000 servers would make Sequestered Solutions a bigger electricity consumer than the Anchorage hospital. For this analysis, an internet server facility electric power demand of 1 MW was considered in the electric power sector.

There have been previous proposals for server facilities in Alaska. Netricity proposed an internet data storage facility in the North Slope or central Alaska area.[75] The proposed data center was to be a $1 billion facility for 500,000 Internet servers in a one billion square foot building with

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[72] Tesoro, Kenai Refinery, http://www.tsocorp.com/stellent/groups/public/documents/published/tsi_bus_ref_t3__kenai.hcsp

[73] S. Hansen, Vice President, Refining, Jim Grossl, Manager, Oils Planning and Quality Control, and Rolf Manzek, Operation Manager, Tesoro Alaska Company, personal communication, September 26, 2005.

[74] Joseph Henri, Director, Sequestered Solutions Alaska, LLC, personal communication, Anchorage, September 28, 2005.

[75] The Greater Fairbanks Chamber of Commerce website: http://www.fairbankschamber.org/resolutions/2002/res23.html

natural gas-fired cogeneration that would sell surplus power to the Railbelt grid. The proposed Netricity server facility is no longer under consideration.

5.9.4 Insulated Wallboard Manufacturing

Insulated wallboard manufacturing has been proposed as an industrial opportunity in South Central Alaska. Insulated wallboard consists of a core made of a synthetic foam insulation, such as expanded polystyrene (EPS), between a structural material such as engineered wood or a steel frame. The wallboard may be used in residential and commercial floors, walls, and roofs. The product controls heat transfer through buildings and resists water filtration or absorption.

There are a number of manufacturers of rigid foam insulation, including Stoam Industries, Premier Industries, Owens Corning, and Dow. Stoam Industries' products include steel framed component wall systems with EPS foam insulation.[76] Premier Building Systems is North America's largest manufacturer and exporter of structural insulated panels, which have applications in commercial and residential construction.[77] Stoam and Premier have expressed interest in operations in Alaska. Stoam has reportedly communicated with the Alaska Industrial Development and Export Authority about a facility in Alaska. Premier Industries currently operates a small Insulfoam facility in Anchorage, and the Anchorage Economic Development Corporation (AEDC) has apparently participated in discussions with Premier regarding further opportunities. However, no business plan or written proposal has been identified. Local customers of insulated wallboard products could include the Alaska Innovative Housing Authority and the U.S. Military, for its compatibility with rapid deployment. The Study assumes that an insulated wallboard manufacturing facility in Alaska would be an export-oriented industry shipping most of its products to foreign customers and the lower 48 States. There may be shipping rate incentives available for products destined for Seattle, because multiple container ships depart Anchorage for Seattle each week without cargo.

This Study assumes a viable market for insulated wallboard products. Three component materials would be required: rolled steel from recycled Alaskan cars or other scrap metal (to be formed into studs), EPS foam beads (to be imported to Anchorage then expanded), and screws for assembly. The energy demands of this industry, which are relatively small, include 2.5 MW of electrical demand, assumed to be purchased from the Railbelt grid, and 0.25 MMcf/d of dry gas. These estimates are based on information from Owens Corning, which announced in June 2004 that it would construct a new 50,000 square foot rigid insulation manufacturing facility in Gresham, Oregon employing 35 people.[78] This is the size used for the proposed Alaska facility. The energy demand estimate is based on the data reported to the U.S. EIA in the 2002 Manufacturing Energy Consumption Survey (MECS)[79] for NAICS code 327993, which applies to mineral wool, a category that includes rigid foam insulation products. Of the manufacturers

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[76] Stoam Industries, http://www.stoam.com/

[77] Premier Panels, http://www.pbspanels.com/home.cfm

[78] "Owens Corning to Build Rigid Foam Plant in Oregon," Gypsum Today, 6/24/04, http://www.gypsumtoday.com/news/viewnews.pl/id=385.

[79] U.S. Energy Information Administration, Manufacturing Energy Consumption Survey 2002, Tables 1.1, 1.4, 6.4, 7.1, and 9.1 (NAICS 327993), http://www.eia.doe.gov/emeu/mecs/mecs2002/.

within this industry that reported to EIA, all use electricity and 88% use gas in their processes. While the preferred approach would be to calculate energy demand per square foot, the proposed plant is assumed to be small, with a footprint of less than half a typical U.S. plant and less than one third of the average number of employees in a U.S. plant. Therefore energy demand per employment-size category provided a more relevant approach. Calculating for 35 employees, based on the MECS average for small plants (less than 50 employees) of 538.1 MMBtu/employee, the proposed plant would consume 5,250 MWh over 2,080 hours (one 8-hour shift per weekday), with a load of 2.5 MW. Gas demand would be 54.9 MMcf over the year.

5.9.5 Rolled Steel/Pipe Forming

A rolled steel/pipe forming industry has been proposed for South Central Alaska to complement the proposed Spur Pipeline construction by supplying formed steel pipe for the pipeline. Although no business plan or written proposal has been identified, the Alaska Natural Gas Development Authority (ANGDA) has expressed interest in attracting this type of industry to the South Central region, and the Shaw Group of Baton Rouge, Louisiana, has approached ANGDA regarding building a pipe forming facility in Alaska to export products to Japan.

In the proposed industry, finishing processes are used to clean the surface of semi-finished, hot-rolled steel products prior to cold rolling or forming/coating operations. Steel that has been hot-rolled and cleaned (pickled) may be cold-rolled to produce a thinner, smoother product suitable for a variety of uses. Pipes and tubes are cold rolled. Cold rolling hardens the steel; to form it, annealing is required. Gas burners indirectly heat coils that are unwound and passed through the furnace.[80] Shaw's pipe fabrication facilities are capable of producing an aggregate of 35,000 pipe spools (10,000 tonnes of products) per month. Shaw has state-of-the-art automated welding and bending machinery in four international and seven U.S. facilities.[81] It is assumed that any facility built in Alaska would be considerably smaller.

Factors affecting production in this industry include semi-finished steel shapes, pickling acids, molten salts, electricity and gas, and labor. The average energy intensities of rolling and finishing processes are as follows:[80]

Processes	Energy Use/Tonne
Reheat Furnace Avg	1.6 MMBtu
Modern Furnace	1.4 MMBtu
Hot Rolling	0.8 MMBtu
Acid Pickling	1.2 MMBtu
Cold Rolling	0.7 MMBtu
Cleaning/Annealing	1.0 MMBtu

The proposed Alaska facility would employ about 50 people. Based on data reported for formed-pipe products in EIA's 2002 MECS, such a plant would consume 4,900 MWh over 8,760

[80] Energetics, Energy and Environmental Profile of the U.S Iron and Steel Industry, DOE/EE-0229, August 2000.
[81] The Shaw Group, Fabrication and Manufacturing, http://www.shawgrp.com/Markets/Fabrication/default.aspx.

hours (24x7), with a load of 0.56 MW. Gas demand would be 24.4 MMcf over the year, based on the MECS reported average of 1,502 MMBtu per employee for NAICS code 3312 (steel products from purchased steel), formed pipe products (NAICS 331221), for small plants (50 to 99 employees).[82] All the U.S. manufacturers in this industry use electricity and 92% consume natural gas. The electricity and gas demand for this proposed industry was included in the integrated analysis but a netback calculation was not conducted.

5.10 Industrial Conclusions

The gas demand and economic feasibility of three dry gas-intensive industries and two NGL intensive industries were assessed in a model for calculation of netback prices. Netback gas prices establish the highest economically attractive price of feedstock that can be charged at the gate to the industry. Higher netback prices suggest lower risk and a more secure investment. The industrial netback results are summarized in Table 15.

Table 15: Summary Assumptions and Netback Prices for Favored Scenarios for Each Modeled Industry (2005$)

	Modeled Industry				
	LNG	**Fertilizer**	**GTL**	**Petrochemical**	**LPG**
Capacity	**MMTPA**	**MMTPA**	**bbl/d**	**MMTPA**	**bbl/d**
Production	1.7	1.25 Ammonia 1.00 Urea	50,000	1.265 Ethylene 0.840 PE 0.622 MEG	63,000
Price/Cost Assumptions	**MMBtu**	**Tonne**	**MMBtu**	**Tonne**	**Tonne**
Product Price	$4.90	$224 Ammonia $184 Urea	$9.15	$1,065 PE $656 MEG	$298
Demand	**MMcf/d**	**MMcf/d**	**MMcf/d**	**MMcf/d and bbl/d**	**bbl/d**
Natural Gas	212	145	496	3	0
Ethane	0	0	0	75,000 bbl/d	0
Propane & butane	0	0	0	0	63,000
Netback	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**	**$/MMBtu**	**$ /MMBtu**
Before Taxes	$3.01	$2.98	$3.75	$6.07	$4.69
Taxes	$0.23	$0.19	$0.57	$1.44	$0.51
After Taxes	$2.78	$2.79	$3.18	$4.63	$4.20

Source: SAIC

[82] Energy Information Administration, Manufacturing Energy Consumption Survey 2002, Tables 1.1, 1.4, 6.4, 7.1, and 9.1 (NAICS 3312), http://www.eia.doe.gov/emeu/mecs/mecs2002/.

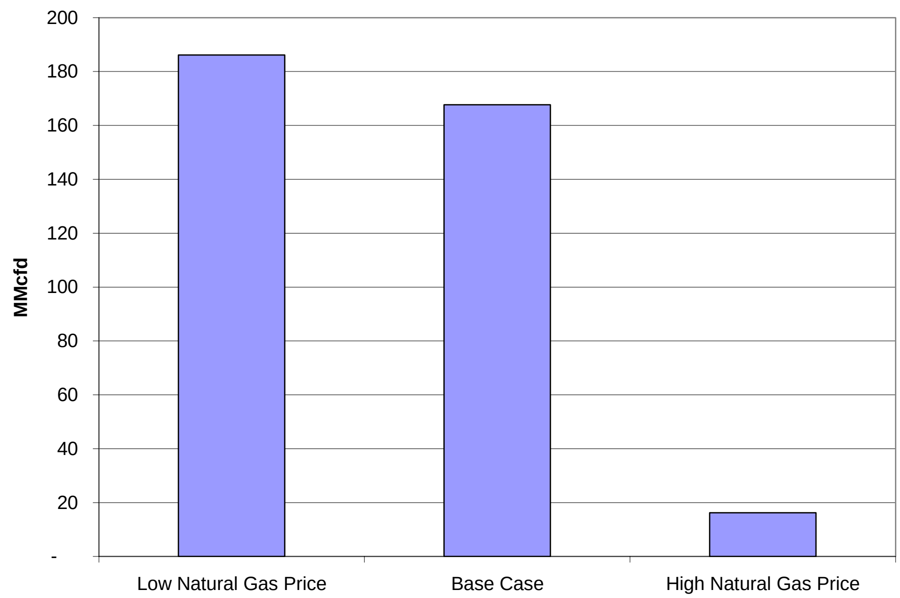
6.0 Potential Gas Demand in the Power Sector

6.1 Background

This chapter provides estimates for natural gas consumption in the electric power sector. The analysis is limited to the interconnected portion of the electric power grid encompassing Fairbanks, the Metropolitan Anchorage region and the Kenai Peninsula. Through a dispatch model of the region's existing electric power system, the approach makes economic decisions for what technology and fuel will be used to minimize costs in the long-run for customers.

The analysis considered three natural gas price scenarios to determine the relationship between price and demand for natural gas in the electric power sector. Figure 37 illustrates this relationship for 2025.

Figure 37: Estimated Natural Gas Usage for the Electric Power Sector for 2025



Source: SAIC

As Figure 37 illustrates, a very small difference exists between the Base and Low Natural Gas Price scenarios. In these two scenarios, natural gas dominates all new generation unit construction. In contrast, the High Natural Gas Price Case triggers the construction of a number of new coal-fired electric generations units that significantly displace not only new but existing natural gas fired electric generation.

Key findings are:

- Natural gas demand for power generation in South Central Alaska will grow significantly. At an average price between \$5.00/MMBtu and \$6.00/MMBtu at the power plant gate, natural gas penetration in the power sector is substantial, and can double from 93 MMcf/d currently to 140 MMcf/d in 2015, 131 MMcf/d in 2025, and 148 MMcf/d in 2035.

- Natural gas demand in Central Alaska will grow from zero currently to 11 MMcf/d by 2015, 37 MMcf/d by 2025, and 42 MMcf/d by 2035.

- Coal loses out to natural gas due to higher capital cost, but captures almost all new growth in the high natural gas price case.

6.2 The Electric Power System in South Central Alaska

The interconnected electric system for South Central Alaska (the Railbelt System) consists of a number of electric utilities in Fairbanks, the Greater Anchorage Area and the Kenai Peninsula. Table 16 lists the main transmission areas and the corresponding electric utilities.

Table 16: Transmission Areas and Utilities in the Railbelt System

Transmission Area	Utility
Anchorage	Anchorage ML&P
	Chugach Retail Load
	Matanuska
Kenai	Seward Electric System
	Homer Electric
Fairbanks-Healy	Golden Valley Electric Association

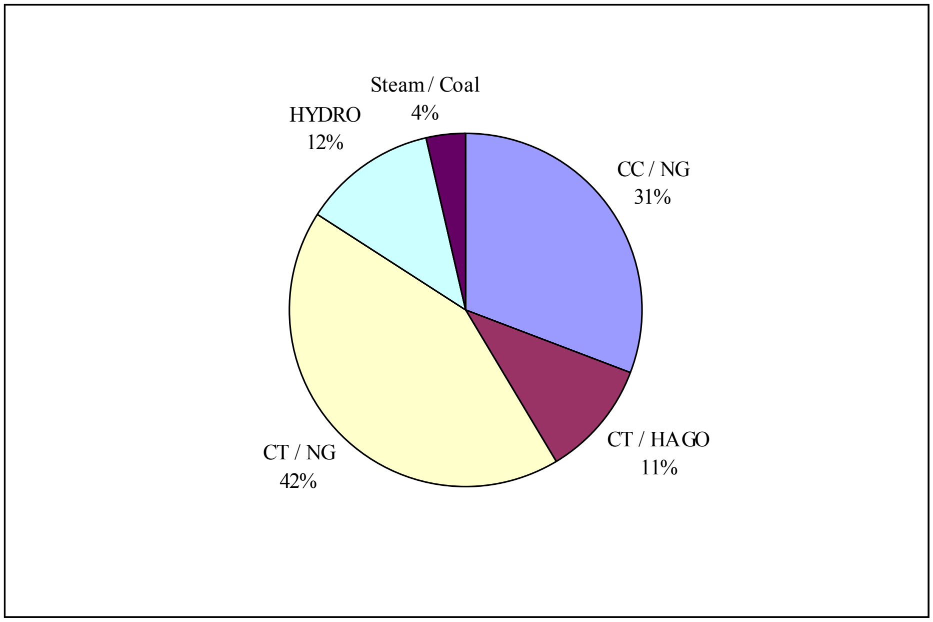
Source: SAIC

The total system peak load of the Railbelt System is 758 MW. This makes the Railbelt System small by standards for utilities in the Lower 48 States. The resource mix of the existing generating portfolio is illustrated in Figure 38.

The Railbelt System is characterized by an extremely high percentage of Simple-Cycle Combustion Turbine (SCCT) generating units. This situation exists for a variety of reasons: (1) historically, natural gas from the Cook Inlet has been sold to a captive market, depressing prices; (2) smaller system loads have limited generating technology choice to smaller sized units; and (3) technologies capable of rapid dispatch have been chosen to minimize outage time if a unit should fail.

The Railbelt System is isolated from all other electric grids in North America. As such, it must be self sufficient in providing electric supply to its customers. The isolation also poses special challenges in providing reliable service to customers.

Figure 38: Existing Portfolio of Resources for the Railbelt Utilities – Capacity in Megawatts



CC = Combined Cycle, CT = Combustion Turbine, HAGO = High Atmospheric Gasoil, NG = Natural Gas
Source: R.W. Beck

6.2.1 Unique Characteristics of the Power Sector within Alaska:

1) Smaller electric utilities within Alaska have different and more limited choices for the type of electric generation technology that can be installed. First, smaller electric generating equipment is more costly because such systems do not achieve the economies of scale of larger generators. For example, a combined-cycle combustion turbine installed in the 500 MW size range will cost $700 to $900 per kilowatt. The same technology installed in a 60 MW size will cost approximately $1300 per kilowatt. The lack of economies of scale influences utility decision making, in turn affecting the quantity of natural gas consumed for electric generation.

2) Another unique characteristic of the Railbelt System is the limited transmission interconnections between the utilities. Railbelt can be characterized as three interconnected electric grids. The three grids are served by linear transmission interconnections, as opposed to a network transmission system that features multiple interconnections between load centers and a high level of reliability in the event of a generation or transmission system outage. The Railbelt's geographic layout makes a network transmission system infeasible.

3) Reliability is a critical standard of performance for electric utilities. Reliability is maintained by installing generation equipment capable of rapid dispatch and by maintaining a very high level of unloaded or not fully utilized generators ("spinning reserve"). Another strategy for maintaining the necessary reliability required by customers is to maintain a high reserve margin. A utility's reserve margin is the excess level of generation over and above the forecasted peak load. A typical utility in the Lower 48 states maintains a reserve margin in the range of 15 to 20%. In contrast,

reserve margins of 40% are common in the Railbelt System. The high reserve margins are a reflection of the risks involved in a unit failure ("trip") and indicate which resources would be required to be synchronized with the electric grid to avoid a collapse of the electric power system.

4) Load factor is the relationship between peak load and level of utilization. A typical electric utility in the Lower 48 States experiences a load factor of 45 to 55%. In the Railbelt Systems, electric utilities encounter load factors in excess of 70%. The higher load factor encourages utilities to install generating technologies with higher capital costs and faster dispatch response.

6.2.2 Drivers for Natural Gas Demand in the Electric Power Sector in Alaska

Natural gas demand for electric power usage in South Central Alaska is ultimately driven by electricity demand, relative fuel pricing, and the relative efficiency of the generators employed. Although natural gas usage for electric power is currently 34 Bcf per year, this quantity could change substantially in the future. Such a change may not be proportional to the amount of electric power generated for the following reasons.

- Natural gas is available for electric power generation throughout the interconnected electricity grid in Alaska with the exception of Fairbanks. Traditionally, natural gas has been very inexpensive and only competed with existing hydroelectric technologies as a viable fuel choice. However, with the introduction of an interconnected natural gas supply with the balance of the continent, local prices will be driven by continental prices. The increase in natural gas prices can make technologies using competing fuels such as coal more attractive (coal prices may not go up due to Alaska's geographic isolation, but coal plant capital costs could be a deterrent in rapid new coal capacity builds).

- The existing inventory of electric generating units in the interconnected portion of Alaska is generally older and less efficient. As new more efficient generating units are introduced they will be able to generate the same quantity of electric power using less fuel. For example, the average heat rate of existing natural gas fired plants in Alaska is 11,000 Btu/kWh; as new efficient plants are built, heat rates could go down to 7,000 Btu/kWh (a decrease of more than 35%).

6.3 Electric Power Market Modeling Methodology

The estimated natural gas demand for electric generation requires a forecast of generation utilization, retirement of existing generating units, and additions of incremental generating units throughout the planning horizon. This was accomplished through a simulation of the dispatch of the interconnected Railbelt System using a proprietary electric power model.

In general, technologies with higher capital costs have lower operating costs and technologies with lower capital costs have higher operating costs – higher per unit capital investments are made to improve the economic efficiency of the technology. An example of this relationship is a simple-cycle combustion turbine and a combined-cycle combustion turbine. The simple-cycle combustion turbine is a large jet aircraft engine with a generator attached. The high-temperature exhaust gases are vented into the atmosphere. A combined-cycle unit adds a heat recovery steam generator (HRSG) to the back end of the combustion turbine to recover the heat lost in a simple-cycle configuration. The HRSG captures the heat from the exhaust gases and uses it to generate steam. The steam then operates a steam turbine attached to a generator, producing electric power in excess of that created by the jet engine. The recovery of the heat that is wasted in the simple-cycle combustion turbine increases the overall efficiency (heat rate) of the generator. The tradeoff for the increase in efficiency is a higher capital cost.

When estimating what new generation will enter service, and what existing generation will be retired, the economics of the total system must be considered. Modeling the expansion of the electric system requires that at any given point in time a decision is made to: (1) Retire one or more generating units that are currently being operated; (2) Add new generation to meet increases in peak demand; and (3) Add new generation units to reduce overall system operating costs.

To perform this forecast for the Railbelt System, the Study used a long-run dispatch model called Market Power® from New Energy Associates. Market Power provides a simplified dispatch of the electric power system using a linear programming algorithm. This algorithm provides the dispatch assuming cost minimization across the region.

Market Power calculates incremental generation additions based upon economic introduction of new plants and retirements of old units. New units are added when the market-based revenues received by that unit overcome the variable and fixed costs of adding that unit (on a net present value taking into account all future years simultaneously; i.e., the net present value of future revenue streams should be positive). The variable costs are defined as the incremental fuel and consumables associated with dispatching the plant. The fixed costs are the fixed O&M and capital recovery associated with installing and maintaining the unit as available for service.

Units can be withdrawn from service ("idled" or "mothballed") if the unit does not receive revenues sufficient to cover the fixed and variable costs of operation. In that case the unit is withdrawn from the dispatch order and the dispatch of the system is recalculated.

6.3.1 Comparisons to Integrated Resource Plan Analyses

Although this analysis has many elements in common and uses tools similar to those used in Integrated Resource Plan (IRP) analyses, there are differences. An IRP analysis focuses on minimizing the costs of a utility or group of utilities subject to internal constraints such as the ability to finance assets. The goal of this Study was to provide baseline and alternative scenarios for natural gas demand for the electric power sector. For example, this analysis did not examine issues that would be critical to an IRP analysis such as the exact date for the installation of a specific generating unit. The Study adopted a more macro view in which electric power plant capacity was added over time to meet electric demand growth. Economics dictated new plant build decisions. It is recognized, however, that an IRP may conclude that assets may be deployed earlier or later due to other constraints.

Further, the Study evaluated the electric power market in South-Central Alaska as a wholesale market. Issues such as specific asset ownership were not considered and it is assumed that assets will be constructed and deployed economically to serve physical load. Existence of contractual obligations and other institutional arrangements were ignored but would have to be considered in an IRP analysis.

For long term market modeling, such as the one conducted here, economic modeling of the electric power sector in the region is reliable and is capable of providing interesting insights into natural gas penetration in the electric sector. Natural gas demand estimates derived from such an analysis are indicative of market evolution over time, if everyone acts rationally with sound economic decision making fundamentals. However, specific results outside of the estimation of natural gas demand may differ from existing and future IRP analyses.

6.4 Assumptions

The Study team visited and held teleconferences with all of the utilities in the Railbelt to collect specific information and data on their operations. Several studies were also examined to define certain conditions:

- Integrated Resource Plan – Chugach Electric System – R.W. Beck, 2004
- Railbelt Energy Study – Ater Wynne, LLP & R.W. Beck, 2004[83]

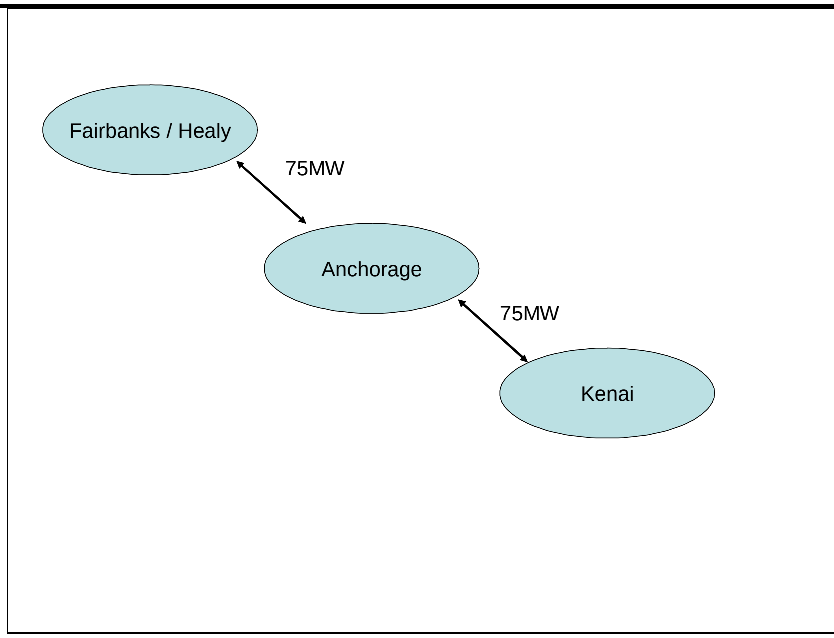
Although a significant amount of data is used from these studies, assumptions have been altered and new forecasts of critical inputs created to reflect current market behavior expectations.

6.4.1 Transmission

The Railbelt is composed of three distinct transmission areas: (1) Fairbanks/Healy; (2) Anchorage; and (3) the Kenai Peninsula. Each transmission area is defined as a relatively integrated network of load and resources. Figure 39 illustrates the interconnections between the three transmission areas.

[83] Beck, R.W., "Railbelt Energy Study," January 15, 2004.

Figure 39: Transmission Interconnections between the Railbelt Transmission Areas



Source: SAIC

Although the transmission interconnections are capable of delivering energy and capacity, local reliability could be compromised if the full rating of a transmission interconnection between regions was used to move capacity on a long-term basis. To avoid this situation, the Study limited capacity transfers between regions to 50% of the line rating while allowing energy to move at the full rating of the transmission line. Transmission constraints within a region were assumed not to exist.

It is assumed that transmission costs for normal hourly transactions would be recovered under existing agreements and no incremental cost would be incurred. This allows robust economic exchanges of power and coordination to occur.

6.4.2 Existing Portfolio of Generation Units

Table 17 shows the existing generation portfolio for the Railbelt utilities. The table shows that the current generation portfolio for the Railbelt Utilities is dominated by natural gas fired simple-cycle combustion turbines with the exception of Fairbanks. In Fairbanks High Atmospheric Gasoil (HAGO) - a heavy liquid petroleum fuel - and coal are the primary boiler fuels for electric power generation.

Table 17: Existing Generation Portfolio in the Railbelt

Name of Generating Unit	Category	Area	Maximum Capacity (MW)
South Central Alaska			
Aurora Chena	Steam Coal	Golden Valley	25
Beluga 1	Simple Cycle CT	Anchorage ML&P	20
Beluga 2	Simple Cycle CT	Anchorage ML&P	20
Beluga 3	Simple Cycle CT	Anchorage ML&P	69
Beluga 5	Simple Cycle CT	Anchorage ML&P	73
Beluga 6/8	Combined Cycle CT	Anchorage ML&P	109
Beluga 7/8	Combined Cycle CT	Anchorage ML&P	109
Bernice Lake 2	Simple Cycle CT	Homer Electric Association	19
Bernice Lake 3	Simple Cycle CT	Homer Electric Association	28
Bernice Lake 4	Simple Cycle CT	Homer Electric Association	23
Bradley Lake	Hydro	Homer Electric Association	90
Cooper Lake	Hydro	Homer Electric Association	20
Eklutna	Hydro	Homer Electric Association	40
International 1	Simple Cycle CT	Anchorage ML&P	15
International 2	Simple Cycle CT	Anchorage ML&P	15
International 3	Simple Cycle CT	Anchorage ML&P	19
ML&P Unit 1	Simple Cycle CT	Anchorage ML&P	17
ML&P UNit 2	Simple Cycle CT	Anchorage ML&P	17
ML&P Unit 3	Simple Cycle CT	Anchorage ML&P	20
ML&P Unit 4	Simple Cycle CT	Anchorage ML&P	35
ML&P Unit 5/6	Combined Cycle CT	Anchorage ML&P	49
ML&P Unit 7/6	Combined Cycle CT	Anchorage ML&P	110
ML&P Unit 8	Simple Cycle CT	Anchorage ML&P	88
Nikiski	Simple Cycle CT	Homer Electric Association	42
Central Alaska			
Healy 1	Steam Coal	Golden Valley	25
North Pole 1	Simple Cycle CT	Golden Valley	63
North Pole 2	Simple Cycle CT	Golden Valley	63
Healy Clean Coal		Homer Electric Assoc. (tentative)	50

Source: SAIC

6.4.3 Peak Demand and Energy Requirements

The Study team contacted the utilities in the Railbelt for current peak load and energy forecasts. Table 18 shows average annual energy and demand growth rates.

