In-State Gas Demand Study
Volume I: Report

Prepared for

TransCanada Alaska Company, LLC

January 2010

Northern Economics
Wisdom • Trust • Relevance • Innovation

In association with

- Institute of Social and Economic Research, University of Alaska
- Science Applications International Corporation

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Abbreviations

2009$	U.S. Dollars, in real 2009 dollars
ADNR	Alaska Department of Natural Resources
AEA	Alaska Energy Authority
AECO	Alberta Energy Company, Alberta gas hub
AHFC	Alaska Housing Finance Corporation
ANGDA	Alaska Natural Gas Development Authority
ANGPA	Alaska Natural Gas Pipeline Act
ANRTL	Alaska Natural Resources to Liquids, LLC
APT	Alaska Power and Telephone
ASRC	Arctic Slope Regional Corporation
AVEC	Alaska Village Electric Cooperative
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
Bpd	Barrels per day
BTU	British thermal units
CEA	Chugach Electric Association
CIRI	Cook Inlet Regional Inc.
CMAI	Chemical Market Associates, Inc.
CVEA	Copper Valley Electric Association
DOG	Alaska Division of Oil and Gas
DSM	Demand side management
EIA	Energy Information Authority
FERC	Federal Energy Regulatory Commission
FNG	Fairbanks Natural Gas, LLC
GTL	Gas to liquids
GVEA	Golden Valley Electric Association
HEA	Homer Electric Association
ISER	Institute of Social and Economic Research
kWh	Kilowatt-hour
LNG	Liquefied Natural Gas
Mcf	Thousand cubic feet
MEA	Matanuska Electric Association

ML&P	Anchorage Municipal Light and Power
MMBtu	Million British thermal units
MMcfd	Million cubic feet per day
MMTPA	million metric tons per annum
MW	megawatt
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratories
NPV	Net present value
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
REGA	Railbelt Energy Generation Authority
RIRP	Regional Integrated Resource Plan
SAIC	Science Applications International Corporation
SES	Seward Electric System
SLP	City of Seward Light and Power
TAPS	TransAlaska Pipeline System

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Executive Summary

This *In-State Gas Demand Study* projects the potential demand from Alaska residents and industries for natural gas and propane that would be available with construction of a natural gas pipeline to commercialize North Slope gas. The purpose of the study is to meet the requirements of §157.34(b) of the FERC open season regulations for Alaska natural gas transportation projects. This study facilitates identification of at least five off-take or delivery points and potential delivery volumes at various locations along the pipeline. The study is also intended to allow the initial design of in-state delivery tariffs, which would help potential pipeline customers plan for the initial open season.

Study Scope and Approach

Potential demand is presented for two different future timeframes: (1) the Year 1 to 5 timeframe, which captures the demand in the first five years of operation of the gas pipeline; and (2) the Year 10 to 15 timeframe, which captures potential demand of various economic development projects or prospects that are expected to take a longer time to develop.

The study considers the two pipeline route configurations proposed by TransCanada: 1) the ***Alberta Line*** – from the North Slope of Alaska to Alberta, Canada following the Alaska-Canada highway, and 2) the ***Valdez LNG Line*** – from the North Slope to Valdez, Alaska, terminating at a liquefied natural gas (LNG) facility and marine terminal[1].

The study evaluates potential future demand for natural gas and propane for industrial uses, electric power generation, and heating demand from the residential and commercial sector, including the military. Stakeholder interviews were valuable in developing assumptions used in the demand projection models for each of the sectors. Industrial and electric power demand analyses were based on an assessment of several different future scenarios. Analysis of the industrial scenarios was based on an evaluation of the economic viability of various potential industrial prospects. Electric power scenarios were based on four future power generation scenarios currently being considered for the Railbelt[2] region. Residential and commercial sector heating demand analysis involved looking at increasing penetration rates as well as expansion of service areas, primarily in the areas with existing piped natural gas distribution systems.

The study employed a probabilistic approach to estimating natural gas demand. Projecting future demand that may occur 10 or more years into the future is challenging due to the considerable uncertainties that exist, particularly regarding future industrial and power demand. Furthermore, the possibility of future increases in Alaskan gas production from Cook Inlet or the Interior, and the rates of fuel-switching add further complexities to projections of in-state demand for North Slope gas. The probability analysis considered these high levels of uncertainty that exist about the energy situation in Alaska[3]. The results of the probability analysis are summarized according to the three most probable industrial demand cases; these are presented in Table ES-1.

[1] The economics and natural gas demand of the new Valdez LNG facility with an associated marine terminal, were not analyzed in this study. Based on information provided by TransCanada, the Valdez LNG facility is assumed to require 3.0 Bcf of natural gas per day.

[2] For this study, the Railbelt is defined as the service areas of the six Railbelt electric utilities including Chugach Electric Association, City of Seward Light and Power, Golden Valley Electric Association, Homer Electric Association, Matanuska Electric Association, and Municipal Light and Power. The service areas of ENSTAR Natural Gas Company and Fairbanks Natural Gas are within the service area boundaries of these electric utilities.

[3] More detailed discussion of the probability analysis and associated assumptions for the different sectors is provided in the main body of the report.

Major Findings

Historically, Alaskan demand for natural gas has been greater for gas-intensive industries than for all other sectors combined (i.e., power, residential, commercial, and other industrial). Hence, the future demand for natural gas in the state of Alaska is substantially affected by the future of Alaskan gas-intensive industries.

Table ES-1 summarizes the results of the probability analysis; it shows results for three demand scenarios categorized as "No Industry", "Current Industry", and "Growth Industry". Recognizing that no in-state gas-intensive industrial load is very certain in the future, the No Industry case represents in-state demand without a large industrial load. The Current Industry case represents a continuation of current trends, with a facility representative of the demand required by the Nikiski LNG terminal operating at full capacity. Finally, the Growth Industry case represents a scenario in which a facility representative of the demand of the existing LNG facility will expand to double its current capacity, but no greenfield projects will be built in years 1 to 5 of pipeline operations. Greenfield (or new) industrial projects are not assumed to be built at the same time as the pipeline because the joint demand for labor and materials could significantly increase the capital costs for a new facility, causing it to be uneconomic. Furthermore, unless owners of the greenfield industrial projects are to secure gas supply and commit to pipeline capacity in the early open seasons, it is unlikely that they would have sufficient gas to support the greenfield projects in the initial years of pipeline operation. In years 10 to 15, greenfield projects with reasonably likely economic feasibility are included under the Growth Industry case.

Table ES-1 also shows the percent chance that each case will occur. The No Industry case is more likely in the first years of pipeline operation than in later years. Under the Alberta project, the Current Industry case is the most likely of the assessed scenarios.

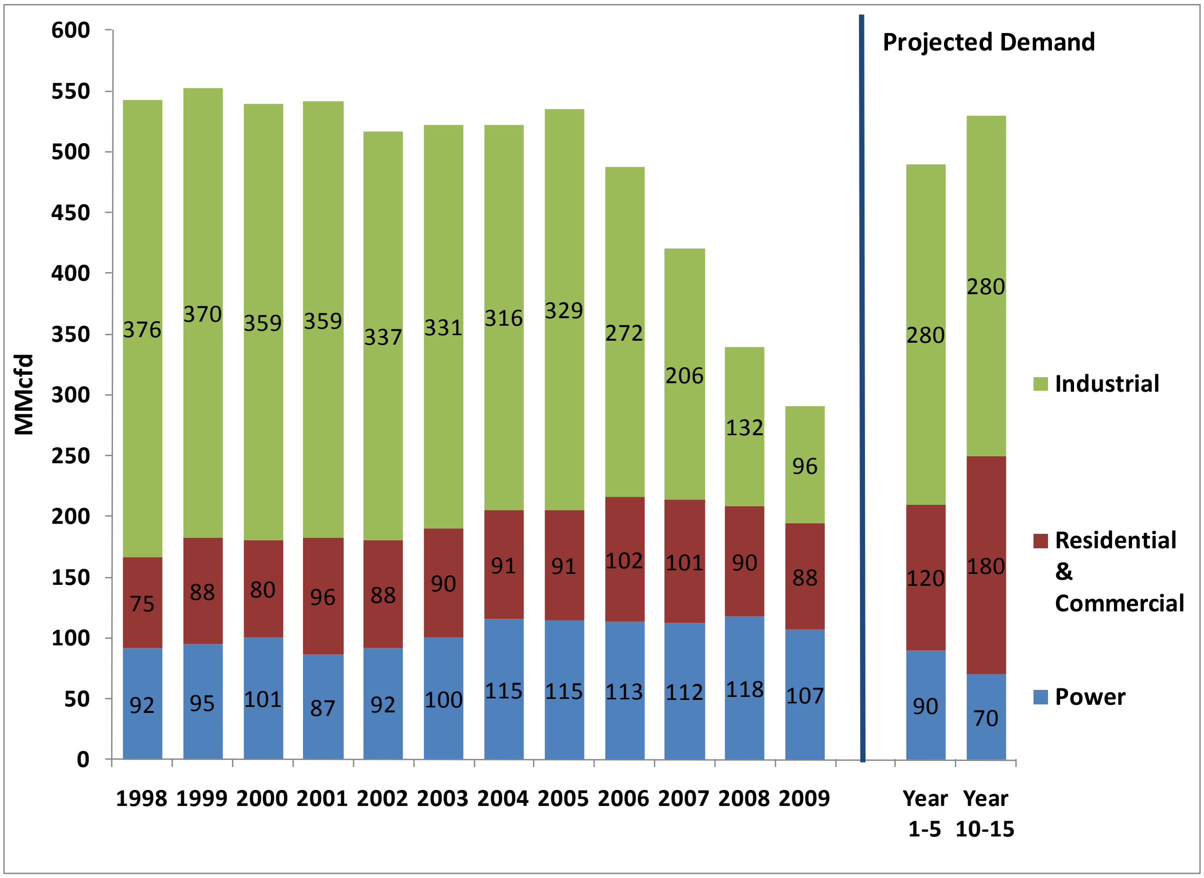
Table ES-1. Total In-State Natural Gas Demand Estimates for Three Scenarios, Alberta Project (MMcfd)

	Year 1 to 5 of Pipeline Operation			Year 10 to 15 of Pipeline Operation		
Demand Scenarios	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level
Alberta Project						
No Industry	260	29	71	290	14	86
Current Industry	490	38	26	520	18	65
Growth Industry	740	12	3	1,120	6	2

Source: Northern Economics, Inc. and SAIC, Inc., 2009.
Note: MMcfd is million cubic feet per day.

Figure ES-1 shows historic consumption of natural gas and the projected demand by sector. The projected demand totals are those depicted by the Current Industry case for the Alberta Project for the first five years of pipeline operations. Since 2006, the Agrium ammonia-urea plant has ceased operation and the LNG plant owned by ConocoPhillips and Marathon has reduced LNG production. The export license for the plant expires in 2011; consequently, the projected gas-intensive industrial demand shown in Figure ES-1 is uncertain.

Figure ES-1. Historic and Projected Total Annual Average Daily Demand for Natural Gas, Current Industry Case for the Alberta Project

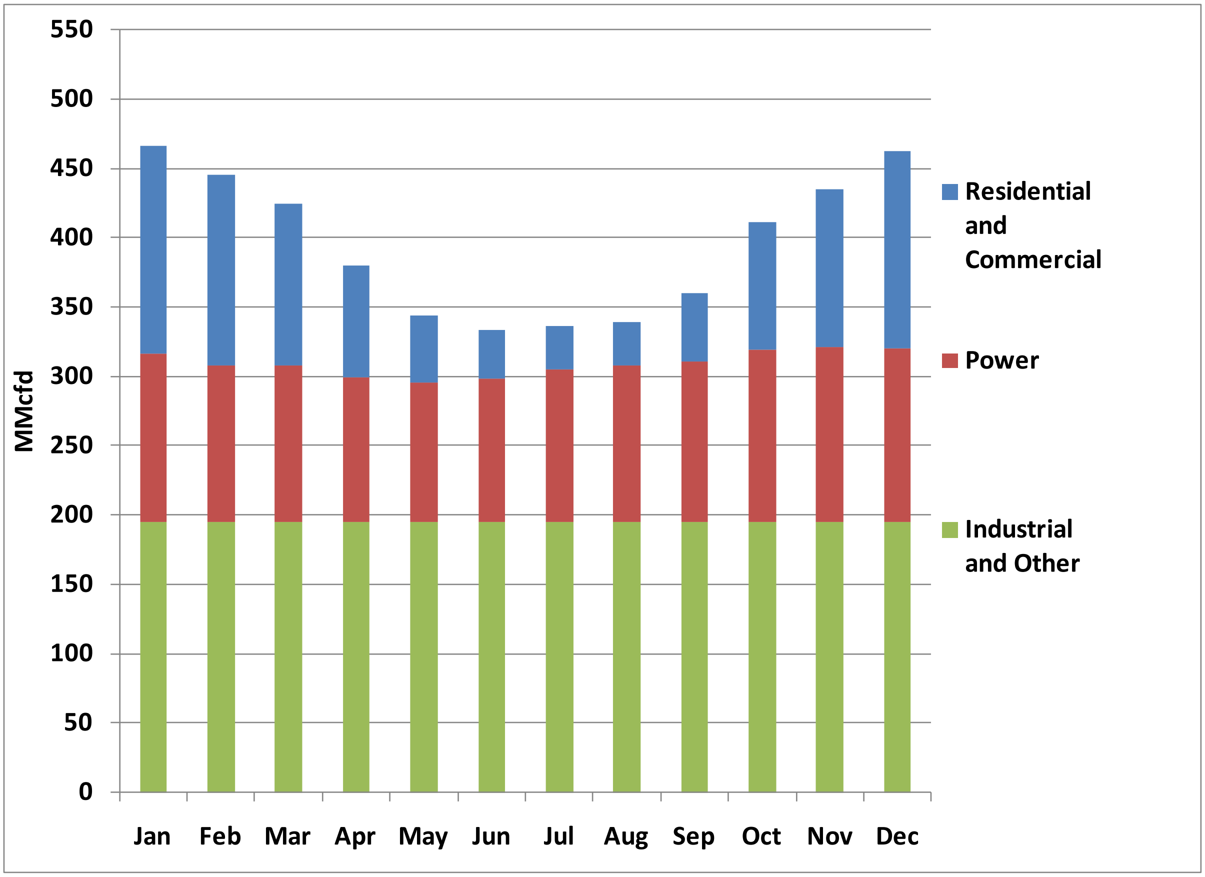


Source: Historical data are from the Division of Oil and Gas, Alaska Department of Natural Resources. Projected demand in Year 1 to 5 and Year 10 to 15 of pipeline operations are based on the results of this study.

Notes: Historical values for industrial sector include gas consumption for the LNG facility, the Ammonia-Urea plant from 1998 to 2007, and for other small operations such as for military bases in Anchorage, the GTL facility, Tesoro refinery, the small liquefaction facility that transports LNG to Fairbanks Natural Gas, etc. Gas consumed in field/lease operations is not included in the values shown above. The sum of the projected values for Year 10-15 in this figure does not match the total Current Industry case demand in Table ES-1 due to rounding.

Figure ES-2 presents the average monthly demand during a calendar year. The monthly average daily demand varies by about 130 million cubic feet per day (MMcfd) over the year. Demand from the industrial sector helps to moderate seasonal variation in the residential, commercial and power sectors, which can experience demand as low as 138 MMcfd in the summer and as high as 271 MMcfd in the winter. The industrial sector curtails its demand if needed in the winter.

Figure ES-2. Typical Total Average Daily Demand for Natural Gas by Month



Source: Data on historical natural gas usage are based on information provided by the Alaska Department of Natural Resources, for the years 1998 to 2009.

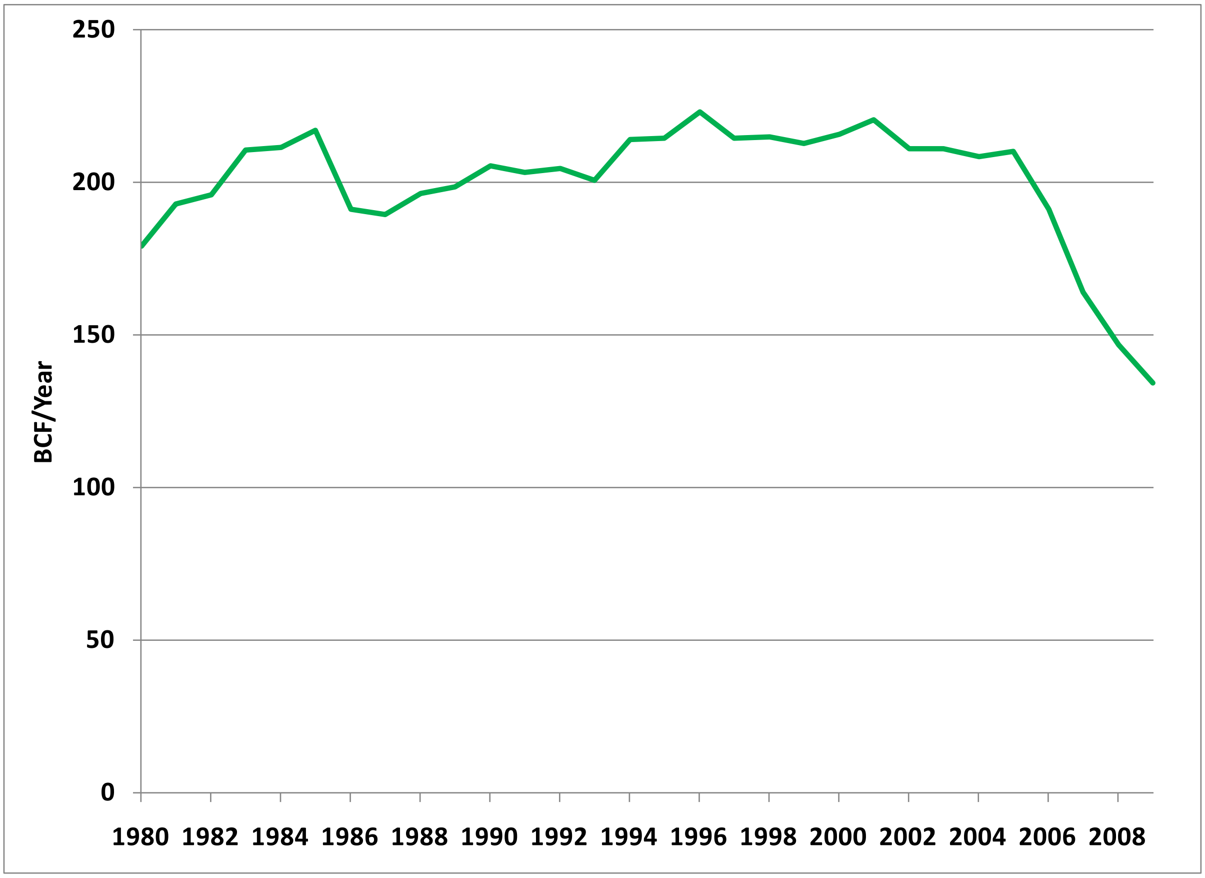
Note: Industrial demand above excludes historical gas volumes used for field operations and for fertilizer production at the Agrium plant.

This study assumes that in the interim years before the proposed pipeline becomes operational, measures to address the natural gas deliverability problems in Southcentral Alaska will be put in place. These measures could be in the form of building new underground gas storage facilities and promoting demand side management such as entering into agreement with industrial gas users on demand curtailment during peak winter season when total demand exceeds supply. It is anticipated that an additional option will be available for managing seasonal swing once the TransCanada Alaska pipeline is in service. Typically, pipelines can deliver more gas during the winter when ambient temperature is lower due to an increase in the compressor efficiency. This enhancement in performance is approximately 5 percent of the nominal design capacity of the pipeline; hence, this pipeline feature can be a flexible tool for in-state gas shippers to meet their winter load demand by contracting short-term firm transportation services during the peak load periods. The development of incremental gas storage facilities, implementation of load shedding demand side management and availability of incremental pipeline capacity during winter allow in-state gas shippers to contract capacity on the pipeline based upon their annual average volumes instead of winter peak demand volumes. For the purpose of calculating an indicative in-state delivery tariff, the projected annual average daily demand for North Slope gas will be used.

Cook Inlet Supply

Figure ES-3 shows historic Cook Inlet natural gas production from 1998 to 2009. Although production has been declining since 2001, the Cook Inlet basin is anticipated to continue production well into the future.

Figure ES-3. Total Historic Cook Inlet Natural Gas Production



Source: Alaska Department of Natural Resources, Division of Oil and Gas.

The Alaska Department of Natural Resources, Division of Oil and Gas (DOG) recently issued a report that evaluated the remaining Cook Inlet natural gas reserves. Table ES-2 presents the DOG estimates for Cook Inlet natural gas volumes. The more conservative estimates are based on engineering analyses using decline curve and material balance techniques. According to DOG, the geologic analysis for the four major fields in Cook Inlet is strong enough to classify these volumes as reserves that have the potential, if developed, to meet the local demand well into and possibly beyond the next decade. Furthermore, there are potential exploration targets throughout the basin that could provide additional gas resources, though there is less certainty for this geologic estimate compared to the gas reserves engineering estimate.

Table ES-2. Remaining Cook Inlet Natural Gas Volumes by Type of Reserves and Resources

Location/Type of Reserve	Derivation of Estimate	Volume
All Fields		**(Bcf)**
Proved, developed, producing	Decline Curve Analysis (DCA)	863
Probable	Material Balance (MB)-DCA (1,142-863)	279
Four Fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River)		
High-confidence pay intervals	Geologic PAY (GP)-MB for 4 fields (1,213-860)	353
Lower-confidence pay intervals	GP+50%-risked Potential Pay-GP (1,856-1,213)	643
Total Estimated Reserves		**2,138**
All Fields		
Higher risk contingent resources	Exploration Leads, Basin-wide	300
Total Estimated Reserves and Resources		**2,438**

Source: Values shown in the table are from, Hartz, J.D., et al, 2009. Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves. Alaska Department of Natural Resources.

The Cook Inlet basin produces enough gas to meet annual average demand. However, supplying the required volumes during spikes in demand on very cold days in the winter is challenging for the current system. Currently, wells are being drilled and storage facilities are being developed, which indicates that investment is being made to address the deliverability issue. The DOG report notes that "infill drilling, perforating undeveloped sands, and targeting marginal reservoirs are effective ways to add reserves to replace production." However, all these costs will need to be absorbed into a market that requires relatively small volumes, which will likely place upward pressure on gas prices.

DOG assumes that "either a significant amount of gas is found by explorers to meet industrial use in the future, or that export of gas out of the basin will stop at the end of the current license period" (2011) for the LNG plant. DOG further assumes that no new demand will occur until reserves are developed to satisfy the market, which requires that sufficient risk-capital be available to explore and develop the higher risk contingent and prospective gas resources.

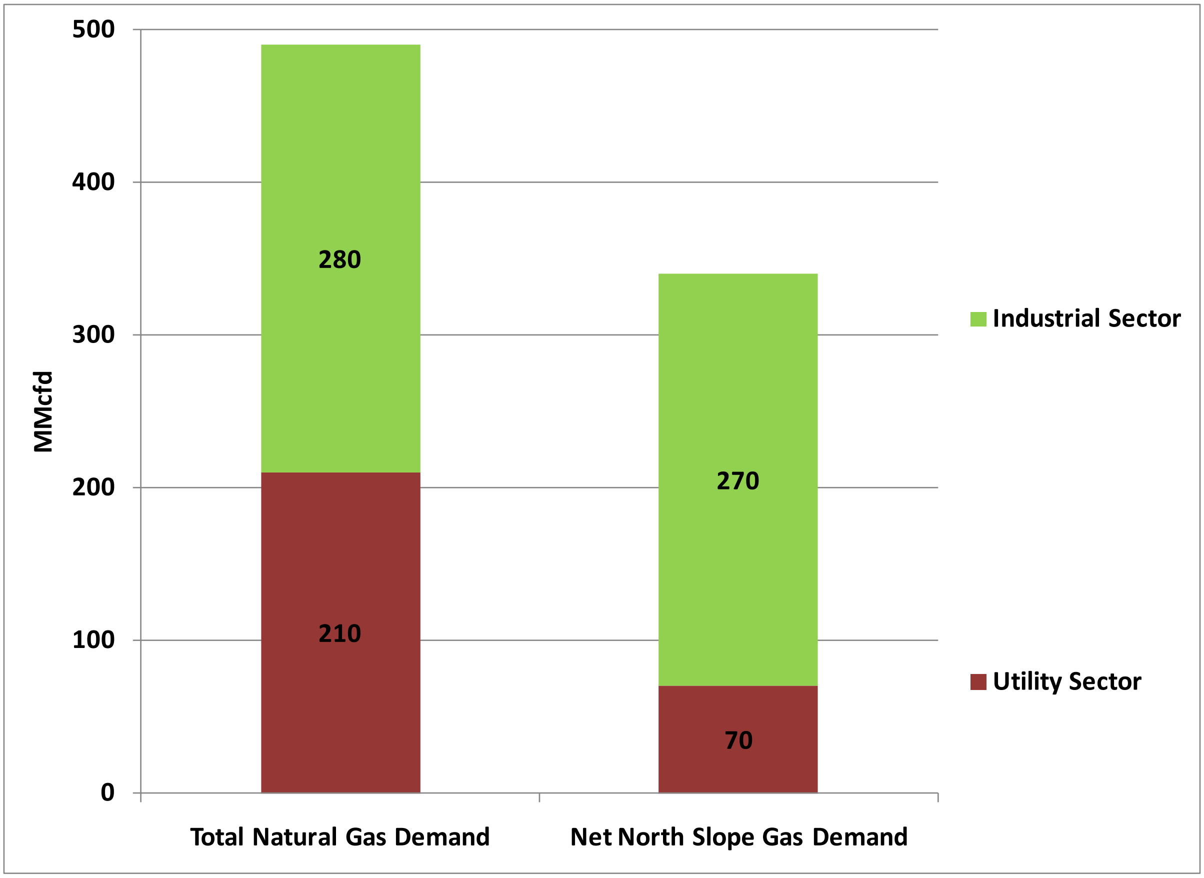
After the proposed spur line to Southcentral Alaska is completed, natural gas prices from both Cook Inlet and the North Slope will begin to converge. Local utilities, as expressed in the Railbelt Integrated Resource Plan (RIRP) (Black & Veatch, 2009), have indicated a desire to reduce their dependence on natural gas with increased demand side management and energy efficiency, increased use of renewable energy sources, and expanded transmission systems. However, even with such diversification and new facilities, natural gas remains a major energy source for the Railbelt, even 50 years into the future. Given this long time frame, utilities would seek to diversify their supplies of natural gas and would consider gas from the North Slope, coal bed methane, landfill gas, underground coal gasification, and other sources. The utilities have indicated that Cook Inlet sources would remain as a very large percentage of their natural gas supplies even if North Slope gas is less expensive.