Table 18: Annual Energy and Demand Growth Rate

Utility	2006-2010	2010-2020	2020-2025
Fairbanks	1.78%	2.10%	2.10%
CEA	1.01%	1.41%	1.97%
MEA	2.45%	2.45%	2.98%
ML&P	0.56%	0.81%	0.94%
HEA	-0.85%	0.53%	0.43%
SES	0.81%	0.56%	0.37%

Source: SAIC

The Base Case scenario also incorporated the new industrial load discussed elsewhere in this report. Specifically, the analysis includes 300 MW of electric power demand from the Pebble Mine project in 2010, at virtually a 100% load factor.

6.4.4 Cost and Performance Characteristics of Power Plants

The small load centers in the Railbelt System limit utility options for new generating units. Many of the technologies currently commercially available are too large to be installed in significant quantity. Although a single unit of this size may be appropriate for this region, multiple units could trigger operational problems impacting local area reliability.

Table 19 lists the technologies used in modeling the Railbelt Electric System.

Table 19: Technologies Used in Modeling of Railbelt Electric System

New Technologies	Category	Maximum Capacity (MW)	Variable O&M (2005$/MWh)	Fixed O&M (2005$/kW-Yr)	Heat Rate (MMBtu/MWh)	Installed Cost (2005$/kW)
Entire Railbelt						
Coal Plant	Steam Coal	50	$ 3.00	$ 35.00	11.875	$ 4,500
South-Central						
LM2500 CCCT	Combined Cycle CT	30	$ 5.30	$ 32.00	9.250	$ 1,483
LM6000 CCCT	Combined Cycle CT	60	$ 5.30	$ 32.00	9.000	$ 1,165
LM2500 SCCT	Simple Cycle CT	25	$ 6.35	$ 16.00	13.625	$ 1,165
LM6000 SCCT	Simple Cycle CT	40	$ 6.35	$ 16.00	12.000	$ 1,165
LMS100 SCCT - Post 2008	Simple Cycle CT	90	$ 6.35	$ 16.00	10.000	$ 1,282
Fairbanks						
GE 6B CCCT	Combined Cycle CT	65	$ 5.30	$ 32.00	9.750	$ 1,150
GE 6B CCCT	Combined Cycle CT	65	$ 5.30	$ 32.00	9.260	$ 1,150
GE 6B SCCT	Simple Cycle CT	42	$ 6.35	$ 16.00	14.875	$ 1,218
GE LM2500 SCCT	Simple Cycle CT	25	$ 6.35	$ 16.00	12.950	$ 1,165
GE LM6000 SCCT - Post 2015	Simple Cycle CT	40	$ 6.35	$ 16.00	11.400	$ 1,165
GE LMS100 SCCT - Post 2015	Simple Cycle CT	90	$ 6.35	$ 16.00	10.000	$ 1,282
GE LM2500 CCCT - Post 2015	Combined Cycle CT	60	$ 5.30	$ 32.00	8.788	$ 1,165
GE LM6000 CCCT - Post 2015	Combined Cycle CT	60	$ 5.30	$ 32.00	8.500	$ 1,165

Source: SAIC

The Study differentiated between units available for construction in Fairbanks versus southern Alaska. The Fairbanks area currently does not have access to natural gas, although access is assumed available in 2015. Furthermore, many of the new high efficiency generating technologies, such as the LM6000, have restrictive fuel quality requirements. Fuels such as HAGO would not be usable in such turbines. Therefore, until such time as the pipeline is installed, the Fairbanks area is limited to either coal plants or the GE 6B technologies burning HAGO. For the South Central region, all technology options are available.

To accommodate technological improvements, the Study assumes that a new family of generation units would be introduced in 2015 that is 5 percent more efficient than previous units.

Additional assumptions and clarifications include:

- A small coal-fired unit would be sized at 50 MW. This size is appropriate for the Railbelt utilities.

- Most wind projects are justified based upon subsidies and/or externally mandated regulatory requirements. In almost all cases, they will not pass an economic test for new capacity; therefore, the Study did not model new wind additions for Alaska.

- The Advisory Committee suggested that a steam generating unit burning residual fuel oil (No. 6) be considered as an additional option. Tesoro Petroleum produces excess residual fuel oil that is currently marketed outside of the region. This fuel could potentially be burned locally at an advantageous price. The Study team, however, decided that the use of residual fuel oil would be highly unlikely. First, constructing a capital-intensive oil-fired steam unit (similar to a coal-fired power plant from a cost and technology standpoint) dependent upon a single fuel source is highly risky and an unlikely resource choice. Second, for this option to be economical, residual fuel oil prices would have to be below those of coal -- $2.00/MMBTU in 2006.

6.4.5 Terminal Retirement of Existing Units

Electric power market analyses typically must consider unit retirements. A terminal retirement occurs when a specific unit becomes so old it is infeasible to continue operating for engineering reasons. The reasons may include metal fatigue or maintenance problems such as replacement parts not being available. For this analysis, however, terminal retirements are ignored. Discussions with the utilities indicate that although a unit may be replaced in the dispatch order, the older units are left in place to provide additional system reliability.

6.4.6 Natural Gas Prices

The EIA *AEO 2005* prices adjusted to South Central prices are used. Appendix D provides the base case price forecast used in the analysis. Although local distribution charges exist, it is assumed that local distribution charges would not influence the incremental dispatch price of natural gas.

Two alternative natural gas prices scenarios are proposed. The high natural gas case assumes a $2.00/MMBtu premium in real terms to base natural gas prices. Conversely, the low natural gas price case assumes a $2.00/MMBtu discount to base natural gas prices.

6.4.7 Non-Natural Gas Fuel Costs

In addition to natural gas, South Central Alaska also uses diesel fuel, coal and HAGO. Diesel fuel is used in such small quantities for electric power generation that ignoring its use will have an inconsequential effect on the results of the analysis.

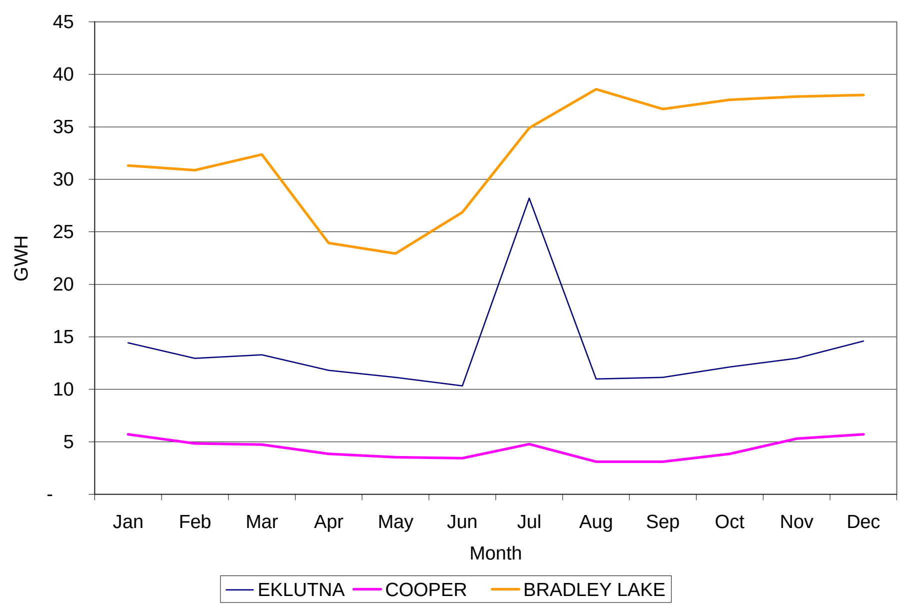
Any new coal-fired power plant development in Alaska will be tied to long-term coal supply contracts. New mine development will likely be required to support these contracts. Therefore, the Study assumes coal supply prices of $2.00/MMBtu in 2006 for new coal-fired power plants. The coal price is then escalated at GDP for the remainder of the forecast time horizon.

HAGO is used extensively in the Fairbanks region. The HAGO price forecast is based on the relationship between HAGO and natural gas cited in the R.W. Beck studies[84] and applying this relationship to future years.

6.4.8 Hydroelectric Dispatch Assumptions

The average annual dispatch of the hydroelectric stations in the Railbelt is detailed in Figure 40.

Figure 40: Distribution of Hydroelectric Dispatch



Source: SAIC

6.5 Forecast of Natural Gas Requirements of the Power Sector

The Study uses a Base Case and two alternative natural gas price cases (a Low Natural Gas Price and a High Natural Gas Price) to forecast natural gas requirements for electric power generation. The results of these cases are provided below in Table 20.

[84] Beck, R.W., "Railbelt Energy Study," January 15, 2004.

Table 20: Summary Natural Gas Usage for the Electric Power Sector (MMcf/d)

Scenario	2006	2010	2015	2020	2025
Low Natural Gas Price	92.25	154.71	156.93	185.57	186.10
Base Case	92.32	145.82	150.11	174.72	167.69
High Natural Gas Price	92.32	91.97	80.98	84.90	16.23

Source: SAIC

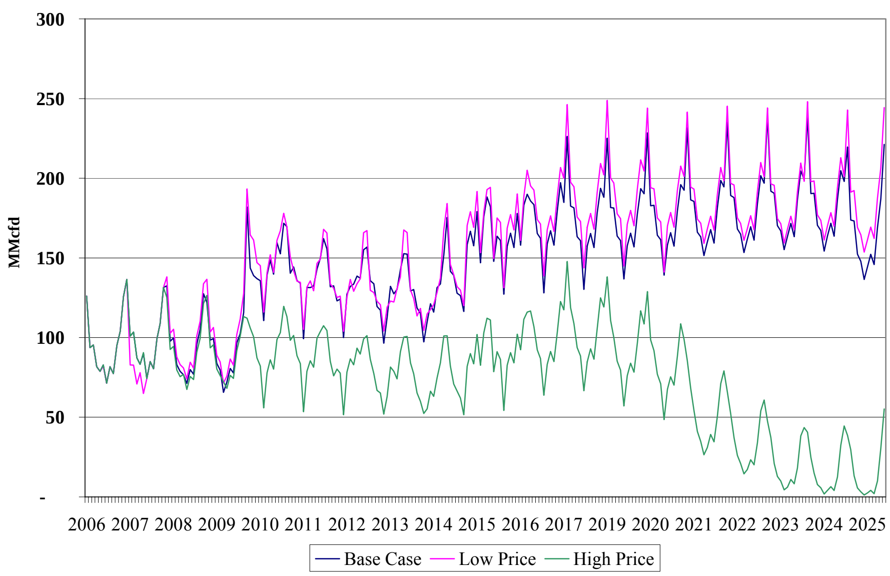
In all cases, initial estimates of natural gas usage for 2006 are relatively close to recent historical values. This result provides support that the modeling is initially mimicking the behavior of the local power market.

The model was tested with historical natural gas prices in order to ascertain if seasonal patterns of natural gas usage were reasonable. Our overall seasonal historical demand for natural gas compared well with historic data. Some of the differences can be attributed to unavailability of exact time of unit maintenance and specific historical peak load curves.

6.5.1 Discussion of Results

The results of the three scenarios for natural gas usage for the electric power sector are summarized in Figure 41.

Figure 41: Annual Natural Gas Usage in the Electric Power Sector



Source: SAIC

The High Natural Price Case triggers a collapse in natural gas demand in this sector. Resource options such as coal become very attractive. Conversely, the difference in natural gas usage for the Base case and the Low Natural Gas Price cases is minimal. Essentially all new generation which has natural gas available is using natural gas.

6.5.2 New Electric Capacity Added

The quantity of new generation added by technology for the period 2006 through 2025 is provided is Table 21.

Table 21: Quantity of New Generation Added by Technology (MW)

Scenario	SCCT	CCCT	Coal
Base Case		910	50
High Natural Gas Price		370	1,000
Low Natural Gas Price	42	670	

Source: SAIC

The High Natural Gas Price Case triggers significant coal plant construction for the Railbelt System. Coal-fired generation displaces not only new natural gas units but also the dispatch of existing natural gas units.

New generation unit construction in the Base Case scenario is dominated by CCCT, with only a single coal plant (constructed in 2025). Given that a significant percentage of the existing portfolio of the Railbelt System is SCCT more efficient units are demonstrated by the market to perform better economically.

The Low Natural Gas Price case contains virtually all CCCT plants with the exception of a single SCCT. Lower gas prices provide a much smaller economic incentive for the utilities to replace older less efficient technologies.

7.0 Cook Inlet Supply and Storage

7.1 Introduction

Cook Inlet's large natural gas reserves have been largely depleted, as documented in a recent report examining historical production and future production prospects.[85] Four major fields anchor Cook Inlet production, accounting for 74.8% of current production: Beluga River, North Cook Inlet, McArthur River, and Kenai. Three smaller fields contribute 18%: Beaver Creek, Cannery Loop, and Ninilchick. Other, still smaller fields collectively contribute less than 8% of production.

Continued exploration for structural and stratigraphic plays and smaller fields, coupled with continued reserves growth, are required to sustain production. The demand response will depend on the price signals associated with evolving production trends.

Other potentially significant natural gas resources include coal bed methane and wildcat exploration in Bristol Bay and Copper River Basin. Exploration activity will likely increase as a results of increasing gas prices and future price projections. However, estimating additional supply from reserves growth and exploration is beyond the defined scope of this study.

The estimated technical remaining reserves (TRR) and the estimated technical ultimate recovery are determined. TRR estimates and production forecasts are analyzed with a detailed economics model of Cook Inlet operations to determine the economic production limit by field. The aggregated economic production is used to determine estimated remaining reserves and the estimated ultimate recovery.

The objective of this analysis is to determine the amount of the Cook Inlet reserves that are economically recoverable, and assess current and future storage capacity needed for peak shaving. The development of current economically recoverable reserves estimates requires an update of the estimated technically recoverable reserves, price deck, and production forecasts that are in the 2004 South Central Alaska Natural Gas Study.[85]

7.2 Methodology

The Cook Inlet gas supply forecast is bounded by engineering and economic analysis considering currently technically recoverable reserves. Technical remaining reserves and technical ultimate recovery are determined from analysis of the production data. The resulting production forecast is then used in an economic model of the Cook Inlet[85] to determine the estimated remaining reserves and estimated ultimate recovery to an economic limit determined under different price assumptions.

[85] Thomas, C.P., Doughty, T.C., Faulder, D.D., and Hite, D.M., South Central Alaska Natural Gas Study, US DOE Contract DE-AM26-99FT40575, June 2004.

7.2.1 Production Forecast and Technically Recoverable Reserves

Production data for each field were updated through August 2005. Technically recoverable reserves are estimated from production forecasts. Production forecasts are estimated with material balance methods that use historical production and pressure data to estimate the original-gas-in-place (OGIP).[86,87] This accepted method relies on a plot of cumulative gas production (G_p) from a pool on the ordinate and the average pressure divided by the gas deviation factor, (p/z) on the abscissa. A volumetrically behaving reservoir corresponds to a straight line, while water influx may cause the volumetric line to deviate from the theoretical response. The OGIP is estimated at the intercept where $p/z = 0$. Water influx into the reservoir can cause the plot to shift to the right indicating larger gas in place than a volumetrically behaving reservoir. If water influx reaches the production wells, the plot will shift to the left due to increased water production and fluid loading in the well, indicating decreased gas in place.

A second method relies on Arps empirical production decline curve method.[88] A combination of these two methods is used to develop individual production forecasts for the seven large fields, the other fields as one aggregate field, and proved undeveloped reserves. Reserves growth and exploration are not considered in this analysis. As such, the presented production forecast is likely conservative.

7.2.2 Economically Recoverable Reserves and Supply-Cost Curves

The remaining technically recoverable reserve forecasts are applied in an economic model that is used to calculate economically recoverable reserves as estimated remaining reserves (ERR) and estimated ultimate recovery (EUR). This model is explained in detail in a prior study.[81] The model includes a detailed treatment of Alaska hydrocarbon taxation.[89] Economic parameters updated for the new review include:

- production forecast
- historical production and cumulative production
- average reservoir pressure
- assessed property tax valuation
- water production (water-cut curve)
- natural gas price forecast.

A supply-cost curve is developed using the economic estimated remaining reserves for gas produced at either long-term contract or at market prices at then current prices using the annual weighted average natural gas cost versus the cumulative gas produced.

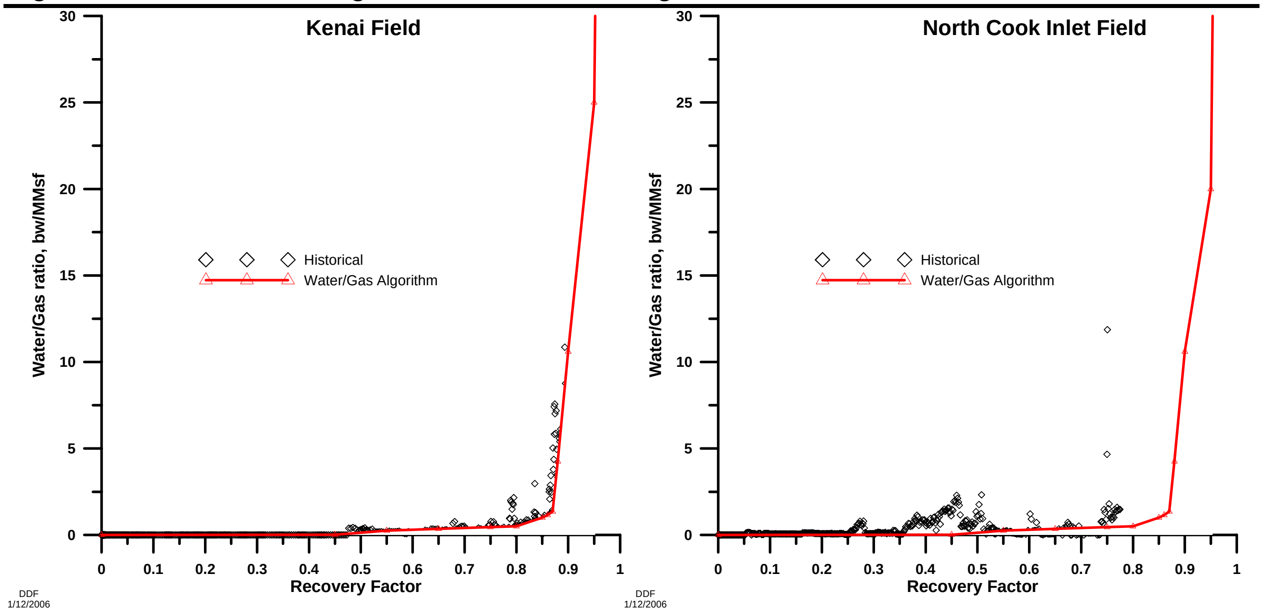
[86] Craft, B.C. and Hawkins, M.F., 1959. Applied Reservoir Engineering, Prentice-Hall, Englewood Cliffs, 39-44.
[87] Dake, L.P., 1978. Fundamentals of Reservoir Engineering, Elsevier Science, Amsterdam, 25-37.
[88] Arps, J.J., 1945. Analysis of Decline Curves, AIME Transactions, 228-247.
[89] State of Alaska Corporate Income Tax, AS 43.20.

7.3 Inputs and Assumptions

Production forecasts are input into the economic model along with historical production data. The economic model is run for each field using the historical production for 2004 and the 2003 property valuations to estimate the year-end 2004 property tax valuations, which were used for the economic evaluations going forward. The tangible property tax valuations used the 2003 Kenai Borough property tax roll.[90]

Water production is estimated using the historical recovery factor versus water-gas ratio (bbls of water/MMcf) and is updated from the prior study.[81] The water-gas ratios for the Kenai and North Cook Inlet fields are presented in Figure 42 with the water-gas algorithm used to forecast water production in the economic models.

Figure 42: Historical water-gas ratio and forecast algorithm for Kenai and North Cook Inlet fields

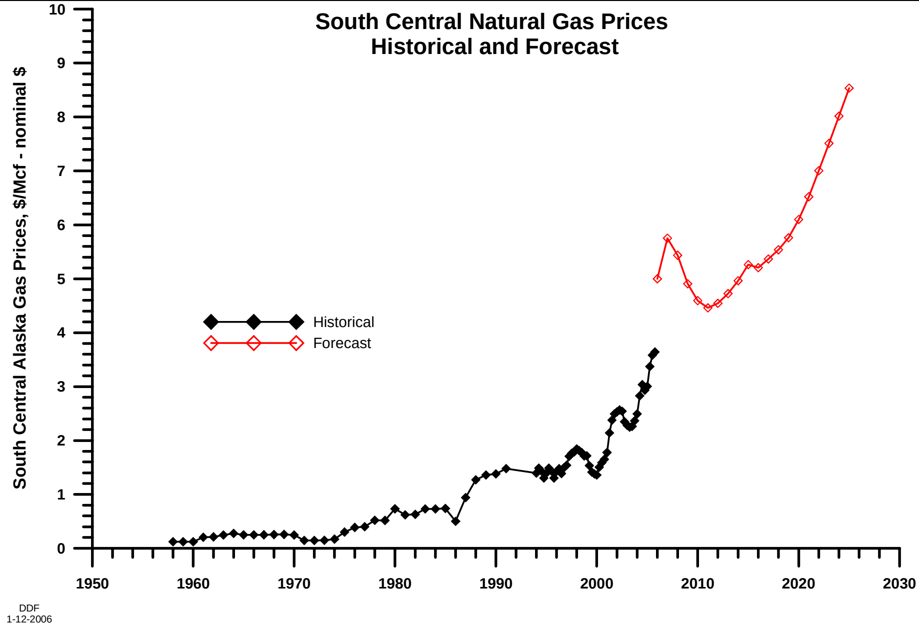


Source: SAIC

The natural gas price forecast is based on EIA's *AEO 2005* for Henry Hub prices. A 36-month lagging average is used to prepare the price forecast for South Central Alaska. A comparison of the historical prices from 1959 through 1991, prevailing value from 1994 through 2005, and the price forecast is presented in Figure 43. The historical time series and price forecast indicate that South Central Alaska natural gas prices will continue to increase, but remain below Lower 48 forecast gas prices.

[90] Assessment Roll for Kenai Peninsula Borough, dated 11/05/2003.

Figure 43: South Central Alaska base case natural gas price (nominal $)



Source: SAIC

Three fields currently sell gas to the Agrium fertilizer and the ConocoPhillips/Marathon LNG facilities: Kenai to Agrium,and McArthur River and North Cook Inlet fields to the LNG facility. It is assumed that the Agrium facility will purchase gas until year-end 2008 and the LNG facility will terminate operations when the current export license expires the first quarter 2009. When operations terminate, the remaining gas will be sold at the then-current natural gas price.

7.4 Cook Inlet Gas Supply Assessment Results

A complete discussion of the individual field production performance through 2025, remaining reserves, and estimated technical remaining reserves is presented in Appendix G. These individual forecasts are aggregated to prepare a composite Cook Inlet gas supply forecast.

7.4.1 Production Forecast

As of December 31, 2004, Cook Inlet fields and reservoirs have a cumulative production of 6,338,623 Mcf.[91] The Cook Inlet historical production and reserves to production (R/P) ratio and the updated production forecast are presented in Figure 44 and Table 22. The production shows the seasonal behavior with a winter peaking demand during seven months of the year. More critical in the near term is the ability of the basin to deliver sufficient gas during periods of peak winter demand. A basin deliverability and storage imbalance currently exists; however, projects are underway by the operators to increase gas storage capacity.[92]

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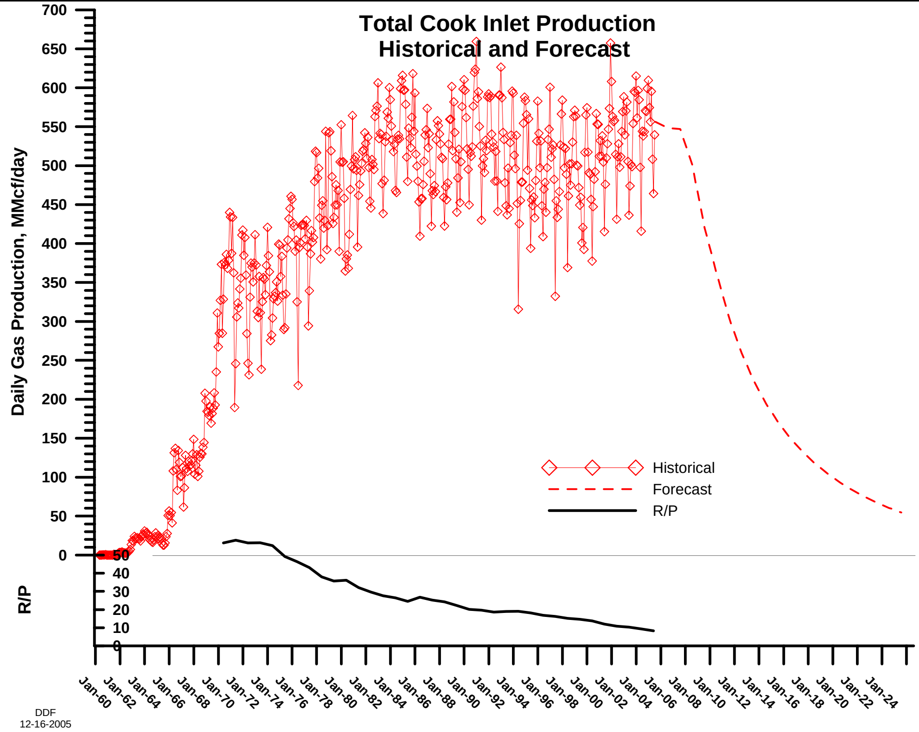
[91] Alaska Oil and Gas Conservation Commission, from production database for Cook Inlet dry gas fields.

[92] Alaska Department of Natural Resources, Division of Oil and Gas, September 13, 2005, Pretty Creek Gas Storage Lease ADL 390776, Final Findings of the Director.

Figure 44: Aggregated Cook Inlet gas production and reserves-to-production ratio



Source: SAIC

Table 22: Forecast Cook Inlet gas production from technically recoverable reserves (TRR) and estimated remaining reserves (ERR)

Year	Bcf/yr	TRR MMcf/d	ERR MMcf/d	Year	Bcf/yr	TRR MMcf/d	ERR MMcf/d
2005	200.2	548.5	548.5	2016	48.2	132.1	127.5
2006	199.7	547.1	547.2	2017	42.8	117.3	113.3
2007	182.6	500.3	500.2	2018	38.1	104.4	101.0
2008	153.1	419.5	419.5	2019	34	93.2	90.3
2009	131.3	359.7	354.3	2020	30.5	83.6	80.9
2010	110.9	303.8	300.8	2021	27.4	75.1	70.6
2011	94.7	259.5	254.3	2022	24.6	67.4	29.7
2012	81.6	223.6	220.3	2023	22.1	60.5	25.9
2013	70.9	194.2	192.2	2024	19.9	54.5	23.4
2014	62	169.9	168.6	2025	18	49.3	14.9
2015	54.5	149.3	148.6	2026	16.2	44.4	0.0

7.4.2 Technically and Economically Recoverable Reserves

Table 23 shows estimates of the remaining technically and economically recoverable gas reserves and ultimate recovery for the large fields and the aggregated remaining smaller fields in addition to cumulative production through December 31, 2004.

Table 23: Cumulative Production and Technically and Economically Recoverable Reserves for Cook Inlet Dry Natural Gas Resources, as of December 31, 2004 (in Mcf)

Field	Np – 12/31/2003	Np – 12/31/2004	2004 Production	Estimated Technically Remaining Reserves	Estimated Technical Ultimate Recovery	Estimated Remaining Reserves	Estimated Ultimate Recovery
Beaver Creek	170,149	178,465	8,316	45,184.0	223,649	35,516	213,981
Beluga River	847,163	904,781	57,618	309,082	1,213,863	308,281	1,213,062
Cannery Loop	110,770	124,410	13,640	44,000	168,410	40,396	164,806
Kenai	2,245,520	2,269,738	24,217	45,682	2,315,420	41,127	2,310,865
McArthur River	963,263	996,428	33,165	147,835	1,144,263	145,165	1,141,593
North Cook Inlet	1,621,353	1,662,365	41,012	568,388	2,230,753	516,866	2,179,231
Ninilchik	3,062	15,430	12,367	183,733	199,163	179,352	194,782
Other	301,368	317,056	15,689	134,247	451,303	132,483	449,539
Proved Undeveloped				185,190	185,190	181,999	181,999
Total Cook Inlet	6,262,649	6,468,672	206,024	1,663,340	8,132,012	1,581,185	8,049,858

Source: SAIC

As of December 31, 2004, the estimated technically recoverable reserves are 1,663.3 Bcf. Approximately 1,581.2 Bcf of this is economic under the assumed natural gas price track, suggesting that approximately 96 Bcf, or about 5.7% of the estimated technically remaining reserves, are uneconomic. This difference between technically and economically recoverable reserves is primarily due to increasing water influx in the older reservoirs and resulting increases in operating costs. The largest reduction occurs in the Kenai field due to rising water production and the associated increase in water disposal costs. The analysis indicates no change in the estimated technical ultimate recovery of 8,132 Bcf. Gas production during 2004 was 206,024 Mcf. The estimated technical ultimate recovery was 7,927 Bcf in the DOE 2004 study, which indicates that about 205 Bcf of technically recoverable reserves have been added in the Cook Inlet since the 2004 study through reserves additions and new discoveries.[93]

7.4.3 Supply-Cost Curve of Technical Remaining Reserves

The supply-cost results are presented in Figure 45. The kink in the curve is due the industrial facilities terminating operations by 2009 and the remaining contract gas supplies are assumed to revert to then current market prices. The supply-cost relationship has the appropriate theoretical shape with the price escalating as proved reserves near exhaustion. The higher order polynomial fit (R^2=0.95) shown suggests the low-cost portion of the curve is linear, with an intercept inferred by the red dashed line at approximately \$1.00/Mcf. This intercept at the abscissa is approximately the estimated Finding, Developing and Acquisition (FD&A) cost of \$0.78/Mcf reported by Unocal in 2003 for Cook Inlet operations.[94]

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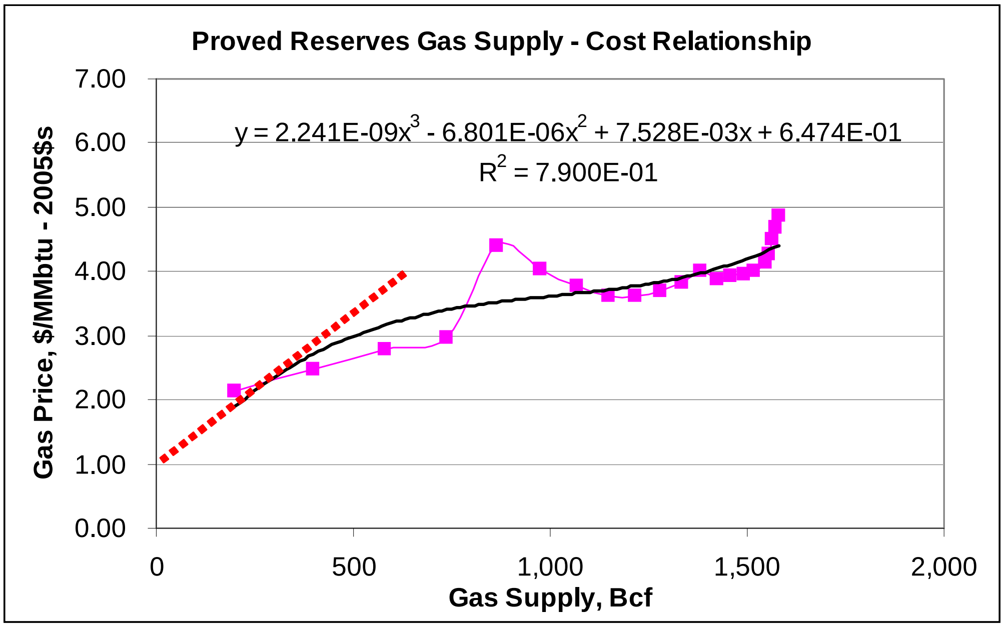
[93] Thomas, C.P., Doughty, T.C., Faulder, D.D., and Hite, D.M., South Central Alaska Natural Gas Study, US DOE Contract DE-AM26-99FT40575, June 2004.

[94] http://www.unocal.com/uclnews/2004ndew/020204.htm, Preliminary 2003 E&P Segment Reserves and Cost Information.

Figure 45: Cook Inlet supply-cost relationship for economic estimated remaining reserves



Source: SAIC

7.5 Cook Inlet Storage

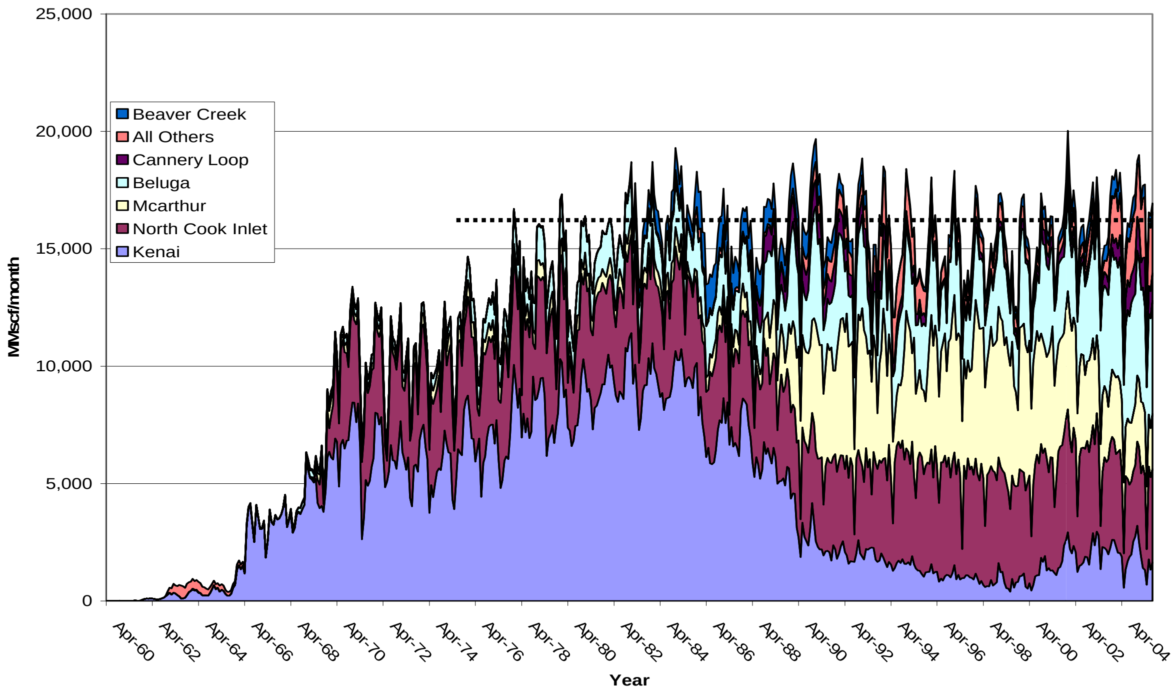
Historically, seasonal fluctuations in demand for Cook Inlet dry gas have been met by adjusting gas production to meet demand. The maximum production rate that can be achieved by the operators will decrease as proved reserves deplete and it will not be possible to continue to meet peak demand periods by increasing production rate. However, during low demand periods, surplus produced gas can be stored for use during peak demand seasons. This practice is referred to as peak shaving. The need for peak shaving will become increasingly important to meet the winter peak demand in the Cook Inlet region. Storage requirements to prevent supply shortfall as long as possible are assessed below, followed by a brief summary of the storage projects.

7.5.1 Storage Requirements

Storage requirements are determined by assessing historical seasonal variability in production. Historical production data for the six large fields and an aggregate of the other fields is shown in Figure 46. The dashed line is a monthly average of 15.7 Bcf/month with seven months above the average and five months below, representing winter and summer demand. This line is constructed to balance the annual production volumes above and below the average for a 14-yr time period. This figure shows the depletion of the old large fields with gas production increasingly being provided by newer and smaller fields.

Seasonal variability is examined in detail in Figure 47, from January 1991 through August 2005. The data are normalized with the annual average production rate required to balance production volumes (15.74 Bcf/month) scaled to 1.0. The average peak is 18.35 Bcf/month or about 117% of the average, the highest peak is 20.113 Bcf/month, and the average minimum volume is 12.65 Bcf/month. This indicates that storage capacity of about 41.6 MMcf/d would be needed during the five months when demand is below the annual average. A peak deliverability of approximately 86 MMcf/d would be required to balance volumes (2.61 Bcf/month). The storage capacity needed to dampen seasonal demand cycles requires an average storage of 6.7 Bcf and peak storage of 15 Bcf. ENSTAR estimates demand for gas on an average annual basis will exceed contracted supply beginning in 2009.[95]

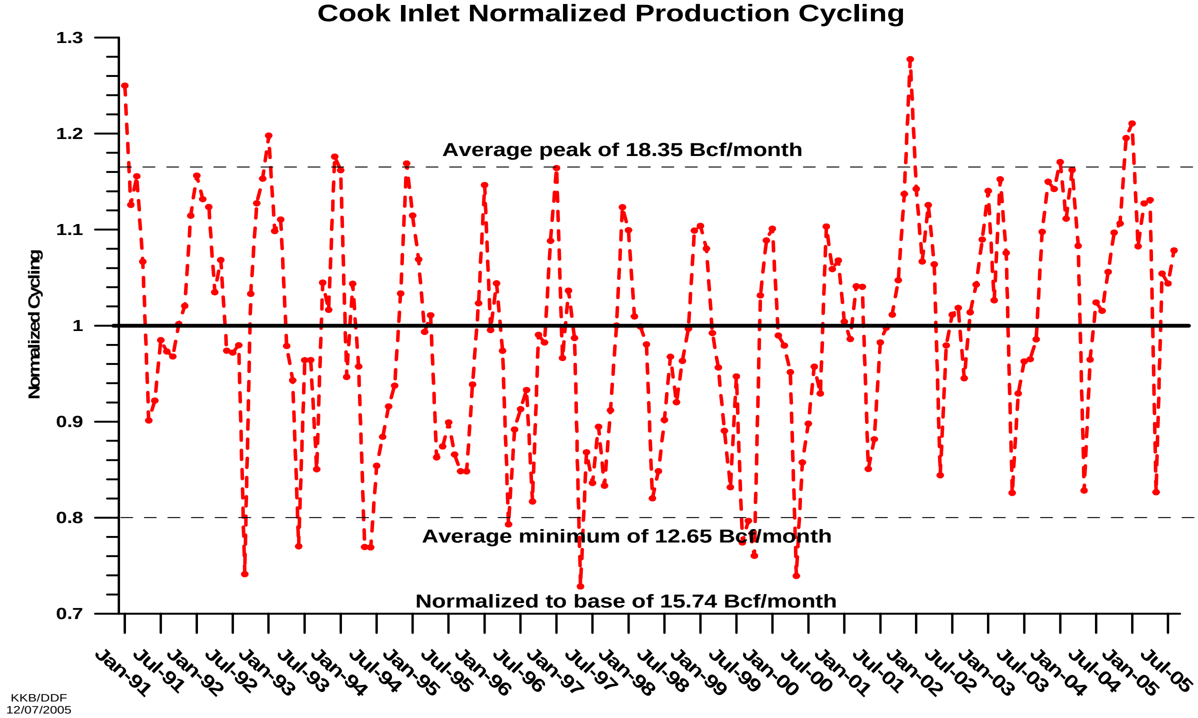
Figure 46: Cook Inlet productions for six large fields and the remaining fields aggregated



Source: SAIC

[95] Alaska Department of Natural Resources, Division of Oil and Gas, September 13, 2005, Pretty Creek Gas Storage Lease ADL 390776, Final Finding of the Director.

Figure 47: Seasonal variations in monthly gas production, from January 1991 through August 2005



Source: SAIC

7.5.2 Storage Projects

The Cook Inlet has very little developed gas storage. Unocal has recently permitted a storage project for the Pretty Creek field,[96] which is currently nearing exhaustion. This was approved in September 2005 and will utilize one well for storage. The proposed Pretty Creek facility could deliver a maximum of 20 MMcf/d to the Cook Inlet gas pipeline grid or 700 MMcf annually during periods of peak demand.[97,98] Peak demand from residential/commercial and power demand surges from 35 MMcf/d in the summer to 200 MMcf/d during the coldest days of winter. The Alaska Department of Natural Resources estimates Cook Inlet will require an additional 9 to 14 Bcf of annual storage capacity to meet peak winter spikes in demand.[97]

[96] Petroleum News, "DNR approves Pretty Creek gas storage lease," Vol. 10, No. 43, October 23, 2005.

[97] Alaska Department of Natural Resources, Division of Oil and Gas, September 13, 2005, Pretty Creek Gas Storage Lease ADL 390776, Final Finding of the Director, page 14.

[98] Petroleum News, "Finding out for Pretty Creek Storage," Vol. 10, No. 39, September 25, 2005.

Alaska Gas Needs and Market Assessment

Appendices

Final

June 2006

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Appendix A: Other Industrials

Industrial Opportunities Disqualified/Not Modeled

This appendix provides the most current and relevant information and data on the cottage industries and other industries explored.

Industry — Seafood Processing

Description — Seafood accounts for 53% of Alaskan exports and the state funds seafood development projects. Most fish processing in Alaska occurs close to the fishing grounds which are far from the South-central region of the State. Canning, processing, chilling, and or temperature-controlled storage of seafood require electricity only and are seasonal (June-August). Highest quality fish are sold fresh, and bigger volume fisheries have air links to markets. Lower quality, non-fresh fish products are frozen and shipped south or exported to Asia. Existing industry is largely locally owned shore-based plants, and decentralized facilities of the major fish producers headquartered in Seattle (e.g., Trident).

Hurdles — South Central Alaska is too far from the State's major fishing grounds, is not on established shipping lanes from those fishing grounds, is distant from large seafood markets, and is not a low-wage area. For these reasons, a large seafood processing facility in South Central Alaska would be at a competitive disadvantage with competing facilities closer to the harvest areas or markets, or located in low-wage regions. The State of Alaska invested over $50 million in an attempt to establish a large fish processing plant in Anchorage, Alaska Seafood International, only to see it fail.

Industry — Value-Added Wood Product

Description — Wood chipping businesses exist near the ports. This opportunity would take the chips and produce a value-added product for in-state and export markets. Different opportunities in Kenai are being investigated, including using beetle-infested birch forests. There's one small sawmill on Kenai that treats and dries lumber. Possible facilities would likely use wood waste in a cogeneration facility and not natural gas.

Hurdles — Environmental limits on logging, lack of major sawmills, finite supplies of destroyed wood, transportation hurdles on roads, rails, and ports all work against such as prospect.

Industry Copper Smelter

Description Gold and copper from Pebble Mine (and possibly Donlin Creek) would have to be shipped to smelters in Canada and elsewhere. Transportation of the unfinished precious metals to smelters adds considerable costs. If a smelter was built in/near the Cook Inlet, Alaska could begin to process its own mined product.

Hurdles The environmental barriers to constructing and operating a smelter in Alaska are likely insurmountable.

Industry Donlin Creek Mine

Description Donlin Creek Mine site is just north of the Koskokwim River in western Alaska. It is estimated to have 20 million oz of gold and possibly diamonds. The Alaska Energy Authority (AEA) was asked by the Denali Commission to work on routing and permit issues for a transmission line between Bethel and Donlin Creek to bring in the 100 MW required by the mine. The study was not completed because Placer Dome determined their best option was to produce power on-site. Placer Dome looked at the possibility of acquiring power from the Railbelt grid, but the cost of a 350 mile transmission line and associated permitting problems proved insurmountable. For those reasons Placer Dome concluded on-site diesel power supplemented with wind power was the way to go.

Hurdles Donlin Creek is more remote than Pebble Mine; further west but not easily connected to the other mine development project. The land-locked situation increases the cost of getting electricity and fuel to the site. The shipping window on the river is 3 to 4 months at best before freeze-up.

Industry Autoclave Aerated Concrete

Description Proposed to AIDEA over two years ago by Jeff Ramsdell [www.aac-nw.com] for export market. Portland cement is mixed with locally-available lime, silica sand (which can be dredged from the Cook Inlet), or recycled fly ash (from coal-burning power plants), water, and aluminum powder or paste and poured into a mold. Steel bars or mesh can also be placed into the mold for reinforcing. The reaction between aluminum and concrete causes microscopic hydrogen bubbles to form, expanding the concrete to about five times its original volume. After evaporation of the hydrogen, the now highly closed-cell, aerated concrete is cut to size and form and steam-cured in a pressurized chamber (an autoclave).

Hurdles Manufacturing the product requires considerable electricity and gas. It was reported that Anchorage Sand & Gravel (the largest such operation in the region) was not interested in expansion.

Appendix B: Spur Line Gas Composition Effects on Supply

The spur line will provide a means to deliver a portion of the stranded natural gas on the 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 (NGLs), 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 NGLs because these components have a higher value per volume than methane.[1] A non-traditional, high-pressure pipeline allows transport of NGLs without development of a separate liquid phase in the line, avoiding the slug flows that occur when a low pressure line includes more NGLs 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 on the Alaska North Slope; each source has a different proportion of methane and NGLs.
- ***Volume of wet gas from which NGLs are separated.*** These NGLs can remain in the ANGP or be separated in varying amounts and used to enrich the gas in a spur pipeline to South Central Alaska.
- ***Percent recovery of NGLs.*** This is determined by the separation technology used for enriching the spur pipeline and used to remove NGLs at the end of the spur pipeline (i.e., Wasilla, Anchorage, or Nikiski).

The following section describes the gas sources at the North Slope; this is followed by the assumptions used in this study regarding gas source, volume from which NGLs are extracted, and percent recovery of NGLs. The final section shows the calculated volume and composition of a wet gas pipeline based on these assumptions.

Gas Sources at Alaska North Slope

Potential sources of gas for the trans-Alaska gas pipeline include feed directly from the North Slope reservoir, and two different gas streams produced by the Prudhoe Bay Unit (PBU) Central Gas Facility (CGF). The CGF is operated to remove NGLs from the natural gas produced at PBU before it is re-injected into the reservoir for pressure maintenance. The NGLs removed or either mixed with crude oil and transported in TAPS to market or used a miscible injectant for enhanced oil recovery in North Slope oil fields. TAPS vapor pressure limitations determine the maximum amount of NGLs that can be transported in TAPS. The CGF processes around 8 Bcf/d of raw gas (directly from the reservoir). Each of the potential sources is described below.

- ***Raw Gas.*** Natural gas removed directly from the reservoir. This gas would pass through a conditioning plant to reduce carbon dioxide (for PBU carbon dioxide is about 12% of the natural gas) to 1.5% prior to introduction into a high pressure pipeline.

- ***Residue Gas.*** This gas is currently produced by the CGF and re-injected into the PBU reservoir after NGLs are removed. The NGLs are compressed and chilled at the CGF to

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

condense some of the ethane and much of the propane, butane, and pentane. Residue gas leaves the top of the low temperature separator. Compared to raw gas, residue gas has more methane, is slightly depleted in ethane, and substantially depleted in propane, butane, and pentane.

- ***Miscible Injectant (MI).*** This gas stream is also created at the CGF. The condensed NGLs removed from the bottom of the separator still contain too many of the lighter NGLs (i.e., ethane and propane) for blending with oil for TAPS. This stream is sent to stabilizer columns where ethane, propane, and about half of the butanes are removed and become miscible injectant (MI), while the remaining stream enters TAPS. Compared to raw gas, the MI stream is highly enriched with ethane and propane, and slightly enriched with butane. Currently, MI gas is injected into floodwater portions of the Alaska North Slope reservoirs to enhance oil recovery.

- ***Re-Injected Reservoir Gas***. It may be possible to recover residue gas and MI gas that has been re-injected into the Alaska North Slope reservoirs as these fields are depleted.

Use of any of the above gas sources would require careful assessment of the ability to maintain the gas source composition over a 20-yr project life. Gas sold from the Alaska North Slope will reduce reservoir pressure, and thus may affect oil production. Blending of multiple gas streams to meet specified South Central demands for methane and each NGL is theoretically possible, but may be logistically difficult.

Gas Source, Volume, and Separation and Extraction Efficiency Assumptions
Recognizing both the need for at least a 20-yr supply of natural gas, and that the use of raw gas may be easier to implement due to its smaller affect on oil recovery, this study assumes that raw gas is used as input to the Alaska Natural Gas Pipeline (ANGP).

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 NGLs. Based on recent designs, extraction of individual NGLs from the liquid stream is assumed to be 100%.

The volume of gas from which NGLs 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 bbl/d 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.

Calculated Gas Composition and Volume of a Wet Gas Pipeline
Two calculations of spur pipeline composition are provided. Scenario 1 provides an example that would be able to supply South Central residential, commercial, and power sectors, and a GTL complex with dry gas, in addition to providing ethane for a petrochemical plant and propane and butane for an LPG industry. The second scenario includes the scenario 1 demand

except for dry gas for the GTL complex. This second scenario would have higher capital or tariff cost associated with gas separation for the petrochemical and LPG industries because a greater volume of gas must be processed by the first straddle separator to obtain a sufficient amount of NGLs. This will also result in the remaining gas in the ANGP being less rich in NGLs that the gas leaving the ANS

Table B-1 shows calculations of spur pipeline composition under Scenario 1, in which 900 MMcf/d of raw gas is processed by a straddle plant separator with an ethane removal efficiency of 95%, and 100% removal efficiency of other NGLs. Separated NGLs are added as enrichment to a 1.0 Bcfd raw gas spur pipeline, yielding a total spur line volume of 1.1 Bcfd. 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 B-1: Scenario 1, Spur line gas composition and volume.[1] *(Assumes ideal gas behavior at 60 F and 14 psia)*

Raw Gas Compon-ent	Raw Gas* Mole %	1st Straddle Input (900 MMscf/d)		1st Straddle Output		Total Spur Input**		2nd Straddle Output	
		MMscf/d	bbl/d	MMscf/d	bbl/d	MMscf/d	bbl/d	MMscf/d	bbl/d
Methane	85.26	767	NA	NA	NA	852	NA	852	NA
Ethane	6.84	62	39,087	58	37,132	127	80,562	121	76,534
Propane	3.44	31	20,250	31	20,250	65	42,749	65	42,749
n-Butane	0.93	8	6,503	8	6,503	18	13,730	18	13,730
i-Butane	0.46	4	3,086	4	3,086	9	6,515	9	6,515
Pentanes	0.93	8	7,234	8	7,234	18	15,272	18	15,272

* Raw gas mole % based on Baker, 2005.
** Total spur pipeline input calculated as 1st straddle output plus 1.0 Bcf/d raw gas.

These spur line inputs and straddle plant efficiencies yield roughly 75,000 bbl/d ethane, meeting the needs of a world class ethylene plant. This line would also supply roughly 63,000 bbl/d of propane and butane for an LPG industry, and 15,000 bbl/d pentanes for sale to other users, i.e., for blending into gasoline.[2] In addition, this line would provide sufficient methane to meet the dry gas demand of the South Central Alaska residential, commercial, and power sectors in addition to supplying sufficient dry gas for a world-class GTL complex.

Table B-2 shows calculation of spur pipeline composition under Scenario 2, in which 1.5 Bcf/d of raw gas is processed by a straddle plant separator with an ethane removal efficiency of 95%, and 100% removal efficiency of other NGLs. Separated NGLs are added as enrichment to a 420 MMcf/d raw gas spur pipeline, yielding a total spur line volume of 594 MMcf/d. This entire stream is processed by a second straddle separator in South Central Alaska (e.g., Anchorage or Nikiski) with efficiencies that are the same as those of the first straddle plant.

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

Table B-2: Scenario 2, 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 (1.5 Bscf/d)		1st Straddle Output		Total Spur Input**		2nd Straddle Output	
		MMscf/d	bbl/d	MMscf/d	bbl/d	MMscf/d	bbl/d	MMscf/d	bbl/d
Methane	85.26	1,279	NA	NA	NA	358	NA	357	NA
Ethane	6.84	103	65,145	97	61,887	126	80,128	120	76,121
Propane	3.44	52	33,749	52	33,749	66	43,199	66	43,199
n-Butane	0.93	14	10,839	14	10,839	18	13,874	18	13,874
i-Butane	0.46	7	5,144	7	5,144	9	6,584	9	6,584
Pentanes	0.93	14	12,057	14	12,057	18	15,433	18	15,433

* Raw gas mole % based on Baker, 2005.
** Total spur pipeline input calculated as 1st straddle output plus 420 MMcf/d raw gas.

These spur line inputs and straddle plant efficiencies yield roughly 75,000 bbl/d ethane, meeting the needs of a world class ethylene plant. This line would also supply roughly 63,000 bbl/d of propane and butane for an LPG industry, and 15,000 bbl/d pentanes for sale to other users, i.e., for blending into gasoline.[3] In addition, enough methane would be available to meet the demand for the South Central Alaska residential, commercial, and power sectors.

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

Appendix C: Tariff Calculations

Introduction

The calculation of pipeline tariffs is a key component of the netback calculation of the natural gas price received from the final delivery point to the wellhead. The estimation of natural gas tariff costs to South Central Alaska requires the determination of tariffs for the large pipeline from the Alaska North Slope (ANS) to Chicago (or at least as far as Fairbanks region or Delta Junction) and tariffs from the Fairbanks region to South Central Alaska. The total tariff for gas delivered to South Central Alaska is the composite of the tariff along this path. An additional nuance is the off-take of natural gas at Fairbanks and delivery to South Central Alaska by the spur pipeline reduces the volume of gas traveling along the rest of the pipeline to Chicago. This off-take requires a compensating tariff adjustment for the gas removed from the ANS to Chicago pipeline to make the delivery tariff of gas to Chicago neutral to the off-take of gas for the spur pipeline. The economic rationale is that the extra volume of gas transported from ANS to Fairbanks will require additional compression for this segment and thus incur additional cost. This section presents the tariff methodology and how different volumes of gas off-take in Fairbanks impacts tariffs for gas delivered to South Central Alaska.

The tariff calculation uses a full life-cycle cost basis that includes the capital cost of: the pipeline, gas separation plant on the North Slope for the removal of CO_2 and other contaminates, compressors, and estimated decommissioning costs after the useful life of the pipeline. The spur pipeline includes the capital cost of natural gas liquids separation plant. Other costs include operating costs, compressor gas usage, capital depreciation, ad valorem, state and Federal income taxes, and the allowable regulatory return on the installed book value of the capital components. The yearly cost of service is the sum of the cost components; operating costs, depreciation, return on the installed book value, ad valorem, state and Federal income taxes, and the yearly amount of the sinking fund for pipeline decommissioning. The tariff is this total annual amount divided by the yearly gas volume throughput of the pipeline segment.

Data used for tariff calculations includes:

- Cost of capital
- Capital cost for pipeline, compressors, and liquid separation facilities
- Regulatory Commission of Alaska filings
- Capital costs are estimated at $15.7828/diameter-inch ft

Economic Model

The Interactive Financial Planning System (IFPS) software package is used to develop an economics model. This model is used to determine the cost of service calculations and the tariff requirements.

The following assumptions are used in the economics model:

1. A 30-yr project life.

2. The capital costs for the spur pipeline varied with pipeline size and volume throughput and for compression and NGL separation facilities. These costs were estimated using results from a recent study by Baker.[4]
3. The ANS pipeline costs include pipe, compression facilities, and a gas plant on the North Slope for the removal of natural gas contaminates.
4. An ad valorem rate of 2% of the adjusted property tax basis, with no ad valorem during the construction period.
5. The property tax basis is adjusted for inflation, divided by the remaining project life.
6. Depreciation used a double-declining balance switching over to straight line.
7. Income taxes are assessed at a 35% Federal and a 9.4% state rate
8. No general inflation is used.
9. The capital structure uses a 50% equity and 50% debt basis.
10. Capital and non-fuel operating expenses are based on 2005 dollars.
11. Non-fuel operating costs are 2.5% of the installed capital.
12. Fuel consumption is 1.1% of the pipeline gas volume.
13. Pipeline decommissioning costs are 2% of the installed capital.
14. The weighted cost of capital is 9.97%.
15. The discount rate is 12%.