Net In-State Demand for North Slope Gas

Discussions with several Southcentral utilities indicated that they might look to source 5 to 50 percent of their total gas demand from the North Slope. These percent estimates, when aggregated, suggest an average daily utility demand of about 40 MMcfd of North Slope Gas in the Southern Railbelt region in Years 1 to 5. In addition, gas-intensive industrial demand in the Southern Railbelt region for the current industry case is assumed to be met solely by North Slope gas. Therefore, the total demand in the Southern Railbelt region that will be supplied by North Slope gas is projected to be about 270 MMcfd for the Alberta route.

The total net demand for North Slope gas including the projected utility and industrial sector demand in the Northern Railbelt region and Livengood is projected to be about 340 MMcfd in Years 1 to 5 after pipeline operations begin (as shown in Figure ES- 4).

Figure ES- 4. Total Natural Gas Demand versus Total North Slope Natural Gas Demand, Current Industry Case, Year 1 to 5 of Pipeline Operations, Alberta Project



Source: Northern Economics, Inc., and SAIC, Inc., 2009.

The Valdez Project

Not counting demand from a new Valdez LNG facility, the Valdez route is estimated to have a higher gas demand than the Alberta route for the three demand scenarios presented above. This is due to the additional industrial demands in the Valdez area with the availability of natural gas. For the first five years of pipeline operations, the projected demand for the No Industry case, Current Industry case, and Growth Industry case, are 270, 500, and 750 MMcfd respectively; and the percent chance of these scenarios happening are 61 percent, 30 percent, and 9 percent respectively.

The total net demand for North Slope gas for the Valdez Project under the Current Industry case is projected to be about 350 MMcfd in Years 1 to 5 of pipeline operations.

Potential Propane Demand

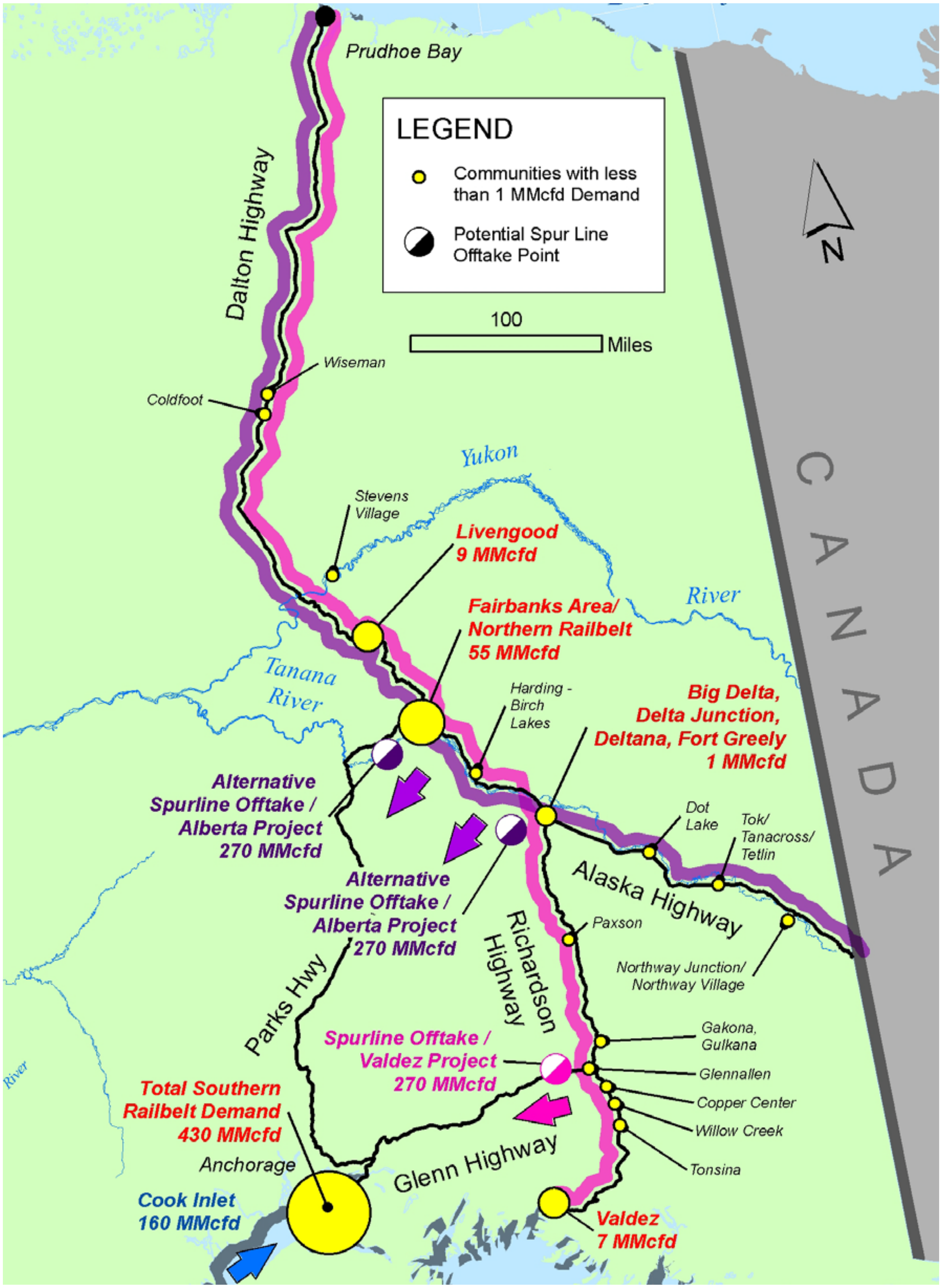
The natural gas stream in the main gas pipeline will contain large volumes of propane and other natural gas liquids; energy needs outside of the Railbelt could be supplied with propane. It is anticipated that the propane will be less expensive than distillate fuels on an energy-equivalent basis in many areas of the state, and there is keen interest in reducing the cost of energy, particularly in rural Alaska. In the initial years there is a 48 percent chance that the propane demand will be about 3,500 bpd. Ten years later there is a 67 percent chance that demand could increase to about 35,000 bpd as the propane infrastructure is built around the state. This study anticipates that propane extraction facilities would be built in the Fairbanks area and in Cook Inlet or Valdez, depending on the route. A comparison of the potential tariffs for a small propane extraction plant and trucking costs indicate that it would be less expensive to truck propane from Fairbanks to communities in the pipeline corridor and on the road system than to pay the tariff for a small plant.

A proposed propane extraction plant at Prudhoe Bay could have lower transportation costs to Arctic and western Alaska and supply propane to those regions. A Prudhoe Bay plant that may be built in the near term could facilitate a faster conversion to propane in the Fairbanks area and along the road system, thus potentially increasing propane demand in the initial years.

Potential Off-Take Points and Volumes

Figure ES-5 shows the potential total energy demand (as natural gas equivalent volumes) along the pipeline corridor. This figure shows the demand by community, as well as for potential spur line off-take points at Delta Junction or Glennallen, assuming a Richardson Highway or Glenn Highway spur line is built. If a Parks Highway spur is built instead of a Richardson Highway or Glenn Highway spur, similar demand would exist at a Parks Highway off-take location. The spur line off-take volume represents the current industry case for the Southern Railbelt region.

Figure ES-5. Potential Net Demand along the Pipeline Corridor, Current Industry Case, Year 1 to 5 of Pipeline Operations



Source: Alaska Map Co. based on the results of this study, 2009.

Table ES-3 shows the most likely off-take points based on the analysis conducted for this report. A proposed gold mine at Livengood is a likely candidate for a delivery point, and one or more off-take points may be required in the Fairbanks area, and another one to provide for a Parks highway spur line to Southcentral Alaska, or for future growth along the Parks Highway. The communities in the Delta Junction area plus Fort Greely are a likely location for an off-take point, which could be on the main gas pipeline or on a proposed spur line that would generally parallel the Richardson and Glenn highways to the Cook Inlet region. The communities in the vicinity of Tok may not have sufficient demand at present to justify an off-take point, but there is the potential for future mineral development and associated demand in the region around Tok. Glennallen and Valdez would be obvious off-take points for a line to Valdez since Glennallen would be the location of a spur line to Southcentral Alaska, and Valdez has community demand plus demand from the Alyeska marine terminal.

Table ES-3. Potential Off-Take Locations along the Alberta Line and the Valdez Line

	Route	
Location	**Alberta**	**Valdez**
Livengood	1	1
Fairbanks	1-2	1-2
Parks Highway spur	1	1
Delta Junction area/ Richardson Highway spur	1	1
Tok	1	NA
Glennallen	NA	1
Valdez	NA	1
Total	**5-6**	**6-7**

Source: Northern Economics, Inc.

At this time, ten years prior to the planned commencement of the TransCanada Alaska pipeline operation, the pro forma in-state gas tariff for the upcoming open season will be an estimate based on the demand net of Cook Inlet supply as noted in this study. The actual tariff for the pipeline will be highly dependent on the actual contracted volume of the pipeline, which will be determined in the initial open season and subsequent open seasons.

1 Introduction

In 2004, Congress passed the Alaska Natural Gas Pipeline Act of 2004 (ANGPA). Section 103 (g) of ANGPA requires a "study of in-State needs, including tie-in points along the Alaska natural gas transportation project for in-State access." In regulations implementing the ANGPA, the U.S Federal Energy Regulatory Commission (FERC) requires an applicant for a FERC Certificate of Public Convenience and Necessity to "conduct or adopt a study of gas consumption needs and prospective points of delivery within the State of Alaska" (18 CFR §157.34(b)). The regulations require that the study's estimate of the pipeline capacity that will be used in-state be included in an applicant's open season proposal.

In 2007, the State of Alaska adopted the Alaska Gasline Inducement Act (AGIA.) This statute provides for issuing a State License to a gas line project proponent that meets specified state criteria for the gas line. The statute further provides that the AGIA Licensee has access to particular inducements provided by the State of Alaska.

In 2008, TransCanada Alaska Company LLC (TransCanada) applied for and was awarded the State AGIA License for TransCanada's described gas line project. This project would transport approximately four and a half billion cubic feet of natural gas per day from Alaska to points within Alaska or to Alberta, Canada.

As the AGIA Licensee, TransCanada is advancing this project and has scheduled an open season for its proposed pipeline project in 2010. In March 2009, TransCanada issued a Request for Proposals for the Alaska in-state gas needs study in order to satisfy the FERC and ANGPA requirements. In May 2009, a contract to complete the study was awarded to the consultant team of Northern Economics, Inc., Science Applications International Corporation (SAIC), and the Institute for Social and Economic Research at the University of Alaska, Anchorage (ISER).

1.1 Purpose

The purpose of the study is to meet the requirements of §157.34(b) of the FERC open season regulations for Alaska natural gas transportation projects. This study will determine natural gas requirements for in-state use and in particular determine potential demand at locations along the pipeline to facilitate the identification of at least five off-take or delivery points.

The location of the potential off-take points and the potential volumes at each location would enable the initial design of in-state delivery tariffs. The initial in-state delivery tariffs would help potential pipeline customers plan for the initial open season. Final tariffs would be established after pipeline customers make transportation commitments during the open season and pipeline design is completed for the committed volumes.

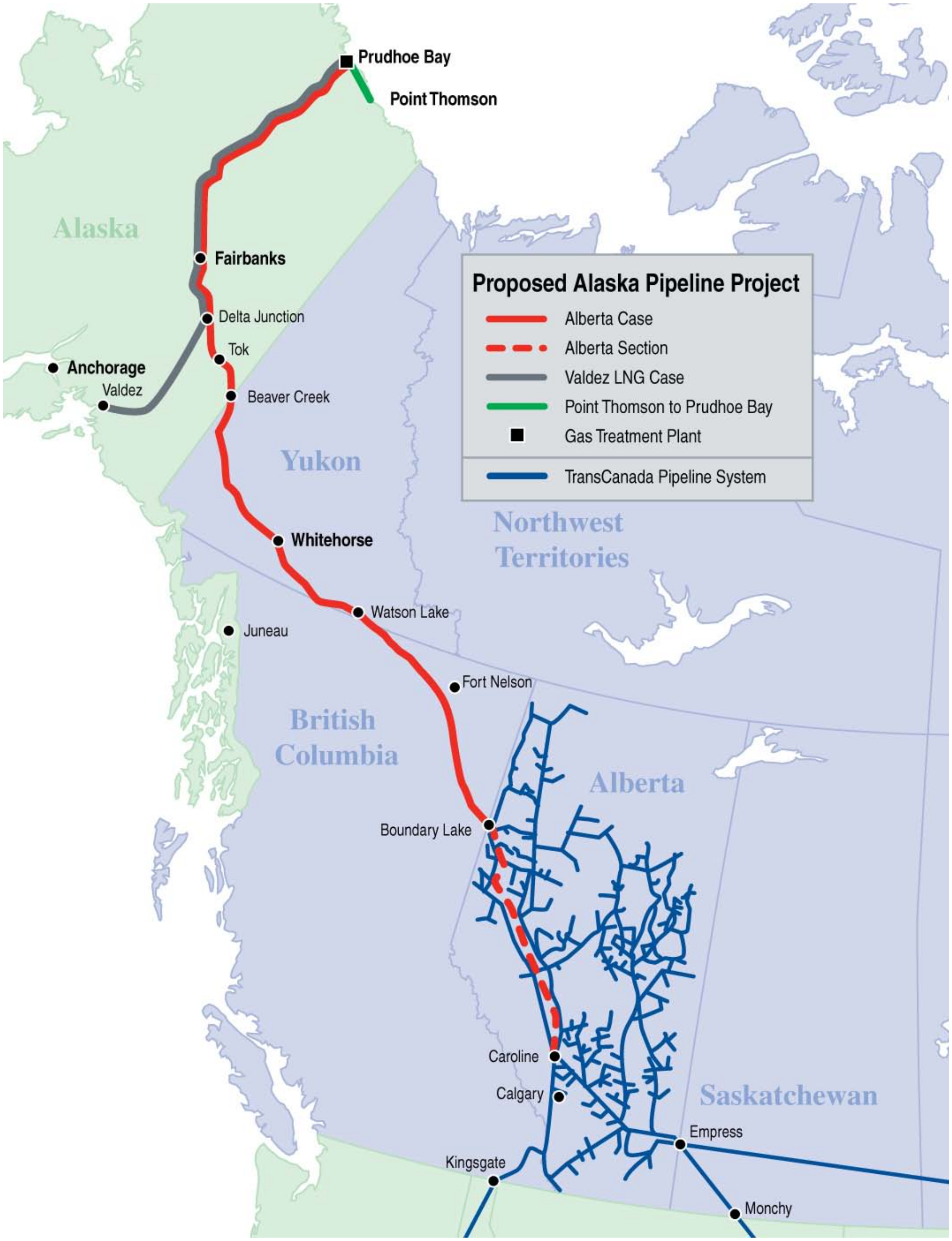
1.2 Study Scope

The study considers the two pipeline routes proposed by TransCanada (shown in Figure 1): (1) the *Alberta Line*—from the North Slope of Alaska to Alberta, Canada following the Dalton and Alaska-Canada highways, and (2) the *Valdez Line*—from the North Slope to Valdez, Alaska, delivering to a liquefied natural gas facility and marine terminal. The Valdez LNG facility is not considered part of this in-state demand study; hence these volumes are not included in the study's demand projections.

This in-state gas demand study takes into consideration the following:

1. Continued growth of existing gas demand from residential, commercial, and electricity generation primarily due to population growth;
2. Potential demand for fuel switching from distillate fuels and coal to natural gas and propane;
3. Incremental demand from potential new or expanded industries and power generation in Alaska as a result of the availability of North Slope natural gas;
4. With a pipeline that would transport natural gas from the North Slope to outside markets, natural gas prices in Alaska will reflect North American market prices adjusted for transportation costs between various markets.

Figure 1. Proposed Alaska Pipeline Project Routes: Alberta Case and Valdez LNG Case



Source: TransCanada, 2009.

1.3 Overview of Research Approach

The demand projections in this study were determined based on information gathered from previous studies, stakeholder interviews, expert opinions, and various secondary data sources.

The stakeholder interview process was a key element in obtaining information on potential demand for natural gas and in identifying future scenarios, economic development prospects, and general economic growth in Alaska. Valuable insights on the approach and data to be used for the analysis were also gained in the process.

The following is a list of the 30 organizations/entities contacted for this study:

1. Electric and gas utilities:
    - Alaska Village Electric Cooperative (AVEC)
    - Anchorage Municipal Light & Power (ML&P)
    - Chugach Electric Association (CEA)
    - Matanuska Electric Association (MEA)
    - ENSTAR Natural Gas
    - Fairbanks Natural Gas, LLC (FNG)
    - Golden Valley Electric Cooperative (GVEA)
    - Copper Valley Electric Cooperative (CVEA)
    - Homer Electric Association (HEA)
    - Alaska Power and Telephone (APT)
    - City of Seward Light and Power Division
2. State Agencies:
    - Alaska Energy Authority (AEA)
    - Alaska Department of Natural Resources (ADNR)
    - Alaska Natural Gas Development Authority (ANGDA)
    - Alaska Housing Finance Corporation
3. Native Corporations:
    - Cook Inlet Regional Inc. (CIRI)
    - Doyon, Ltd.
    - Village Corporations of the Upper Tanana
    - Arctic Slope Regional Corporation
4. Industry:
    - Agrium
    - Nikiski LNG facility owners: ConocoPhillips and Marathon Oil
    - Donlin Creek, LLC (Donlin Creek mine)

- International Tower Hill Mines (Livengood prospect)
- PetroStar
- Alyeska Pipeline Service Company

5. Other entities:
   - Fairbanks Economic Development Corporation
   - Doyon utilities (power plant operator at military bases)
   - Alaska Natural Resources to Liquids, LLC (Alaska GTL project proponent)
   - Black and Veatch (Regional Integrated Resource Plan (RIRP) consultants and author of the Railbelt Energy Generation Authority (REGA) study)

The potential in-state demand for natural gas was determined for two different future timeframes: (1) the Year 1 to 5 timeframe, which captures the demand in the first five years of operations of the gas pipeline; and (2) the Year 10 to 15 timeframe, which captures potential demand of various economic development projects or prospects that are expected to take a longer time to develop after the pipeline comes on line.

To address the high degree of uncertainty regarding potential future outcomes, a probability-based analysis using *@RISK*, a probability analysis software program, was conducted. The *@RISK* analysis allows the uncertainty present in the future demand estimates to be explicitly incorporated in the analysis, and generate results that show possible outcomes given the range of uncertainty. The model uses Monte Carlo simulation to do the risk analysis.

Given the variability in possible outcomes (demand estimates) resulting from various assumptions used in the probability analysis, the results of the study are summarized by presenting three probable demand scenarios representing the following: i) No Large Industry case; ii) Current Industry case; and iii) a Growth Industry case, for each of the 2 future timeframes (see Section 9: Integration for more details).

Communities and industries with large demand in proximity to the main gas pipeline project or a spur line, or with existing piped distribution networks are anticipated to use natural gas from these projects. Communities or industries with smaller demand or at some distance from the main gas pipeline or a spur line could convert from distillate fuels to propane if propane is more cost-effective than distillate fuels. Potential demand for natural gas and for propane are analyzed separately and presented in separate sections in the report.

The analysis for natural gas and propane include the following major consumer sectors:

1. Residential and commercial sector (demand for space heating, water heating, and cooking);
2. Electric power sector (demand for generation of electricity); and
3. Industrial sector (both demand for heating and power generation, and for feedstock gas).

Projected in-state demand is also presented by region. This allows potential demand to be summarized on a regional basis to facilitate determination of potential delivery volumes at various areas along the pipeline. While demand for natural gas consumption is anticipated to be concentrated in the Southcentral (Southern Railbelt) and the Fairbanks (Northern Railbelt) regions, potential demand for propane could be identified in locations outside of the Railbelt region. As shown in Figure 2, nine Alaska regions are defined for this study.

The Boroughs and Census Areas that comprise the Regions are:

- Northern Railbelt region (the Fairbanks North Star Borough and the Denali Borough)
- Southern Railbelt (sometimes referred to as Southcentral Alaska; includes Municipality of Anchorage, Matanuska-Susitna Borough, and the Kenai Peninsula Borough)
- Southeast Fairbanks
- Valdez-Cordova (includes Valdez and Cordova)
- Southeast (includes Skagway-Hoonah Angoon, Yakutat, Haines, Juneau, Sitka, Wrangell-Petersburg, Prince of Wales-Outer, Ketchikan)
- Northwest Arctic (includes North Slope Borough, Northwest Arctic Borough, and Nome)
- Southwest (includes Dillingham, Lake and Peninsula, Bristol Bay Borough, Aleutians East, Aleutians West, and Kodiak)
- Yukon-Kuskokwin (includes Wade Hampton and Bethel)
- Yukon-Kuyukok.

Figure 2. Regions for In-State Gas Demand Analysis

Source: Alaska Map Company, 2009.

Finally, it should be noted that this study assumes that in the interim years before the proposed pipeline becomes operational, measures to address the natural gas deliverability problems in Southcentral Alaska will be put in place. These measures could be in the form of building new underground gas storage facilities and promoting demand side management such as entering into agreement with industrial gas users on demand curtailment during peak winter season when total demand exceeds supply. It is anticipated that an additional option will be available for managing seasonal swing once the TransCanada Alaska pipeline is in-service. Typically, pipelines can deliver more gas during the winter when ambient temperature is lower due to an increase in the compressor efficiency. This enhancement in performance is approximately five percent of the nominal design capacity of the pipeline; hence, this feature can be a flexible tool for in-state gas shippers to meet their winter load demand by contracting short-term firm transportation services during the peak load periods. The development of incremental gas storage facilities, implementation of load shedding demand side management and availability of incremental pipeline capacity during winter allow in-state gas shippers to contract capacity on the pipeline based upon their annual average volumes instead of winter peak demand volumes. For the purpose of calculating an indicative in-state delivery tariff, the projected annual average daily demand for North Slope gas will be used.

More detailed descriptions of assumptions and methodology are presented in each of the sector demand analysis sections of the report.

1.4 Organization of the Report

This report is organized into 12 sections and 6 technical appendices.

Section 1 is this introduction that includes the purpose, study scope, approach, and the organization of the report.

Section 2 provides context on the evolving energy picture in Alaska and the uncertainties regarding the future that may affect in-state natural gas consumption.

Section 3 discusses the statewide economic and demographic projection. The outputs of the projection were used in estimating potential demand in the sector analyses.

Section 4 discusses the potential residential and commercial sector demand for natural gas; including model assumptions and approach.

Section 5 discusses the potential power sector demand for natural gas in the Railbelt region considering four alternative future energy scenarios.

Section 6 discusses the potential industrial sector demand for natural gas for two types of industries: 1) industries that use natural gas for feedstock; and 2) industries that use natural gas to generate power and process heat.

Section 7 presents the potential demand for natural gas by the military.

Section 8 presents potential demand for propane across the state by sector—residential and commercial, power, and industrial sector.

Section 9 presents a summary of the Alaska Department of Natural Resources' report on remaining Cook Inlet Gas Reserves.

Section 10 is an integration of all the sector demand results for natural gas. This section ties together all the components of in-state demand including the net effect of the availability of Cook Inlet supplies on potential pipeline delivery volumes. This section summarizes the demand estimates generated by the probability analyses under the Alberta and the Valdez line projects in the two future timeframes under consideration.

Section 11 presents the potential community demand along the pipeline corridors.

Section 12 lists all the references used in the report.

The technical appendices include the following:

Appendix A: MAP Model Methodology, Assumptions, and Projection Summary

Appendix B: Summary Tables: Table 1: Estimated Demand Ranges by Sector and Table 2: Projected Annual Average Daily Propane Demand by Sector, in Two Future Time Frames for the Alberta Route (in Barrels per day).