Cost of Service

The annual cost of service was used to estimate the yearly tariffs required to achieve a return of capital levelized for the life of the project. The annual cost of service is the sum of the operating costs, depreciation, regulatory return on the installed capital, decommissioning costs (as a sinking fund), ad valorem, and state and Federal income taxes. The annual tariff is the cost of service divided by the annual pipeline volume, Q_t. The tariffs used in the economic model are averaged over the time period 2015 and 2027 and are in 2005$. Mathematically, the annual tariff is:

$$tarifff_t = \frac{\sum_{2015}^{2027} OpEx_t + Depr_t + CaptialR_t + Decomm_t + AdV_t + IncomeTax_t}{Q_t}$$

The tariff time series was then averaged over the 12-yr period for a levelized tariff. The annual tariffs vary due to differences primarily in the timing of depreciation, interest on debt, operating cost inflation, and property valuation methodology. The operating cost is assumed to be 2.5% of the cumulative capital cost and to increase 2.4%/yr. Depreciation used a double-declining balance switching over to straight line. The return on capital is the weighted average cost of capital times the book value of the capital asset. Decommissioning costs are 2% of the cumulative installed capital expensed as a sinking fund. The property valuation is determined by:

$$Valuation_t = \left(Valuation_{t-1} + \frac{Valuation_{t-1}}{(T-t)} \right)(1+f)^t + Capital_t$$

[4] Michael Baker, Jr., Inc., 2005, Transport of North Slope Gas to Tidewater, for the Alaska Natural Gas Development Authority.

The current year valuation is a function of the previous year valuation adjusted for the remaining project life *(T-t)* and inflation and any capital expended in the current year. Income taxes are the statutory rate times the BFIT. State income taxes are a deduction for Federal taxes.

Estimated Pipeline Size

Through the focus of this effort is not to recommend a pipeline size, the evaluation required the examination of a range of potential off-take volumes. Over the range examined, 100 to 1,200 MMsf/d, the optimal combination of flowrate and capital expense varies. Thus, an engineering basis is used to estimate pipeline size and flow rates. Pipeline size estimates for the spur pipeline at different design rates uses the empirical Panhandle Eastern equation.[5]

$$Q = 883E\left(\frac{P_1^2 - P_2^2}{L}\right)^{0.5394} d^{2.6182}$$

Where:

Flow rate, Q = cf/day
Pipeline efficiency, E= .92
Inlet pressure, p_1 = psi, assume 2500 psi
Discharge pressure, p_2 = psi, assume about 1660 psi
Length, L = miles
Internal diameter, d = inches, solve for d.

Scenarios

Three scenarios were examined: tariff for a 3,600 mile, 52-inch pipeline from ANS to Chicago; a 300 mile spur pipeline from the Fairbanks area to South Central Alaska; and a tariff adjustment for gas off-take from Fairbanks for the 52-inch pipeline. The tariff calculations are performed for a range of flow rates to examine the tariff structure and sensitivity to flow rate.

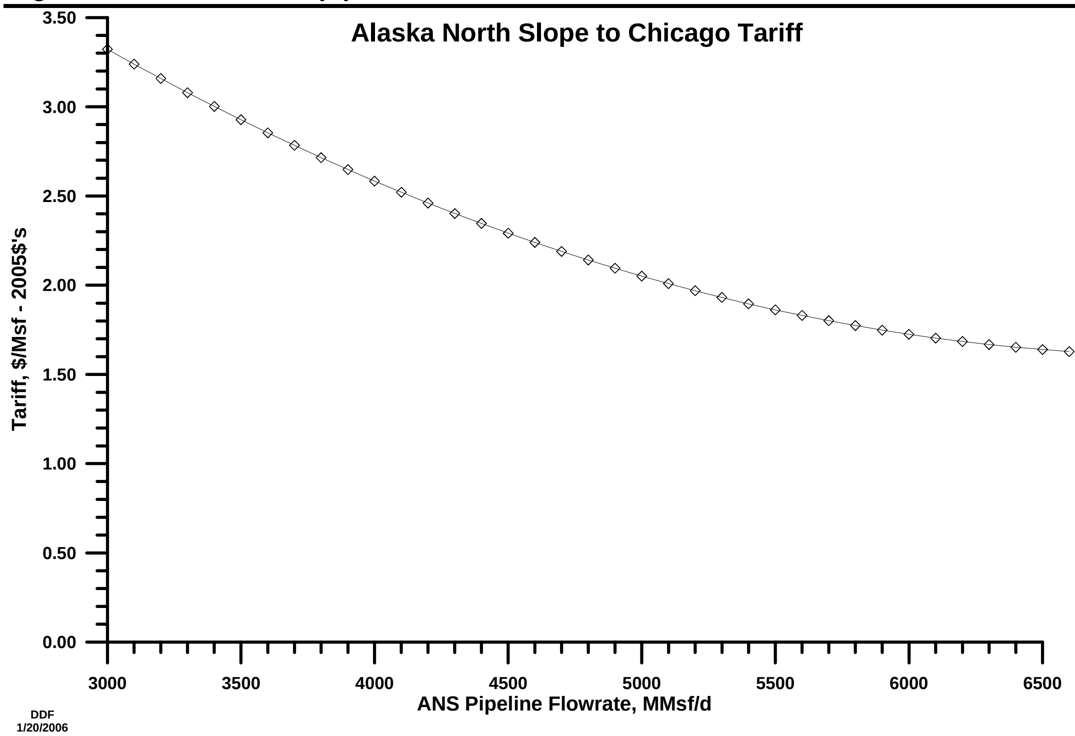
The tariff adjustment for gas off-take is made to determine the tariff for gas taken off at Fairbanks. The 52-inch pipeline has a required cost of service and the reduction of gas volume from Fairbanks to Chicago will reduce the recovered costs, hence the gas removed at Fairbanks will need to pay a tariff that will recoup the lost tariff for the remaining gas volume to Chicago. This adjustment assumes that Chicago delivered gas (or Alberta delivered gas) does not incur a tariff penalty for gas removed at Fairbanks.

Results

The tariff as a function of flow rate for the 52-inch pipeline is presented in Figure C-1. Capital costs for this pipeline project where estimated at $25/diameter-in foot, $3.6 billion for compressors, and $2.4 billion for a gas conditioning plant at the pipeline inlet for the removal of gas contaminates (2005$).

[5] Katz et al., 1959. Handbook of Natural Gas Engineering, p 626.

Figure C-1: ANS 52 inch pipeline tariff, 2005$



The tariff values are presented in Table C-1. The tariffs presented are the 12-yr average from 2015 to 2026. Yearly tariffs vary due to the nature of the property, and income taxes.

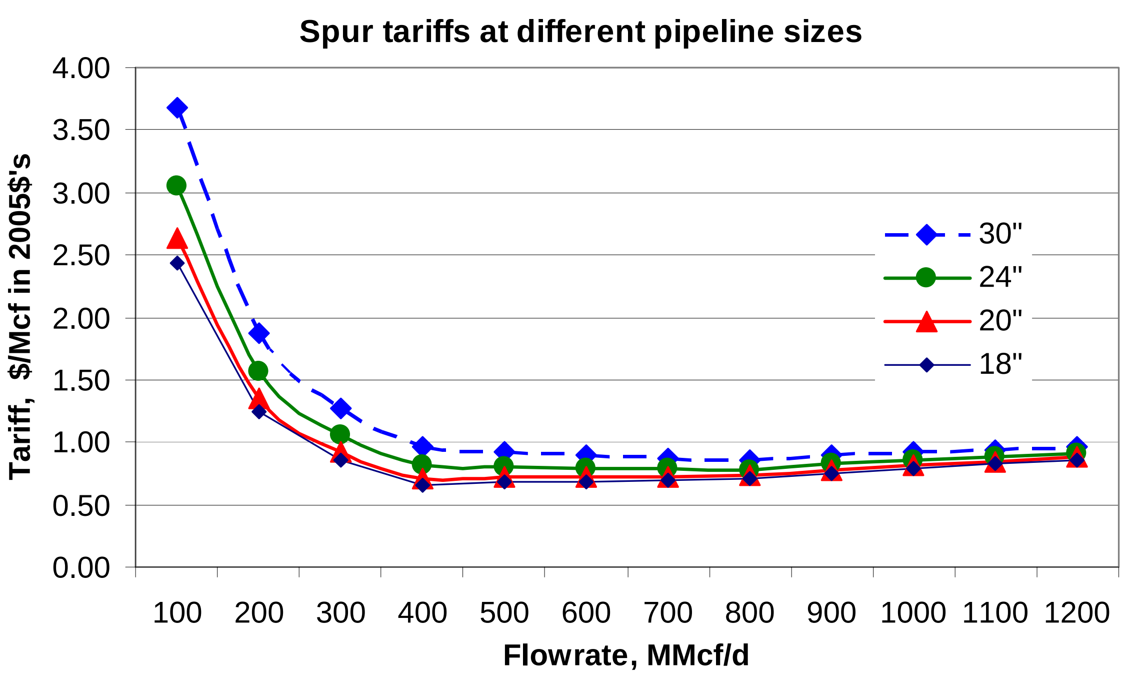
Table C-1: ANS tariff to Chicago, 2005$

Flowrate MMcf/d	*$/Mcf*	*Flowrate MMcf/d*	*$/Mcf*
3000	*3.322*	*4900*	*2.095*
3100	*3.239*	*5000*	*2.051*
3200	*3.158*	*5100*	*2.009*
3300	*3.079*	*5200*	*1.969*
3400	*3.002*	*5300*	*1.932*
3500	*2.927*	*5400*	*1.896*
3600	*2.854*	*5500*	*1.862*
3700	*2.784*	*5600*	*1.831*
3800	*2.715*	*5700*	*1.801*
3900	*2.648*	*5800*	*1.774*
4000	*2.584*	*5900*	*1.748*
4100	*2.521*	*6000*	*1.725*
4200	*2.461*	*6100*	*1.704*
4300	*2.402*	*6200*	*1.684*

Flowrate MMcf/d	*$/Mcf*	*Flowrate MMcf/d*	*$/Mcf*
4400	*2.346*	*6300*	*1.667*
4500	*2.292*	*6400*	*1.652*
4600	*2.239*	*6500*	*1.639*
4700	*2.189*	*6600*	*1.628*
4800	*2.141*		

Similarly, the pipeline tariff for the spur pipeline is estimated at four potential pipeline sizes of 18, 20, 24, and 30 in. and at flow rates from 100 to 1,200 MMcf/d and using the compression cost algorithm of Baker et al.[6] The results are shown in Figure C-2. No pipeline sizing and flow rate constraints where considered in this first approximation across the range of flow rates considered.

Figure C-2: Tariffs at various pipeline sizes, 2005$



A third tariff calculation considers the off-take of natural gas at Fairbanks and the impact this has on the remaining tariff for gas delivered to Chicago. The calculation is predicated on the assumption that the Chicago consumers do not have to pay an incremental tariff due to gas off-take at Fairbanks and is shown is Table C-2.

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[6] Michael Baker, Jr., Inc., 2005, Transport of North Slope Gas to Tidewater, for the Alaska Natural Gas Development Authority.

Table C-2: Tariff from Fairbanks to South Central Alaska, 2005$

Flowrate MMsf/d	*\$/Mcf 18 inch*	*\$/Mcf 20 inch*	*\$/Mcf 24 inch*	*\$/Mcf 30 inch*
100	*2.433*	*2.640*	*3.056*	*3.679*
200	*1.249*	*1.353*	*1.561*	*1.872*
300	*0.854*	*0.924*	*1.062*	*1.270*
400	*0.657*	*0.709*	*0.813*	*0.969*
500	*0.676*	*0.717*	*0.801*	*0.925*
600	*0.688*	*0.723*	*0.792*	*0.896*
700	*0.697*	*0.727*	*0.786*	*0.875*
800	*0.704*	*0.730*	*0.782*	*0.860*
900	*0.755*	*0.778*	*0.824*	*0.893*
1000	*0.795*	*0.816*	*0.858*	*0.920*
1100	*0.828*	*0.847*	*0.885*	*0.942*
1200	*0.862*	*0.879*	*0.914*	*0.966*

As shown in Figure C-3 and Table C-3, for ANS pipeline volumes leaving the North Slope less than 4,800 MMcf/d, there is a significant increase in the tariff for gas delivered to the spur pipeline. ANS starting volumes greater than about 5000 MMcf/d results in a fairly flat tariff for the range of gas volumes delivered to the spur pipeline, less than \$1.00/Mcf.

Figure C-3: Tariffs for gas off-take from Fairbanks for the spur pipeline, 2005\$'s

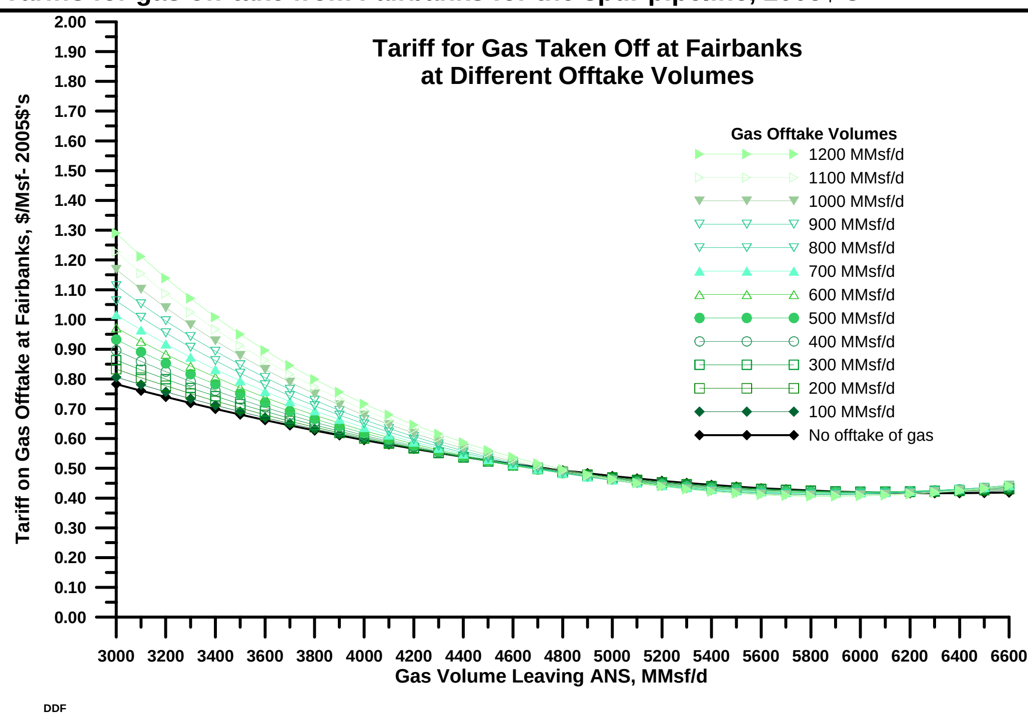


Table C-3: Spur Pipeline Tariff for ANS to Fairbanks, $/Mcf, 2005$'

ANS MMcf/d	*Spur Pipeline Off-take Volumes, MMcf/d*												
	0	***100***	***200***	***300***	***400***	***500***	***600***	***700***	***800***	***900***	***1000***	***1100***	***1200***
3000	0.783	0.806	0.833	0.863	0.896	0.932	0.972	1.015	1.062	1.113	1.168	1.227	1.291
3100	0.761	0.781	0.804	0.830	0.859	0.891	0.926	0.965	1.007	1.052	1.102	1.155	1.212
3200	0.740	0.757	0.777	0.799	0.825	0.853	0.883	0.918	0.955	0.995	1.039	1.087	1.139
3300	0.719	0.734	0.751	0.770	0.792	0.816	0.843	0.873	0.906	0.943	0.982	1.025	1.071
3400	0.700	0.712	0.726	0.742	0.761	0.782	0.806	0.832	0.861	0.893	0.928	0.967	1.008
3500	0.681	0.690	0.702	0.716	0.732	0.750	0.771	0.794	0.819	0.848	0.879	0.913	0.950
3600	0.662	0.670	0.680	0.691	0.705	0.720	0.738	0.758	0.780	0.805	0.832	0.863	0.896
3700	0.644	0.651	0.658	0.668	0.679	0.692	0.707	0.724	0.744	0.765	0.790	0.816	0.846
3800	0.627	0.632	0.638	0.646	0.655	0.666	0.678	0.693	0.710	0.729	0.750	0.773	0.799
3900	0.611	0.614	0.619	0.625	0.632	0.641	0.652	0.664	0.678	0.694	0.713	0.734	0.756
4000	0.595	0.597	0.600	0.605	0.611	0.618	0.626	0.637	0.649	0.663	0.679	0.697	0.717
4100	0.580	0.581	0.583	0.586	0.591	0.596	0.603	0.612	0.622	0.634	0.647	0.663	0.680
4200	0.566	0.566	0.567	0.569	0.572	0.576	0.582	0.588	0.597	0.607	0.618	0.631	0.646
4300	0.552	0.551	0.551	0.552	0.554	0.557	0.562	0.567	0.574	0.582	0.591	0.603	0.615
4400	0.539	0.538	0.537	0.537	0.538	0.540	0.543	0.547	0.552	0.559	0.567	0.576	0.587
4500	0.526	0.525	0.524	0.523	0.523	0.524	0.526	0.529	0.533	0.538	0.544	0.552	0.561
4600	0.515	0.513	0.511	0.510	0.509	0.509	0.510	0.512	0.515	0.519	0.524	0.530	0.538
4700	0.504	0.501	0.499	0.497	0.496	0.496	0.496	0.497	0.499	0.501	0.505	0.510	0.516
4800	0.493	0.491	0.488	0.486	0.485	0.484	0.483	0.483	0.484	0.486	0.488	0.492	0.497
4900	0.483	0.481	0.478	0.476	0.474	0.472	0.471	0.471	0.471	0.472	0.474	0.476	0.480
5000	0.474	0.472	0.469	0.467	0.464	0.462	0.461	0.460	0.459	0.460	0.460	0.462	0.465
5100	0.466	0.463	0.461	0.458	0.456	0.454	0.452	0.450	0.449	0.449	0.449	0.450	0.451
5200	0.458	0.456	0.453	0.451	0.448	0.446	0.444	0.442	0.440	0.439	0.439	0.439	0.440
5300	0.451	0.449	0.446	0.444	0.441	0.439	0.437	0.435	0.433	0.431	0.430	0.430	0.430
5400	0.444	0.443	0.440	0.438	0.436	0.433	0.431	0.429	0.427	0.425	0.423	0.422	0.422
5500	0.439	0.437	0.435	0.433	0.431	0.429	0.426	0.424	0.422	0.420	0.418	0.417	0.416
5600	0.433	0.432	0.431	0.429	0.427	0.425	0.423	0.420	0.418	0.416	0.414	0.412	0.411
5700	0.429	0.428	0.427	0.426	0.424	0.422	0.420	0.418	0.416	0.413	0.411	0.409	0.408
5800	0.425	0.425	0.425	0.424	0.422	0.421	0.419	0.416	0.414	0.412	0.410	0.408	0.406
5900	0.422	0.423	0.423	0.422	0.421	0.420	0.418	0.416	0.414	0.412	0.410	0.407	0.405
6000	0.420	0.421	0.421	0.421	0.421	0.420	0.419	0.417	0.415	0.413	0.411	0.409	0.406

ANS MMcf/d	Spur Pipeline Off-take Volumes, MMcf/d												
	0	100	200	300	400	500	600	700	800	900	1000	1100	1200
6100	0.418	0.420	0.421	0.422	0.422	0.421	0.420	0.419	0.417	0.415	0.413	0.411	0.409
6200	0.417	0.419	0.421	0.422	0.423	0.423	0.422	0.422	0.420	0.419	0.417	0.415	0.413
6300	0.416	0.420	0.422	0.424	0.425	0.426	0.426	0.425	0.424	0.423	0.422	0.420	0.418
6400	0.416	0.421	0.424	0.427	0.428	0.430	0.430	0.430	0.430	0.429	0.427	0.426	0.424
6500	0.417	0.422	0.427	0.430	0.432	0.434	0.435	0.436	0.436	0.435	0.435	0.433	0.432
6600	0.419	0.425	0.430	0.434	0.437	0.440	0.442	0.443	0.443	0.443	0.443	0.442	0.441

The total tariff for gas delivered to South Central Alaska is the sum of the tariff from the ANS to Fairbanks and the tariff from Fairbanks to South Central Alaska. A matrix using Table C-2 and Table C-3 can be used to examine the interplay of spur pipeline size, volumes, ANS pipeline initial volumes, and spur off-take volumes to calculate the tariff on natural gas delivered to South Central Alaska.

A sensitivity case was run to see what the impact would be on the price of gas delivered to South Central Alaska if capital costs were to increase significantly for ANGP as a result of increased steel prices and escalating construction costs. It was assumed that the capital costs would increase by 25% for ANGP. It was also assumed that the same cost increases would impact the spur pipeline resulting in 25% increase in capital costs for the spur pipeline. This increase in capital costs results in an increase in the ANGP tariff of \$0.59/MMBtu for the 4.5 Bcf/d rate, resulting in a lower ANS wellhead price. However, the tariff for delivery from ANS to Fairbanks and the spur pipeline tariff increased by \$0.53/MMBtu for the 4.5 Bcf/d rate and the 20-in., 350 MMcf/d spur pipeline rate. Hence, the assumed increase in capital costs would result in a change of less than \$0.06/MMBtu in the cost for gas delivered to South Central Alaska. Therefore, the impact from a cost over run on pipeline construction costs is a lower ANS producer wellhead price but no significant improvement for gas delivered to South Central Alaska. Also, the state of Alaska would receive a lower value for the state’s royalty gas and lower production taxes.

Appendix D: Natural Gas and Oil Price Forecast

Table D-1: Natural Gas and Oil Price Forecast

	Natural Gas									
Year	Ave Wellhead $/MMBtu	Henry Hub $/MMBtu	BC $/MMBtu	Baja $/MMBtu	S. Cal $/MMBtu	S. Central Alaska $/MMBtu	Japan $/MMBtu	Alaska Distillate $/MMBtu	Crude Oil $/Bbl	West Coast Distillate $/MMBtu
1989		$2.38					$4.61	$8.87	$24.55	$0.00
1990		$2.22					$4.92	$14.02	$29.98	$0.00
1991		$1.94					$5.22	$9.56	$25.23	$0.00
1992		$2.26					$4.63	$9.26	$23.63	$5.46
1993		$2.65					$4.40	$7.77	$20.44	$5.48
1994		$2.35					$3.89	$8.90	$19.15	$4.94
1995		$2.02					$4.15	$8.72	$20.60	$5.06
1996		$3.24					$4.30	$8.56	$24.13	$5.97
1997		$2.92					$4.52	$9.25	$22.11	$5.61
1998		$2.38					$3.49	$8.83	$14.32	$4.03
1999		$2.56					$3.54	$7.94	$19.47	$5.12
2000		$4.66					$5.21	$8.73	$30.91	$7.76
2001		$4.39					$5.00	$10.63	$25.49	$6.33
2002	$3.19	$3.53					$4.53	$8.43	$25.63	$5.73
2003	$5.19	$5.86					$4.97	$9.35	$29.55	$6.94
2004	$5.70	$5.97	$5.76	$6.36	$6.41	$3.11	$5.28	$11.21	$37.10	$9.70
2005	$7.45	$9.00	$8.80	$9.39	$9.44	$3.93	$6.38	$12.11	$45.44	$9.52
2006	$8.83	$9.63	$9.44	$10.02	$10.07	$4.91	$5.76	$11.02	$39.54	$8.48
2007	$7.78	$8.53	$8.34	$8.91	$8.95	$7.93	$5.71	$10.90	$39.31	$8.40
2008	$4.04	$4.43	$4.24	$4.80	$4.85	$8.72	$5.64	$10.78	$39.04	$8.33
2009	$3.91	$4.28	$4.10	$4.64	$4.69	$7.21	$5.58	$10.65	$38.79	$8.25
2010	$3.90	$4.27	$4.09	$4.63	$4.67	$5.48	$5.52	$10.52	$38.53	$8.17
2011	$3.99	$4.37	$4.20	$4.72	$4.76	$4.13	$5.55	$10.55	$39.29	$8.26
2012	$4.08	$4.48	$4.31	$4.81	$4.86	$4.11	$5.59	$10.59	$40.05	$8.36
2013	$4.21	$4.61	$4.44	$4.94	$4.98	$4.17	$5.62	$10.64	$40.82	$8.45
2014	$4.41	$4.84	$4.68	$5.16	$5.20	$4.28	$5.66	$10.68	$41.58	$8.55
2015	$4.54	$4.98	$4.82	$5.29	$5.33	$4.14	$5.70	$10.73	$42.35	$8.65
2016	$4.66	$5.11	$4.95	$5.41	$5.45	$4.29	$5.74	$10.78	$43.11	$8.75
2017	$4.66	$5.11	$4.96	$5.41	$5.45	$4.32	$5.78	$10.83	$43.88	$8.85
2018	$4.66	$5.11	$4.96	$5.40	$5.44	$4.34	$5.82	$10.88	$44.64	$8.94
2019	$4.69	$5.14	$5.00	$5.43	$5.46	$4.39	$5.85	$10.92	$45.40	$9.04
2020	$4.79	$5.25	$5.11	$5.53	$5.56	$4.52	$5.89	$10.97	$46.16	$9.14
2021	$4.93	$5.41	$5.27	$5.67	$5.71	$4.69	$5.93	$11.01	$46.93	$9.23
2022	$5.09	$5.59	$5.45	$5.85	$5.88	$4.89	$5.96	$11.06	$47.70	$9.33
2023	$5.26	$5.77	$5.64	$6.02	$6.05	$5.09	$6.00	$11.10	$48.46	$9.43
2024	$5.40	$5.93	$5.80	$6.17	$6.20	$5.28	$6.04	$11.15	$49.22	$9.53
2025	$5.54	$6.08	$5.96	$6.32	$6.35	$5.45	$6.08	$11.20	$49.98	$9.62

Source: Average Wellhead Gas Price & Crude Oil Price, AEO 2005.

Price Assumptions

For purposes of this study, the price forecasts for Lower 48 natural gas and world oil prices published by the US Energy Information Administration in the Annual Energy Outlook 2005 (AEO 2005) are used. The EIA's reference-case gas price forecast and their High B World Oil price case are used. The High B World Oil price case is used because this price forecast most closely reflects thinking on the evolution of global oil markets that prevailed among analysts in the second half of 2005. EIA assumptions behind the forecasts are provided below, however a fuller treatment can be found in the AEE 2005.

World Oil Price

- EIA's High B world oil price case assumes a continued rise in prices through 2005 to \$45.44/bbl, followed by a gradual decline to \$38.53/bbl by 2010, and then rising to \$49.98/bbl by 2025.

- OPEC producers will be less able or willing to expand their productive capacity and their output growth will be considerable constrained. There is also great cohesiveness among OPEC nations to continue to constrain long term production growth and thus keep prices high.

- Higher priced non-OPEC oil sources step in to make up the shortfall in OPEC oil production. These include oil from tar sands. Also, synthetic oil from coal and natural gas, and non-conventional liquids begin to make up a larger share of oil supply

- The OPEC shortfall is also made up from reduced global oil demand due to continued high prices and substitution of other fuels, plus reduced global growth in GDP.

Natural Gas Prices

- For 2005, 2006, and 2007, SAIC spliced EIA's forecast of gas prices published in the Short Term Energy Outlook (STEO), January 10, 2006, to their price forecast provided in the AEO 2005. The fourth quarter 2005 STEO forecast a gas price of \$9.80/MMBtu in 2006 and \$8.84/MMBtu in 2007. EIA's long-term reference case gas price forecast published in the AEO 2005 shows that the average wellhead gas price falls to \$3.90/MMBtu by 2010, and then rises to \$5.54/MMBtu by 2025.

- Natural gas prices are forecast to decline from recent highs due to drilling level increases, new gas production, and increasing LNG imports.

- Technically recoverable resources of over 1,337 Tcf are expected to be adequate to support projected production increases. As Lower 48 conventional resources are depleted along the Gulf Coast, Mid- Continent, and west, an increasing proportion of U.S. natural gas supply is projected to come from Alaska and unconventional production (primarily the Rockies).

- EIA projected that net imports from Canada would decline through 2009 and then begin to increase again as declining production from the Western Canadian Sedimentary Basin is more than offset by conventional production from the Mackenzie Delta and Eastern Canada. Import growth comes in the form of LNG, which increases to 6.4 Tcf by 2025.

- Total US natural gas consumption increases from 22 Tcf in 2003 to 30.7 Tcf by 2025, with most of this growth coming from the electric sector.

Appendix E: Residential/Commercial Methodology

Forecasting Equations

FORM OF FORECASTING EQUATION:

$$RES\_CONS_t = e^{\beta_0} RELPRICE_t^{\beta_1} HDD_t^{\beta_2} HH_t^{\beta_3} RES\_CONS_{t-1}^{\rho}$$
$$* e^{-\rho\beta_0} RELPRICE_{t-1}^{-\rho\beta_1} HDD_{t-1}^{-\rho\beta_2} HH_{t-1}^{-\rho\beta_3}$$

LN_RES_CONS = natural log of residential consumption in month t
LN_RELPRICE = natural log of (natural gas price/distillate price) in month t
LN_PRICE2003 = natural log of the natural gas price in month t in US$2003
LN_PDIST2003 = natural log of the distillate price in month t in US$2003
LN_HDD = natural log of heating degree days in month t
LN_RES_CUST = natural log of the number of residential customers in month t (Note: there is no change in this variable by month within a calendar year)
LN_HH = natural log of the number of households in month t (Note: there is no change in this variable by month within a calendar year)
LN_POP = natural log of population in month t (Note: there is no change in this variable by month within a calendar year)
RHO = serial correlation parameter

The equations are estimated in natural log form. The forecasting equations are obtained by exponentiating both sides of the estimated equations.

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Objective function: Exact ML (keep first obs.)

CONVERGENCE ACHIEVED AFTER 7 ITERATIONS

Dependent variable: LN_RES_CONS
Current sample: 1 to 192
Number of observations: 192

Mean of dep. var. = 7.01791	R-squared = 0.936529
Std. dev. of dep. var. = 0.568532	Adjusted R-squared = 0.935171
Sum of squared residuals = 4.11952	Durbin-Watson = 1.90285
Variance of residuals = 0.022030	Schwarz B.I.C. = -83.1126
Std. error of regression = 0.148423	Log likelihood = 96.2563

Parameter	Estimate	Standard Error	t-statistic	P-value
C	-12.6109	4.24260	-2.97245	[.003]
LN_RELPRICE	-0.542223	0.136602	-3.96935	[.000]
LN_HDD	0.674308	0.033184	20.3205	[.000]
LN_HH	1.08733	0.351051	3.09737	[.002]
RHO	0.569576	0.076421	7.45312	[.000]

Calculation of Netback Value of Natural Gas in Anchorage to Replace Heating Oil

Because ENSTAR's distribution system is already extensive, the net back cost example provided is for the case of a rural residential conversion to gas. This will be the most difficult case for future natural gas accounts, as the costs of the boiler conversion to gas as well as the additional length of line (estimated here to be 500 feet) must be recovered in a reasonable time frame. A 5-yr recovery period has been used here as this is a standard recovery period used in utility planning to decide if an account will convert to natural gas. The table also includes assumptions of heating oil price, boiler replacement costs, natural gas distribution line costs, etc.

Case 1 - SC Alaska outlying community - heating replacement - 2015/25 average prices (real $)		
Heating oil price ($/MMBtu) - $2.55/gallon @ 138,000 Btu/gallon	$18.50	
Heating oil price ($/Mcf) @ 1.035 MMBtu/Mcf	$19.15	
Replacement cost		$3,000
Replacement cost amortized over 5 years - 175 Mcf/yr use (A)	$3.43	
Distribution line - $8.80/ft installed		$4,400
Distribution cost amortized over 5 years - 175 Mcf/yr use (B)	$5.03	
System O&M costs (ENSTAR data) (C)	$1.64	
Total costs (A+B+C)	$10.10	
Netback price at delivery point ($/Mcf)	$9.05	
Netback price at delivery point ($/MMBtu)	$8.74	
Case 1A - SC Alaska outlying community - heating replacement - low sensitivity case		
Heating oil price ($/MMBtu) - 2015 price (real $)	$16.50	
Heating oil price ($/Mcf) @ 1.035 MMBtu/MCF	$17.08	
Replacement cost		$3,000
Replacement cost amortized over 5 years - 175 Mcf/yr use (A)	$3.43	
Distribution line - $8.80/ft installed		$4,400
Distribution cost amortized over 5 years - 175 Mcf/yr use (B)	$5.03	
System O&M costs (ENSTAR data) (C)	$1.64	
Total costs (A+B+C)	$10.10	
Netback price at delivery point ($/Mcf)	$6.98	
Netback price at delivery point ($/MMBtu)	$6.74	
Case 1B - SC Alaska outlying community - heating replacement - high sensitivity case		
Heating oil price ($/MMBtu) - 2015 price (real $)	$20.50	
Heating oil price ($/Mcf) @ 1.035 MMBtu/MCF	$21.22	
Replacement cost		$3,000
Replacement cost amortized over 5 years - 175 Mcf/yr use (A)	$3.43	
Distribution line - $8.80/ft installed		$4,400
Distribution cost amortized over 5 years - 175 Mcf/yr use (B)	$5.03	
System O&M costs (ENSTAR data) (C)	$1.64	
Total costs (A+B+C)	$10.10	
Netback price at delivery point ($/Mcf)	$11.12	
Netback price at delivery point ($/MMBtu)	$10.74	

Source: SAIC

The above net back analyses for the "difficult" case of a rural residential conversion show favorable net back pricing compared to real natural gas prices for the same time periods (e.g. $4.75/MMBtu Henry Hub Price in 2015 and $5.16/MMBtu average real price 2015 to 2025).

New residential hook ups will be much easier to justify as the boiler replacement cost will not be an issue and commercial accounts will have higher per unit volumes to justify natural gas. This leads to the overall conclusion that ENSTAR's projections of increased penetration in South Central Alaska are justified and that the natural gas use projections for the new and existing accounts are sound.

Calculation of Netback Value of Natural Gas in Fairbanks to Replace Heating Oil

An example of the calculation of netback gas price for a Fairbanks area residential account in a fairly rural situation that is currently using fuel oil and requires a complete boiler replacement is shown below. The table also includes assumptions of heating oil price, boiler replacement costs, natural gas distribution line costs, etc.

Case 2 - Fairbanks NS Borough outlying community - heating replacement - 2015/25 average prices (real $)		
Heating oil price ($/MMBtu) - $2.44/gallon @ 132,000 Btu/gallon	$18.50	
Heating oil price ($/Mcf) @ 1.035 MMBtu/MCF	$19.15	
Replacement cost		$3,000
Replacement cost amortized over 5 years - 190 Mcf/yr use	$3.16	
Distribution line - $8.80/ft (distance extrapolated from Fairbanks NG data)		$4,400
Distribution cost amortized over 5 years - 190 Mcf/yr use	$4.63	
System O&M costs (Fairbanks NG estimate)	$3.00	
Total costs	$10.79	
Netback price at delivery point ($/Mcf)	$8.36	
Netback price at delivery point ($/MMBtu)	$8.08	
Case 2A – Fairbanks NS Borough outlying community - heating replacement - low sensitivity case		
Heating oil price ($/MMBtu) - 2015-25 average price (real $)	$16.50	
Heating oil price ($/Mcf) @ 1.035 MMBtu/MCF	$17.08	
Replacement cost		$3,000
Replacement cost amortized over 5 years - 190 Mcf/yr use	$3.16	
Distribution line - $8.80/ft (distance extrapolated from Fairbanks NG data)		$4,400
Distribution cost amortized over 5 years - 190 Mcf/yr use	$4.63	
System O&M costs (Fairbanks NG estimate)	$3.00	
Total costs	$10.79	
Netback price at delivery point ($/Mcf)	$6.29	
Netback price at delivery point ($/MMBtu)	$6.08	
Case 2B – Fairbanks NS Borough outlying community - heating replacement - high sensitivity case		
Heating oil price ($/MMBtu) - 2015-25 average price (real $)	$20.50	
Heating oil price ($/Mcf) @ 1.035 MMBtu/MCF	$21.22	
Replacement cost		$3,000
Replacement cost amortized over 5 years - 190 Mcf/yr use	$3.16	
Distribution line - $8.80/ft (distance extrapolated from Fairbanks NG data)		$4,400
Distribution cost amortized over 5 years - 190 Mcf/yr use	$4.63	
System O&M costs (Fairbanks NG estimate)	$3.00	
Total costs	$10.79	
Netback price at delivery point ($/Mcf)	$10.43	
Netback price at delivery point ($/MMBtu)	$10.08	

Source: SAIC

The above net back analyses for the “difficult” case of a rural residential conversion show favorable net back pricing compared to real natural gas prices for the same time periods (e.g. \$4.75/MMBtu Henry Hub Price in 2015 and \$5.16/MMBtu average real price 2015 to 2025). New residential hook ups will be much easier to justify as the boiler replacement cost will not be an issue and commercial accounts will have higher per unit volumes to justify natural gas. This leads to the overall conclusion that the study’s projections of natural gas penetration in Central Alaska are justified when ANS pipeline gas becomes available.

Appendix F: Integrated Market Methodology and Model Description

Modeling Approach

The integrated market analysis was performed with GEMS, which utilized as the key input net demand curves for the natural gas supplied via the ANGP pipeline to Alberta, projected from a series of runs of the National Energy Modeling System (NEMS). A schematic of the modeling approach is presented in Figure F-1.

GEMS seeks a natural gas market equilibrium between the demand and supply curves defined for the major natural gas transportation nodes.

The model simulated four major natural gas transportation nodes: North Slope, Central Alaska (Fairbanks and the surrounding area), South Central Alaska (Anchorage and the surrounding area), and the node in Alberta where the ANGP pipeline connects to the existing natural gas pipeline system carrying natural gas down to the Lower 48 states of the US. The simulated nodes were interconnected with transportation arcs of exogenously defined maximum capacities, representing the following pipelines:

i. Upper portion of the ANGP, carrying natural gas from North Slope to Central Alaska
ii. The Alaskan Spur pipeline carrying natural gas from Central Alaska to South-Central Alaska, and
iii. The lower portion of the ANGP, carrying natural gas all the way from Central Alaska to Alberta

Figure F-1: Schematic for Integrated Market Modeling

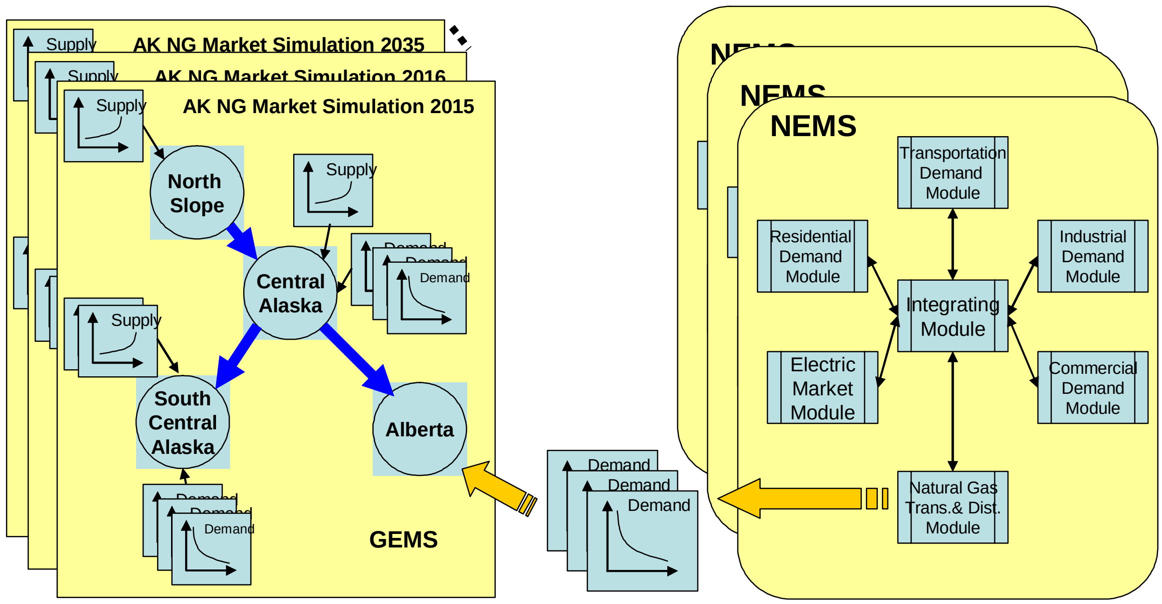


Fig. 69 Schematic for Integrated Market Modeling

Source: SAIC

Each of the arcs was defined with the following inputs: maximum transportation capacity in Bcf/day, pipeline tariff in $/MMBtu, and the percent of fuel used by compressors.

The model also simulated optimal utilization of potential under-ground storage capacity in South Central Alaska. The under-ground storage was defined with similar inputs as the transportation arcs; i.e., the maximum amount of gas that can be withdrawn in Bcf/day, storage tariff in $/MMBtu of withdrawn gas, and the natural gas losses. The model optimized the amounts of natural gas withdrawn from storage during the peak and shoulder seasons, assuring that corresponding amounts of natural gas were injected into the storage during the off-peak season.

In each of the transportation nodes seasonal supply and demand curves were provided as exogenous input. North Slope production was represented as a sole supply node, thus no demand curves were specified for it. The Alberta node was represented as a pure demand node, where the demand was defined as a set of seasonal demand curves differentiated over the years, projected from the results of multiple runs of the NEMS model. In the two remaining nodes the demand curves consisted of segments representing the residential/commercial sector, various industries, and the natural gas demand for electric generation.

To represent seasonal fluctuations in demand, the model simulated three seasons in the year:

1) Peak season including January
2) Shoulder season including: February, March and December, and
3) Off-peak season including the remainder of the year.

The time horizon of the simulation extended from 2015 until 2035. The model was run for each of the years.

As was mentioned earlier, the model simulations are performed for three different natural gas price scenarios, both assuming that the spur pipeline is built and for a reference case without the pipeline being constructed.

Model Formulation

The GEMS was developed as a linear program that seeks market equilibrium between the demand and supply at each of the years of the time horizon.

Model indices:

p = 1...P – pipelines
s = 1...S – seasons
u = 1…U – pipeline utilization segments
n = 1…N – natural gas transportation nodes
d = 1…D – demand segments
g = 1…G – supply sources
k= 1…K natural gas utilization segments
pi – pipelines incoming to the node
po – pipelines outgoing from the node

Model variables:

$f_{p,s,u}$ – natural gas flow on pipeline p, season s, within the segment of utilization u
$c_{n,s,d}$ – natural gas consumption in region n, season s, of the demand segment d
$s_{n,s,g}$ – natural gas supply in region n, season s, from the supply source g
$w_{n,s,k}$ – natural gas withdrawal from storage in region n, season s, segment of utilization k
$i_{n,s}$ – natural gas injections into storage in region n, season s

Model constraints:

Seasonal natural gas balance between supply and demand in each node:

$$\Sigma_{pi,u}\, f_{p,s,u}*(1-\tau_p) - \Sigma_{po,u}\, f_{p,s,u} + \Sigma_g\, s_{n,s,g} - \Sigma_d\, c_{n,s,d} + \Sigma_k\, w_{n,s,k}*(1-\gamma_n) - i_{n,s} \geq 0$$

Where:
τ_p – natural gas used in compressors as a fraction of gas entering the pipeline
γ_n – natural gas lost during the injection/withdrawal process as a fraction of gas injected
Such a constraint is created for every node and season in each annual matrix

Annual balance of natural gas in the storage in each node:

$\Sigma_{s,k}\ w_{n,s,k} - \Sigma_s\ i_{n,s} \leq 0$

Such a constraint is created for every node where storage is available, in each annual matrix

Bounds on model variables:

$f_{p,s,u} \leq F_{p,s,u}$ – natural gas flow on pipeline p, season s, within the segment of utilization u
$c_{n,s,d} \leq C_{n,s,d}$ – natural gas consumption in region n, season s, of the demand segment d
$s_{n,s,g} \leq S_{n,s,g}$ – natural gas supply in region n, season s, from the supply source g
$w_{n,s,k} \leq W_{n,s,k}$ – natural gas withdrawal from storage in region n, season s, segment of utilization u

Such bounds are created for all the combinations of indices of the variables.

Objective function:

Total cost of meeting the demand less the value of the natural gas to the consumers:

$\Sigma_{p,s,u}\ f_{p,s,u} * T_{p,u} + \Sigma_{n,s,g}\ s_{n,s,g} * C_{n,s,g} - \Sigma_{n,s,d}\ c_{n,s,d} * P_{n,s,d} + \Sigma_{n,s,k}\ w_{n,s,k} * Q_{n,s,k} \rightarrow \min$

Where:

$T_{p,u}$ – pipeline tariff
$C_{n,s,g}$ – cost of natural gas production
$P_{n,s,d}$ – natural gas price associated with a given segment of demand
$Q_{n,s,k}$ - underground storage tariff

The linear program specified above is run separately for each year of the simulation time horizon.

Appendix G: Production Review and Forecast for Large Fields

Large Fields

Seven fields currently supply over 92% of the dry natural gas produced in the Cook Inlet basin; Beaver Creek, Beluga River, Cannery Loop, Kenai, McArthur River, Ninilchik, and North Cook Inlet. The reservoir performance of these fields and their individual reservoirs were reviewed using standard methods. The sections below will discuss the historical production response, the technically recoverable reserves, producing wells, and production forecast.

As stated in Section 7.2, the estimated technical ultimate recovery presented is likely to be conservative because this review does not include likely resources growth, field extensions, and some level of exploration that may result in new discoveries.

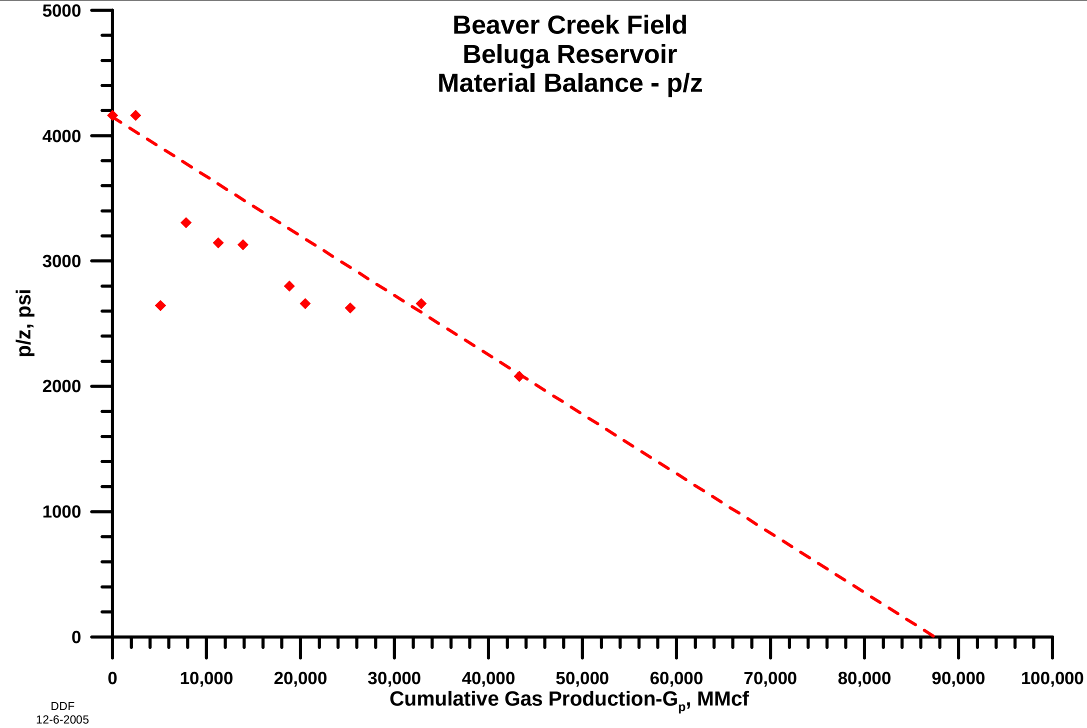
Beaver Creek

The Beaver Creek field, located on the eastern side of Cook Inlet, was discovered in 1972. Formations shown to be productive were the Hemlock (oil) and the Beluga, Sterling, and Tyonek for gas. Initial production occurred in 1972 from the Beaver Creek Oil Pool. Cumulative production through December 31, 2004 from all pools is 178.465 Bsf. Historical production, technically remaining gas reserves, and future production rates for the three gas formations are presented in the following sections.

Beluga Formation

Production started from the Beluga formation January 1989 with a cumulative recovery from the Beluga formation through December 31, 2004 of 47.321 Bcf. The material balance plot, Figure G-1, indicates an original-gas-in-place of 88 Bcf. The current recovery factor is 54% of the OGIP. The estimated technical recovery is 85% of the OGIP leaving estimated technical remaining reserves of 27.478 Bcf. Reservoir performance shows no indication of water influx with good linearity developing from the last set of points back to the initial reservoir pressure. The recent deviation cumulative production from approximately 30 to 40 Bcf with approximately constant *p/z* suggests the completion of new zones at higher initial reservoir pressures.

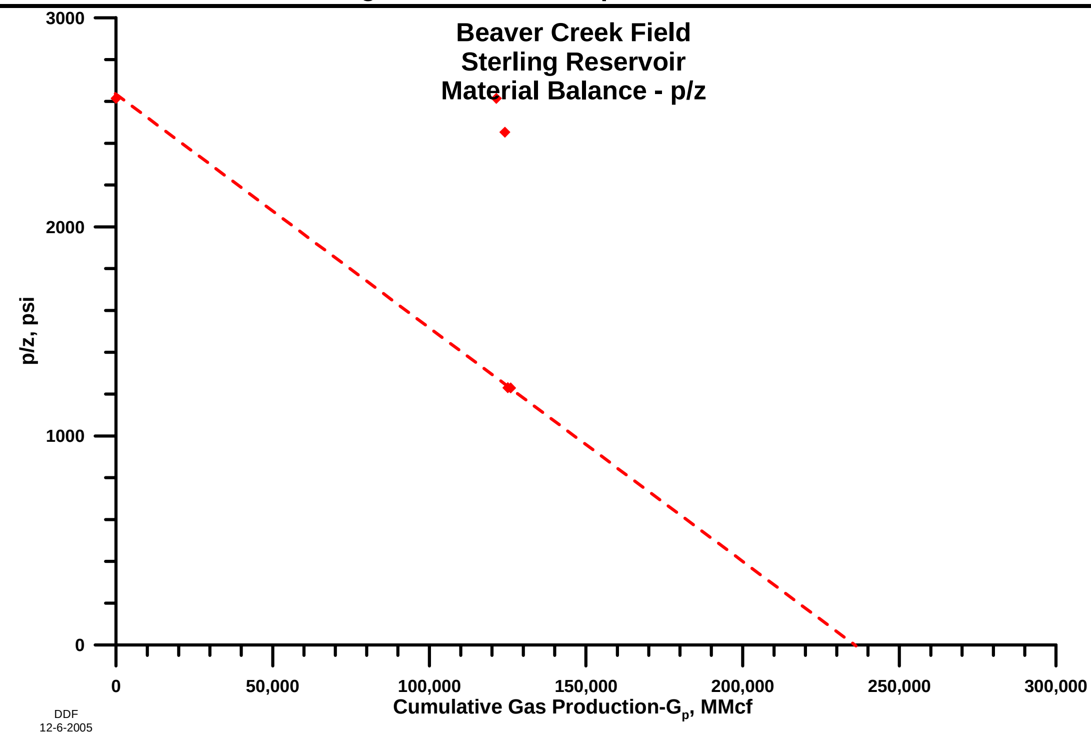
Figure G-1: Beaver Creek – Beluga material balance performance



Sterling Formation

The Sterling formation has been historically the largest reservoir at Beaver Creek with cumulative recovery through December 31, 2004 of 125.934 Bcf or 69% of the total Unit recovery. Production has been intermittent since early 1994 at which time water production began to increase. Production since June 1994 is 2,150 MMcf. The material balance plot suggests an OGIP of 235 Bcf, Figure G-2, but the sparse pressure data results in uncertainty of the in-place-gas estimate. Due to the intermittent nature of production and no production has occurred from June 2004 through August 2005, no remaining reserves are assigned to this formation.

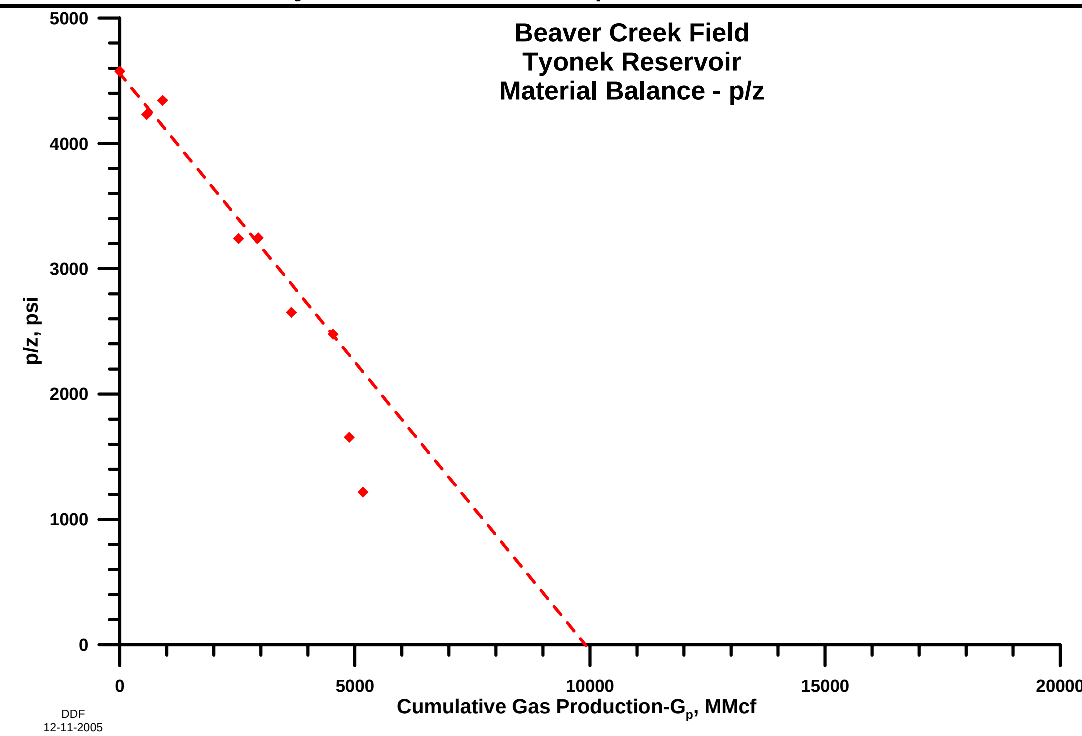
Figure G-2: Beaver Creek – Sterling material balance performance



Tyonek Formation

Production from the Tyonek started April 1996 with a cumulative recovery through December 31, 2004 of 5,209 MMcf. This minor pool has produced 2.9% of the total Unit production. The material balance performance is presented in Figure G-3. The material balance plot is showing indications of water influx as indicated by the deviation of the data from the prior established linear behavior.

Figure G-3: Beaver Creek – Tyonek material balance performance



The composite historical and forecast gas production from the Beaver Creek field is presented below in Figure G-4. The forecast empirical decline is 11.2% per year, exponential. The forecast production volumes are presented in Table G-1.