Appendix C: Power Sector Demand Analysis

Appendix D: Alaskan Propane Extraction Facilities Cost Estimates for 0.5, 65, and 300 MMcfd Plants

Appendix E: Fuel Price Forecasts

Appendix F: Industrial Product Price Forecasts

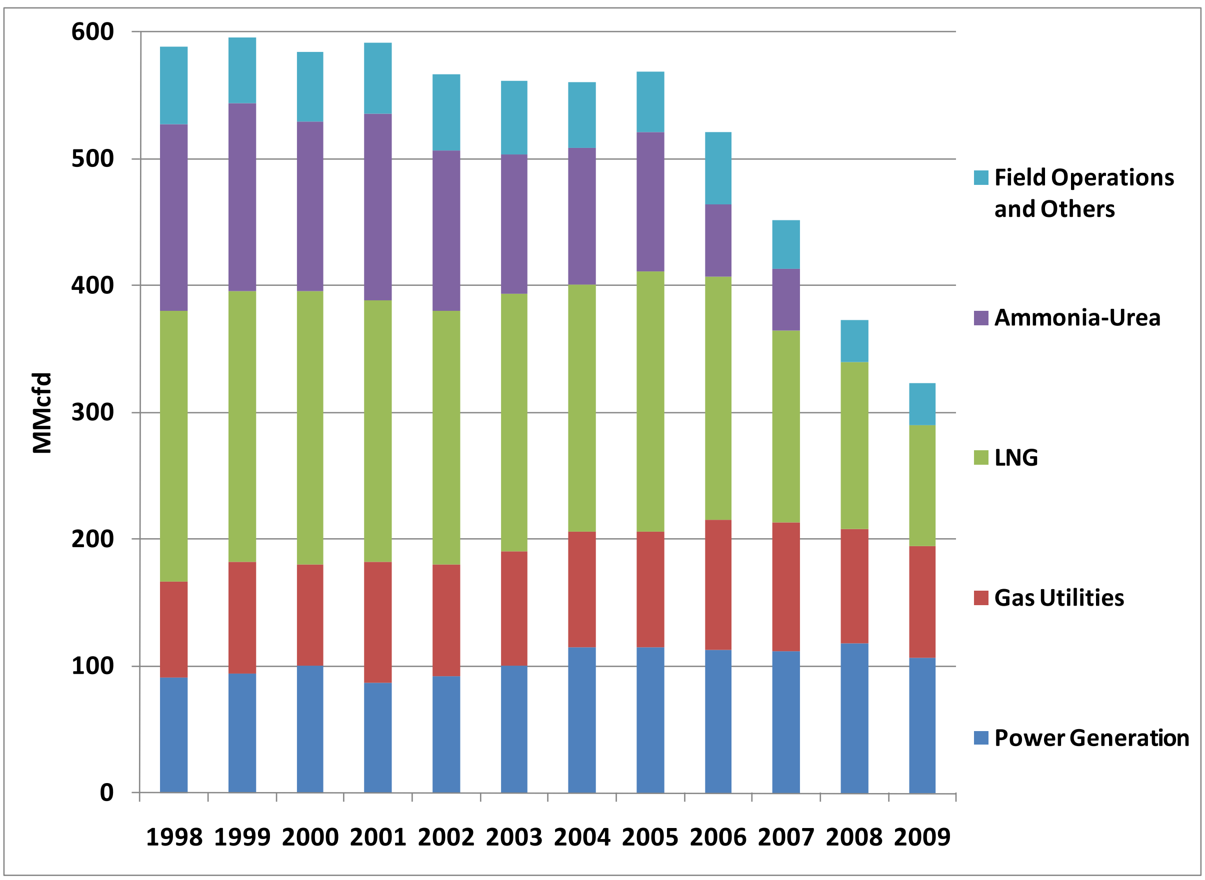
2 The Evolving Energy Picture in Alaska

This section provides context on the evolving energy picture in Alaska, and highlights uncertainties about the future that may affect Alaska's demand for natural gas when the proposed pipeline comes on line.

It is common knowledge that the petroleum industry has long been the most important natural resource sector in Alaska. The industry dominates the private sector economy in terms of gross state product—if it disappeared overnight, a third of the jobs for Alaskans would also disappear (Goldsmith, 2008). Perhaps what is less known is that natural gas, not oil, generates the energy for electricity and heating in the majority of Alaska homes and businesses. This is because Alaska's population is concentrated in the Southcentral region where there is an established natural gas-based power and heating infrastructure. Currently, natural gas is used to generate 54 percent of the electricity consumed in Alaska (Alaska Energy Authority, 2009).

Natural gas is currently produced at Cook Inlet and the North Slope. The historical gas consumption in Southcentral Alaska by sector, as reported by the Alaska Department of Natural Resources, is shown in Figure 3. The graph shows the significant decrease in industrial consumption over the years (from 2001 to 2009).

Figure 3. Historical Natural Gas Consumption of Cook Inlet Gas by Sector



Source: Alaska Department of Natural Resources, Division of Oil and Gas.

Cook Inlet gas is consumed by residential, commercial, power generation, and industrial users in the Southcentral and Interior regions. The Interior consumption occurs due to the availability of an electrical transmission line from the Cook Inlet region to Fairbanks, and to the transportation of natural gas in the form of LNG from Cook Inlet to Fairbanks. Most North Slope gas produced in association with oil operations is re-injected for field maintenance; a small portion is used for oil field equipment, operations, and pipelines (including the first four TransAlaska Pipeline System (TAPS) pump stations), and also for local sales to North Slope utilities. Compared to total Cook Inlet gas production however, the North Slope lease and field operations (not including re-injected gas) use approximately 50 percent more gas than has been historically produced from Cook Inlet on an annual basis (Alaska Department of Revenue 2006). Because of the lack of infrastructure to transport North Slope gas to markets beyond the North Slope region, Cook Inlet gas has been the sole source of natural gas for in-state uses outside the North Slope.

Historically, the largest uses of Cook Inlet gas have been LNG export from the plant owned jointly by ConocoPhillips Alaska, Inc. and Marathon Oil Corporation, and ammonia-urea fertilizer production at the plant owned by Agrium, Inc. Natural gas consumption by these two facilities, accounted for about 57 percent of total Cook Inlet gas consumption for the period 1997 to 2006, while gas consumed for power generation and space heating has accounted for 33 percent of total Cook Inlet gas consumption (ADNR, DOG 2007). Generally, natural gas consumed for power generation and space heating has increased in step with steady growth in residential and commercial demand.

Annual Cook Inlet gas consumption averaged over the period 1998 through 2007 was 204 Bcf. After 2007, there was a drop in consumption due to the shutdown of the Agrium facility[4]; annual consumption since then has averaged only 127 Bcf/yr.

Southcentral Alaska had a surplus of relatively inexpensive natural gas resources for decades, but that era has ended with declining production from older fields (Alaska Department of Revenue 2006). Industrial gas users that depend on low-cost base-load gas have been confronted with the implications. As noted above, the Agrium ammonia-urea plant closed in 2007.

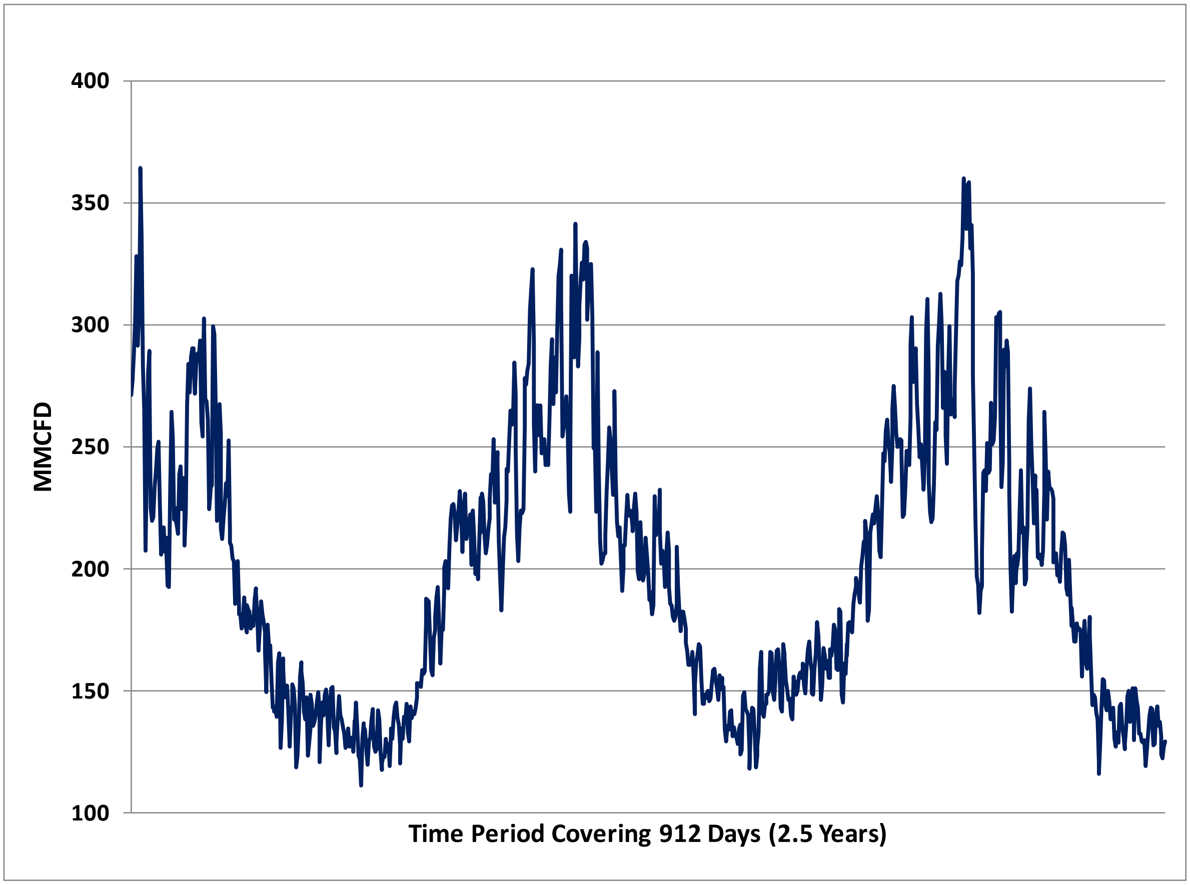
The future of the ConocoPhillips-Marathon LNG plant is uncertain beyond 2011, when its LNG export permit expires. The facility owners could apply for an extension on their permit, but a condition to the U.S. Department of Energy's approval of an export permit extension requires a showing that the permit extension is consistent with the 'public interest.' One public interest criteria considered is whether adequate natural gas supplies exist to meet both proposed exports as well as local needs during the proposed export term.

Figure 4 shows seasonal fluctuations in demand for Cook Inlet gas for combined electric power generation and residential and commercial heating – the primary sectors with seasonal demand fluctuations. As one would expect, demand is highest in winter, when the need for heat and electricity is greatest. Over the course of a typical year, daily gas demand for heating and electricity ranges from around 120 MMcfd in the summer, to 360 MMcfd in the winter – a roughly 3-fold increase.

Figure 5 illustrates the typical total average daily demand for natural gas, including industrial sector demand by month; the average monthly demand over a typical year vary by as much as 130 MMcfd.

[4] In 2007, gas price and supply issues forced the closure of the Agrium plant.

Figure 4. Historical Daily Gas Usage for Power and Heating in Southcentral Alaska



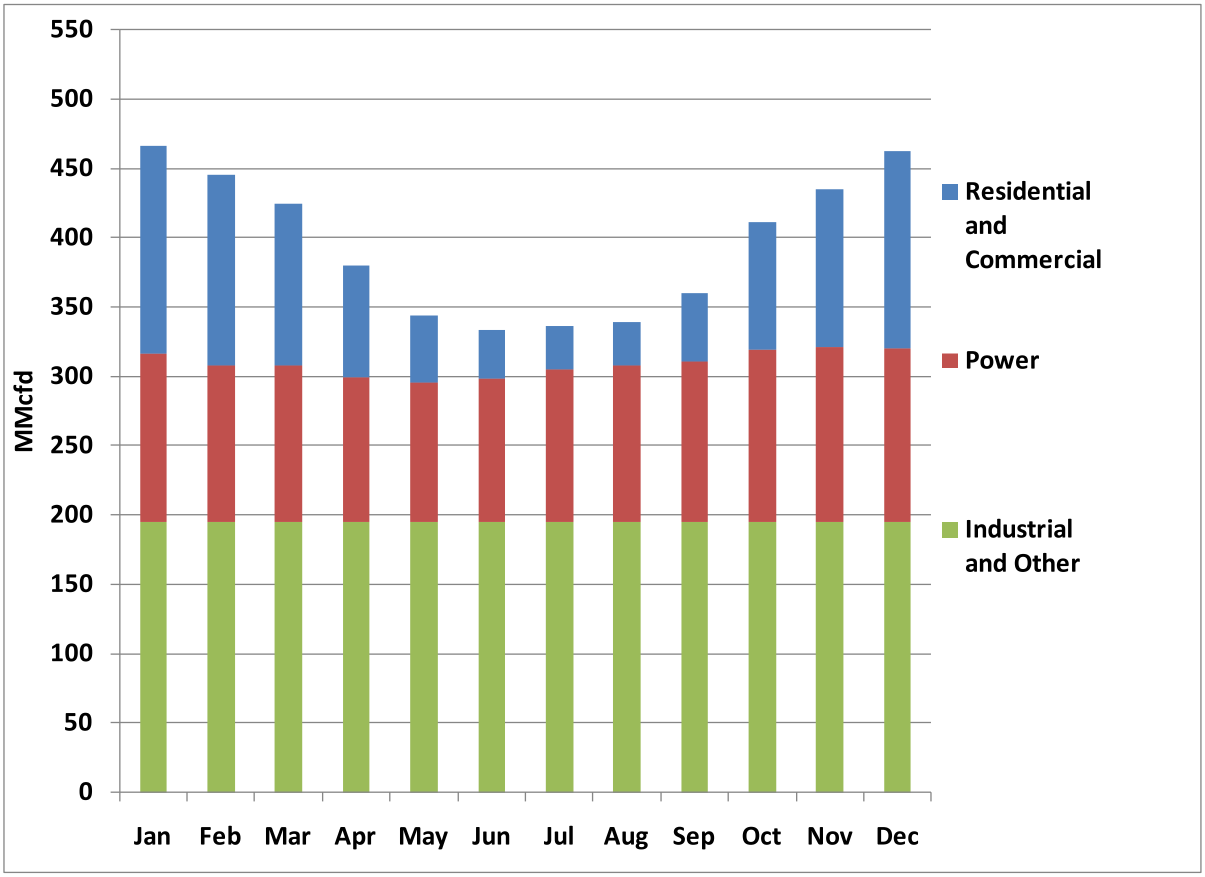
Source: Alaska Department of Natural Resources, (2009)

Cook Inlet gas production is better able to approach or meet Southcentral demand on an annual basis than on a seasonal basis due to high swings in seasonal demand and limited field delivery rates. Seasonal swings can be accommodated through gas additions to storage during low-demand periods, and withdrawals from storage during high-demand periods.

Cook Inlet gas production could be increased through reserves growth in the existing fields, and/or timely exploration success and development of new fields. If increased production from Cook Inlet is not sufficient and exploration in other basins is not successful, alternative solutions include various combinations of increased storage, demand reduction strategies, an in-state gas pipeline from the North Slope to Southcentral Alaska, LNG imports, increased power generation from renewable sources such as solar, wind, geothermal, and tidal, and coal gasification; especially in the interim before North Slope gas may become available.

Overall, Southcentral Alaska is facing a deliverability problem during periods of peak demand, and a potential gas supply shortfall could become more costly and difficult to manage before a mainline and a spur line are in place. The remedy is to encourage more development and exploration, provide adequate storage for seasonal peaking, and begin the process of developing options to supplement Cook Inlet gas.

Figure 5. Typical Total Average Daily Demand for Natural Gas by Month



Source: Data on historical natural gas usage are based on information provided by the Alaska Department of Natural Resources, for the years 1998 to 2009.

Note: Industrial demand above excludes historical gas volumes used for field operations and for fertilizer production at the Agrium plant.

In the Fairbanks region, the current market for natural gas has been limited due to similar supply constraints. Most residential and commercial customers in this region use heating oil for space heating and domestic hot water. Market expansion of natural gas will require expansion of existing infrastructure. There are also several ongoing exploration efforts near Nenana and in the Yukon Flats that could potentially serve the region in the long-term if discoveries are made. In addition, recent developments suggest that there is a possibility that Fairbanks may have access to North Slope gas in the form of LNG before the pipeline comes on line if the proposed LNG project in the North Slope that is being pursued by the Alaska Gasline Port Authority is developed. In the near future however, expansion of the natural gas distribution system would continue to be affected by the availability of natural gas supplies from Cook Inlet.

A Regional Integrated Resource Plan (RIRP) has been developed to identify and evaluate the best resource mix to ensure that least-cost options for electricity are developed in the Railbelt region. The RIRP considered a portfolio of energy options for Railbelt power generation in the future, including large hydropower dams; renewable energy sources such as geothermal, wind, tidal, and solar; and demand side management. However, natural gas remains a major energy source in the Railbelt even 50 years into the future.

Although most Alaskan homes and businesses are powered and heated by natural gas, there are many areas of Alaska where natural gas is currently unavailable due to the significant cost of gas exploration and development, or because transportation from areas of large known accumulations to areas where it can be utilized for heat and power by a smaller population base is costly (Alaska Energy Authority 2009). Over 150 communities in rural Alaska depend on diesel fuel for electric generation and home heating. Most of these communities are geographically isolated and have populations less than 1,000. They have no access to a power grid, and must import diesel fuel to operate a local electric generator (Colt et al. 2003). Costs are high due to the expense of moving fuel to rural Alaska and the small scale of operations.

These electric generators have been increasingly expensive to operate as fuel costs increase. As the operation costs of village electric generators have escalated, the price of electricity has also increased. A recent study indicated low-income households in remote rural Alaska may be paying 47 percent of their income on home energy use, compared to less than five percent for the average Alaska household (Haley et al. 2008). High energy prices combined with high unemployment rates, limited local economies, and local governments struggling to provide basic services have presented rural communities and households in the Interior and elsewhere in Alaska with challenging circumstances (Grewe and Caldwell 2008).

In some rural Alaska communities alternative energy technologies, such as wind turbines, offset some of their dependence on diesel fuel to produce electricity. Due to the high price of diesel, Alaska is fast becoming a testing ground for such technologies (Milkowski 2009). About 24 percent of the state's power already comes from renewable energy—mostly hydropower from Southeast Alaska. Moreover, recent advances in diesel engine efficiency, automated generator controls, heat recovery, and continuous operations and maintenance techniques have made possible diesel fuel efficiency improvements of more than 50 percent in some rural community powerhouses (Alaska Energy Authority 2009).

All of these energy related issues are evolving and the approach used by industry and government to address these issues is going to be determined in the next several years. This study attempts to incorporate these uncertainties in the different sector demand analyses. Assumptions and approaches in dealing with these uncertainties are explained in succeeding sections.

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3 Statewide Economic and Demographic Projection

Regional estimates of residential and commercial sector demand for natural gas in the Northern and Southern Railbelt and propane demand in the rest of the state are determined using the projected number of households in each region. These regional household projections were derived from a statewide economic and demographic projection conducted by ISER using the MAP projection model. (See Appendix A for a description of the model structure).

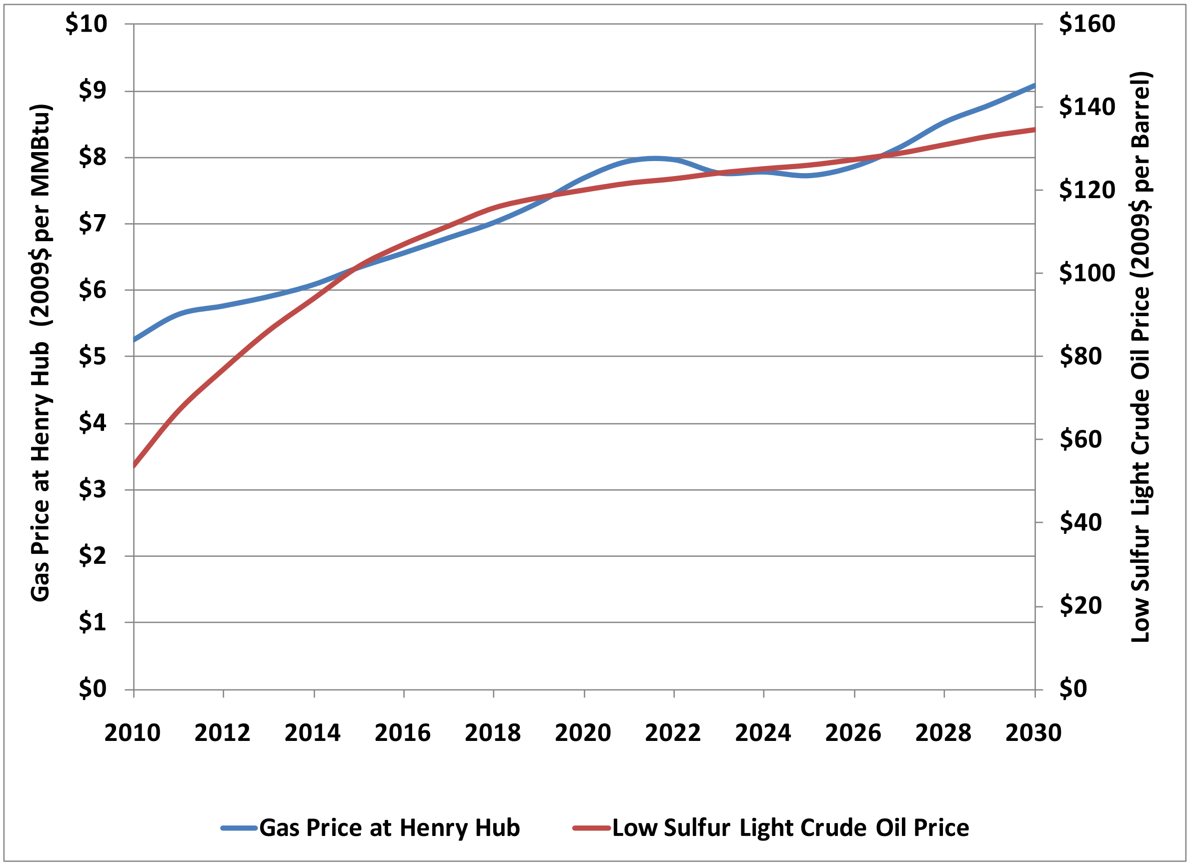
The economic and demographic model projects an average annual growth in wage and salary jobs between 2010 and 2030 of 1.3 percent based on a large number of assumptions contained in an *Economic Development Scenario* (See Appendix A). The highlights of that *Scenario* are as follows:

- World oil price gradually increases over time and averages about $100 (2009 $) over the period 2010-2030 (see Figure 6; based on Annual Energy Outlook, EIA, 2009)
- Cumulative onshore oil production from the Central North Slope over the period 2010-2030 is 4.1 billion barrels
- Natural gas price (Henry Hub) gradually increases over time and averages $6.60 (2009 $) over the period 2010-2030 (see Figure 6, based on Annual Energy Outlook, EIA, 2009)
- A gas pipeline is constructed and becomes operational in 2019 with a capacity of 4.5 Bcf/day
- OCS oil production from the Beaufort Sea begins 2021
- Donlin Creek Mine begins production in 2014
- Pebble Mine begins production in 2024
- Active duty military force level trends slowly downward from its current high level
- Annual growth in tourist visitors resumes in 2011, but from a lower base
- Growth in federal spending falls below the historical trend
- US recession slows the Alaska economy in 2009 and 2010 with growth resuming in 2011

Figure 6 shows the oil and gas price forecast used in the model.

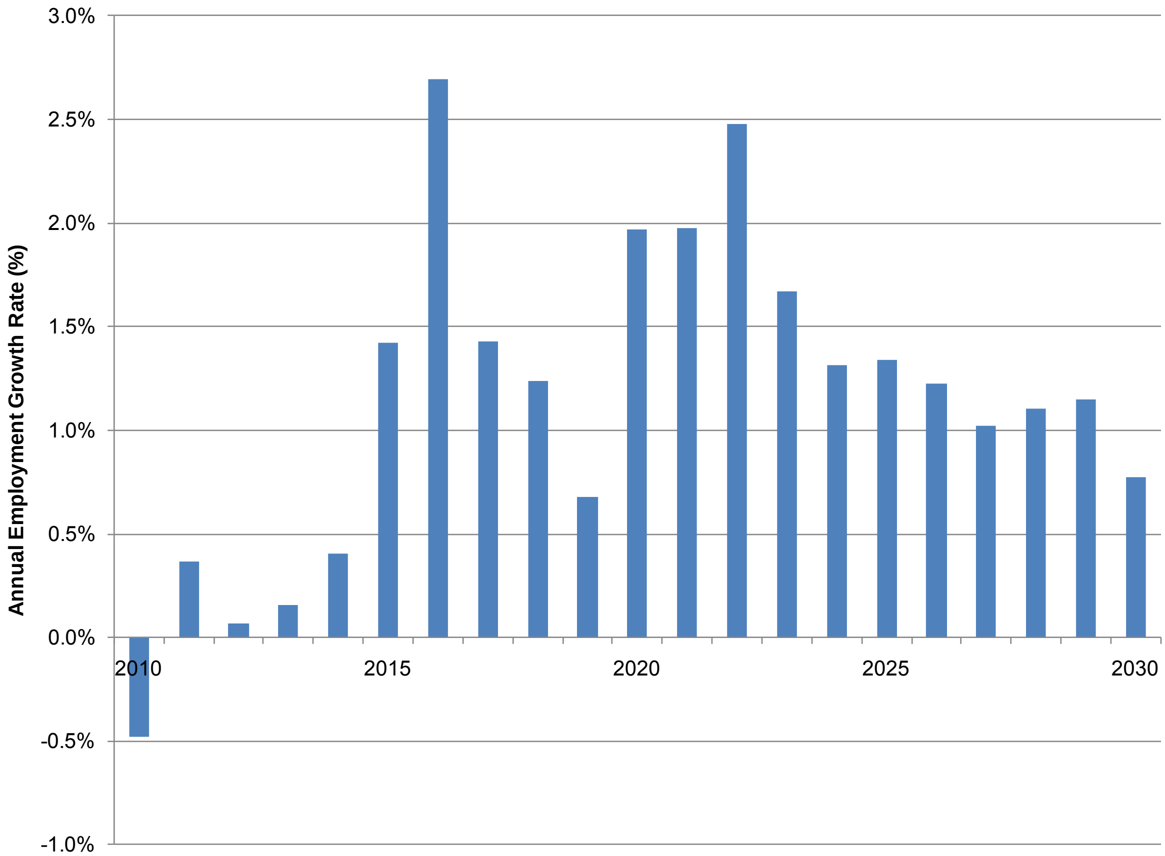
These assumptions result in a pattern of employment growth that begins with a slow recovery from the current recession (see Figure 7). This slow recovery is followed by an acceleration of growth associated primarily with construction of the gas pipeline. There is then a slowdown followed in the next decade by renewed growth driven by OCS development. Revenues from oil and gas production are sufficient to allow state spending to continue to increase, and this also contributes to employment growth (See Appendix A for more detailed state projection results).