Figure G-4: Beaver Creek Field historical and forecast productions for all pools

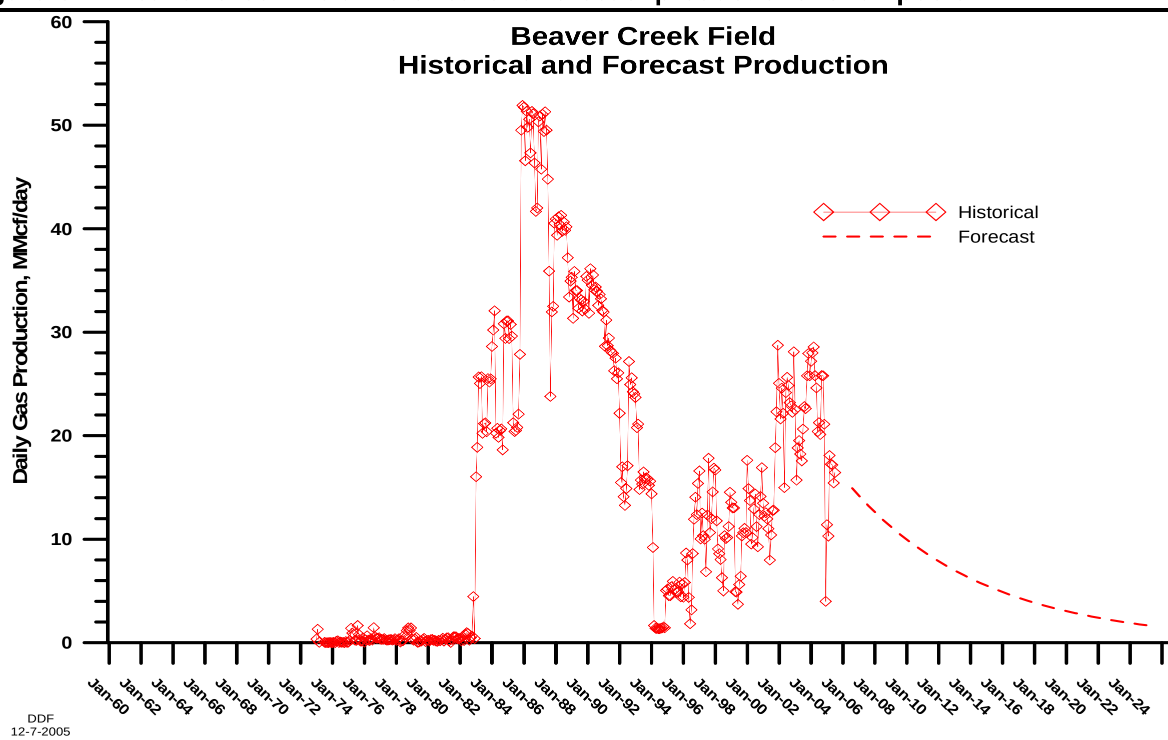


Table G-1: Forecast Beaver Creek gas production from proved reserves

Year	*Bcf/yr*	*Year*	*Bcf/yr*
2005	*5.444*	*2016*	*0.000*
2006	*4.837*	*2017*	*0.000*
2007	*4.297*	*2018*	*0.000*
2008	*3.818*	*2019*	*0.000*
2009	*3.392*	*2020*	*0.000*
2010	*3.013*	*2021*	*0.000*
2011	*2.677*	*2022*	*0.000*
2012	*2.379*	*2023*	*0.000*
2013	*2.113*	*2024*	*0.000*
2014	*1.878*	*2025*	*0.000*
2015	*1.668*	*2026*	*0.000*

Beluga River

The Beluga River field located on the west side of the Cook Inlet was discovered in 1962. Gas production began in 1968 from the Sterling and Beluga formations. Cumulative gas production is 904,780,672 Mcf through December 31, 2004. Production from both zones has been commingled in the well bores.

Beluga/Sterling combined

The Sterling and Beluga gas productions are commingled in the well bore in all wells. Although some wells are predominately completed in the Sterling and others predominately in the Beluga, there is no method to accurately determine production and pressures by formation. Therefore, total unit production and averaged bottom hole pressure data are used. The material balance in Figure G-5, performance plot indicates an OGIP of 1530 Bcf, unchanged from the prior year's analysis. The analysis shows no indication of water influx to date with good linearity intercepting with the initial reservoir pressure.

The historical and forecast gas production from the Beluga River field is presented in Figure G-6 and Table G-2. The forecast decline starting in 2008 is 27.7% empirical for a remaining reserves as of December 31, 2004 is 309.08 Bcf for an estimated technical ultimate recovery of 1213.86 Bcf.

Figure G-5: Beluga River – Beluga-Sterling combined material balance performance

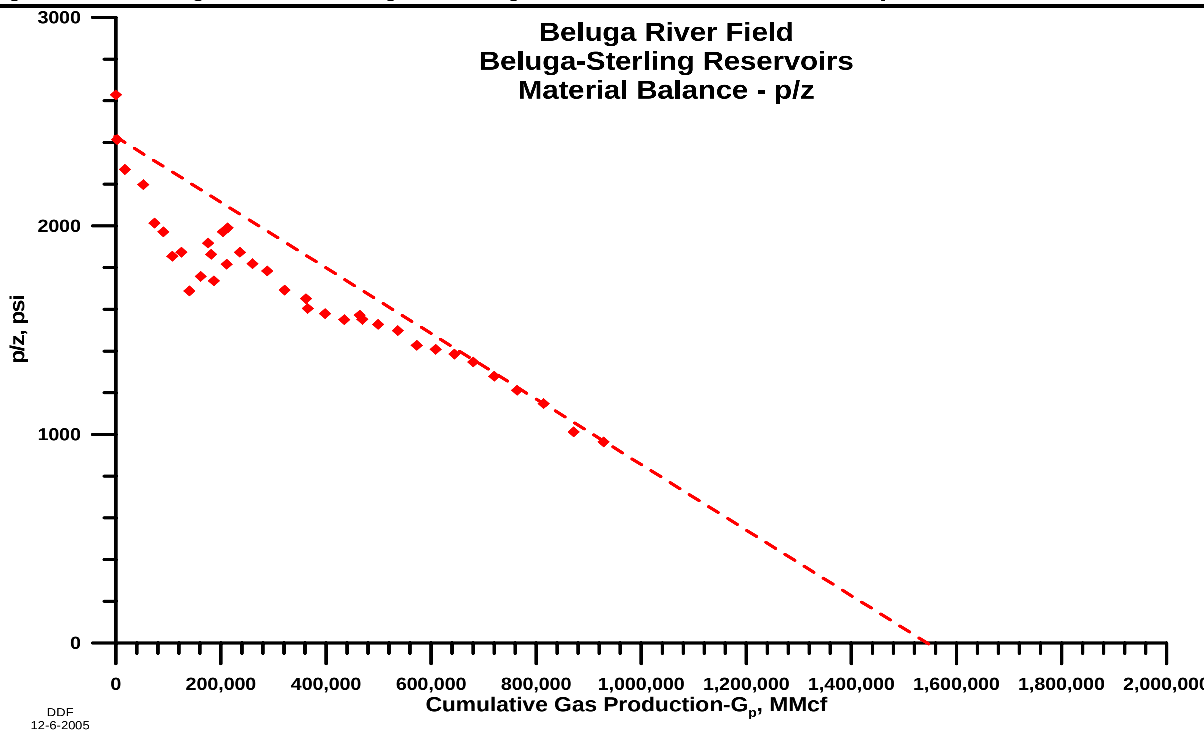
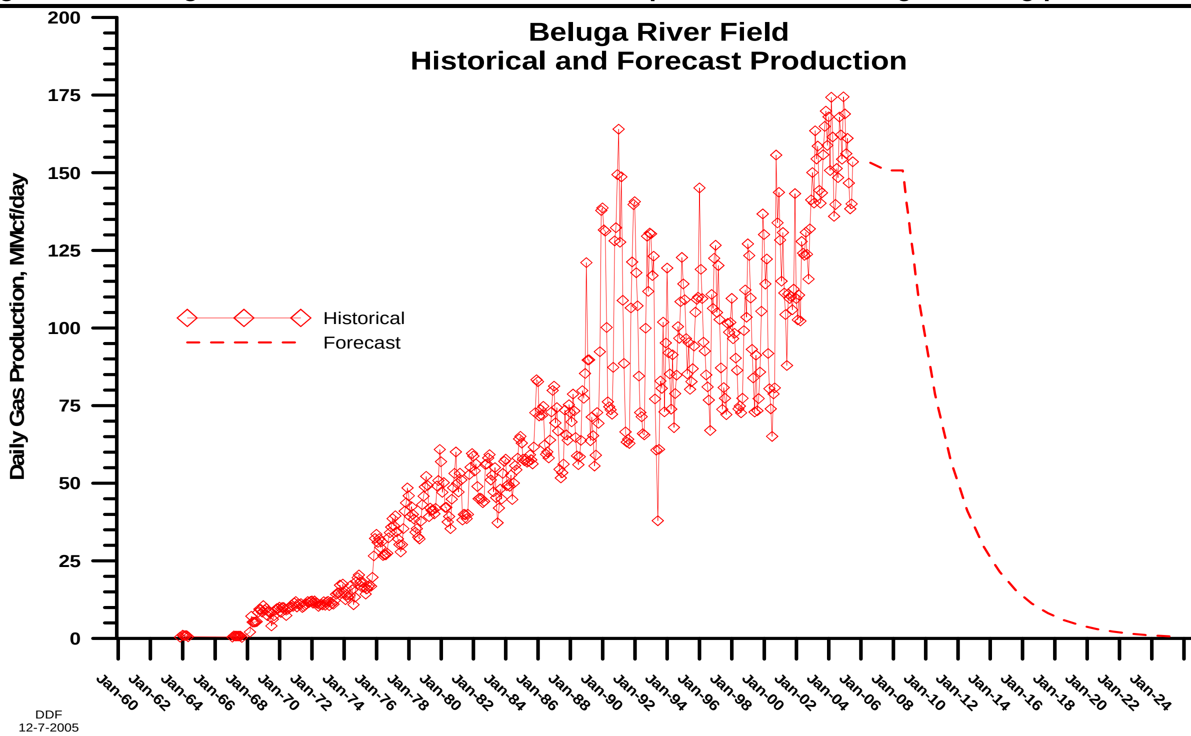


Table G-2: Forecast Beluga River gas production from proved reserves

Year	Bcf/yr	Year	Bcf/yr
2005	55.931	2016	2.964
2006	55.000	2017	2.142
2007	55.000	2018	1.549
2008	39.757	2019	1.119
2009	28.739	2020	0.809
2010	20.774	2021	0
2011	15.016	2022	
2012	10.855	2023	
2013	7.846	2024	
2014	5.672	2025	
2015	4.100	2026	

Figure G-6: Beluga River field historical and forecast production for Beluga-Sterling pools



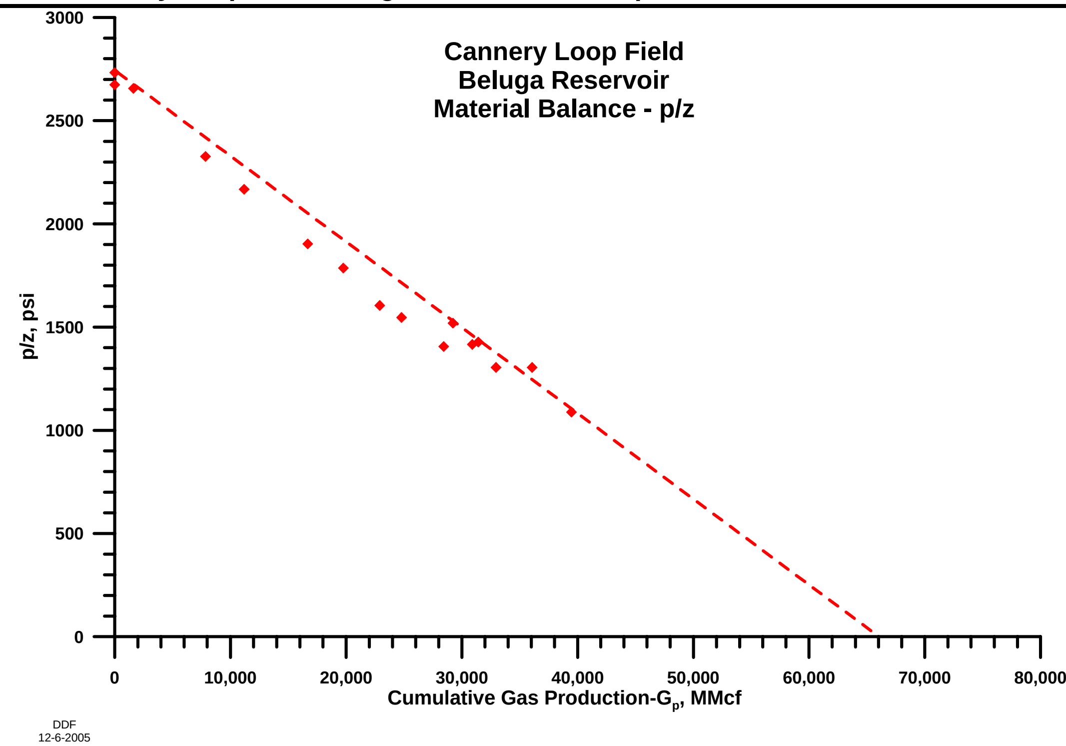
Cannery Loop

The Cannery Loop field is located on the eastern side of the Cook Inlet, adjacent to the Kenai field. Production started January 1988 from the Beluga and Upper Tyonek reservoirs. Gas is produced from the Beluga, Upper Tyonek, Tyonek Deep, and Sterling formations. Cumulative recovery from all reservoirs through December 31, 2004 is 124,410,019 Mcf. Estimates of individual formation gas reserves and production forecasts are discussed in the following sections.

Beluga formation

Production from the Beluga formation began January 1988 with a cumulative recovery through December 31, 2004 of 44,162,598 Mcf. The material balance plot indicates an OGIP of 66 Bcf for a current recovery factor of 66.9%. The performance plot, Figure G-7, shows good linearity with no indication of water influx. Assuming a recovery factor of 85%, the estimated technical ultimate recovery is 56.1 Bcf for a estimated technical remaining reserves of 11.938 Bcf.

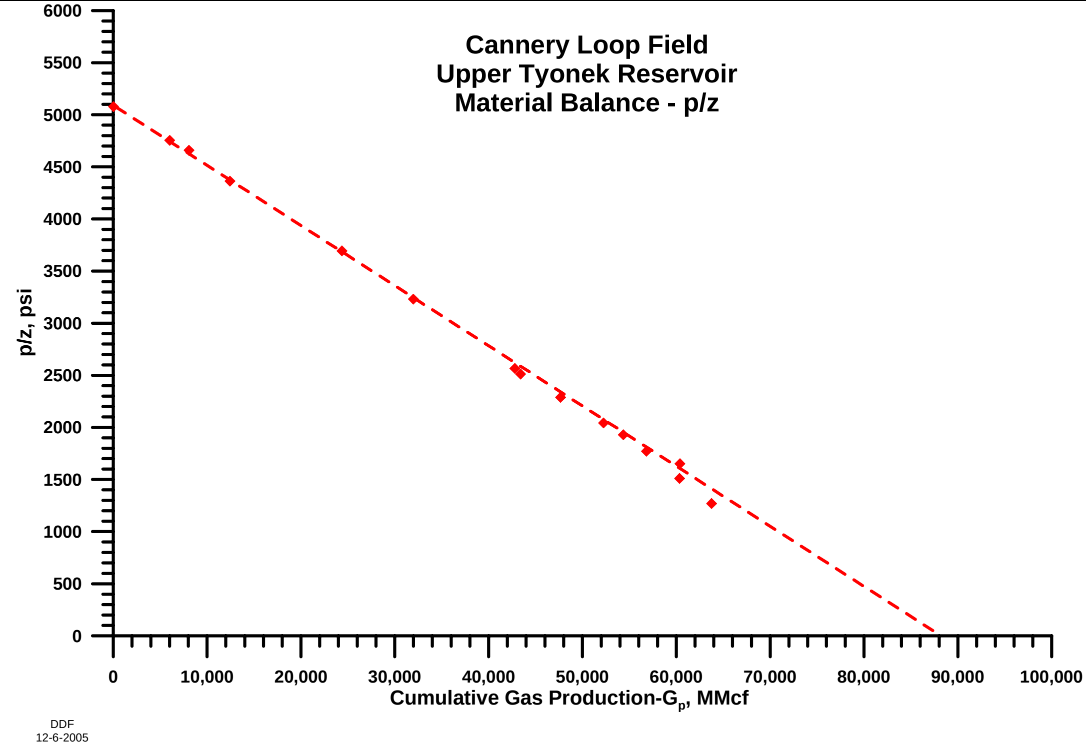
Figure G-7: **Cannery Loop field, Beluga material balance performance**



Upper Tyonek formation

Production from the Upper Tyonek began concurrently with the Beluga formation with a cumulative recovery through December 31, 2004 of 65,993,500 Mcf. Figure G-8 presents the material balance performance of the pool and indicates an OGIP of 88 Bcf for a recovery factor of 75.0%. The performance plot shows good linearity with no indication of water influx. Assuming a recovery factor of 85%, the estimated technical ultimate recovery is 74.8 Bcf for a estimated technical remaining reserves of 8.807 Bcf.

Figure G-8: Cannery Loop field, Upper Tyonek material balance performance



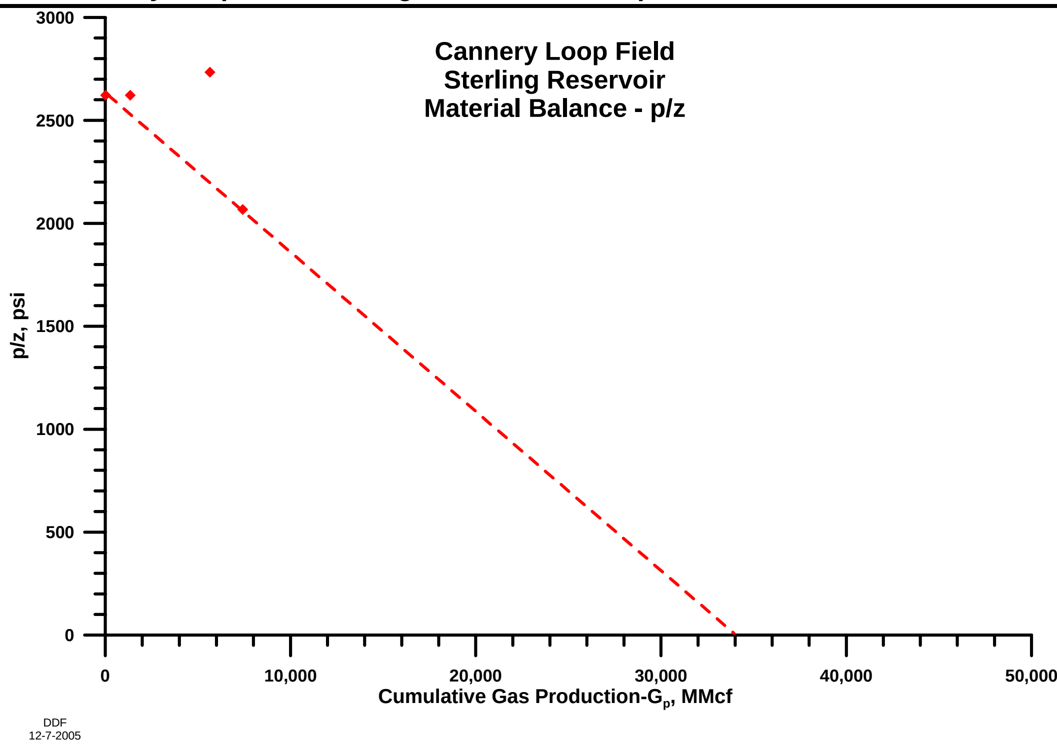
Tyonek Deep formation

The Tyonek Deep formation produced for ten months in 1988 with no production since then. Cumulative recovery is 1,399 Mcf. No reserves are assigned to this formation.

Sterling formation

Production from the Sterling formation began October 2000 with a cumulative recovery through December 31, 2004 of 12,854,536 Mcf. The material balance plot, Figure G-9 does not have much data, but the indicated OGIP is 34 Bcf, for a recovery factor of 37.8%. An 85% recovery factor would indicate the estimated technical ultimate recovery of 16.046 Bcf and a estimated technical ultimate recovery of 28.9 Bcf.

Figure G-9: Cannery Loop field, Sterling material balance performance



The total field historical and forecast production presented below (Figure G-10).

Figure G-10: Cannery Loop field historical and forecast production from proved reserves

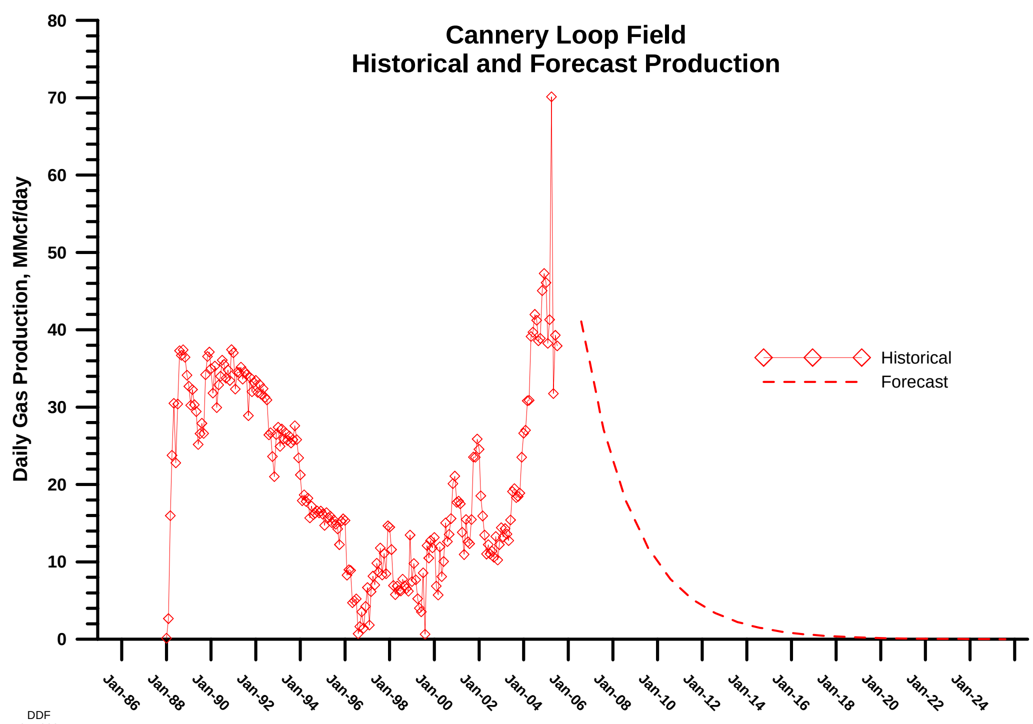


Table G-3: Cannery Loop forecast production from proved reserves

Year	*Bcf/yr*	*Year*	*Bcf/yr*
2005	*15.000*	*2016*	*0.153*
2006	*9.887*	*2017*	*0.101*
2007	*6.517*	*2018*	*0.066*
2008	*4.295*	*2019*	*0.044*
2009	*2.831*	*2020*	*0.029*
2010	*1.866*	*2021*	*0.019*
2011	*1.230*	*2022*	*0.013*
2012	*0.811*	*2023*	*0.008*
2013	*0.534*	*2024*	*0.005*
2014	*0.352*	*2025*	*0.004*
2015	*0.232*	*2026*	*0.002*

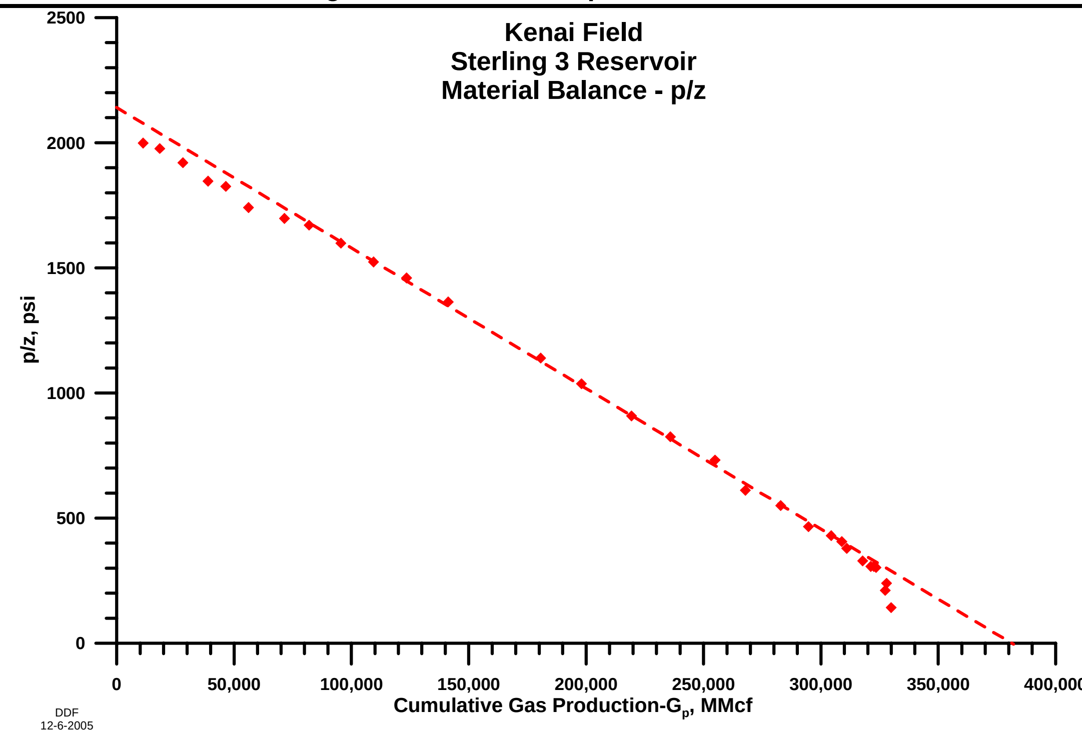
Kenai River Unit

The Kenai River field, located on-shore on the eastern side of Cook Inlet, was discovered in 1959. Gas has been produced from the Sterling 3, Sterling 4, Sterling 5.1, Sterling 5.2, Sterling 6, Beluga, and Tyonek formations. Cumulative recovery from all formations is 2,269,737,511 Mcf through December 31, 2004. Determination of individual formation gas reserves and producing rates are discussed in the following sections.

Sterling 3 formation

The Sterling 3 formation began producing during 1965 with continuous production commencing in 1968. Cumulative recovery to December 31, 2004, is 330,224,352 Mcf. The material balance plot indicates an OGIP of 380 Bcf for an 86.9% recovery factor. The recent production response seen in Figure G-11 demonstrates increasing signs of water influx and the pool is likely nearing depletion. No remaining reserves are assigned to this pool.