Figure 6. Natural Gas and Oil Price Forecasts, 2009$



Source: SAIC, Inc. estimates. See Appendix E for details.

Figure 7. Projected Alaska Annual Growth Rate of Jobs



Source: ISER, 2009.

Statewide population growth is determined by the growth in employment. When job growth is rapid, the increase in the demand for labor results in net immigration to Alaska and this adds to the growth attributable to natural increase (births minus deaths).

Projecting the number of households in each region of the state depends on the share of jobs within each region and the historical relationship between jobs and population. The regional household projections show an increase in each region of the state, although growth is somewhat concentrated in the Railbelt regions (See Table 1 and Table 2).

Table 1. Alaska Households by Region

Region	Year 2010	2019	2030
Southern Railbelt	155,330	176,340	216,360
Municipality of Anchorage	*106,020*	*118,390*	*145,960*
Matanuska-Susitna	*29,300*	*35,840*	*44,400*
Kenai Peninsula	*20,010*	*22,110*	*26,010*
Northern Railbelt	37,100	39,910	45,930
Fairbanks North Star	*36,380*	*39,060*	*44,880*
Denali	*720*	*850*	*1,050*
Northwest-Arctic	6,880	7,640	8,800
Southeast Fairbanks	2,430	2,660	3,120
Southeast	27,330	30,860	37,450
Southwest	8,450	8,950	9,670
Valdez-Cordova	3,730	4,130	4,750
Yukon – Koyukuk	2,070	2,260	2,550
Yukon – Kuskokwim	6,550	7,210	8,220
Total Households	249,870	279,960	336,850

Source: ISER, 2009.

Table 2. Alaska Households: Annual Growth Rates by Region (%)

Region	Timeframe and Growth Rate 2010-2019	2019-2030
Southern Railbelt	1.40	1.90
Municipality of Anchorage	*2.30*	*2.00*
Matanuska-Susitna	*1.20*	*1.90*
Kenai Peninsula	*1.10*	*1.50*
Northern Railbelt	0.80	1.30
Fairbanks North Star Borough	*0.80*	*1.30*
Denali	*1.80*	*2.00*
Northwest-Arctic	1.20	1.30
Southeast Fairbanks	1.00	1.50
Southeast	1.40	1.80
Southwest	0.60	0.70
Valdez-Cordova	1.10	1.30
Yukon – Koyukuk	1.00	1.10
Yukon – Kuskokwim	1.10	1.20
Average Growth Rate	1.30	1.70

Source: ISER, 2009.

4 Potential Residential and Commercial Sector Demand for Natural Gas

This section presents the historical and projected residential and commercial sector demand for natural gas in Alaska. The projected residential and commercial sector demand covers the demand in communities that are in proximity to the proposed natural gas pipeline with a large population base or with a significant commercial demand that are anticipated to have their energy needs met by a piped natural gas distribution network. The energy requirements of smaller communities and those located some distance from the main gas pipeline (or a spur line) on the other hand, are anticipated to be supplied by propane; and the projected in-state demand for propane is presented in a separate section (see Section 8).

Generally, residential consumption refers to natural gas used in private dwellings (including apartments) for heating, air conditioning, cooking, water heating, and other household uses, while commercial consumption refers to gas used by non-manufacturing establishments or agencies primarily engaged in the sale of goods and services. The commercial sector typically includes establishments such as hotels, restaurants, wholesale and retail stores, and other service enterprises, as well as local, state, and federal agencies engaged in non-manufacturing activities.

Historically, residential and commercial consumption of natural gas in Alaska was limited to the Railbelt region and Barrow, a community of about 4,500 residents on the North Slope that has access to a nearby gas field. More recently, the community of Nuiqsut has obtained gas supplies from the Alpine Field on the North Slope. Natural gas consumption in Barrow and Nuiqsut, however, will not directly be affected by the availability of natural gas through the proposed main gas pipeline; the demand analysis presented in this section therefore, does not include potential future demand in Barrow or Nuiqsut.

Natural gas consumption in the Railbelt region is concentrated in two major areas: 1) Southcentral Alaska which encompasses the greater Anchorage area, including the Matanuska-Susitna Borough and the Kenai Peninsula; and 2) Fairbanks. These two areas have natural gas piped distribution systems that are served by two separate local distribution companies—ENSTAR and Fairbanks Natural Gas (FNG), respectively. Both Southcentral and Fairbanks areas are supplied with gas coming from Cook Inlet production.

To be consistent with the Alaska regions as defined in the study scope in Section 1.2, the Southcentral region will be referred to as the Southern Railbelt and the Fairbanks area will be part of the Northern Railbelt region. Heating demand outside of the Fairbanks area in the Northern Railbelt region is assumed to be met with propane and is discussed in Section 8.

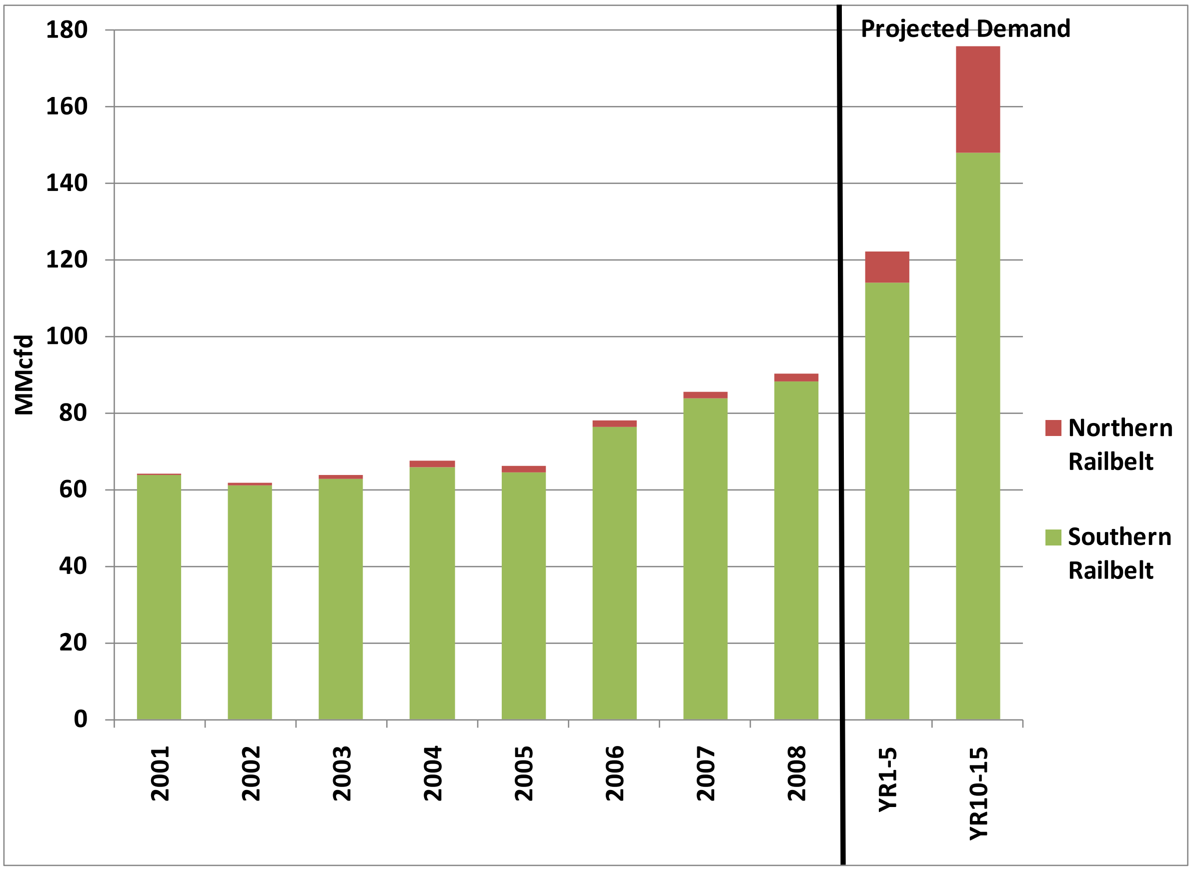
Figure 8 summarizes the findings of this section. Figure 8 shows the historical and the estimated natural gas consumption by region in the two future timeframes under consideration: Year 1 to 5 and Year 10 to 15 of pipeline operations. As shown in the figure, residential and commercial sector demand for natural gas is estimated to increase from the current consumption of about 90 MMcfd to about 122 MMCfd and 175 MMCfd[5] in the Year 1 to 5 and Year 10 to 15 timeframe, respectively.

As evident in Figure 8, the Southern Railbelt region accounts for a majority of the residential and commercial sector natural gas consumption. The Southern Railbelt region has in fact the highest concentration of population within the State; with an estimated 155,000 households (see Table 1 in Section 3). Currently, about 78 percent of the residential market in the Southern Railbelt region is

[5] These projected demand volumes represent the mean estimate resulting from the probability analysis.

served with natural gas. In contrast, in the Northern Railbelt region, particularly the Fairbanks North Star Borough, less than 2 percent of the residential market (with an estimated 35,400 households) is supplied with natural gas for their heating requirements. A majority of the homes in this region use oil for space heating.

Figure 8. Historical and Projected Annual Average Daily Residential and Commercial Sector Demand for Natural Gas



Source: Data from 2001 to 2007 are from the Energy Information Administration, 2008 data are from ENSTAR and the Interior Issues Council report, and demand projections in the two future timeframes are estimated based on this study's analysis.

The following sections provide more detail on the current and projected residential and commercial sector demand for natural gas in the Northern and Southern Railbelt regions.

4.1 Current Demand Estimates

In 2008, total consumption of natural gas by residential and commercial customers in Alaska was about 33 billion cubic feet (Bcf), an increase of about two Bcf from the previous year[6]. As noted in the

[6] The 2008 natural gas consumption by residential and commercial customers is the sum of ENSTAR and FNG natural gas sales in 2008. Data are from ENSTAR and the Interior Issues Council report entitled *In-State Gas Pipeline Supply Option Studies* (February 5, 2009).

previous section, the Southern Railbelt accounted for most of this residential and commercial gas consumption.

The subsequent sections describe in more detail the current residential and commercial sector market in the state. The discussion is focused on the Southcentral region and in Fairbanks, the only two areas of the state with a piped natural gas distribution system. Again, to conform with the classification of regions as defined in Section 1.2, the discussion is broken out into the Southern Railbelt and Northern Railbelt regions.

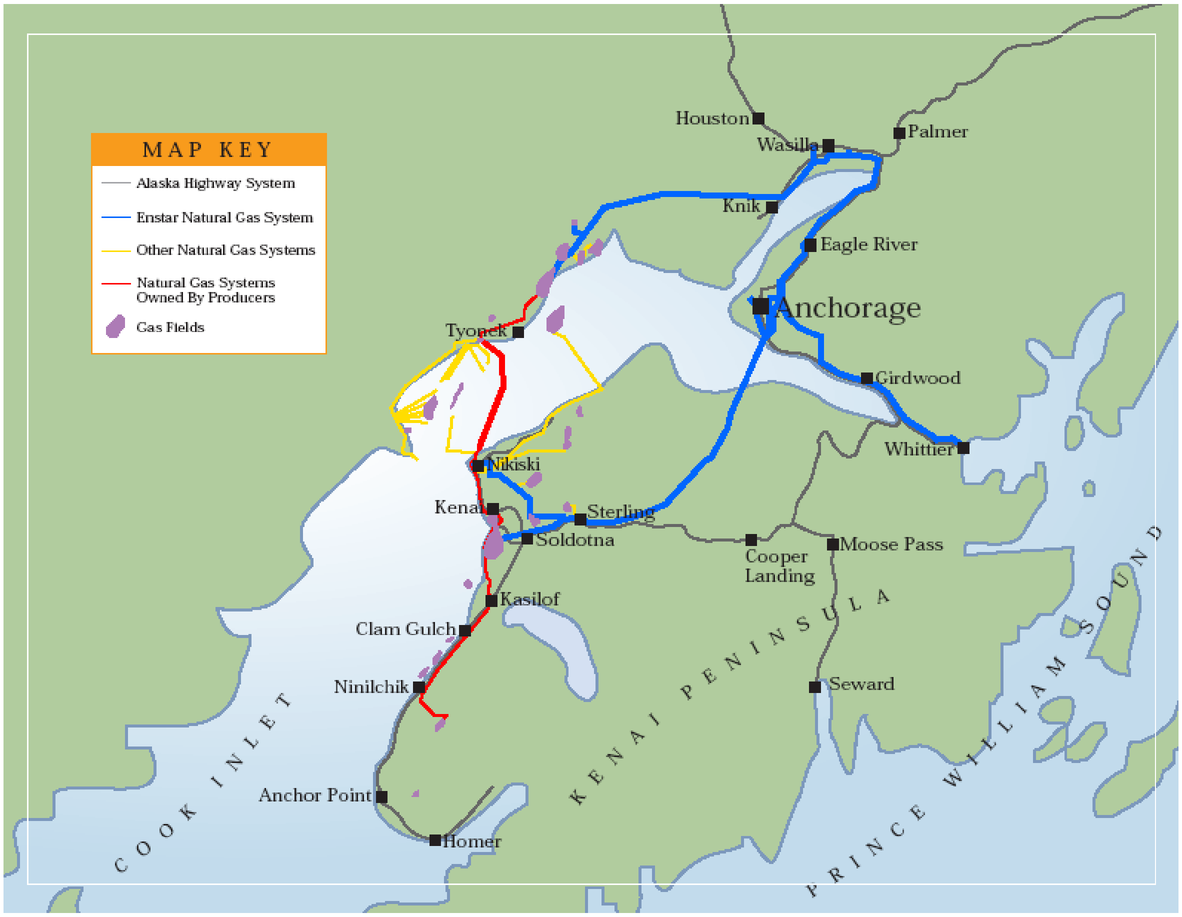
4.1.1 Southern Railbelt Region

ENSTAR is the local distribution company serving the Southern Railbelt region. The company was established in 1961. Today, ENSTAR has over 3,200 miles of distribution and transmission mains, with 129,000 customers, and is serving an estimated 348,800 Southcentral Alaska residents (ENSTAR, 2009).

Figure 9 is a map of the gas distribution system in Southcentral Alaska. The blue line represents the major gas transmission pipelines in the ENSTAR natural gas system. ENSTAR currently has gas supply contracts with Cook Inlet producers; however, sources of future gas supplies (beyond 2011) are still uncertain.

ENSTAR has more than 116,000 residential and about 13,000 commercial accounts. In 2005, penetration in the residential market was already about 75 percent. In 2007, ENSTAR added another 1,757 customers.

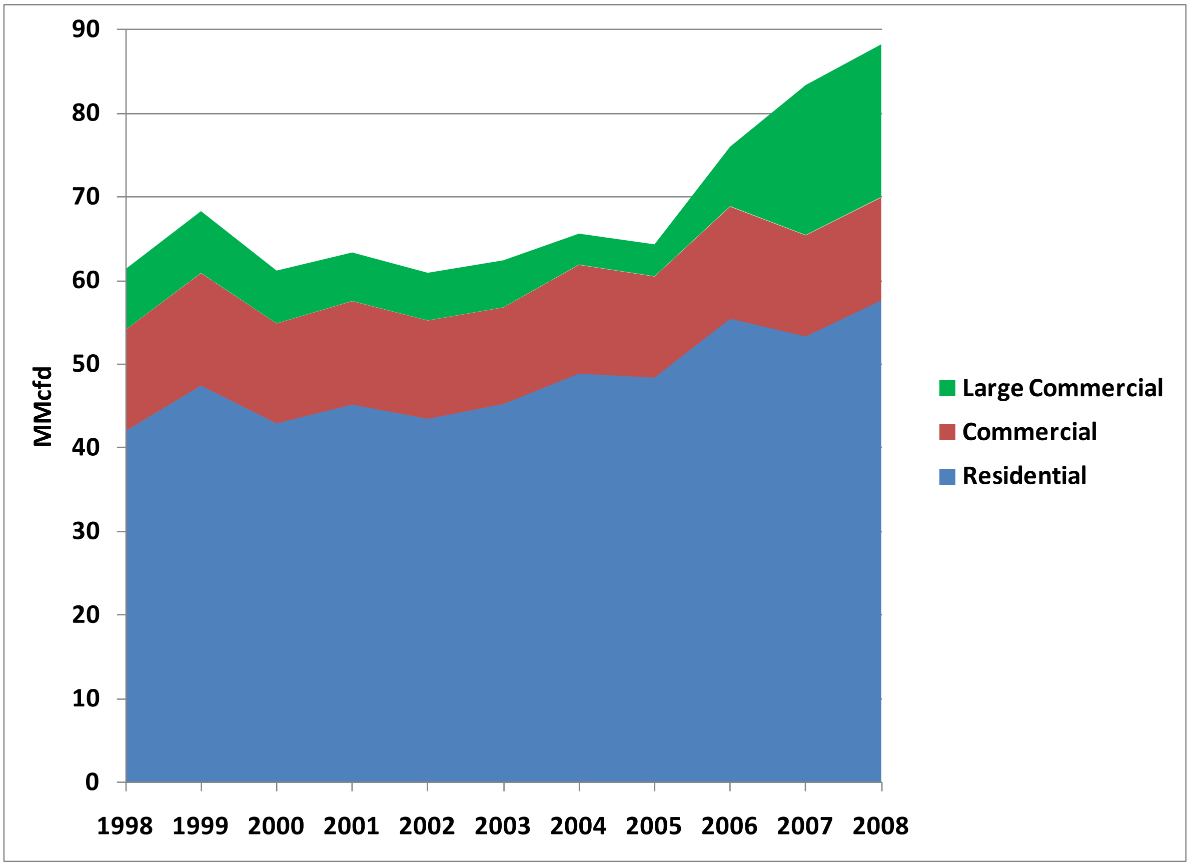
Figure 9. Southcentral, Alaska Gas Distribution System



Source: ENSTAR Natural Gas Company presentation to the Commonwealth North Energy Action Committee, May 22, 2009.

Annual average daily natural gas consumption data for ENSTAR in the past 10 years are shown in Figure 10. Residential sector demand has increased from about 61 MMcfd in 1998 to 88 MMcfd in 2008; a 37 percent increase in demand. Natural gas consumption by small to medium commercial customers has been relatively steady, fluctuating from a low of about 12 MMcfd in 2003 to a high of 13 MMcfd in 1999 and 2006. Average annual daily consumption by the large commercial customers on the other hand has increased significantly in recent years from 7 MMcfd in 2006 to 18 MMcfd in 2008.

Figure 10. Annual Average Daily Residential and Commercial Sector Gas Consumption, ENSTAR Service Area 1998 to 2008 (MMcfd)



Source: ENSTAR, 2009.

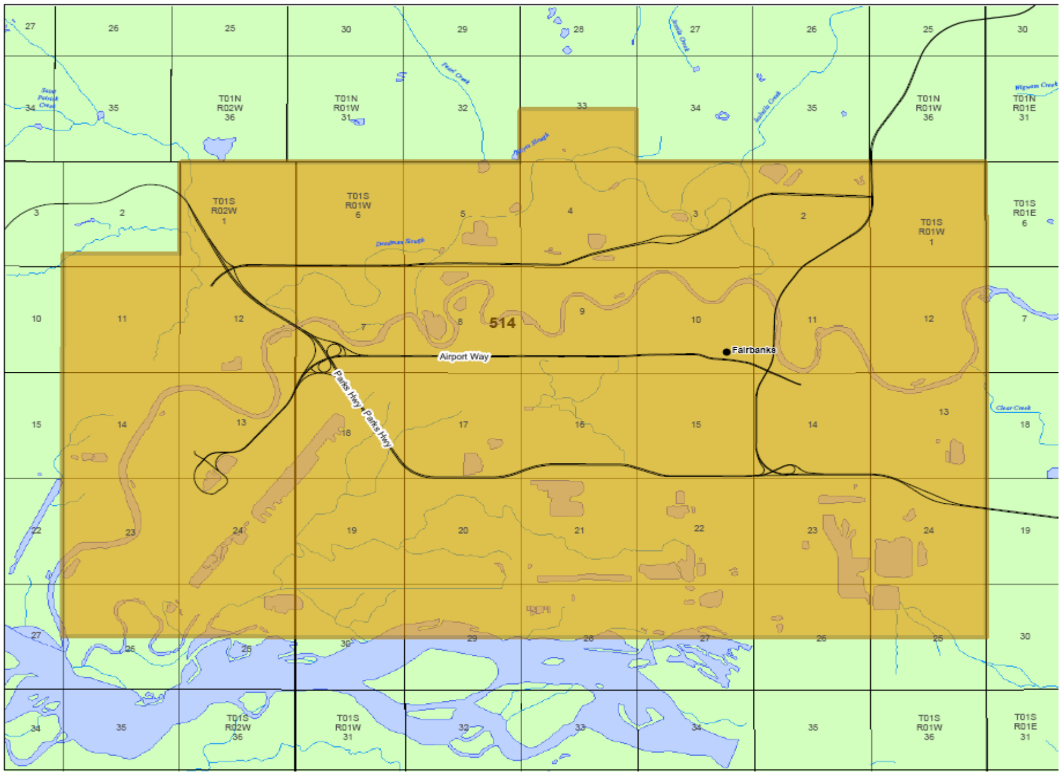
4.1.2 Northern Railbelt Region (Fairbanks North Star Borough)

Fairbanks Natural Gas (FNG) is the local distribution company serving Fairbanks. FNG began natural gas service to the area in 1998 by transporting LNG from a liquefaction plant at Point McKenzie to Fairbanks, a distance of approximately 300 miles. Currently, LNG is trucked in specialized tanker trailers to its two LNG storage and regasification facilities. On average, about three 800 Mcf truckloads per day are transported.

Unlike the ENSTAR service area, penetration into the residential market has been relatively slow since 1998, primarily because FNG does not have ready access to natural gas and also because of the added expense of trucking LNG. As noted in a previous study, in 2005, only 2 percent of the roughly 11,500 housing units in Fairbanks were using natural gas. The majority of the houses use heating oil for space heating. On the other hand, natural gas penetration in the commercial sector is close to 50 percent of the estimated 1,277 commercial units. The conversion rate in the commercial sector has been faster than the residential sector because higher fuel use per commercial customer makes recovery of conversion costs faster (RDS LLC, 2006).

Figure 11 shows FNG's service area. The distribution system has 65 miles of pipe (IIC, 2009). FNG is presently supply-constrained and is not expanding their service area or taking new customers within the area served by their existing distribution system. They have a large transmission backbone to their present system and could readily expand if gas were available. Commercial customers account for 90 percent of the total volume of gas sales. Average annual consumption of residential customers is 190 Mcf (Dan Britton, personal communication, 2009).

Figure 11. Fairbanks Natural Gas Service Area



Source: Regulatory Commission of Alaska, 2009
(http://rca.alaska.gov/RCAWeb/Certificate/CertificateDetails.aspx?id=14aed247-df8f-4dc6-8b2a-325acf1cb3c7)

In 2008, total residential sector demand was 63,515 Mcf, accounting for 7 percent of FNG's total gas sales that year. In contrast, commercial customers accounted for 73 percent of total gas sales, with a combined 624,169 Mcf of natural gas usage for small and large commercial customers. Residential sector demand increased by 13 percent from the previous year. Likewise, demand from small commercial customers and large commercial customers increased by 16 percent and 18 percent, respectively, from 2007 numbers.

In addition, FNG serves the hospital, the University, and the CIRI Talkeetna Lodge (located in Talkeetna, Alaska which is not within the Fairbanks North Star Borough). These three customers accounted for 20 percent of FNG's gas sales in 2008. As shown in Table 3, there was a significant increase in gas sales to the University from 2007 to 2008.

Table 3 also shows natural gas consumption by FNG customers in terms of annual average daily consumption (expressed in MMcfd).

Table 3. FNG Natural Gas Sales by Type of Customer, 2007 and 2008 (in Mcf per year and MMcfd)

	2007		2008	
Customers	**MCF/Yr**	**MMcfd**	**MCF/Yr**	**MMcfd**
Residential Customers	56,286	0.15	63,515	0.17
Small Commercial Customers	373,322	1.02	431,998	1.18
Large Commercial Customers	162,397	0.44	192,171	0.53
Hospital	104,452	0.29	107,892	0.30
University of Alaska Fairbanks	10,967	0.03	50,549	0.14
CIRI Talkeetna Lodge	11,998	0.03	13,410	0.04
Total:	719,422	1.97	859,535	2.35

Source: Interior Issues Council, *In-State Gas Pipeline Supply Options*, February 5, 2009.

4.2 Future Demand Estimates

New residential and commercial natural gas customers in Alaska are expected from increased market penetration in existing ENSTAR and Fairbanks Natural Gas demand service areas, as well as an expansion of these service areas. The potential future demand is presented in two future timeframes: Year 1 to 5 and Year 10 to 15 of pipeline operations. The following sections discuss the assumptions, approach, and results of the demand analysis.

4.2.1 Assumptions and Approach

Residential and commercial sector demand estimates for the Year 1 to 5 timeframe are based on market studies conducted by ENSTAR, the Interior Issues Council (IIC), and Fairbanks Natural Gas for the Southcentral and Fairbanks regions. Demand projections for the Year 10 to 15 timeframe are based on projected growth in population and employment in the region; estimated using the MAP model as described in Section 3 and Appendix A.

To account for potential variability in the critical assumptions used in the demand projections, a probability analysis was conducted to generate a range of potential demand estimates given different levels of probability. The "uncertainty" variables that were varied and tested in the probability analysis include the following:

- Percent growth in number of households
- Percent growth in employment
- Load per residential customer
- Load per medium and large commercial customer
- Residential and commercial market penetration rates
- Start year of build-out rate in the Fairbanks region
- Annual build-out rate
- Annual rate of growth in Southcentral (Southern Railbelt region) natural gas demand

The projections for the Fairbanks Northstar Borough region are based on a build out schedule as envisioned by FNG. Personal communication with Mr. Dan Britton, president of FNG, indicated that the company does not expect to start their build out until after the proposed mainline construction has been completed (Britton, 2009). However, recent developments suggest that there is a possibility that FNG could receive natural gas in the form of LNG (trucked from the North Slope to Fairbanks) even before the main gas pipeline comes on line. On September 29, 2009, the Alaska Gasline Port Authority announced that it has executed a letter of intent to buy FNG and develop a North Slope liquefaction plant that would allow liquefied natural gas to be trucked to Fairbanks (Petroleum News, 2009). To account for this possibility the demand analysis considered different start years for the build out in Fairbanks with 2013 being the earliest start year and 2019 as the latest start year. The base assumption is that the build out start year is in 2017. The demand projection assumes a fairly modest build out rate of 12.5 percent. By Year 10 to 15 of pipeline operations however, it is assumed that the build out will have been completed and therefore the demand projection reflects the maximum projected load as determined by the build out plan plus additional load from natural population and household growth.

To estimate growth in number of commercial customers, employment projections from the MAP model were used as a proxy measure. The U.S. Census Bureau *County Business Patterns* provides data on the total number of establishments, total number of paid employees, and the number of establishments by firm size (i.e. 1 to 4 employees, 5 to 9 employees, etc.). This information was used to determine the potential number of establishments or commercial customers that would be considered small, medium, and large. The average natural gas consumption by type of customer was used to project future demand.

The projections for the Southcentral Region are based on the load forecast developed by ENSTAR. As noted in the previous demand analysis, the ENSTAR projections provide reliable estimates of demand given the already high rate of natural gas penetration in the Southcentral region and the company's history in tracking current accounts and forecasting future accounts (RDS LLC, 2006). ENSTAR's load forecast covered the years 2009 to 2018. The forecast assumed normal temperatures resulting in 9,911 heating degree days annually. A traditional time series trend was used to project demand further into 2030. This time series approach extrapolates the underlying trend in natural gas usage over time period for the residential and commercial sector. To account for potential variation in this growth trend, the annual rate of growth was varied from a low of 1.5 percent to a high of 3.25 percent.

4.2.2 Projected Natural Gas Demand by Region

The residential and commercial sector demand projections for the Northern Railbelt and the Southern Railbelt regions are presented in this section. As noted above, for the Alberta Line, potential natural gas demand is identified only for the Railbelt region (both Northern and Southern Railbelt). These regions directly correspond to potential future load for FNG and ENSTAR, the two local gas distribution companies operating in the Railbelt region. The Valdez Line would add the City of Valdez to areas served with natural gas. This demand is also presented in this section.

4.2.2.1 Northern Railbelt Region

Table 4 shows the mean projected demand generated by the probability analysis of the demand in the Northern Railbelt region for the two future timeframes. While the Denali Borough is part of the Northern Railbelt region, the potential demand for natural gas presented below reflects future demand for a portion of the Fairbanks North Star Borough only; this is the portion which has a reasonably foreseeable chance of being part of the build out plan for the region's piped natural gas distribution system. The remainder of the Fairbanks North Star Borough and all of the Denali Borough are addressed in the Propane Analysis (Section 8).

The combined residential and commercial sector demand in the Year 1 to 5 timeframe is expected to be about 8 MMcfd, and in the Year 10 to 15 timeframe, the demand is expected to be about 28 MMcfd. The later timeframe potential demand reflects potential load after planned build out has been completed by FNG with an additional load resulting from natural population growth.

Table 4. Projected Annual Average Daily Residential and Commercial Sector Demand in the Northern Railbelt Region, in Two Future Timeframes (in MMcfd)

Type	Year 1 to 5 of Pipeline Operations	Year 10 to 15 of Pipeline Operations
Residential	4.04	18.43
Commercial	4.22	9.32
Total:	8.26	27.75

Source: Northern Economics estimates, 2009.

4.2.2.2 Southern Railbelt Region

Table 5 shows the mean projected demand generated by the probability analysis of demand for the Southern Railbelt; which corresponds to the current ENSTAR service area plus modest expansion of the service area in the future. The results show the range of possible outcomes given the variability in the rate of growth in residential and commercial customers in the region.

In the Year 1 to 5 timeframe, potential demand in this region is expected to be about 114 MMcfd. In the Year 10 to 15 timeframe, potential demand in this region is expected to be about 148 MMcfd.

Table 5. Projected Annual Average Daily Residential and Commercial Sector Demand in the Southern Railbelt Region, in Two Future Timeframes (in MMcfd)

Type	Year 1 to 5 of Pipeline Operations	Year 10 to 15 of Pipeline Operations
Residential	74.69	96.78
Commercial	39.55	51.24
Total:	114.24	148.02

Source: Northern Economics estimates, 2009.

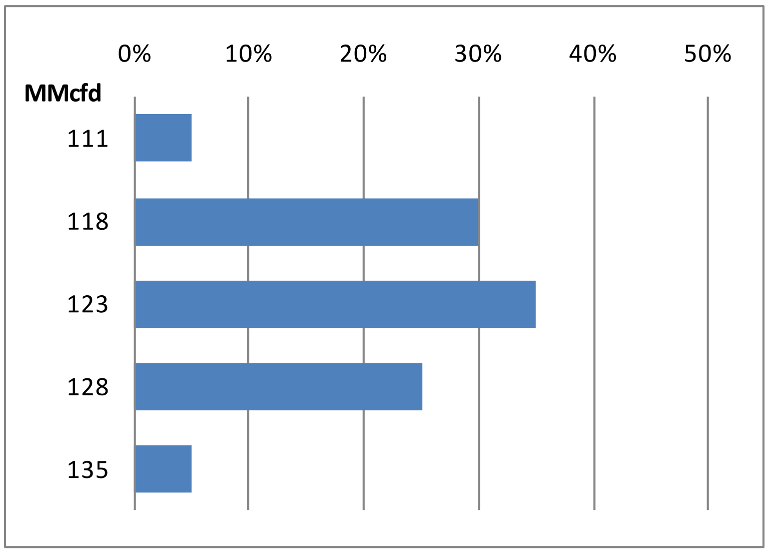
4.2.2.3 Valdez-Cordova Region

The discussion of potential demand in the sections above so far considers the Alberta Line configuration--the main pipeline from the North Slope of Alaska to Alberta, Canada. Considering the Valdez Line route—a main pipeline from the North Slope to Valdez, it is anticipated that the City of Valdez would switch from heating oil to natural gas based space heating systems if the terminus of the main gas pipeline is located in their vicinity. The estimated residential and commercial sector demand (mean values) in this region is 0.96 MMcfd for the Year 1 to 5 timeframe and 1.10 MMcfd for the Year 10 to 15 timeframe.

4.2.2.4 Probability Analysis of Total Projected Natural Gas Demand for the Residential and Commercial Sector

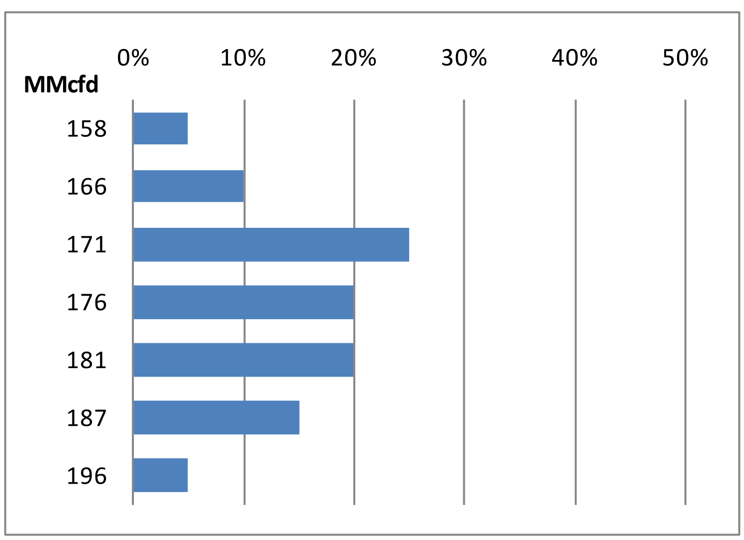
Figure 12 and Figure 13 provide a different perspective (probabilistic analysis) on the estimated demand for residential and commercial sector in the state for the Alberta Line during the two time periods. Both figures show the percent probability that demand will fall within one of the demand categories shown on the vertical axis. The most likely outcome in Figure 12 is about 123 MMcfd (which is the sum of demand shown in Table 4 and Table 5) while there is a 30 percent chance that demand could exceed that estimate. The results of the probability analysis for the Valdez Line are very similar; hence, are not shown below.

Figure 12. Chances of Residential and Commercial Sector Demand, Alberta Line, Year 1 to 5



Source: Northern Economics, Inc., 2009.

Figure 13. Chances of Residential and Commercial Sector Demand, Alberta Route, Year 10 to 15



Source: Northern Economics, Inc., 2009

5 Potential Power Sector Demand for Natural Gas

5.1 Current Demand Estimates

This assessment is limited to the interconnected portion of the electric power grid called the Railbelt, encompassing Fairbanks, the Denali Borough, the greater Anchorage area (including the Matanuska-Susitna Borough) and the Kenai Peninsula. The Alaska Energy Policy Task Force Report defined the Railbelt as: "the power-sharing area between Interior Alaska, from Fairbanks, and Southcentral, to Homer, connected by roads, generating facilities and transmission lines, which include the Alaska Intertie and the Bradley Lake Hydro Project." (Alaska Energy Policy Task Force, 2004). The interconnected electric system for Southcentral Alaska (the Railbelt System) consists of six electric utilities in Fairbanks, the greater Anchorage area and the Kenai Peninsula. Table 6 lists the main generation areas and the corresponding electric utilities. Detailed background information for each utility is provided in Appendix C, Section 2.

Table 6. Generation Areas and Utilities in the Railbelt System

Generation Area	Utilities
Greater Anchorage	Municipal Light & Power (ML&P)
	Chugach Electric Association (CEA)
	Matanuska Electric Association (MEA)
Kenai	Seward Electric System (SES)
	Homer Electric Association (HEA)
Fairbanks-Healy	Golden Valley Electric Association (GVEA)

The current assessment of the Railbelt power sector builds upon a previous 2008 study sponsored by the Alaska Energy Authority (AEA). The study, performed by Black and Veatch, evaluated the feasibility, and economic and non-economic benefits, associated with the formation of a regional generation and transmission (G&T) entity called the Railbelt Electrical Grid Authority (REGA), whose purpose is to manage and dispatch electric power on the Railbelt grid (Black and Veatch, 2008). In order to evaluate the value of REGA, detailed capacity and dispatch modeling of the region's existing electric power system was performed, with the model making economic decisions to select those technology and fuel options that minimize long-term costs for customers. This analysis was based upon the following:

- Application of a power cost model to perform a least-cost resource systems optimization to develop optimal portfolios of resources for each of four alternative scenarios.
- Cost and performance characteristics of the region's existing generation and transmission assets, as described in Appendix C, Section 2.
- Cost and performance characteristics of various resources that could be added to the region's resource portfolio, as briefly described in Appendix C, Section 3.

To maintain consistency, the current study did not perform independent utility systems modeling, but builds upon the outcomes of the REGA Study utility capacity and dispatch modeling results. The REGA outcomes were adjusted based on new information gathered for this project (see Appendix C, Section 3.5)

This study estimates that the current total Railbelt installed capacity is 1,246 MW based on the B&V study data and updated utility information provided through key informant interviews (see Table 7).

Table 7. Railbelt Installed Capacity (MW)

Utility	Thermal Plants: Existing Capacity	Hydroelectric Plant Capacity			Total
		Bradley Lake	Eklutna Lake	Cooper Lake	
MEA	0	12.4	6.7	0	19.1
HEA	39	10.8	0	0	49.8
CEA	504	27.4	12	20	563.4
GVEA	275	15.2	0	0	290.2
ML&P	278	23.3	21.3	0	322.6
SES	0	0.9	0	0	0.9
Total	**1,096**	**90**	**40**	**20**	**1,246**

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study- Final Report," September 12, 2008 and SAIC.

The current Railbelt utility electricity supply to satisfy demand is listed in Table 8, as well as the electricity supplied by natural gas-based generators. As shown, 79 percent of current generation is supplied by natural gas.

Table 8. Current Aggregate Railbelt Utility Electricity Supply to Satisfy Demand

Total Railbelt Electricity Supply (MW-Hours)	Total Railbelt Electricity Supply From Natural Gas (MW-Hours)	Total Railbelt Electricity Supply From Natural Gas (%)
5,246,000	4,120,000	79

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

Table 9 provides the current associated aggregate Railbelt power sector natural gas consumption data. While the table indicates that the Fairbanks region does not consume natural gas, there is an intertie between the utilities in the southern portion of the Railbelt and Golden Valley Electric that is generally used to transmit electricity from the natural gas-fired plants in Southcentral Alaska to GVEA since the gas-fired electricity is less expensive than the fuels available to GVEA.

Table 9. Current Aggregate Railbelt Utility Natural Gas Consumption

Total Railbelt Natural Gas Consumption (BBtu/Year)	Total Railbelt Natural Gas Consumption (Bcf/Year)	Total Railbelt Natural Gas Consumption - Fairbanks Region (Bcf/Year)	Total Railbelt Natural Gas Consumption - South-Central Region (Bcf/Year)
42,255	41.67	0	41.67

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

5.2 Future Demand Estimates

Based on the AEA/B&V study methodology, future natural gas consumption estimates have been developed for four "Evaluation Scenarios" that are considered alternative energy futures for the Railbelt region. These are defined as follows:

- **Natural Gas Scenario:** Assumes that all of the future generation resources will be natural gas-fired facilities, continuing the region's dependence upon natural gas.
- **Mixed Resource Portfolio Scenario:** Assumes that a combination of large hydroelectric, renewables, demand side management (DSM)/energy efficiency programs, coal, and natural gas resources is added over the next 30 years to meet the future needs of the region.
- **Large Hydro/ Renewables/ DSM/ Energy Efficiency Scenario:** Assumes that the majority of the future regional generation resources that are added to the region include one or more large hydroelectric plants (greater than 200 MW), other renewable resources, and DSM and energy efficiency programs.
- **Coal Scenario:** Assumes the addition of coal plants to meet the future needs of the region.

Discussions were held with James Strandberg of AEA and Kevin Harper, the B&V project manager for the Regional Integrated Resource Plan (RIRP) study, the follow-on study to the REGA study, to assess the probability of occurrence of these scenarios. Table 10 presents the consensus from them regarding the probability of each scenario in the two subject timeframes. The probability of the natural gas scenario is higher in the Year 1 to 5 than the Year 10 to 15 timeframe because gas is considered a "bridge fuel" until other alternatives can be brought onboard.

Table 10. Assumed Probabilities of Occurrence for Alternative Energy Scenarios

	Future Timeframes	
	Year 1 to 5	Year 10 to 15
Scenario	(%)	
Natural Gas	45	20
Mixed	25	60
Large hydro	20	15
Coal	10	5

Source: James Strandberg of AEA and Kevin Harper, the B&V project manager for the RIRP study

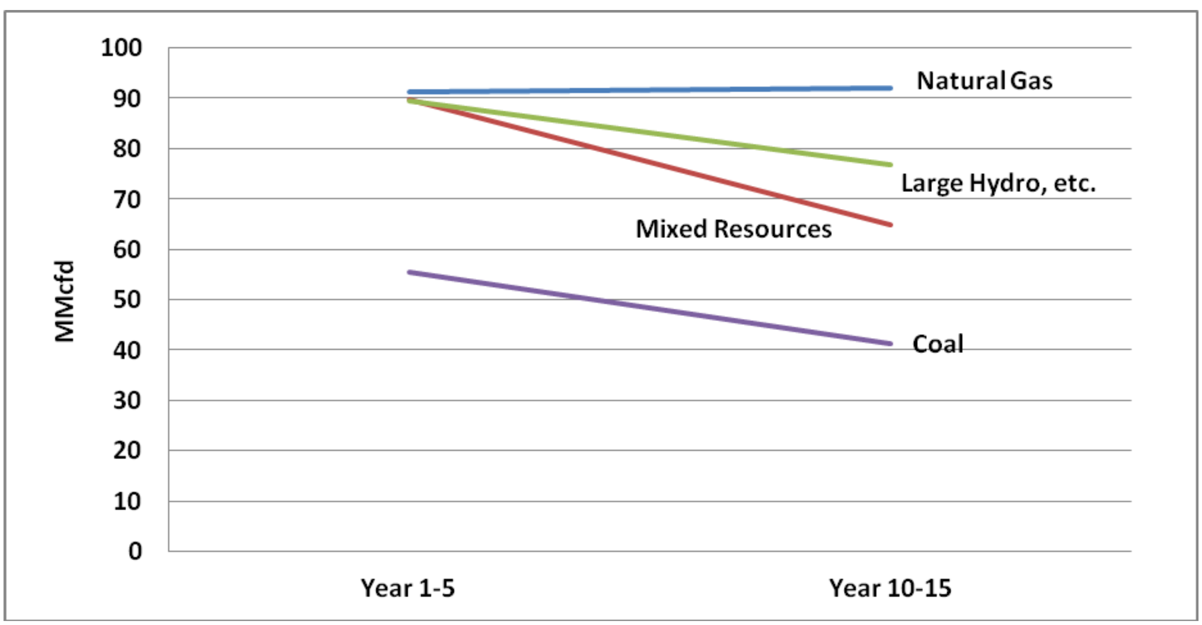
Table 11 provides the projection of average daily future natural gas demand in the two future timeframes for the Fairbanks area and the Southcentral area of the Railbelt and the total Railbelt power sector under these four scenarios. Figure 14 and Figure 15 display the projected change in total power sector natural gas demand used in these scenarios for the two pipeline projects, respectively. It should be noted that AEA and B&V have completed a Regional Integrated Resource Plan (RIRP) as follow-on to the REGA study (on which the current study is based). Scenarios are defined differently in REGA and RIRP; hence, demand estimates in RIRP and in the current study will differ.

Table 11. Projected Future Natural Gas Demand for the Railbelt Electric Power Utilities in MMcfd

Geographic Location	Year 1 to 5	Year 10 to 15
Large Hydro / Renewables / DSM / Energy Efficiency Scenario		
Northern Railbelt (Fairbanks, North Pole)	19.7	26.0
Southern Railbelt (Southcentral)	76.7	57.2
Total:	**96.5**	**82.8**
Natural Gas Scenario		
Northern Railbelt (Fairbanks, North Pole)	22.2	29.0
Southern Railbelt (Southcentral)	76.3	70.3
Total:	**98.5**	**99.3**
Coal Scenario		
Northern Railbelt (Fairbanks, North Pole)	12.8	15.8
Southern Railbelt (Southcentral)	47.2	28.8
Total:	**60.0**	**44.6**
Mixed Resource Scenario		
Northern Railbelt (Fairbanks, North Pole)	19.2	14.7
Southern Railbelt (Southcentral)	77.6	55.4
Total:	**96.8**	**70.1**

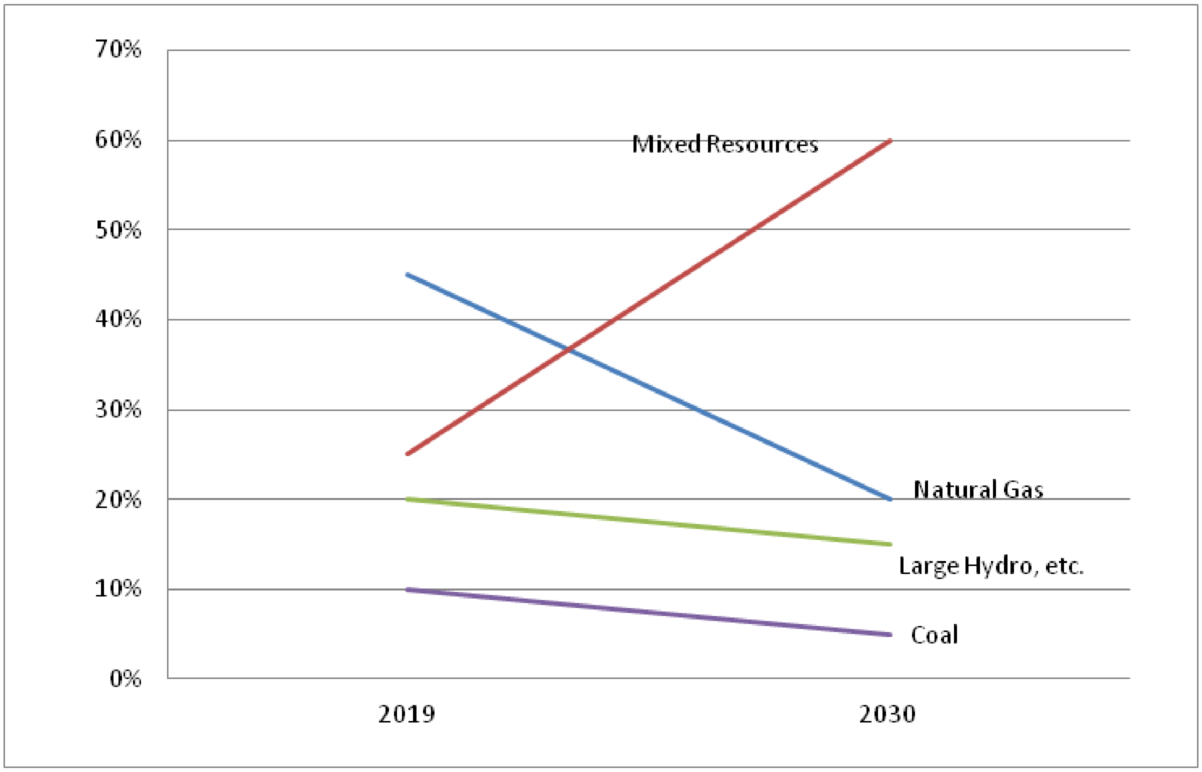
Source: Black and Veatch, “Alaska Railbelt Electrical Grid Authority (REGA) Study- Final Report,” September 12, 2008 and SAIC.

Figure 14. Change in Total Power Sector Natural Gas Demand under Four Scenarios in MMcfd



Source: SAIC, Inc., 2009.

Figure 15. Change in Percent Chance of Occurrence for Power Sector Scenarios



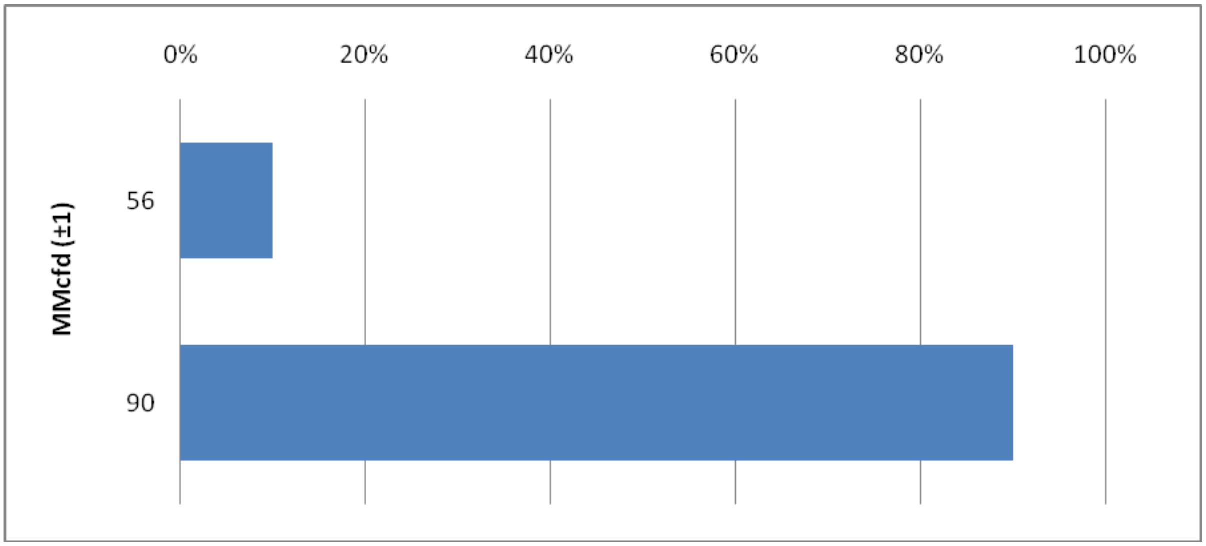
Source: SAIC, Inc., 2009.

As seen Figure 14, the highest natural gas demand occurs under the natural gas scenario, while lowest demand occurs under the coal scenario. For all scenarios other than the natural gas scenario, the shift in power sector energy sources continues over time, thus differences between the scenarios are greater in 2030 than in 2019.

For the probabilistic analysis of natural gas demand from the Railbelt power sector, natural gas demand from each sub-region was modeled as a discrete distribution of demand as reported in Table 11, with the associated probabilities as reported in Table 10. This allows the range of possible Railbelt power demand to be reflected in overall demand estimates. Figure 15 shows the percent chance of the different power sector scenarios over time.