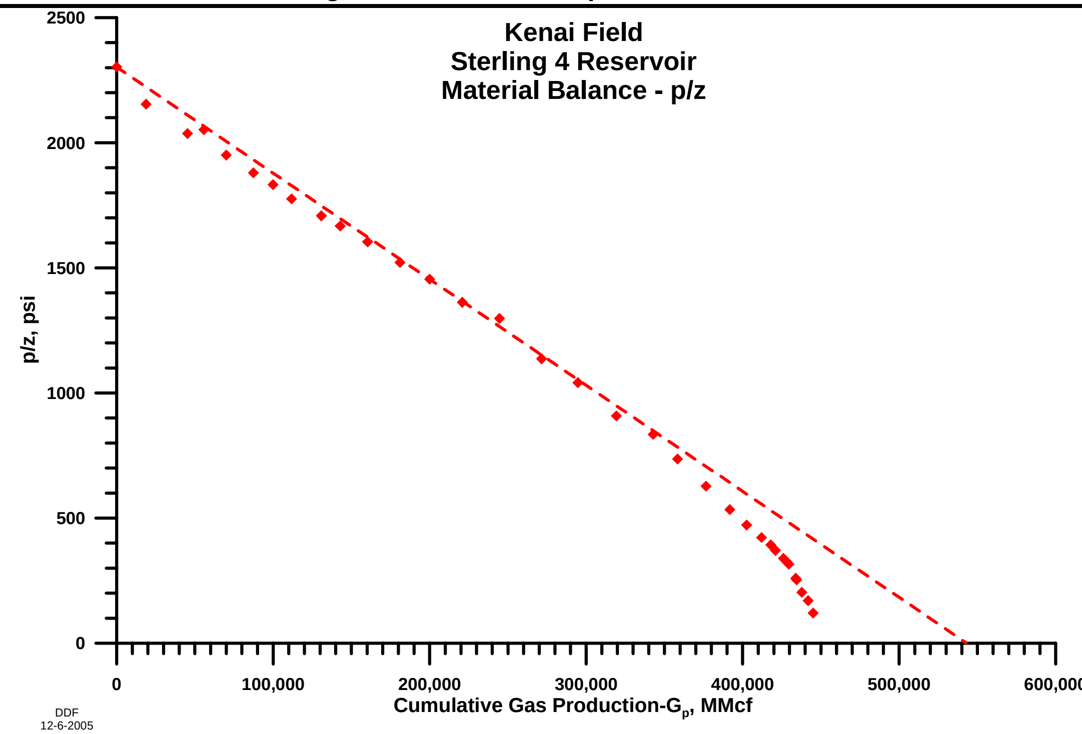
Figure G-11: Kenai field, Sterling 3 material balance performance



Sterling 4 formation

The Sterling 4 formation began producing in 1965. Cumulative recovery to December 31, 2004 is 447,083,173 Mcf. Production from January through August 2005 averaged 211.319 MMcf/d. The material balance performance indicates an OGIP of about 545 Bcf for a recovery factor of 82%. The production performance shown in Figure G-12 indicates increasing water influx as the field is nearing depletion. A recovery factor of 85% would suggest an ultimate recovery of 463,250 Mcf for an upside remaining technical reserves of 16.2 Bcf.

Figure G-12: Kenai field, Sterling 4 material balance performance



Sterling 5.1 formation

The Sterling 5.1 formation produced 7. 4 Mcf in 2005, no reserves are assigned to this formation.

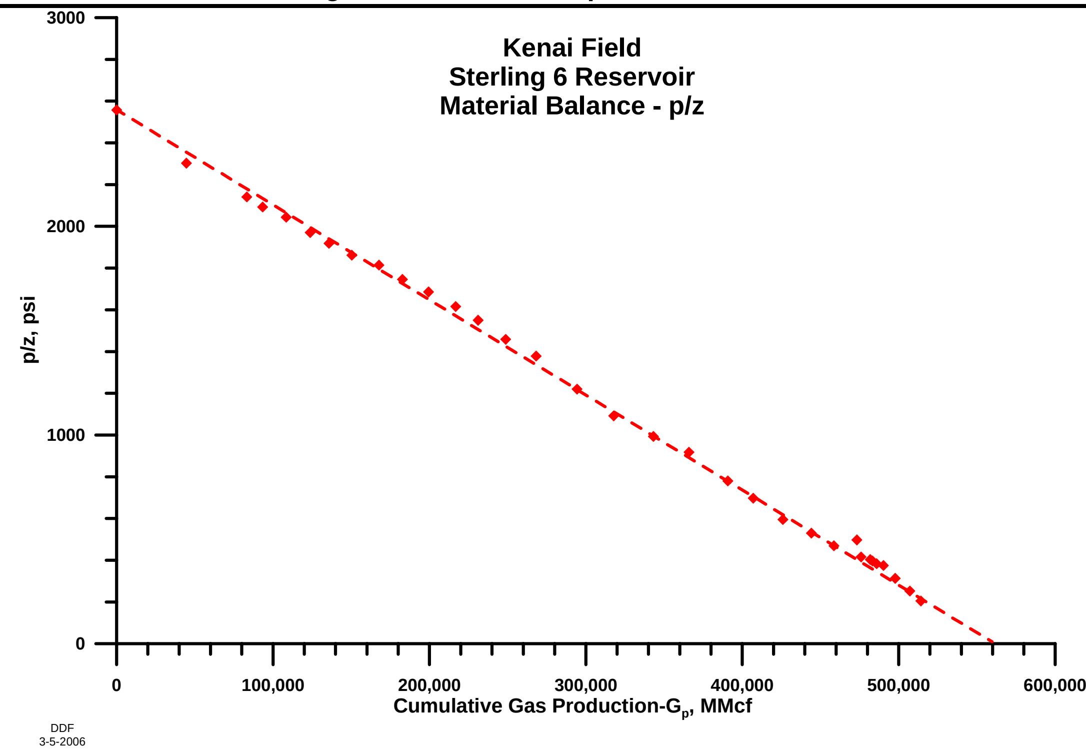
Sterling 5.2 formation

No production has occurred since 1982, no reserves are assigned to this formation.

Sterling 6 formation

Initial production from the Sterling 6 formation began in 1961. Cumulative recovery through December 31, 2004 is 517,638,198 Mcf. The material balance performance shown in Figure G-13 indicates an OGIP of 560 Bcf for a recovery of 92.4%. This recovery factor is high and may suggest the OGIP estimate is low. The reservoir performance shows no indication of water influx with good linear behavior.

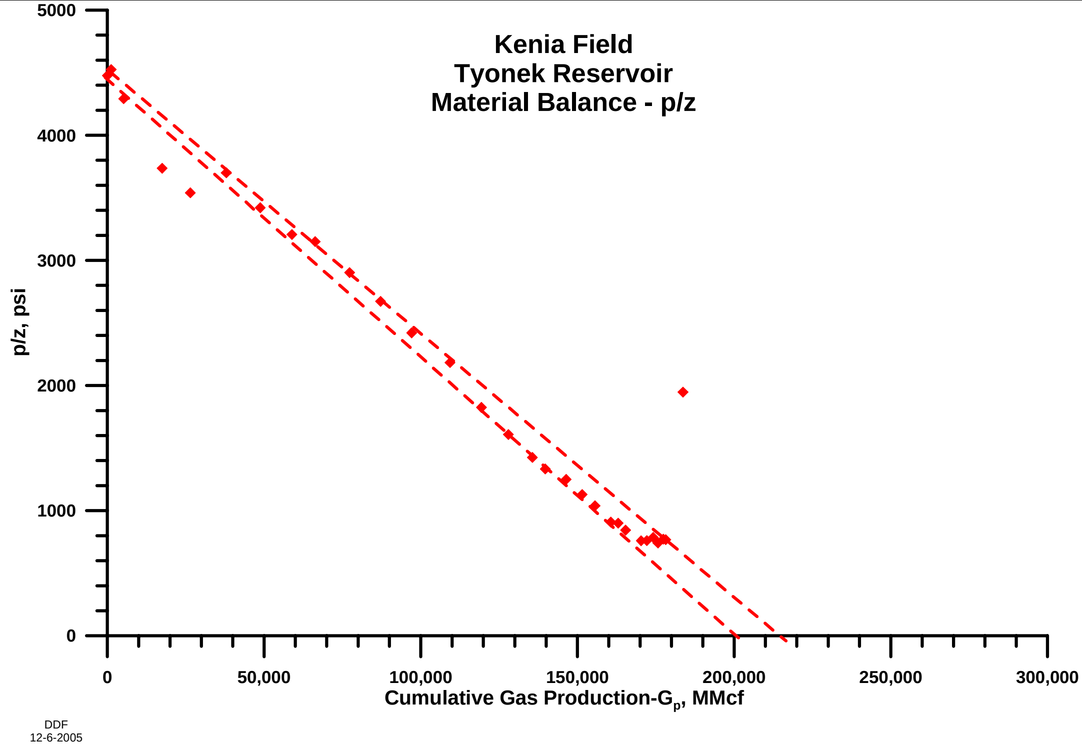
Figure G-13: Kenai field, Sterling 6 material balance performance



Tyonek formation

Initial production from the Tyonek formation began in 1968. The cumulative recovery through December 31, 2004, was 184,554,952 Mcf gas. The material balance performance is presented in Figure G-14 and an OGIP of 212 Bcf is indicated for a recovery of 87.1%. The material balance shows good linearity until recently with a shift indicating additional reserves due to additional productive zones at initial reservoir pressures being accessed with inferred reserves growth of at least 10 Bcf.

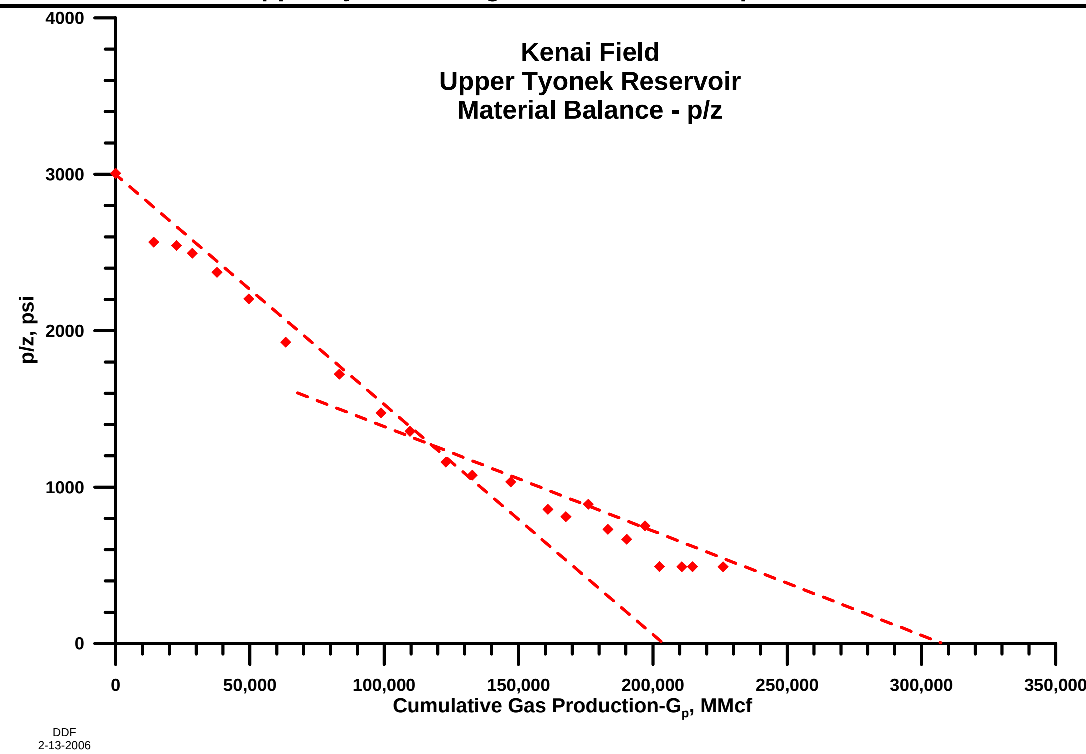
Figure G-14: Kenai field, Tyonek material balance performance



Upper Tyonek Beluga formation

Initial production from the Upper Tyonek formation began in 1968. The cumulative recovery through December 31, 2004 is 261,525,860 Mcf. The material balance plot is presented in FigureG-15. The material balance plot indicates an initial OGIP of 198 Bcf. Indicated improvement in recovery of at least 30 Bcf due to a workover program to access additional productive zones at initial reservoir pressures causes the later performance data to deviate to the right. The indicated improvement in recovery may be as much as 100 Bcf although additional pressure data at the current level of depletion is not available.

Figure G-15: Kenai field, Upper Tyonek Beluga material balance performance



The composite production forecast is presented in Figure G-16 and Table G-4. The production forecast is likely conservative as several pools indicate ongoing improved recovery due to efforts and access additional zones.

Figure G-16: Kenai field historical and forecast production

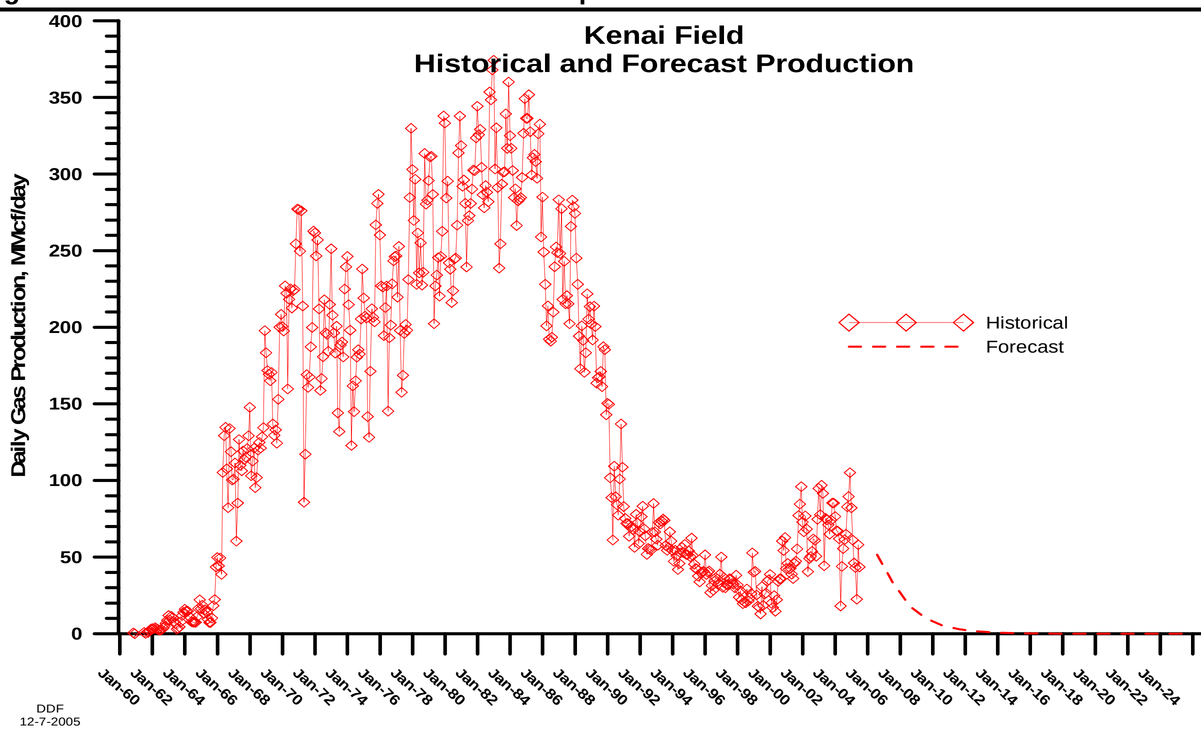


Table G-5: Forecast Kenai gas production from proved reserves

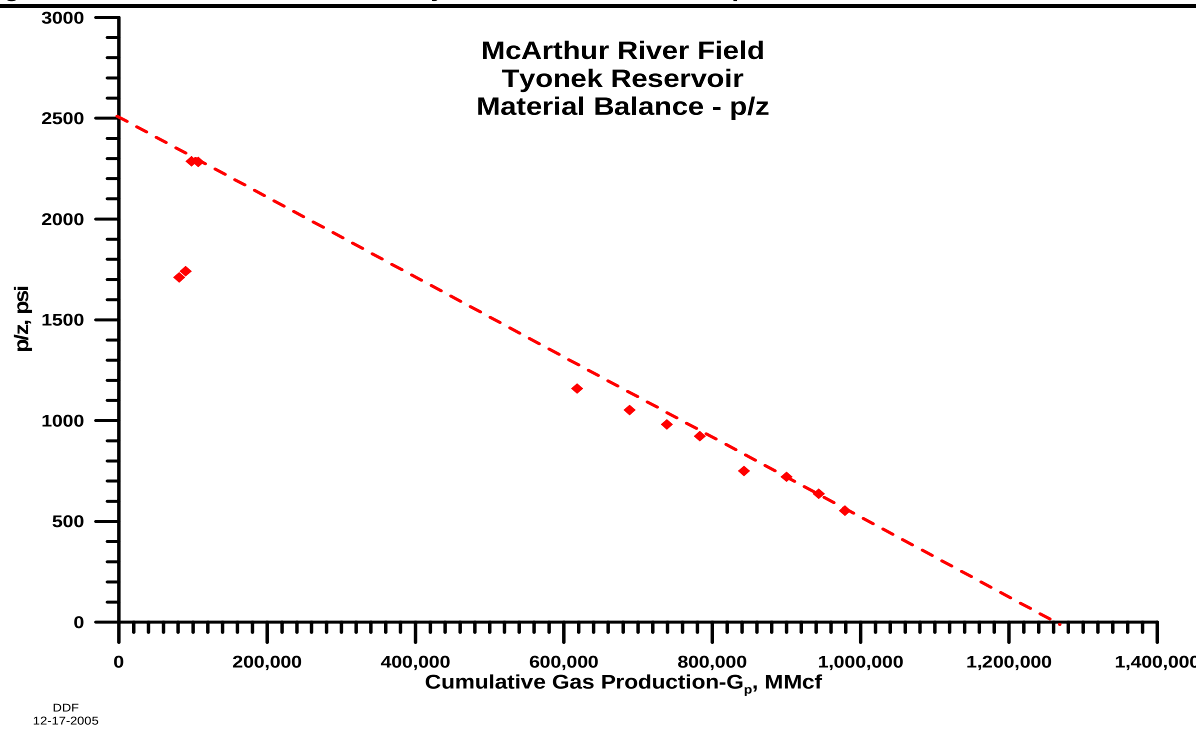
Year	*Bcf/yr*	*Year*	*Bcf/yr*
2005	18.810	2016	
2006	12.000	2017	
2007	6.641	2018	
2008	3.676	2019	
2009	2.034	2020	
2010	0.000	2021	
2011		2022	
2012		2023	
2013		2024	
2014		2025	
2015		2026	

McArthur River (Trading Bay Unit)

The McArthur River gas field is a part of the Trading Bay Unit and is produced from the Steelhead platform. It is located offshore near the west side of the Cook Inlet. The McArthur River gas field began producing from the Mid-Kenai formation in 1969. Cumulative production from this formation is 996,427,729 Mcf gas through December 31, 2004.

The material balance performance indicates an OGIP of 1,265 Bcf for a recovery of 78.8%, Figure G-17 and exhibits good linearity. The estimated ultimate recovery assuming an 85% recovery factor is 1,075 Bcf, indicating remaining reserves of 78.8 Bcf.

Figure G-17: McArthur River field, Tyonek material balance performance



The historical and forecast production is presented in Figure G-18 and forecast in Table G-5.

Figure G-18: McArthur historical and forecast production

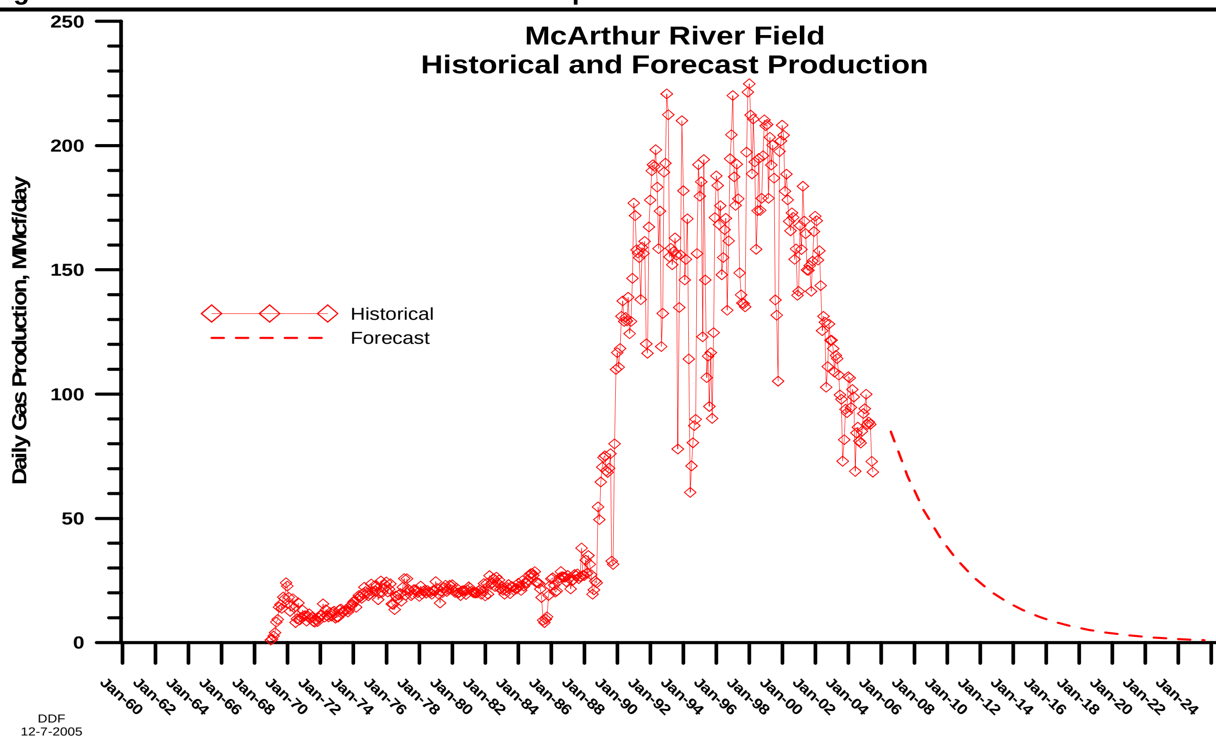


Table G-5: Forecast McArthur gas production from proved reserves

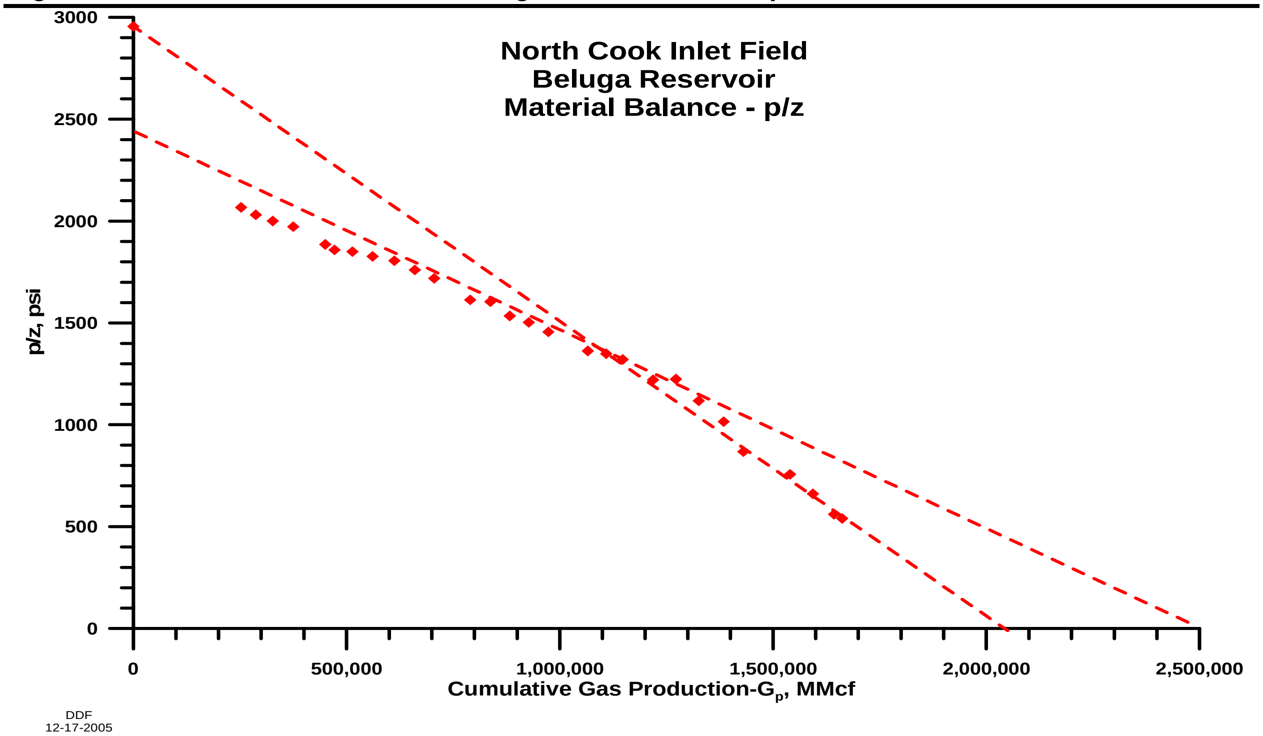
Year	*Bcf/yr*	*Year*	*Bcf/yr*
2005	*30.978*	*2016*	
2006	*24.525*	*2017*	
2007	*19.416*	*2018*	
2008	*15.371*	*2019*	
2009	*12.169*	*2020*	
2010	*9.634*	*2021*	
2011	*7.627*	*2022*	
2012	*6.038*	*2023*	
2013	*4.780*	*2024*	
2014	*0.000*	*2025*	
2015		*2026*	

North Cook Inlet field

The North Cook Inlet field was discovered in 1962. The field is located offshore in the northern part of the Cook Inlet about eight miles from the western shore. Production began in 1969 from the Sterling and Beluga formations. Cumulative production through December 31, 2004, was 1,662,365,485 Mcf of gas.

The material balance plot indicates an OGIP of 2,050 Bcf for a recovery of 81.1%. The plot shows a downward deviation of the data points at about 1,300 MMcf of gas recovery in 1998. This is believed to have been caused by workovers performed in the early 1990s. Many producing intervals were blanked off by packers or were squeeze cemented, reducing reservoir volume. As can be seen in Figure G-19 the apparent reservoir volume being drained prior to the workovers was about 2,500 Bcf and the reservoir volume after the workovers is about 2,050 Bcf. This volume of gas may be available if these zones can be returned to economic production.

Figure G-19: North Cook Inlet field, Beluga material balance performance



The historical and forecast production is presented in Figure G-20 and the data in Table G-6. It is assumed field production of 44 Bcf per year can be maintained through 2009 before going on decline.