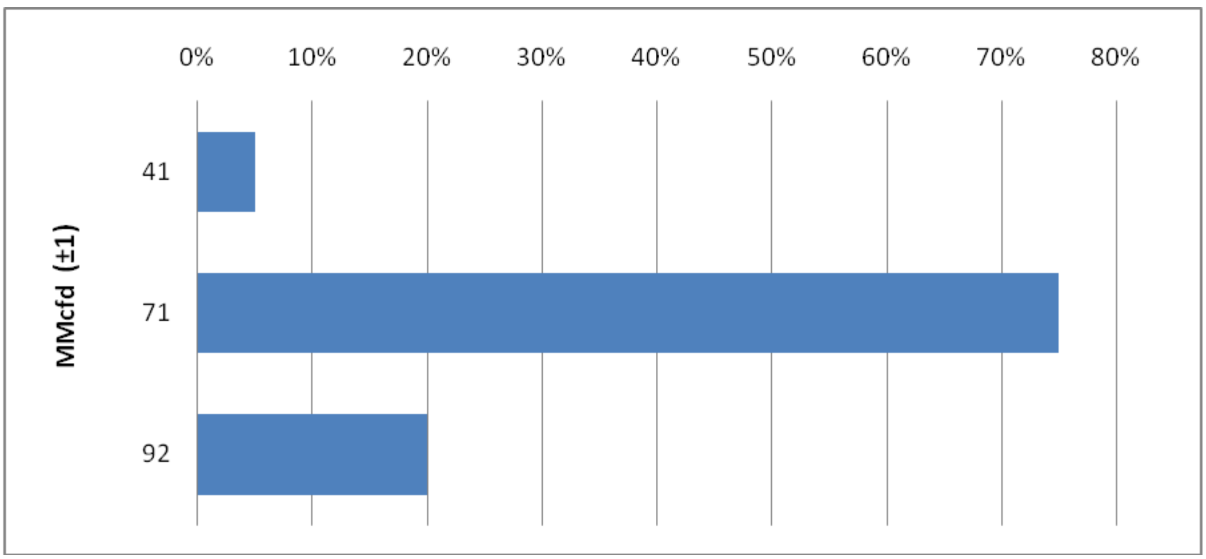
Figure 16 and Figure 17 show the chance of occurrence that demand will approximate the volumes shown on the vertical axis. For example, in the first five years of operation, there is about a 90 percent chance that demand will be about 90 MMcfd, and a 10 percent chance that demand will be about 56 MMcfd. In the later years of the project power demand would have about a 70 percent chance of requiring 71 MMcfd and a 20 percent chance of requiring 92 MMcfd. The reduction is due to the anticipated transition from a large reliance on natural gas as the primary fuel for electric power generation to a more balanced portfolio of generation fuels.

Figure 16. Chances of Power Demand, Year 1 to 5



Source: SAIC, Inc., 2009.

Figure 17. Chances of Power Demand, Year 10 to 15



Source: SAIC, Inc., 2009.

6 Potential Industrial Sector Demand for Natural Gas

Industrial demand comprises two basic types of gas use: use as a fuel for heating and electricity, and use as a feedstock to create products. Natural gas is just one of several alternatives that can meet industrial fuel needs. In contrast, feedstock demand for natural gas can often be met only with natural gas. Furthermore, industries that use natural gas for feedstock typically need much larger amounts of gas than industries with only fuel needs, and thus are referred to as gas-intensive industries. Gas-intensive industries provide anchor customers for a gas pipeline because their continuous need for large volumes of gas enables them to sign long-term contracts for large deliveries. These contracts provide financial stability for gas pipeline owners, and allow other gas customers to benefit from the economies of scale that may be achieved with the construction of a larger pipeline.

The large amount of gas needed by gas-intensive industries typically causes them to be very sensitive to gas price in order for their products to compete on the world market. Alaska's ability to attract and maintain gas-intensive industries largely depends on the ability to provide long-term gas supply agreements that are indexed to relatively low gas prices.

In recent years, there has been a decline in Alaskan gas-intensive industries along with declines in Cook Inlet gas production. However, historically, gas-intensive industrial demand for natural gas has exceeded the combined demand of all other sectors in Alaska (i.e., power, residential, commercial, and other industrial). Hence, the future demand for natural gas in the state of Alaska is substantially affected by the future of Alaskan gas-intensive industries.

The following sections address current Alaskan industrial demand for natural gas, and possible future demand based on the ability of North Slope gas to provide an economically feasible source of natural gas for gas-intensive industries.

6.1 Current Demand Estimates

There is currently only one operating source of gas-intensive industry demand in Alaska—the ConocoPhillips/Marathon LNG terminal, located in Nikiski on the Kenai Peninsula (Southern Railbelt). When not under curtailment, the LNG terminal consumes up to 230 MMcfd. Under the current export license for this facility (i.e., from April 1, 2009 to March 31, 2011), it is limited to about 49 Bcf/year (Petroleum News, June 8, 2008), which is equivalent to an annual average of 134 MMcfd.

Consumption of natural gas by other industries that are not gas-intensive also currently occurs only in the Southern Railbelt region. This demand is from the Tesoro Refinery located in Nikiski on the Kenai Peninsula. Tesoro processes crude oil from the Kenai Peninsula and Cook Inlet oil fields, and supplements it with purchases from the North Slope (via Valdez) and imported crude. The Tesoro refinery has a rated crude oil capacity of 72,000 barrels per day (bpd), and on average, operates at roughly 65,000 bpd. The refinery's maximum natural gas demand is 18 MMcfd, with typical consumption rates of 11 MMcfd (Hansen et al., 2005).

6.2 Future Demand Estimates

Future industrial demand for natural gas will be substantially determined by whether or not the price of gas in Alaska results in economic feasibility for gas-intensive industries. Given the 2011 expiration of the export license for the LNG terminal and uncertainty in license renewal, there is currently no highly likely gas-intensive industrial demand in Alaska for the first 15 years of pipeline operation. While further development of Cook Inlet fields may provide natural gas to meet future industrial demand, for the purposes of this analysis, gas prices are based on the assumption that essentially all industrial natural gas demand will be met by North Slope gas transported through the TransCanada Alaska pipeline and a spur line with Cook Inlet production meeting electric and gas utility demand.

Growth in natural gas demand for the residential and commercial sectors generally occurs with the addition of many small increments. In contrast, growth in demand from gas-intensive industries generally occurs in substantial steps because these industries typically need to operate at near-full capacity to be economically viable. Thus, projections of large industrial demand are developed through the analysis of several potential gas-intensive industrial projects.

Potential gas-intensive industries were assessed with a net present value (NPV) analysis. This analysis incorporates feedstock and product prices, capital expenses, operational and maintenance (O&M) cost, salvage price, and the time value of money. Appendix F provides more detail regarding the industrial product price forecasts used in the analysis.

The following assumptions were used in the NPV analyses:

- 20-year project-life
- after-tax discount rate of 15 percent
- Federal tax rate of 35 percent
- State tax rate of 4.5 percent

Projects with favorable economics have an NPV that is equal to or higher than zero—these are the projects that are more likely to be developed. Use of NPV to determine the likelihood of project implementation is a significant simplification for the purposes of this study. It should be recognized that final investment decisions are based on many other factors that are not included in an NPV analysis, such as corporate strategic planning; geopolitical distribution of assets; local development incentives and acceptance; risk, profit, and other criteria compared to other investment options, etc.

The natural gas price forecast was developed with the National Energy Modeling System (NEMS), using inputs similar to those used by the EIA in the Annual Energy Outlook, adjusted to reflect commencement of pipeline operations in 2019. Further details of the natural gas price forecasts applied in this report are available in Appendix E.

The probability distributions for capital expenses, feed prices, and product prices were modeled as distributions characterized by the estimated most-likely value, and lowest and highest expected values. Feed and product prices were correlated, with correlation coefficients determined from their historical relationships.

Each project-specific analysis resulted in a series of NPV values representing NPV results under the various possible capital costs, and feed and product prices. The proportion of the simulations that result in a positive NPV corresponds to the chances of the project being economically feasible, and hence being developed with the associated natural gas demand.

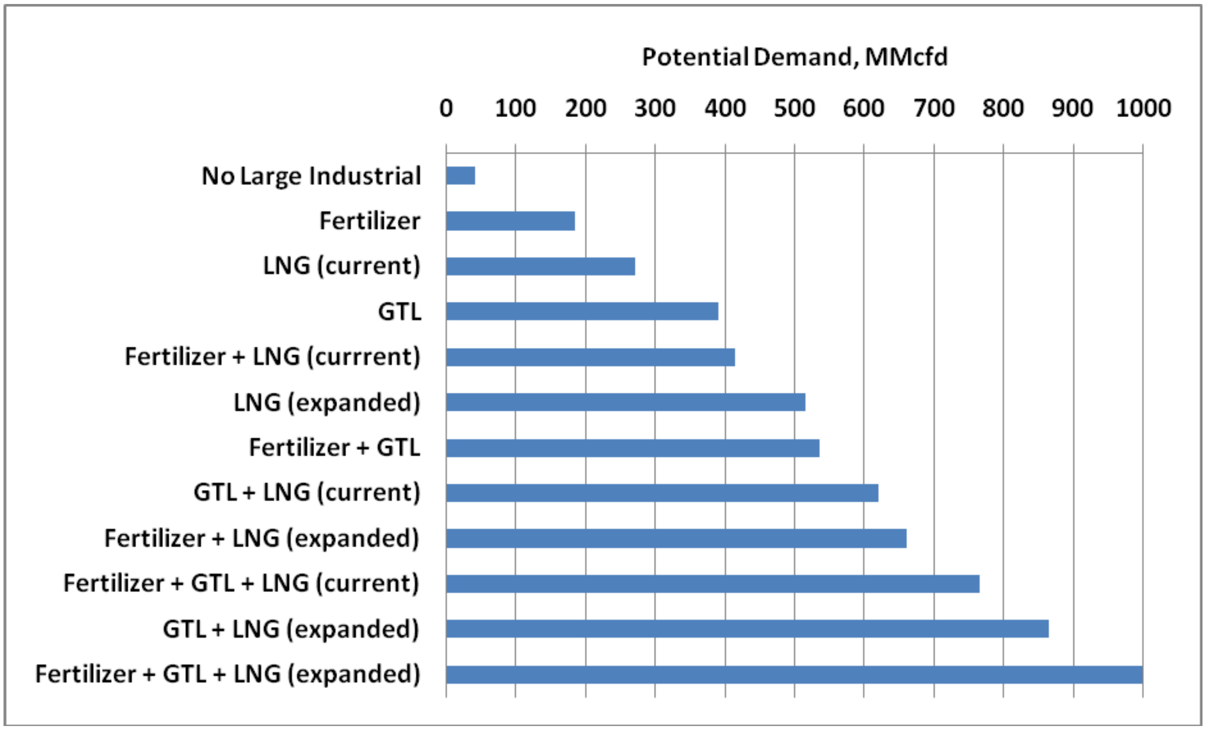
The example projects analyzed and their associated natural gas demand are as follows:

- Continuation of the Nikiski LNG export terminal operating at the current capacity, with a demand for 230 MMcfd.
- Expansion of the Nikiski LNG export terminal operating at roughly twice the current capacity, with a demand for 475 MMcfd.
- Re-start of the Agrium fertilizer plant operating at the historic capacity, with a demand of approximately 145 MMcfd.

- Greenfield development of a Gas-to-Liquids (GTL) complex with a capacity of 38,000 bpd, representing a demand of approximately 350 MMcfd.

Demand for all of the possible combinations of modeled industrial projects is shown in Figure 18.

Figure 18. Natural Gas Demand from All Possible Combinations of Modeled Large Industrial Projects



Source: SAIC, Inc., 2009

The focus of this analysis is on dry gas; hence, potential gas-intensive industry demand for natural gas liquids (i.e., ethane, butane, propane) was only assessed at a cursory level. Under the Alberta pipeline scenario, assuming industry development near a port (i.e., Anchorage) for easy access to world markets, the amount of NGLs in a 1,000 MMcfd spur line would be insufficient for a world-class petrochemical complex. In particular, new petrochemical complexes typically require at least 75,000 bpd ethane, and a 1,000 MMcfd spur line carrying gas with a composition as in the "Rich Gas Case" composition (as published in the AGIA Request for Applications) could only provide about 42,000 bpd.[7] However, under the Valdez pipeline scenario, 3,000 MMcfd of North Slope gas would be transported to Valdez. This would contain a sufficient volume of ethane to support a world-class petrochemical complex under the "Lean Gas Case" (as published in the AGIA Request for Applications).

[7] A recent white paper commissioned by the Anchorage Economic Development Corporation and ANGDA and conducted by Chemical Market Associates, Inc. (CMAI, 2009) indicates that Alaska could offer an opportunity for Pacific Rim chemical companies to diversify their sources of supply and develop new facilities in Cook Inlet that would use feedstock from the North Slope of Alaska. A straddle plant on the main pipeline could extract liquids for an enriched gas stream in the spur line, providing sufficient natural gas liquids (NGLs) for an Alaskan petrochemical complex. NGL demand from new projects would likely have to compete with currently operational NGL demand sites in Alberta with expected surplus capacity.

Each of the example gas-intensive industrial projects that use dry gas (i.e., fertilizer, LNG, and GTL) are further described in the sections below, followed by projected demand for other industries that are not considered as gas-intensive industries, and discussion of the total estimated demand for the industrial sector.

6.2.1 Fertilizer

Agrium U.S., Inc. has a world class ammonia and urea production facility in Nikiski on the Kenai Peninsula in the Southern Railbelt region. At full capacity, the plant produces 1.25 million gross tonnes of anhydrous ammonia and 1 million tonnes of urea annually, which it has previously sold to world markets and domestic customers. In 2007, increases in natural gas prices associated with reduced natural gas production caused Agrium to curtail its Kenai operations. Production ceased altogether in late 2007 (Petroleum News, January 20, 2008 and March 8, 2009). Agrium is reportedly seeking buyers for the Nikiski plant, and concurrently continuing efforts to identify future feedstock sources.

The Agrium Kenai plant is not in operation at this time. The company has removed all chemicals and catalysts, removed exchanger bundles, and undertaken other closure activities. Assuming the plant is not dismantled, the facility would require refurbishments prior to operation in 2019. These refurbishments are to eliminate the need for additional major capital improvements/expenditures during the 20-year operating life. Capital costs for refurbishment are based on the 2006 study prepared for the National Energy Technology Laboratory, *Alaska Natural Gas Needs and Market Assessment* (RDS LLC, 2006), adjusted to mid-$2009. The adjusted estimate of $257 million was modeled as the “most-likely” capital costs, with low costs estimated as 38 percent less, and high costs estimated as 75 percent more.

The price forecast for ammonia is based on the historical relationship of ammonia prices to natural gas. The correlation between these prices was modeled as 0.9, based on historical correlations of annual average prices. The price forecast for natural gas was developed as described above (Section 2.2).

Table 12 summarizes key assumptions and results of the probabilistic NPV analysis of a resumption of operations at the Agrium fertilizer production facility.

Table 12. Fertilizer Industrial Analysis: Assumptions and Results

Static Assumptions			
Capacity	1.25 MMTPA Ammonia 1.16 MMTPA Urea		
Natural Gas Demand, MMcfd	145		
Annual O&M *(excluding gas)*	$69 million		
Probability Distribution Parameters			
	Low	**Mid**	**High**
Capital, $ millions *(Depreciable cost basis)*	$160	$257	$450
Alberta Pipeline, Gas Price, $/Mcf	$5.11	$7.57	$10.46
Valdez Pipeline, Gas Price, $/Mcf	$7.66	$8.71	$10.05
Ammonia, $/MT	$320	$370	$417
Results: Probability NPV ≥ 0			
Alberta Pipeline		0.22	
Valdez Pipeline		<0.01	

Source: SAIC, Inc., 2009
Note: MMTPA is million metric tons per annum.

As shown in Table 12, low, mid, and high estimates were applied for capital costs, gas prices under both pipeline scenarios, and ammonia prices on the global market. Net present value was calculated for the given size of the fertilizer plant, and the cost and price ranges shown. Under the Alberta pipeline scenario, the NPV exceeded zero 22 percent of the time, indicating a probability of 0.22 that this project will be economically feasible. Under the Valdez pipeline scenario, higher gas prices reduced the probability of economic feasibility to less than 0.01 (i.e., less than a one percent chance that this project will be realized).

6.2.1.1 LNG

This analysis models LNG scenarios for projects in Nikiski, which may occur with the main pipeline terminating in either Alberta or Valdez. Under the Valdez pipeline scenario, it is assumed that the proposed Valdez LNG facility will reserve pipeline capacity prior to any decision to terminate the main pipeline in Valdez. Hence, the feasibility of an LNG terminal in Valdez will have already been favorably assessed by the project investors.

Nikiski currently has one operating LNG liquefaction terminal, with capacity of 1.5 MMTPA. This represents a 230 MMcfd demand for natural gas, including gas consumed in processing. The Nikiski terminal is 40 years old, and is relatively small by contemporary standards. Many new world class LNG facilities have capacities of 730 MMcfd to 3.0 Bcfd (5 to 20 MMTPA).

The Nikiski LNG terminal is operated by ConocoPhillips, which has 70 percent ownership. Marathon has the remaining 30 percent interest, and is responsible for operation of the specialized LNG carriers that transport the LNG to Japan. Until the recent curtailment of the LNG terminal operations, there were two specialized LNG carriers with reinforced hulls for navigation in ice-covered waters. The carriers both had capacities of 88,000 cubic meters—a mid-size carrier, but the maximum size that can currently be accommodated at the Nikiski terminal. One of these carriers has since been sold.

Capital costs for the two LNG scenarios considered in this analysis are based on the 2006 ANGDA report conducted by Stone & Webster titled, *Commercial Future of the Kenai LNG Plant*. It was concluded in the 2006 ANDGA report that the remaining useful life of the Kenai plant was on the order of 6 years without significant investment to modernize key elements, specifically, replacement of the aging combustion turbines. Hence, plant operation much beyond the 2011 export license expiration will require significant capital investment.

In addition to continued operation of the current LNG capacity, the ANDGA report also includes estimates for an expansion of the facility to 3.0 MMTPA. This includes new pre-treatment and liquefaction systems, a full-containment LNG storage tank to meet current standards, and expansion of utility and support facilities. All costs taken from the 2006 ANDGA report were adjusted to mid-$2009. The adjusted capital cost estimates of $355 million and $1.85 billion for current and expanded capacity, respectively, were modeled as the “most-likely” capital costs, with low costs estimated as 38 percent less, and high costs estimated as 75 percent more.

For this analysis, it is assumed that LNG will be sold in the Japanese market. Japanese and Korean LNG prices are typically higher than those in the United States and Europe. The differentials are due to the formulae for calculating the LNG price: in the U.S. and Europe, the LNG price is typically linked to the pre-burner price of alternative fuels (heating oil, heavy fuel oil, coal, etc.) while in Japan and Korea, LNG prices are typically linked to the price of crude oil. East Asian buyers also pay higher rates due to an “Asian Premium,” which is attributed to the lack of indigenous sources of natural gas supply and the security-conscious, long-term nature of most East Asian energy contracts. In energy equivalent terms, the Asian Premium on LNG has been found to be greater than the Asian Premium on crude oil. While analysts speculate that the magnitude of the difference in Asian LNG prices compared to the rest of the world will not be sustained indefinitely, there are no clear trends indicating near or mid-term changes in the status quo. Indeed, recent 20-year LNG contract values suggest at least some LNG sold to Asia will maintain the recent Asian Premium through 2029. Thus, the current pricing formulae are assumed in this analysis for long term (e.g., 20-year) contracts that would be negotiated within the next decade.

The exact pricing formulae in LNG contracts are rarely disclosed, but it is widely known that current Japanese and Korean long term LNG contracts are linked to the “Japanese Crude Cocktail” (JCC) price, which is a weighted-average of all crude import prices reported by the Japanese Customs office. Hence, the LNG product prices used in this analysis are based on the historical relationship of Japanese LNG prices to the JCC, and the JCC historical relationship to the price of crude oil in the U.S. The modeled correlation between LNG product prices and natural gas is 0.8, based on historical correlations of annual average prices.

The price forecast for natural gas feed for the LNG terminal was developed as described above (Section 2.2). Table 13, below, summarizes key assumptions and results of the probabilistic NPV analysis for continued operation of the Nikiski LNG terminal at both current capacity, and with expansion to double the current capacity.

Table 13. LNG Industrial Analysis: Assumptions and Results

	LNG Current Capacity			LNG Expanded		
Static Assumptions						
Capacity		1.5 MMTPA			3.0 MMTPA	
Natural Gas Demand, MMcfd		230			475	
Annual O&M *(excluding gas)*		$86 million			$222 million	
Probability Distribution Parameters						
	Low	**Mid**	**High**	**Low**	**Mid**	**High**
Capital, $ millions *(Depreciable cost basis)*	$286	$461	$806	$1,590	$2,565	$4,489
Alberta Pipeline, Gas Price, $/Mcf	$5.11	$7.57	$10.46	$5.11	$7.57	$10.46
Valdez Pipeline, Gas Price, $/Mcf	$7.66	$8.71	$10.05	$7.66	$8.71	$10.05
LNG (cif), $/MMBtu	$6.78	$12.06	$17.70	$6.78	$12.06	$17.70
Results: Probability NPV ≥ 0						
Alberta Pipeline		0.63			0.15	
Valdez Pipeline		0.39			0.09	

Source: SAIC, Inc., 2009.

As shown in Table 13, low, mid, and high estimates were applied for capital costs, gas prices under both pipeline scenarios, and LNG prices on the Asian market. Net present value was calculated for the given sizes of the LNG terminals, and the cost and price ranges shown. Under the Alberta pipeline project, the NPV exceeded zero 63 percent of the time, indicating a probability of 0.63 that this project will be economically feasible. Under the Valdez pipeline project, higher gas prices reduced the probability of economic feasibility to 0.39 (i.e., a 39 percent chance of project realization).

6.2.1.2 GTL

The conversion of natural gas to liquid (GTL) represents another way to monetize stranded natural gas, and for Alaskans, it could also represent an alternative source of liquid fuels. GTL technology uses the Fisher Tropsch (F-T) process to convert natural gas to longer chain, liquid hydrocarbons. The advantage of GTL-produced liquid fuels is that they are substantially cheaper to store and transport than gaseous fuels, and they contain virtually no sulfur, nitrogen, or metals, and thus burn cleanly.

Capital cost estimates for an Alaskan GTL complex are based on a review of past and expected future costs. While each of the several processes incorporated in the GTL process have been applied for decades independent of the GTL process, the best technical way to combine these processes and optimize each sub-process for the purposes of the overall GTL process is far from mature. New technological developments are in demonstration phases for several key GTL sub-processes, offering potential for substantial reductions in cost. Until greater technological maturity is achieved, GTL capital costs will likely remain quite variable and difficult to predict, making GTL investments particularly high-risk. However, between the present and the end of the timeframe considered in this analysis, i.e., beyond 2030, it is reasonable to assume that there will be movement towards a more mature GTL technology.

While there are perhaps a half-dozen GTL projects under consideration across the globe, there are currently only two full-scale operating GTL complexes that have been completed since 1990. These are Bintulu in Malaysia, with a capacity of 14,700 bpd brought on-line in 1993; and Oryx in Qatar, with a capacity of 34,000 bpd brought on-line in 2008. An additional two are under construction (Pearl in Qatar, 140,000 bpd, and Escravos in Nigeria, 33,000 bpd). Reported costs for these facilities are often provided as total project costs, rather than just costs associated with the GTL process. Non-GTL costs for projects such as Shell's Pearl include offshore platforms and gathering lines, which represent a significant portion of the project costs. In contrast, it is assumed that an Alaskan GTL complex would not have significant non-GTL costs because wells, gathering lines, and delivery systems are already in place.

At this time, economies of scale have yet to be realized for GTL; hence, prices are often discussed in terms of $ per billion barrels ($/bbl). Low-end estimates for GTL costs alone begin around $25,000/bbl, and are comparable to costs realized for the Oryx complex. High-end costs are in the range of $100,000/bbl and more, such as those reported for the Pearl complex, which has seen construction delays, and is currently scheduled for operation in 2012. While not specified in media reports, the high-end Pearl costs are suspected to include non-GTL, gas production costs. For the purposes of this analysis of a potential Alaskan GTL project, a mid-cost was estimated as $35,000/bbl and adjusted to Alaskan prices by a multiplier of 1.5 for construction in the Southern Railbelt, yielding $53,000/bbl. For construction in Valdez, a multiplier of 1.8 was used to compensate for the expected additional construction costs associated with the relatively small amount of available flat terrain in this area, yielding $63,000/bbl. Low and high costs were estimated as 38 percent less and 75 percent more. This cost range does not incorporate reasonably likely significant technological advances over the next 10 to 15 years, which may provide capital cost reductions in excess of 25 percent (Carolan et. al., 2002).

The modeled GTL complex was sized similarly to the recently completed Oryx GTL complex in Qatar. While a GTL complex could be constructed at North Slope, avoiding gas pipeline tariffs, it is assumed that the cost of pipeline gas transport to a port (for export), is lower than the cost of trucking liquid products to port.[8] Hence under the mainline to Alberta scenario, the GTL complex is assumed to be located in the Southern Railbelt. Under the mainline to Valdez scenario, it is located in Valdez, because over the life of the project, avoidance of the tariff associated with a spur line provides greater savings than the higher capital costs associated with construction in Valdez.

Transportation diesel fuel prices were forecast along with the Lower 48 natural gas prices developed with NEMS. An Asian premium was added based on the lowest annual premium paid in Japan on before-tax transportation diesel compared to Lower 48 before-tax transportation diesel from 1998 to 2008, as reported on the International Energy Association website. The lowest annual premium during this period was $0.11 per gallon, which is equivalent to $4.62 per barrel. The modeled correlation between diesel product prices and natural gas is 0.82, based on historical relationships.

The price forecast for natural gas feed for the GTL complex was developed as described above (Section 2.2). Table 14, below, summarizes key assumptions and results of the probabilistic NPV analysis of a Greenfield GTL complex.

[8] Trucking is assumed as the transport mode in order to avoid contamination of the GTL fuel with crude oil if the GTL were shipped in the TAPS line.

Table 14. GTL Industrial Analysis: Assumptions and Results

Static Assumptions			
Capacity	38,000 Bpd		
Natural Gas Demand, MMcfd	350		
Annual O&M *(excluding gas)*	$154 million		
Probability Distribution Parameters			
	Low	**Mid**	**High**
South Railbelt Capital, $ millions *(Depreciable cost basis)*	$1,701	$2,744	$4,803
Valdez Capital, $ millions *(Depreciable cost basis)*	$1,990	$3,210	$5,618
Alberta Pipeline, Gas Price, $/Mcf	$5.1	$7.57	$10.46
Valdez Pipeline, Gas Price, $/Mcf	$7.53	$7.71	$7.89
Diesel Fuel, $/bbl	$77	$145	$216
Results: Probability NPV ≥ 0			
Alberta Pipeline		0.52	
Valdez Pipeline		0.41	

Source: SAIC, Inc., 2009.

As shown in Table 14, low, mid, and high estimates were applied for capital costs, gas prices under both pipeline scenarios, and diesel prices on the Asian market. Net present value (NPV) was calculated for the given size the GTL complex, and the cost and price ranges shown. Under the Alberta pipeline project, the NPV exceeded zero 52 percent of the time, indicating a probability of 0.52 that this project will be economically feasible. Under the Valdez pipeline project, the range of forecast gas prices (i.e., the difference between low and high price estimates) is reduced because it is assumed that the GTL complex would be built in Valdez to avoid a spur line tariff and the substantial uncertainty associated with this tariff. Overall, the probability of GTL complex economic feasibility is lower under the Valdez pipeline scenario than the Alberta pipeline scenario (i.e., 0.41, representing a 41 percent chance of feasibility).

6.2.2 Other Industry

6.2.2.1 Refining

The future natural gas demand of the Tesoro refinery is assumed to be similar to the current demand of 11 MMcfd (as discussed above, in Section 2.2). Refineries in other regions of the state are expected to switch to use of natural gas to meet their process and space heating needs under pipeline scenarios that are likely to allow development of a gas distribution system in their local area.

Under both Alberta and Valdez pipeline scenarios, refineries in North Pole (Railbelt North) are expected to represent new demand for natural gas. These refineries, Flint Hills and Petro Star, process crude oil from the North Slope, with rated capacities of 220,000 and 12,000 bpd, respectively. Both facilities currently produce heat for their processing needs from crude. These facilities are considered very likely to switch to natural gas as it becomes available, with estimated demands of 12.3 MMcfd and 0.9 MMcfd for Flint Hills and Petro Star, respectively, as reported by the Interior Issues Council (2008), with Flint Hills demand further confirmed (Cook, 2009). This demand is based on the continuation of production at roughly 25 percent facility capacity. Total dry gas demand from refineries in Region 9 (Railbelt North) was projected as 13.2 MMcfd beginning shortly after commencement of pipeline operations.

Under the Valdez pipeline scenario, the Petro Star refinery in Valdez (Valdez-Cordova) is expected to represent new demand for natural gas. This crude oil refinery has a rated capacity of 48,000 bpd. The refinery provides fuel to a cogeneration unit operated by Copper Valley Electric Association (CVEA), which in turn provides heat for Petro Star's distillation tower and electricity for other refinery needs. Under the Valdez pipeline scenario, natural gas for CVEA is anticipated to be less expensive than fuel from the refinery, so CVEA will convert to using natural gas and so will the refinery. The demand from the Petro Star's Valdez refinery is estimated to be 2.6 MMcfd, based on a simplifying assumption of operations similar to the North Pole refineries.

6.2.2.2 Alyeska Terminal and Pump Stations

Under the Valdez pipeline scenario, additional industrial natural gas demand is likely as Alyeska switches its terminal operations in Valdez to natural gas; although Alyeska will need to conduct an economic analysis to confirm this conversion. Based on information from Alyeska (Robertson, 2009), the estimated demand for the terminal is estimated at approximately 2 MMcfd.

In the event that the mainline to Alberta is constructed, none of the Alyeska operations are expected to convert to dry gas, although the marine terminal in Valdez could convert to propane.

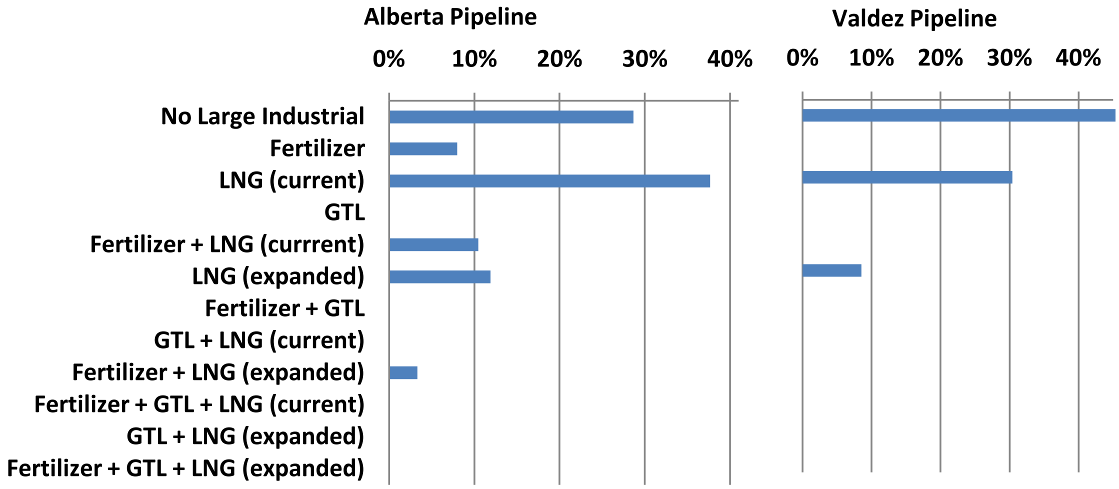
6.2.3 Total Industrial Demand for Natural Gas

Figure 20 shows the chances of large, gas-intensive industrial development based on the probability of economic feasibility (i.e., NPV > 0). For demand projections in this report, it is assumed that Greenfield development will not become operational until after the first several years of pipeline operation. Hence in projecting demand for the first 5 years of pipeline operation, industrial scenarios that include GTL are not considered.

Comparison of the chances of large industrial development for the two pipeline projects suggests that under the Valdez pipeline project, the overall chances of large industrial development (beyond the assumed LNG complex in Valdez) are reduced. This is indicated by the 36 percent chance of "no large industrial" (i.e., top bar) under the Valdez project versus the 14 percent chance of "no large industrial" under the Alberta project.

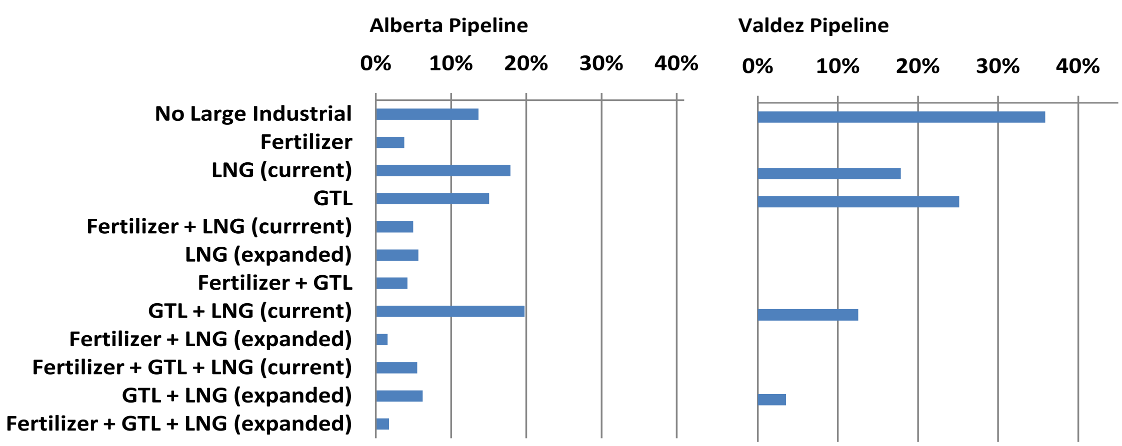
Furthermore, as indicated in Figure 20, the economic feasibility of the assessed fertilizer project (i.e., renovation of the Agrium plant in Nikiski) is relatively unlikely under the Alberta pipeline project, and has virtually no chance of realization under the higher Southern Railbelt gas prices of the Valdez pipeline project. The GTL is the only individual project assessed that has a greater chance of realization under the Valdez pipeline project. This is due to the assumption that under the Valdez pipeline project, GTL would be located in Valdez, thereby avoiding the spur line tariff.

Figure 19. Percent Chance of Development (i.e., NPV > 0) for Assessed Industrial Scenarios, Year 1 to 5



Source: SAIC, Inc., 2009

Figure 20. Percent Chance of Development (i.e., NPV > 0) for Assessed Industrial Scenarios, Year 10 to 15



Source: SAIC, Inc., 2009.

Finally, it should be noted that it is reasonably likely that none of the large gas-intensive industrial projects will be represented in the first open season, simply because these projects require significant investment, and given commencement of pipeline operations in 2019, these investment decisions do not need to be finalized for several more years (with the possible exception of Nikiski LNG terminal refurbishment). Most of the modeled industrial projects are of sufficient size that they could merit a pipeline expansion if and when a positive investment decision is made.

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7 Potential Military Demand for Natural Gas

Military bases in the Northern Railbelt could also potentially increase the demand for natural gas in the future. Doyon Utilities operates the power plant at Fort Wainwright and Fort Greeley. Fort Wainwright uses coal-fired boilers to provide steam for heating to the base, and also to generate electricity. Fort Greeley uses oil to heat the base and to provide standby power to the electricity that is provided by Golden Valley Electric Association. Eielson Air Force Base is also powered by a coal-fired power plant.

It was noted during the stakeholder interview that the military would be interested in converting from their existing coal-fired facilities if an analysis demonstrated that the gas fuel price and the conversion costs would provide a lower cost of energy for the bases. The military would also be interested for environmental reasons, such as reduced carbon emissions.

According to the Interior Issues Council report potential natural gas demand for Eielson Air Force Base and Fort Wainwright is 2,828,448 and 3,013,920 Mcf per year, respectively. This suggests a daily demand of approximately 16 MMcf.

The ENSTAR market study provided an estimate of the potential natural gas demand at Fort Greeley. According to the report, the daily demand would be approximately 0.9 MMcf.

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8 Potential Propane Demand

The proposed gas pipeline from the North Slope to Alberta or Valdez will transport a large quantity of natural gas liquids, including propane. Propane is presently used in most, if not all, Alaska communities. Its primary function at the household level is for cooking, followed by water heating, and, to a lesser extent, space heating.

This section provides information on current consumption of propane and the potential demand if all cooking, heating, and electrical generation needs currently supplied by distillate fuels in that portion of the state not anticipated to be served with natural gas (primarily the Fairbanks area and the ENSTAR service area) converted to propane. It should be noted that the volume of propane available for residential, commercial, power, and industrial consumption in Alaska would be a function of the volume of gas taken off the mainline, or in the case of a propane extraction facility in Cook Inlet, the volume of propane available would be a function of the throughput of the spur line to Southcentral Alaska. This section also describes key elements of a spreadsheet model that compares the cost of propane and distillate fuels in various regions around the state to determine if residents and businesses would convert to propane. The spreadsheet model incorporates a probability analysis to reflect the uncertainty about future prices and costs.

8.1 Current Demand Estimates

In a prior study of propane feasibility, PND (PND, Inc., 2005) estimated that propane demand in Alaska was approximately 15 million gallons per year (approximately 1,000 bpd). About half of this demand was met by production from the Tesoro refinery (500 bpd) and the balance was imported from Canada via barge/rail and truck. Data from the U.S. Energy Information Administration (EIA) for sales or consumption of propane in Alaska is seldom published to avoid disclosure of proprietary information. The last reported sales statistics are for 2005 and 2006, which indicated that approximately 31,000 and 32,000 gallons per day (740 to 760 bpd) were sold in those years. In the mid-1990s, sales were as high as 45,000 gallons per day (Energy Information Administration, 2009). Propane demand has likely increased since the PND estimate due to the higher cost of distillate fuels in comparison to propane, and commencement of operations at the Pogo gold mine which consumes one million gallons of propane each winter (Shaw, 2009).

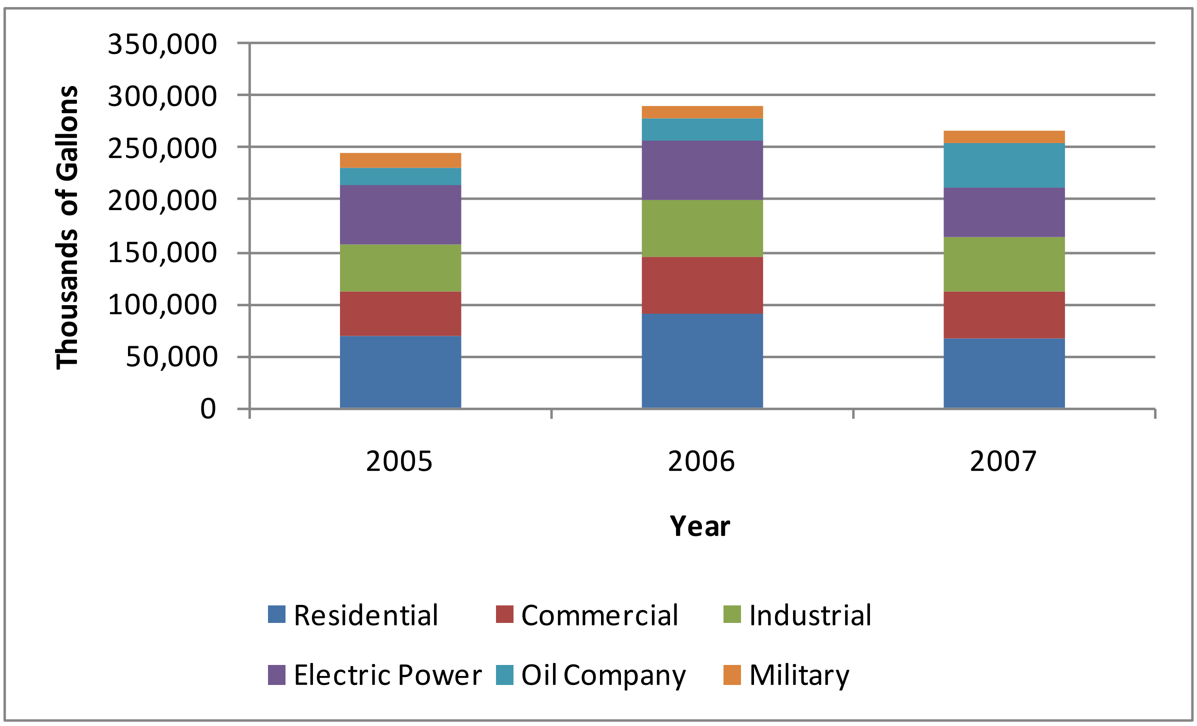
The EIA provides annual estimates of total distillate fuels by end use (Energy Information Administration, 2008). Total distillate consumption has ranged from about 565 million gallons in 2005 to 622 million in 2006 (See Table 15). Propane is not anticipated to replace distillates used in transportation. The potential volumes of distillates used for end uses other than transportation, ranges from about 246 million to 291 million gallons (See Figure 21). A portion of this consumption could be displaced by natural gas when the gas pipeline is operational, and a portion could be displaced by propane that would be extracted from the natural gas stream.

Table 15. Distillate Fuel Oil and Kerosene Sales in Alaska by End Use, 2005-2007 (thousands of gallons)

End Use	Year 2005	Year 2006	Year 2007
Residential	69,253	90,341	66,924
Commercial	42,239	55,447	44,937
Industrial	44,852	53,219	53,605
Electric Power	57,455	56,777	47,477
Oil Company	17,515	21,347	40,742
Military	14,401	13,786	12,390
Subtotal	245,715	290,917	266,075
Transportation	319,069	330,723	335,298
Total	**564,784**	**621,640**	**601,373**

Source: Energy Information Administration, 2008.

Figure 21. Distillate Fuel Oil and Kerosene Sales in Alaska by End Use, 2005-2007



Source: Energy Information Administration, 2008.

8.2 Future Energy Demand

As noted earlier, the Fairbanks area and most of the Cook Inlet region are expected to be served by a piped natural gas distribution system, with Fairbanks served by the main gas pipeline, and Cook Inlet served by a spur line connecting to an expanded ENSTAR distribution network. If the main gas line runs to Valdez, then it is anticipated that the City of Valdez would also be served by a piped natural gas distribution system. The remainder of the state is a potential market for propane extracted from the natural gas stream and trucked or barged to communities. Some communities with sufficient density of development could have piped natural gas distribution networks, but propane transported to the community would be the primary basis for the gas supply.

Future energy demand outside of the Fairbanks and Cook Inlet areas was estimated for residential and commercial, electric power, and industrial sectors. The following paragraphs describe the assumptions and approach used to estimate future energy demand.

8.2.1 Approach

The approach used to estimate the potential demand for propane outside of the areas served by natural gas-based distribution systems includes developing a basic spreadsheet model that estimates potential demand for energy in each region, and compares the projected price of distillate fuels with the anticipated price of propane calculated in the model to evaluate if residents and businesses would convert to using propane. The following subsections provide additional detail on the approach used for the propane-based residential and commercial sector, followed by electric power and industrial sectors.

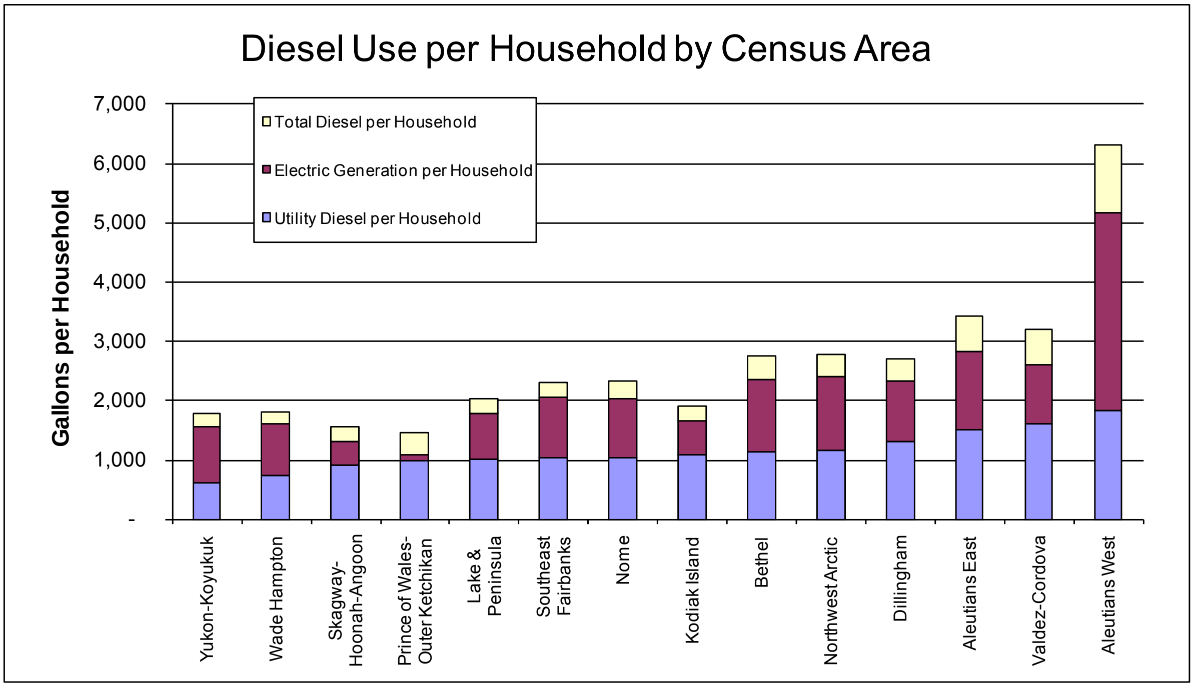
8.2.2 Residential and Commercial Demand

As noted earlier, the primary use of propane currently is for cooking with some used for water heating and a lesser amount for space heating. In contrast, residential and commercial demand for distillate fuel, excluding transportation fuel, is primarily a space heating load with additional consumption for cooking and heating water.

8.2.2.1 Current Energy Demand

ISER conducted a study in 2008 that surveyed fuel use in a number of Alaska communities (Institute of Social and Economic Research, University of Alaska Anchorage, 2008). The results of the survey were then aggregated at the census area level into average fuel use per household for transportation, electric generation, and utility (i.e., heating) fuel (See Figure 22).

Figure 22. Diesel Use per Household by Census Area, 2008



Source: Institute of Social and Economic Research, University of Alaska Anchorage, 2008.

It is anticipated that propane would not displace distillates used as transportation fuels so the estimates for heating and power generation represent the distillate volumes that might be replaced by propane. The estimates for utility diesel (primarily heating fuel) were reviewed and considered to be representative of the demand for heating fuel, given differences in heating degree days, per capita income, and other fuels (e.g., biomass) that could be used for heating among the census areas. Fuel use for community electricity generation was also reviewed and considered to be representative. Industries that generate their own power are modeled separately and included in the industrial demand (See Section 6.2.2). Per household estimates of distillate consumption for each region are presented in Table 16.

Table 16. Estimated Gallons of Distillate Use per Household in 2008

Region	Utility	Electricity	Total
Northwest-Arctic	1,109	1,119	2,228
Yukon – Koyukuk	605	951	1,556
Northern Railbelt	1,033	1,019	2,052
Southeast Fairbanks	1,033	1,019	2,052
Yukon - Kuskokwim	942	1,036	1,977
Southwest	1,270	1,580	2,850
Southern Railbelt	1,353	786	2,139
Valdez-Cordova	1,612	997	2,609
Southeast	947	256	1,202

Source: Calculated by Northern Economics from data contained in ISER, 2008.

Heating fuel consumption has been increasing in Alaska but the higher fuel prices that began in 2007 have resulted in a significant decrease in demand throughout the state, and particularly in those regions with lower household incomes. The crude oil forecast used in this analysis is based on the National Energy System Modeling System used by EIA and assumes increasing prices over time. The crude oil forecast is similar to the April 2009 forecast published by EIA (Energy Information Administration, 2009) with adjustments to account for differences in timing for the main gas pipeline to be in operation and a potential gas pipeline to Valdez. Higher prices have resulted in energy conservation and efforts to increase energy efficiency in appliances and facilities. It is anticipated that conservation and energy efficiency efforts will offset any potential increases associated with higher household incomes in the future so that average household consumption remains near these levels.

Change in the number of households is the other factor used in estimating residential and commercial heating demand; as the number of households in the community changes total consumption in the community is expected to change. As discussed earlier in this report, ISER prepared statewide forecasts of population, households, and employment for this study. The estimated number of households in each region for 2009 and the future years of interest are shown in Table 17.

Table 17. Estimated Number of Households by Region (in Thousands)

	Years		
Region	**2009**	**2019**	**2030**
Northwest-Arctic	6.819	7.64	8.802
Yukon – Koyukuk	2.05	2.264	2.554
Northern Railbelt	36.971	39.906	45.93
Southeast Fairbanks	2.419	2.66	3.12
Yukon – Kuskokwim	6.446	7.21	8.216
Southwest	8.343	8.95	9.675
Southern Railbelt	153.881	176.341	216.358
Valdez-Cordova	3.709	4.128	4.748
Southeast	27.163	30.865	37.446
Total	**247.801**	**279.964**	**336.849**

Source: Institute of Social and Economic Research, 2009.

Specific adjustments are made to the household numbers in the model as necessary to account for community-specific situations. For example, Barrow households were subtracted from the Northwest-Arctic region estimates since Barrow has a natural gas supply from nearby gas fields and would not need propane in any significant quantities. Many households in the Southern Railbelt and Northern Railbelt would also be served by gas and the number of households is reduced to account for this situation.

Multiplying the number of households that might use propane in each region by the heating fuel and electric generation fuel consumption estimates developed by ISER (Table 16) results in the following demand for distillate fuel in each region (See Table 18).

Table 18. Estimated Gallons of Distillate Fuels Required (Thousands of Gallons)

	2019		2030	
Region	Utility	Electricity	Utility	Electricity
Northwest-Arctic	7,032	7,098	8,102	8,177
Yukon – Koyukuk	1,369	2,153	1,545	2,429
Northern Railbelt	11,545	11,389	13,288	13,107
Southeast Fairbanks	2,748	2,711	3,224	3,180
Yukon – Kuskokwim	6,790	7,469	7,737	8,512
Southwest	11,373	14,142	12,295	15,287
Southern Railbelt	11,932	6,933	14,640	8,506
Valdez-Cordova	6,655	4,118	7,654	4,736
Southeast	29,219	7,897	35,449	9,581
Total	**88,664**	**63,910**	**103,932**	**73,516**

Source: Northern Economics, Inc., 2009

8.2.2.2 Potential Propane Demand

Propane has lower energy content per gallon than distillate fuels. A gallon of propane contains approximately 91,000 Btus while distillate fuels can range from approximately 135,000 to 140,000 Btus per gallon with various sources reporting different average values. Kerosene and Diesel No. 1 are at the lower end of the range and Diesel No. 2 is at the higher end of the range. The result of the lower energy content of propane is that additional volumes of propane are required to generate the same amount of energy for heating. Table 19 shows the estimated potential demand for propane in each region based on a conversion rate of 91,000 Btus for propane and 135,000 Btus for distillate fuels. This potential demand assumes that propane would replace all distillate fuels for use by the residential and commercial sectors in each region.