Figure G-20: North Cook Inlet field historical and forecast production

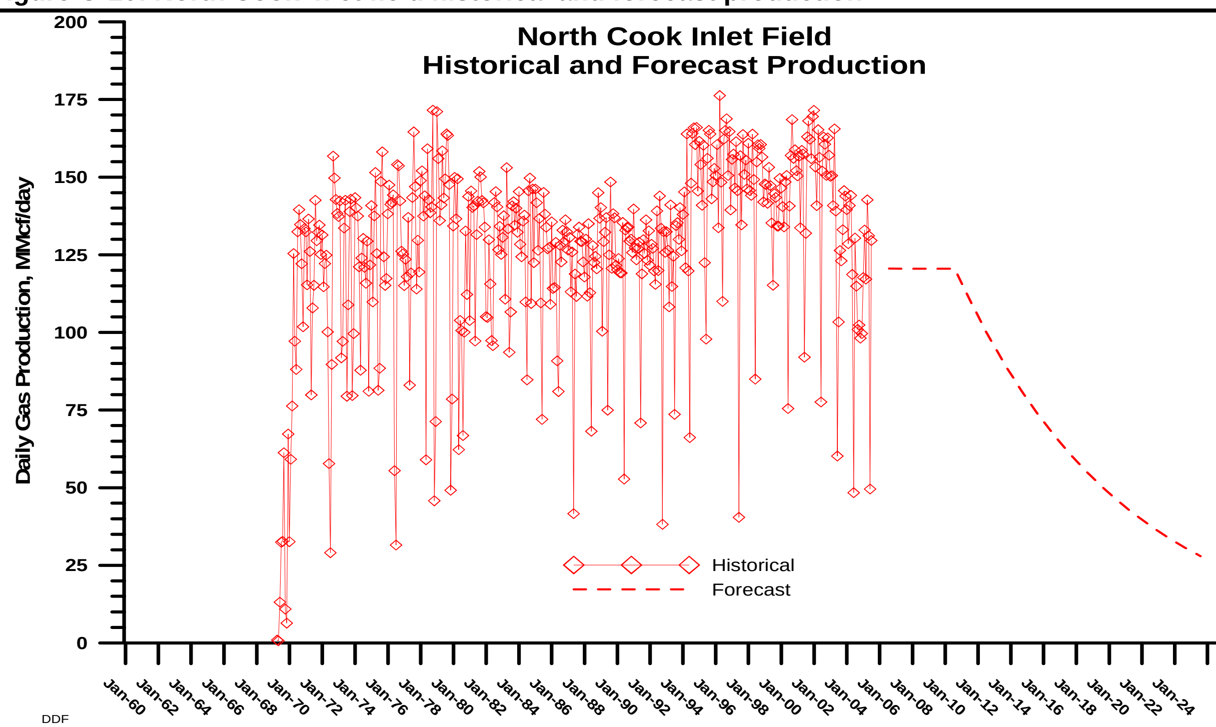


Table G-6: Forecast North Cook Inlet gas production from proved reserves

Year	Bcf/yr	Year	Bcf/yr
2005	44.001	2016	22.276
2006	44.000	2017	20.206
2007	44.000	2018	18.327
2008	44.000	2019	16.624
2009	44.000	2020	15.079
2010	40.000	2021	13.677
2011	36.282	2022	0.000
2012	32.909	2023	
2013	29.850	2024	
2014	27.076	2025	
2015	24.559	2026	

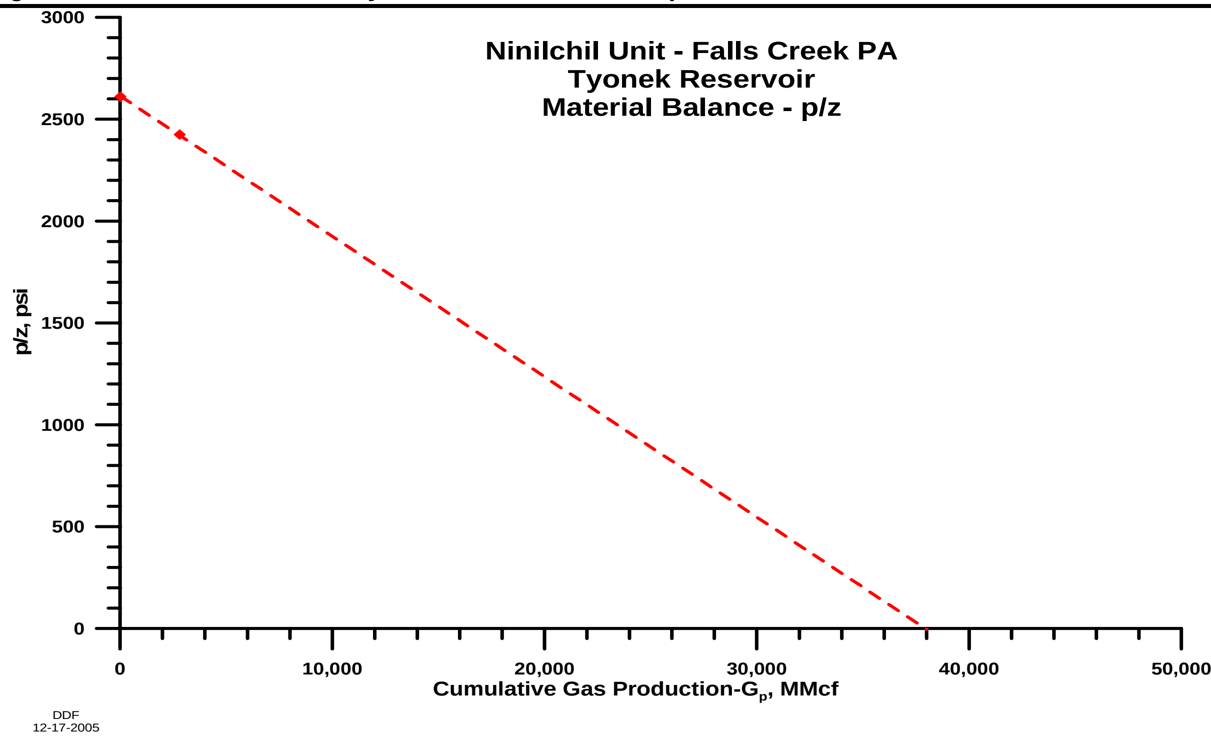
Ninilchik Unit

The Ninilchik Unit consists of four participating areas (PA); Falls Creek, Grassim Oskolkoff, Susan Dionne, and Paxton pools, all producing from the Tyonek formation. The first production from Falls Creek and Grassim Oskolkoff occurred September 2003 and Susan Dionne in December 2003. The Paxton participating area started production January 2005. Cumulative production through December 31, 2004 from the Unit is 15,429,538 Mcf. Production for the first eight months of 2005 averaged 35,180 Mcf/d. Individual PA reservoir performance is presented below.

Falls Creek PA

The Falls Creek PA has a cumulative production through December 31, 2004 of 5,979,065 Mcf. The production rate has been increasing since first production and during the first eight months of 2005 averaged 13,574 Mcf/d. The material balance performance, Figure G-21 indicates an OGIP of 38 Bcf for a current recovery of 15.7%. Assuming an 85% recovery factor indicates a technical ultimate recovery of 32.3 Bcf and technically estimated reserves of 26.321 Bcf.

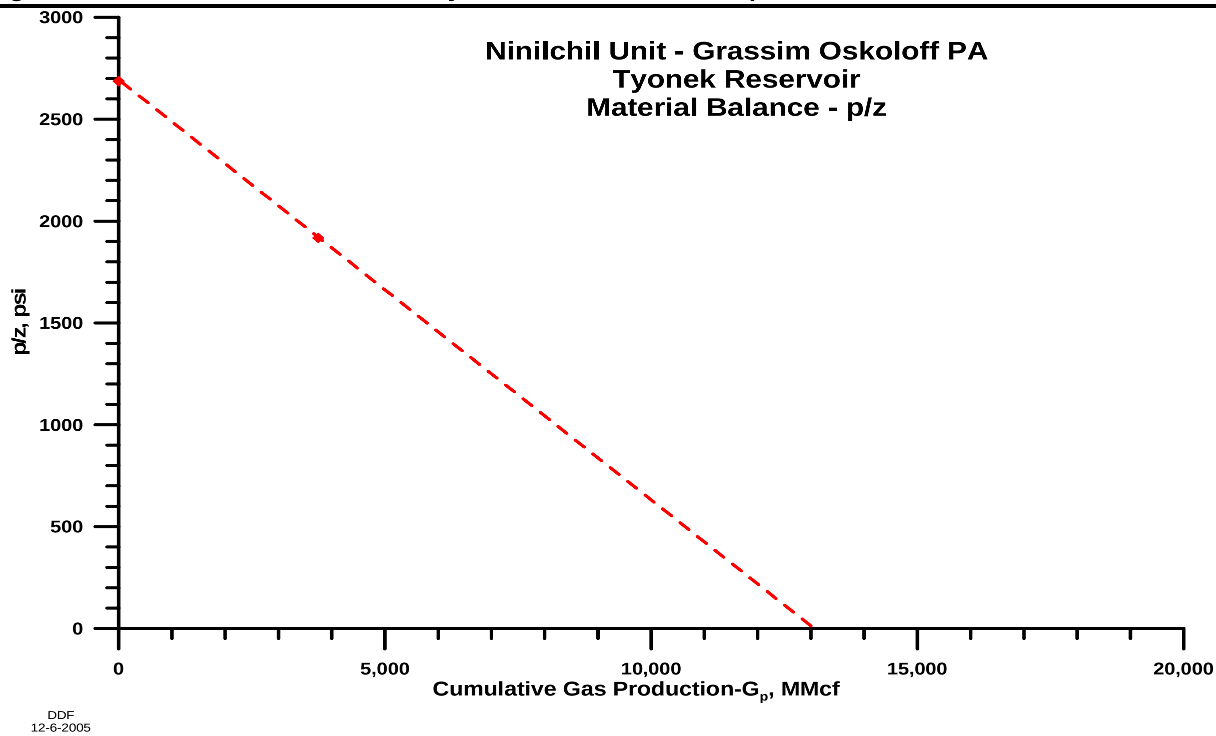
Figure G-21: Falls Creek PA, Tyonek material balance performance



Grassim Oskolkoff PA

The Grassim Oskolkoff PA has a cumulative production through December 31, 2004 of 5,462,004 Mcf. The production rate has been increasing since first production and during the first eight months of 2005 averaged 4,775 Mcf/d. The material balance performance, Figure G-22, indicates an OGIP of 13 Bcf for a current recovery of 42.0%. Assuming an 85% recovery factor indicates a technical ultimate recovery of 11.05 Bcf and technically estimated reserves of 5.588 Bcf.

Figure G-22: Grassim Oskoloff PA, Tyonek material balance performance



Susan Dionne PA

The Susan Dionne PA has a cumulative production through December 31, 2004 of 3,988,469 Mcf. The production rate has been increasing since first production and during the first eight months of 2005 averaged 15,368 Mcf/d. There is no material balance performance data, so no estimate of the OGIP is available from production performance. Production has been increasing since the start of production and production during the second quarter of 2005 averaged 19,400 Mcf/d.

Paxton PA

The Paxton well #1 started production January 2005 with peak production occurring in March at 2,204 Mcf/d and is now on decline with August 2005 production of 1,539 Mcfd. No material balance performance data are available to estimate OGIP.

Ninilchik technically estimated ultimate recovery was estimated at 200 Bcf by the prior study and no additional information is available to revise otherwise. The historical and forecast total Unit production is presented in Figure G-23 and the forecast data in Table G-7.

Figure G-23: Ninilchik Unit historical and forecast production

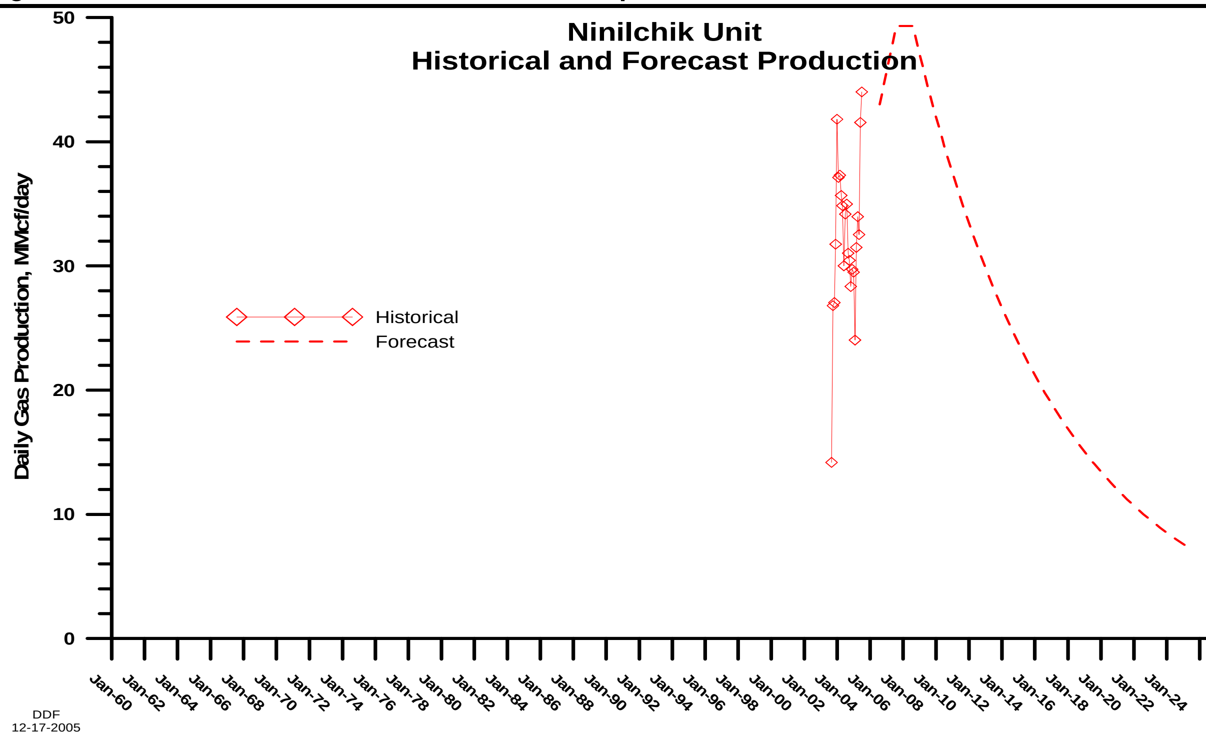


Table G-7: Forecast Ninilchik gas production from proved reserves

Year	*Bcf/yr*	*Year*	*Bcf/yr*
2005	*15.695*	*2016*	*6.456*
2006	*18.000*	*2017*	*5.760*
2007	*18.000*	*2018*	*5.140*
2008	*16.062*	*2019*	*4.587*
2009	*14.332*	*2020*	*4.093*
2010	*12.789*	*2021*	*3.652*
2011	*11.412*	*2022*	*3.259*
2012	*10.183*	*2023*	*2.908*
2013	*9.086*	*2024*	*2.595*
2014	*8.108*	*2025*	*0.000*
2015	*7.235*	*2026*	

Other Developed Fields

The remaining fields were aggregated and a forecast prepared. These fields started production at various times with a cumulative production of 317,056 Mcf through December 2004. No material balance performance data is available to estimate the aggregate OGIP for these small accumulations. The aggregated technical estimated ultimate recovery is 451 Bcf and the technical estimated remaining reserves are 134,247 Mcf. The historical and forecast production is presented in Figure G-24 and Table G-8.

Figure G-24: All other developed fields, historical and forecast production

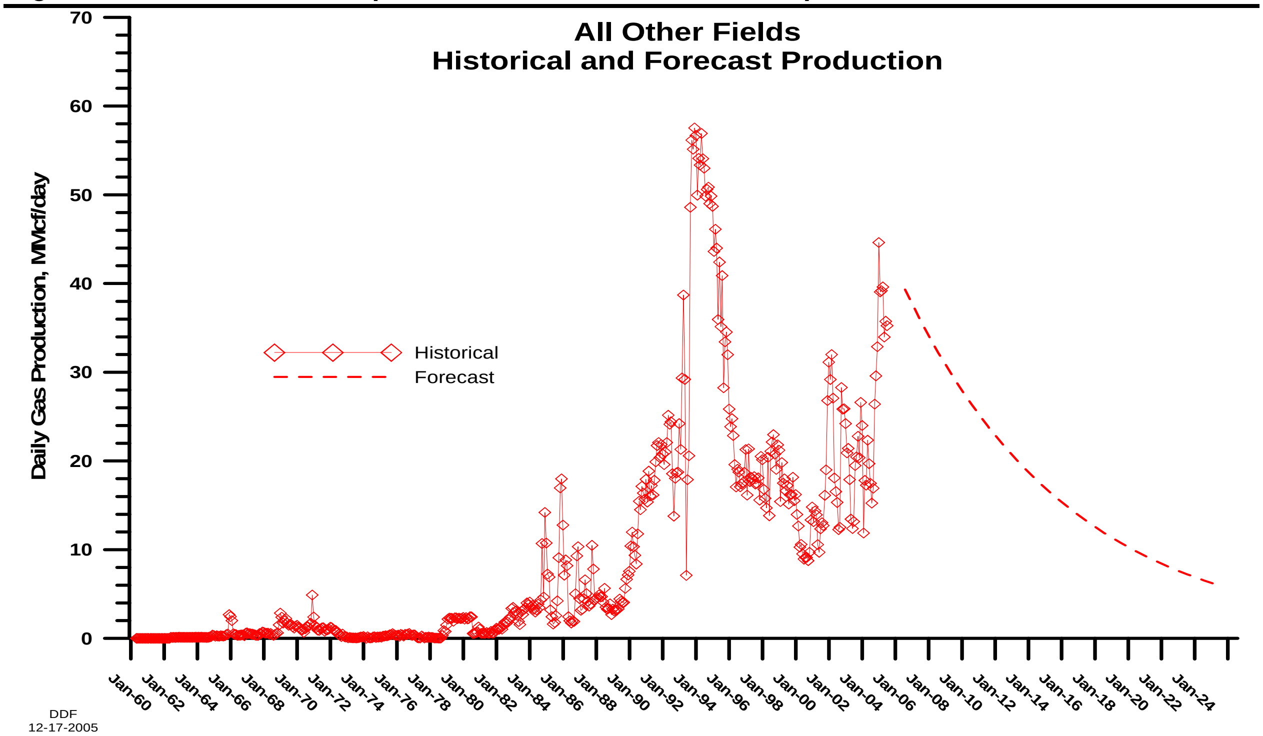


Table G-8: Forecast All Other Developed gas production from proved reserves

Year	*Bcf/yr*	*Year*	*Bcf/yr*
2005	*14.350*	*2016*	*4.786*
2006	*12.987*	*2017*	*4.331*
2007	*11.753*	*2018*	*3.920*
2008	*10.636*	*2019*	*3.547*
2009	*9.626*	*2020*	*3.211*
2010	*8.711*	*2021*	*2.905*
2011	*7.884*	*2022*	*2.629*
2012	*7.135*	*2023*	*2.380*
2013	*6.457*	*2024*	*2.154*
2014	*5.844*	*2025*	*1.949*
2015	*5.288*	*2026*	*0.000*

Proved Undeveloped

Proved undeveloped reserves are for new discoveries or reserves developed with delineation drilling from producing fields. The technical estimated remaining reserves are 185,190 Mcf. The production forecast and data are presented in Figure G-25 and Table G-9.

Figure G-25: Proved undeveloped fields forecast production

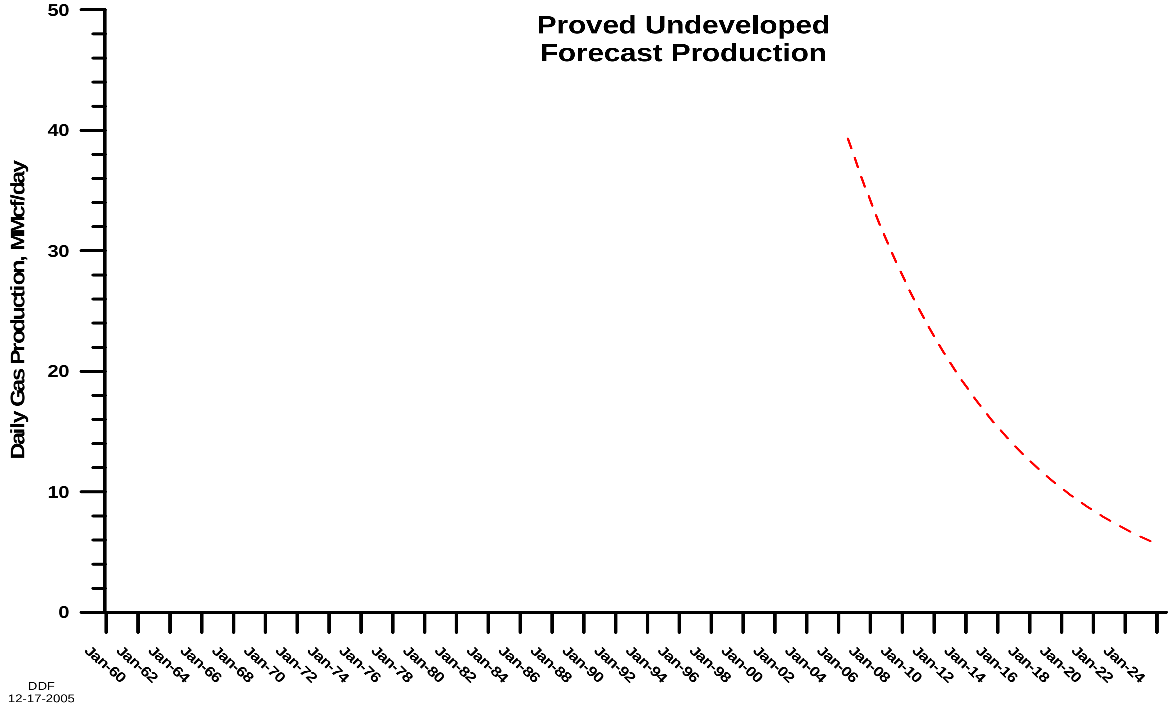


Table G-9: Forecast Proved Undeveloped gas production from proved reserves

Year	*Bcf/yr*	*Year*	*Bcf/yr*
2005	0.000	2016	7.684
2006	18.500	2017	7.038
2007	16.944	2018	6.446
2008	15.519	2019	5.904
2009	14.213	2020	5.407
2010	13.018	2021	4.952
2011	11.923	2022	4.536
2012	10.920	2023	4.154
2013	10.001	2024	3.805
2014	9.160	2025	3.485
2015	8.390	2026	0.000

Appendix H: Literature Review

This literature review was conducted to develop the current state of knowledge about historical and projected natural gas supply and demand by sector, especially in South Central Alaska and adjacent areas. In addition, the literature review was used to identify methodological approach options for developing nascent market natural gas demand estimates. The research efforts for each sector (i.e., industrial, commercial, residential, transportation [e.g., gas-to-liquids] and electric power generation) were launched from the collective and specific findings of the literature review.

The literature review covered prior studies conducted by or on behalf of Federal Government organizations, including the National Energy Technology Laboratory (NETL), the U.S. Department of Energy Office of Fossil Energy, the U.S. Department of Agriculture, and the Army Corps of Engineers; the State of Alaska and related entities such as the Alaska Natural Gas Development Authority (ANGDA) and the Alaska Department of Natural Resources (DNR); the Alaskan utility ENSTAR; the trade publication *Petroleum News*; academia; and foreign countries. The reviewed media ranged from major studies to websites and news articles. The following items were included in the literature review. An annotated bibliography, which summarizes each work cited, its objective, and major findings, was also prepared separately.

1. ANGDA (2004a). "The All-Alaska LNG Project - A Report to the People." (12 pp).
2. ANGDA (2004b). *Interim Feasibility Report All-Alaska LNG Project* (58 pp).
3. Alaska Power Association (2004). "New Energy for Alaska" (26 pp).
4. Bagnall, Curtis, et al. (2005). *Joint Long-Range Energy Study for Greater Fairbanks Military Complex*, Final Report Prepared for U.S. Army Corps of Engineers (406 pp).
5. Bailey, A. (2005). "Increasing natural gas usage in Fairbanks: Natural gas costs substantially less than fuel oil but other energy sources compete for electricity generation in the Interior," *Petroleum News*, Vol. 10, No. 37, September 11.
6. Baker, M. (2005). *Transport of North Slope Natural Gas to Tidewater. Leveraging Issues, Configuration Descriptions & Issues, New Project Concept*. Prepared for ANGDA (133 pp).
7. Beck, R. W. (2004). "Railbelt Energy Study," prepared for Railbelt Energy Utilities (83 pp).
8. Brooks, D. and Richard W. Haynes (2001). Recreation and Tourism in South-Central Alaska: Synthesis of Recent Trends and Prospects.
9. CEC (2003). *Transportation Fuels, Technologies and Infrastructure Assessment, Final Commission Report* (92pp).
10. Dismukes, D. et al. (2002a). *Alaska Natural Gas In-State Demand Study ASP 2001-1000-2650, Volume 1: Technical Report* for Alaska DNR (174pp).
11. Dismukes, D. et al.. (2002b). "New Role for North Slope Gas in South Central Alaska." *Natural Gas Monthly,* September (6 pp).
12. DOE, FE (1998). "Alaska Fossil Energy Workshop: One Decade Later - What's Alaska's Future?"

13. ENSTAR (2005). “South Central Alaska Natural Gas Demand,” Presented to State of Alaska, Joint House and Senate Resources Committee (25 slides).
14. ICF Consulting (2000). *A Market Analysis of Natural Gas Resources Offshore Newfoundland - Final Report*, prepared for Newfoundland Ocean Industries Association (93pp).
15. Jaffe, A. and D. Victor (2004). Geopolitics of Gas Working Paper Series - Executive Summary. Geopolitics of Natural Gas Study (21 pp).
16. Myers, M. (2005a). “Review of Alaska Oil and Gas Development Activity- 2004 and Beyond,” Alaska DNR, PAC COM Expo and Conference (37 pp).
17. Myers, M. (2005b). “State of Alaska Briefing Document on Proposal to Reauthorize Methane Hydrate Research and Development Act of 2000” Alaska DNR (16 pp.).
18. Myers, M. (2005c). “Unlocking Alaska’s Natural Gas Hydrates: A Major New Domestic Resource,” Alaska DNR, Interstate Oil and Gas Compact Commission Midyear Issues Summit (15 pp).
19. NETL Arctic Energy Office website (2005). “Remote Electric Power Generation”
20. NETL (2004) Facts sheet: “Delivering Alaskan North Slope Gas to Market”
21. NETL (200?). “Alaska’s Coal and CBM Resources” (2 pp).
22. Northern Economics (2002). “Appendix E- Commodities Study: Rail Corridor Commodity Flows,” (97 pp).
23. Odsather (2004). *Cook Inlet Gas Spur Line Project: Alignment, Economic, and Regulatory Feasibility Review* (7 pp).
24. Posey et al. (2004). “Southcentral Alaska Natural Gas Study: Gas Shortage Imminent” (45 pp).
25. Rogers, B. et al. (2004). *Stranded Gas Development Act Municipal Impact Analysis*, Prepared for Municipal Advisory Group, Alaska Department of Revenue (241 pp).
26. Stiles, R.B. (2002). “The Future of Alaskan Coal Production and Utilization” (16 pp).
27. Thomas, Charles P. et al. (2004). *South-Central Alaska Natural Gas Study,* Prepared for NETL Arctic Energy Office, (211 pp).
28. Wade Locke and Strategic Concepts, Inc. (2004). Exploring Issues Related to Local Benefit Capture in Atlantic Canada's Oil and Gas Industry - Final Report. Petroleum Research Atlantic Canada, (88 pp).
29. Wisdom, H. (1990). “Transportation costs for forest products from the Puget Sound area and Alaska to Pacific Rim markets.” U.S. Department of Agriculture, Forest Service, Pacific Northwest Research Station (25 pp).

Findings from the literature review indicate that Cook Inlet natural gas supply can be extended to the South Central region for electric power generation until about 2012 and to residential and commercial customers until about 2015, provided that supply is discontinued to the two industrial facilities, the Agrium urea manufacturing plant in 2005, and the Marathon LNG facility in 2009. The various studies explain the future natural gas supply options, such as further exploration of Cook Inlet, development of Nanana resources, and a spur line from the North Slope pipeline, and energy alternatives such as coal.

Among the highlights of the most relevant literature reviewed, ENSTAR (2005) and Posey et al. (2004) describe the imminent need for natural gas to replace dwindling Cook Inlet supplies in South Central Alaska from the local stakeholders’ prospective. Thomas et al. (2004) presents a geologic, engineering, and economic assessment of the options to meet the natural gas demand for the South Central Alaska region. The report describes the remaining reserves and prospects for further exploration in Cook Inlet; predicts the future shortage; and describes the cost and capacity of a spur pipeline. ANGDA (2004a) describes the proposed All-Alaska LNG project to build a natural gas pipeline from the North Slope to Valdez for LNG export, and ANGDA (2004b) describes the technical feasibility and infrastructure requirements of the proposed project. Dismukes (2002b) and other sources found that while a gas spur line may be attractive to residential, commercial, and power generation consumers, it is not likely to provide an economical source of base load gas for industrial users. However, residential, commercial, and power generation demands alone are unlikely to justify the spur.

Key studies that addressed natural gas demand in the region of the proposed natural gas spur line include Bagnall (2005) and Dismukes (2002a), which report detailed estimates of the projected natural gas demand for Military facilities and each sector in the South Central and Interior Alaskan regions. Beck 2004 identifies electric power generation and transmission needs in the Railbelt through 2033, and options to meet those needs. Several studies discuss potential industrial opportunities that would involve significant gas demand levels. For example, Dismukes (2002a) describes the expected gas demand for a hypothetical internet server farm and a petrochemical facility; Baker (2005) proposed a pipeline to Cook Inlet to carry propane-enriched gas for extraction, centralized hydrocarbon processing, and domestic use or export as LPG; and CEC (2003) notes that it is seeking gas-to-liquid fuels from remote gas supplies, such as in Alaska, to displace some of its conventional diesel consumption. A review of similar natural gas demand studies of other regions, including Newfoundland and Southeast Asia, was conducted to develop a methodology or template for analysis. Collectively, this literature review served as a foundation for more detailed research, analysis, and estimate of future gas demand volume and price threshold for the South Central Alaskan region.

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