Table 19. Potential Residential and Commercial Demand for Propane (Thousands of Gallons)

Region	Years 1-5	Years 10-15
Northwest-Arctic	10,432	12,019
Yukon – Koyukuk	2,031	2,292
Northern Railbelt	17,128	19,712
Southeast Fairbanks	4,077	4,782
Yukon – Kuskokwim	10,073	11,479
Southwest	16,872	18,058
Southern Railbelt	17,701	21,718
Valdez-Cordova	9,872	11,355
Southeast	43,347	52,590
Total	131,534	154,185

Source: Northern Economics, Inc., 2009.

The future price of distillate fuels in each region is based on a spreadsheet model developed by ISER for the Alaska Energy Authority's alternative energy grant application program. The model, which provides price forecasts for individual communities, was adapted by Northern Economics to provide regional information and using NEMS model runs for crude oil price forecasts that are similar to the EIA April 2009 forecast rather than the 2008 EIA forecast in the ISER model. The resulting average price per gallon for distillate fuels in each region is presented in Table 20.

Table 20. Estimated Distillate Fuel Prices by Region, 2019 and 2030 (Dollars per Gallon)

Region	Year	
	2019	2030
Northwest-Arctic	$4.65	$5.05
Yukon-Koyukuk	$4.78	$5.19
Northern Railbelt	$4.55	$4.95
Southeast Fairbanks	$4.23	$4.62
Yukon-Kuskokwim	$4.83	$5.26
Southwest	$5.37	$5.86
Southern Railbelt	$4.13	$4.46
Valdez-Cordova	$4.43	$4.81
Southeast	$4.90	$5.38

Source: Adapted by Northern Economics from Institute of Social and Economic Research, 2008.

It is anticipated that once the main gas pipeline is operational, natural gas prices in Alaska will be linked to national prices for natural gas. The NEMS model projects future natural gas prices at Henry Hub, which is a major gas pipeline interconnect point in Louisiana. Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange. TransCanada has observed over the years that natural gas prices at a similar hub in Alberta (AECO) are about $0.75 per MMBtu less than natural gas prices at Henry Hub (Lee, 2009). Thus, the wellhead price of natural gas on the North Slope can be estimated by taking the Henry Hub price, subtracting the price differential between Henry Hub and AECO, and then subtracting the estimated mainline tariff of approximately $3.50± per MMBtu for the main gas pipeline from the North Slope to AECO and the gas treatment plant (TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd., 2007). At a hypothetical future price of $7.00 per MMBtu at Henry Hub, the wellhead value in Prudhoe Bay would be $7.50 - $0.75 - $3.50 = $3.25 per MMBtu.

Prices for propane are estimated in a spreadsheet model that is based on prior work to assess the feasibility of propane distribution to coastal communities in Alaska (PND, Inc., 2005). The model was updated to reflect current (2009) prices and also revised to estimate propane prices delivered to communities on major river systems and to communities on the road system. Delivery costs on river systems and truck delivery costs are based on work conducted for the Alaska Department of Transportation & Public Facilities(CH2M-Hill, Inc., 2003), updated with more recent Corps guidance on tow boat and barge costs (U.S. Army Corps of Engineers, Directorate of Civil Works, 2004), and updating the truck and towboat and barge cost information to 2009 dollars using the producer price index for Coastal and Intercoastal Towing Transportation (Bureau of Labor Statistics, 2009). The following bullets summarize the major features of this model.

The price of propane to a community in western Alaska consists of the following cost items:

- Wellhead value of natural gas on the North Slope expressed in energy content (MMBtu)

- Tariff on the main gas line to a spur line to Cook Inlet ($2.00± per Mcf) or Valdez $2.50± per MMBtu)
- Tariff on the spur line to Cook Inlet ($2.25± per MMBtu), if required
- Tariffs at a propane extraction plant, a product pipeline (Cook Inlet only), and a marine terminal (approximately $0.30± per gallon combined)
- Marine shipping costs via tug and barge delivery to representative communities in each region
- Offloading, storage, operations and maintenance, and refurbishment and repair costs of storage facilities in each representative community
- Taxes and distribution costs (if any).

The price of propane on an energy basis (MMBtu) was calculated for each region and compared with the projected price of distillate fuels on an energy basis. Adjustments were made for the combustion characteristics of propane which require about ten percent more fuel when used in a turbine or reciprocating engine (PND, Inc., 2005), and to account for the costs of converting from distillate fuels to propane. If the cost of propane was 90 percent or less of the cost of distillate fuels on an energy equivalent basis then the region was assumed to switch to propane.

Distribution to Southeast Alaska is assumed to be by barge from either Cook Inlet or Valdez. If a pipeline from Haines Junction to Haines was found to be commercially viable, propane distribution from Haines to other communities in Southeast Alaska might provide cost savings over shipping from Cook Inlet or Valdez. However, an off-take point at Haines Junction would be outside of Alaska and it is not evaluated in this report.

8.2.2.3 Probability Analysis

As discussed previously, a probability analysis was conducted to account for the uncertainty about the future of residential and commercial sector demand. Table 21 shows the variables that are incorporated in the probability modeling for propane use in the residential and commercial sector. The mid-point and high and low estimates are also shown. The electric power sector demand for propane uses these same variables. A brief discussion of these variables follows the table.

Table 21. Variables for Residential and Commercial Sector Probability Analysis

	Years 1-5			Years 10-15		
Variables	Mid	Low	High	Mid	Low	High
Crude price (2009$/barrel)	115.88	47.75	191.23	128.19	47.75	212.29
Gas Price at Henry Hub (2009$/MMBtu)	7.04	6.29	7.79	8.50	7.26	9.55
Mainline tariff to AECO (2009$/MMBtu)	2.62	1.96	3.27	2.62	1.96	3.27
Mainline tariff for in-state off-take (2009$/MMBtu)	1.49	1.12	1.87	1.49	1.12	1.87
Spurline tariff (2009$/MMBtu)	1.68	1.75	2.99	1.68	1.75	2.99
Capital cost range (% of initial estimate)	100%	62%	175%	100%	62%	175%
Propane market penetration rate						
Community (% per year convert to propane)	7%	5%	10%	7%	5%	10%
Households (thousands)						
Northwest-Arctic	6.34	6.18	6.50	7.31	7.13	7.49
Yukon-Koyukuk	2.26	2.21	2.32	2.55	2.49	2.62
Northern Railbelt	11.17	10.90	11.46	12.86	12.54	13.19
Southeast Fairbanks	2.66	2.59	2.73	3.12	3.04	3.20
Yukon-Kuskokwim	7.21	7.03	7.39	8.22	8.01	8.42
Southwest	8.95	8.73	9.18	9.68	9.44	9.92
Southern Railbelt	8.82	8.60	9.04	10.82	10.55	11.09
Valdez-Cordova	4.13	4.03	4.23	4.75	4.63	4.87
Southeast	30.87	30.10	31.65	37.45	36.52	38.39

Source: Northern Economics, Inc.

Note: Specific adjustments are made to the household numbers in the model as necessary to account for community-specific situations such as subtracting Barrow households from the Northwest-Arctic region estimates since Barrow has a natural gas supply from nearby gas fields and would not need propane in any significant quantities. Many households in the Southern Railbelt and Northern Railbelt would also be served by gas and the number of households is reduced to account for this situation.

The analysis varies the prices for crude oil and natural gas separately. The mid-point and the range of prices for natural gas are linked to the price of crude oil in NEMS but each commodity is varied independently in the probability analysis. Prices of crude oil and natural gas have historically been correlated on an energy equivalent basis, but recent natural gas prices have been much lower than crude oil prices, and EIA forecasts indicate that the historical relationship is not expected to return. This analysis also assumes that the potential price savings that might accrue with use of North Slope propane are passed on to consumers and not captured by intermediaries that could price North Slope propane just under the price of heating fuel.

The capital costs of the main gas pipeline and the spur line are still unknown and changes in the capital cost would affect the future tariffs and the cost of natural gas to the consumer. In addition, the volume of gas that may be transported by the spur line and the location of the spur line (Parks highway route or the Richardson/Glenn highway) are also unknown so the range of possible tariffs for the spur line is very large.

The capital cost estimates for building propane tank farms are also uncertain since large propane vessels are not fabricated in Alaska and the cost estimates are from Lower 48 vendors. It is anticipated that with a large demand in-state manufacturers would come forward and the capital cost location factor accounts for variations in the cost of manufacturing in Alaska compared to the Lower 48. The mid-point of 1.5 is the same as that estimated by GLE for the propane extraction plants (Gas Liquids Engineering Ltd., 2009).

GLE provided cost estimates for three different sizes of propane extraction facilities (See Appendix D). One facility of about 0.5 MMcfd which a small community (e.g., Tok and the surrounding area) might require, one of about 65 MMcfd, potentially the off-take volumes for the Fairbanks area, and 300 MMcfd which might be near the delivery volumes to the Cook Inlet area. A pro forma analysis of the potential tariffs for each plant indicate that the capital cost for the smallest plant are too large in comparison to the throughput and that it would be less expensive to truck propane from Fairbanks or another location rather than build a very small plant along the pipeline route.

To account for the cost of conversion to new heating appliances, prime movers for electricity generation, and other equipment the model assumes that the price of propane has to be 90 percent or less of the cost of distillate fuels on an energy equivalent basis. However, conversion to community-wide propane use could take some years to implement since a propane tank farm would need to be built and, based on the time span that the State and others have been involved in the current Bulk Fuel Tank Farm program, it is assumed that the rate of conversion will take a number of years. This conversion rate is incorporated in the probability analysis and limits the propane demand in the initial years.

The number of households is also subject to change with resultant affect on the heating and electric power demand. The mid-point is based on the MAP model output (Institute of Social and Economic Research, 2009) and the range is based on a plus or minus 0.25 percent change in the annual rate of growth calculated from the ISER projections.

The regional aggregation (e.g., the Yukon-Koyukuk census area would rank fifth in size behind Montana if it were a state) and the use of one community per region in general results in estimates for the region as if all demand was located at the selected community or communities. However, some communities would be located closer to the origin shipping point than the community used in the model which could make a difference in the cost of propane delivered to the community, and the estimate of potential demand. For example, Galena is used as the destination community for the Yukon-Koyukuk region and transportation costs to Tanana would be less than Galena. Conversely, demand in the Southeast Fairbanks census area assumes year-round truck access but the Taylor Highway is not maintained in the winter which would increase the storage costs for communities that are accessed by that road and potentially reduce demand in that region.

The costs of transportation and storage are important factors in determining the competitiveness of propane versus distillate fuels. A gallon of propane has about two-thirds of the energy content of a gallon of distillate fuels so to obtain the same amount of energy about 50 percent more gallons of propane must be transported to a community or industrial site. In addition, over 50 percent more storage must be built in a community since propane tanks are normally only filled to 80 percent of rated (water gallon) capacity compared to about 90 percent or greater for distillate fuel tanks. Moreover, the costs for propane tanks, since they are pressure vessels, could be about 60 percent higher than bulk fuel tanks in rural Alaska based on the differences in vendor prices in the lower 48 states for 30,000 gallon (water gallon) fuel tanks and propane tanks.

This analysis assumes there are no subsidies or grants for building propane tank farms or converting equipment and appliances to use propane although such grants are routinely provided for bulk fuel tank farms and diesel generating plants. If similar subsidies were available for propane facilities then the estimated propane demand would be larger.

At volumes higher than about 100 million gallons per year of propane additional propane extraction facilities or a straddle plant would be required on the main gas pipeline to Alberta. The additional tariff for this plant is based on capital cost estimates in the NETL report ((National Energy Technology laboratory, 2006) and updated by the producer price index for other pipeline transportation (Bureau of Labor Statistics, 2009) plus operating costs.

8.2.3 Electric Power Demand

The electric power demand described here is for communities that are not served by the six Railbelt utilities. With the exception of the Southeast region where a substantial amount of hydroelectric facilities are in place, most of this electricity demand is met by small utilities which generate local requirements with diesel-electric generators.

8.2.3.1 Potential Propane Demand

The approach to estimate electric generation demand for distillate fuels in communities not served by the six Railbelt utilities is identical to that described earlier for heating demand estimates. The current volume of fuel required for electric generation on a per household basis (Institute of Social and Economic Research, University of Alaska Anchorage, 2008) is assumed to remain constant and is multiplied by the projected number of households in 2019 and 2030 (See Table 17).

The total gallons of diesel fuel are then converted into Btus to establish the total energy demand required for electric generation in 2019 and 2030. Propane has certain combustion characteristics that result in propane providing about 10 percent less power than diesel fuel when used in turbines or reciprocating engines so additional propane will be needed to provide the required electricity output (PND, Inc., 2005) and an adjustment is made for that factor. The vast majority of the households in the Northern and Southern Railbelt regions would be served by natural gas-fired electric generation rather than propane so zero demand is shown for propane in those regions. Much of the electric generation in Southeast is generated by hydroelectric plants and it is anticipated that this generation would continue, if not expand. The potential demand shown in Table 22 would be the total propane requirements if all communities in each region were to switch 100 percent of their diesel generation to propane use.

Table 22. Potential Propane Demand for Electric Generation, 2019 and 2030 (Thousands of Gallons)

Region	Years 1-5	Years 10-15
Northwest-Arctic	13,952	16,074
Yukon – Koyukuk	3,514	3,964
Northern Railbelt	0	0
Southeast Fairbanks	4,423	5,188
Yukon – Kuskokwim	12,187	13,887
Southwest	23,073	24,942
Southern Railbelt	0	0
Valdez-Cordova	6,718	7,727
Southeast	12,884	15,631
Total	76,752	87,414

Source: Northern Economics, 2009.

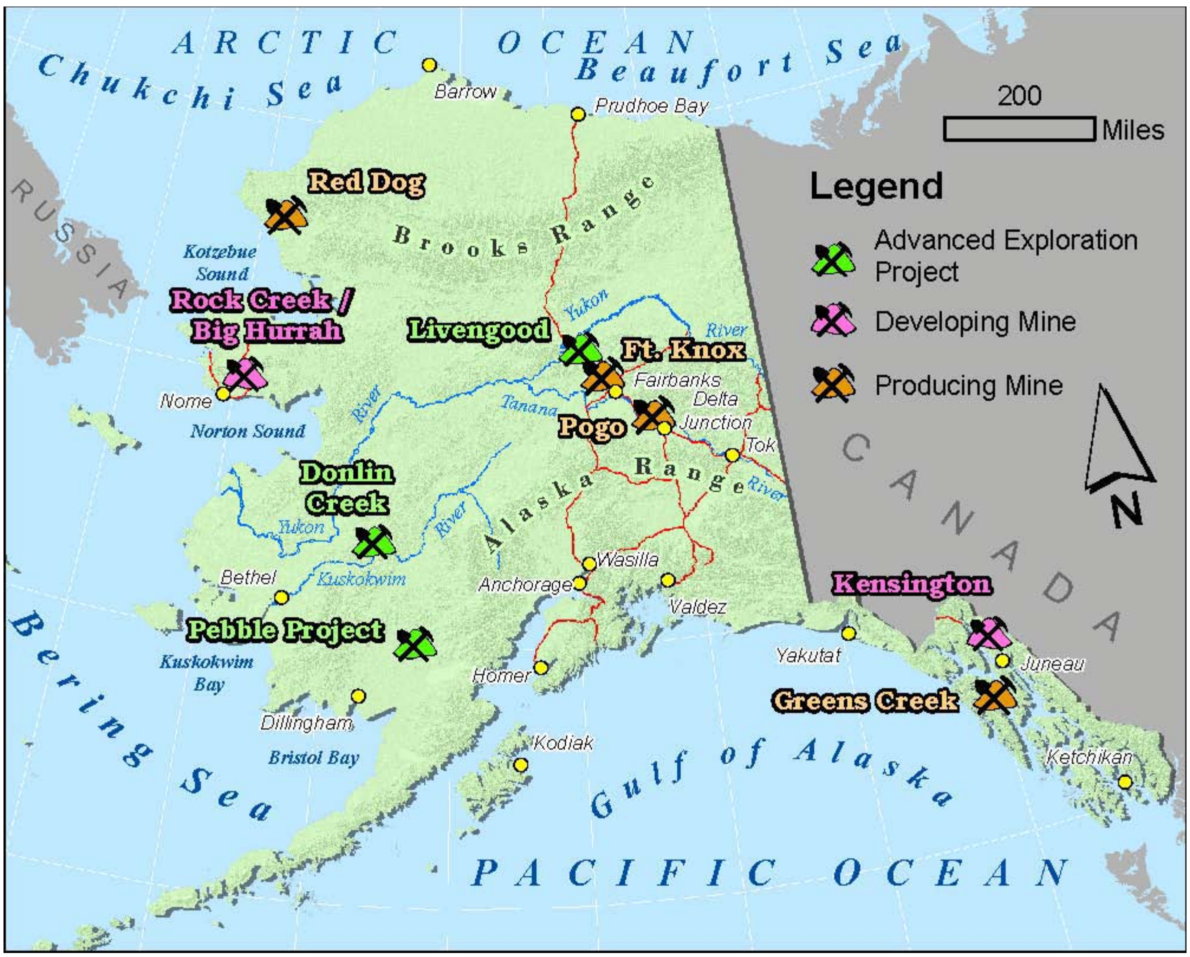
8.2.4 Industrial Demand

Demand by other, non-gas intensive industries is primarily for process and space heating, and for self-generation of electricity. The industrial demand estimated in this analysis incorporates statewide demand by the mining industry and the seafood processing industry, and potential propane demand by Alyeska Pipeline Service Company for pump stations and marine terminal operations.

8.2.4.1 Mining Industry

The mining industry demand reflects existing and anticipated demand at the major mines and exploration projects circled in Figure 23.

Figure 23. Existing and Potential Major Metal Mines in Alaska



Source: Alaska Map Company, 2009.

The Fort Knox mine and the Pogo mine are both served by Golden Valley Electric (GVEA) and it is not anticipated that they would generate their own power if natural gas became available since GVEA's cost of electricity would also decrease with the availability of natural gas. According to Shaw, the Pogo mine currently uses about one million gallons of propane each winter and this need would be expected to be met with propane extracted from the gas pipeline stream since it would be less expensive than propane transported from the Tesoro refinery on the Kenai Peninsula or imported from Canada.

The potential Livengood gold mine is expected to require 20 to 25 megawatts of power with peak demand occurring in the 2016 to 2018 period (Pontius, 2009). GVEA could potentially extend their transmission lines north to Livengood but since the potential demand from the Livengood project is not included in the Railbelt power demand estimates that were generated in 2008 (See Section 5 for additional detail), it is assumed that the Livengood project would commence operations with dual fuel generating systems and switch to propane or natural gas depending on the availability of each fuel. Future Livengood demand is captured in natural gas estimates.

Energy demand for the Red Dog, Greens Creek, and the Kensington Mine are held constant at the levels provided by Shaw (2009). Although one or more of these mines may close during the time period of this analysis it is anticipated that other, yet-to-be identified mines will open, or additional deposits will be found in the vicinity of the mines to enable them to continue operation.

The Donlin Creek and Pebble projects are advanced exploration projects. In developing assumptions for ISER's MAP model it was anticipated that the Donlin Creek mine would be online prior to the main pipeline and spur line being completed, and that the Pebble project would come online after the main pipeline and spur line are completed although the scale of the Pebble project and the resultant energy demand is uncertain.

8.2.4.2 Seafood Industry

The seafood industry analysis estimates the demand to meet process heat, space heat, and power generation by certain shore-based seafood processing plants. The Intent to Operate database maintained by the Alaska Department of Fish & Game (Alaska Department of Fish & Game, 2009) was the basis for identifying shore-based seafood processors throughout the state. The seafood processors were then placed into three categories to aid in estimating fuel consumption. The largest category (Industrial Scale) were identified by reviewing air quality permit databases to determine which seafood processors had significant power generation or other equipment that resulted in the need for an air quality permit (Alaska Department of Environmental Conservation, 2009). Seafood processors requiring such permits are very large processors operating year-round and processing significant volumes of product. A number of processors operating in Unalaska as well as other plants in communities such as Akutan and King Cove require such permits and had the highest average demand for distillate fuels by plant.

The second category (Large Scale) consisted of plants that required permits but did not operate year round, or those that operate year round and generate their own power but do not require air quality permits. This categorization was based on a review of the plants by Northern Economics staff with significant experience in the seafood industry. A similar professional review was conducted to estimate the number of small plants (Small Scale) operating seasonally that generate their own power but have emissions lower than permit thresholds, and those that operate year-round but obtain power from the local community and only require distillate for space heat in the winter and process heat when operating. No growth in seafood energy demand is projected for the future.

8.2.4.3 Total Distillate Demand for Mining and Seafood Industries

Table 23 shows the estimated distillate demand for the major metal mines and the seafood processing sector in Alaska for the years of interest. In the event that the mainline to Alberta is constructed, the crude oil marine terminal in Valdez could convert to propane. Demand at the Alyeska marine terminal is presented in the mining column in the Valdez-Cordova region.

Table 23. Estimated Distillate Demand by Mining and Seafood Processing Sectors by Region (Thousands of Gallons)

Region	Years 1-5			Years 10-15		
	Mining/ Alyeska	Seafood	Total	Mining/ Alyeska	Seafood	Total
Northwest-Arctic	16,141	100	16,241	16,141	100	16,241
Yukon – Koyukuk	0	0	0	0	0	0
Northern Railbelt	0	0	0	0	0	0
Southeast Fairbanks	674	0	674	674	0	674
Yukon - Kuskokwim	68,204	500	68,704	68,204	500	68,704
Southwest	68,560	10,700	79,260	68,560	10,700	79,260
Southern Railbelt	4,485	700	5,185	99,819	700	100,519
Valdez-Cordova	8,148	1,100	9,248	8,148	1,100	9,248
Southeast	24,136	2,800	26,936	24,136	2,800	26,936
Total	205,147	15,900	221,047	300,481	15,900	310,582

Source: Northern Economics, Inc., 2009.

8.2.4.4 Potential Propane Demand

The potential demand for propane (i.e., assuming all potential industrial consumers switch to propane) is estimated in a manner similar to that described for the electric power sector with adjustments for the combustion characteristics of propane (See Table 24).

Table 24. Potential Industrial Propane Demand (Thousands of Gallons)

Region	Years 1-5			Years 10-15		
	Mining/ Aleyska	Seafood	Total	Mining/ Alyeska	Seafood	Total
Northwest-Arctic	23,945	148	24,093	23,945	148	24,093
Yukon - Koyukuk	0	0	0	0	0	0
Northern Railbelt	0	0	0	0	0	0
Southeast Fairbanks	1,000	0	1,000	1,000	0	1,000
Yukon - Kuskokwim	101,182	742	101,924	101,182	742	101,924
Southwest	101,710	15,874	117,584	101,710	15,874	117,874
Southern Railbelt	6,654	1,038	7,692	148,083	1,038	149,121
Valdez-Cordova	10,456	1,632	12,088	10,456	1,632	12,088
Southeast	35,806	4,154	39,960	35,806	4,154	39,960
Total	280,751	23,588	304,339	422,180	23,588	445,768

Source: Northern Economics, Inc.

The difference in potential propane demand between the initial and later years is the proposed Pebble mine. This demand could possibly be met with gas-fired electrical generation in the Southern Railbelt with transmission lines to the mine site but this situation was not modeled in the 2008 REGA study so it is assumed that propane would be used so that this potential demand is included.

8.2.4.5 Probability Analysis

To estimate industrial demand for propane, two additional variables were added to the list of probability variables described for the propane residential and commercial sector. These variables are shown in Table 25.

Table 25. Probability Analysis Variables for Industrial Demand

	Years 1-5			Years 10-15		
Variables	Mid	Low	High	Mid	Low	High
Propane market penetration rate						
Industrial (% per year convert to propane)	20%	10%	25%			
Pebble mine potential load (MW)				200	100	250

Source: Northern Economics, Inc.

The industrial sector is anticipated to be more responsive to potential cost savings than the residential and commercial or the electric power sector in rural Alaska. The market penetration rate reflects that assumption with a mid-point of 20 percent per year (full conversion in five years), and a range from 10 percent to 25 percent. No values are shown for the later years since even the low range would result in 100 percent conversion by the tenth year.

The proposed Pebble mine could result in a significant demand for energy but it is assumed that the demand would occur after the main gas pipeline and the spur line are built. This assumption is consistent with ISER MAP model assumptions. The project is very early in the planning stage and estimates of power or energy demand are uncertain (Shaw, 2009). The potential power demand from Pebble is not modeled in the Alaska Railbelt Electrical Grid Authority Study done for the Alaska Energy Authority in 2008 (Black & Veatch, 2008) although there have been discussions between HEA and the Pebble mine sponsors. To ensure that this potential demand is included in the analysis it is assumed that propane would be used to generate power for the mine.

Information available for power demand at the Pebble mine suggests that the power load could be more than 200 MW (Shaw, 2009) but there is a limited amount of information on which to base the estimate at this stage in the project development. A mid-point of 200 MW is used with a range from 100 to 250 MW.

Table B-2 in Appendix B summarizes the maximum potential propane demand for residential and commercial, electric power, and industry in years 1-5 if propane were less expensive than distillate fuels in all regions. The following section provides propane demand estimates that account for the fact that propane may be more costly than distillate fuels in some regions due to the additional cost to transport and store larger volumes of propane.

8.3 Propane Demand Estimates

The following material provides propane demand estimates for the residential and commercial sector, the electric power sector, and the industrial sector, for the Alberta route and the Valdez route.

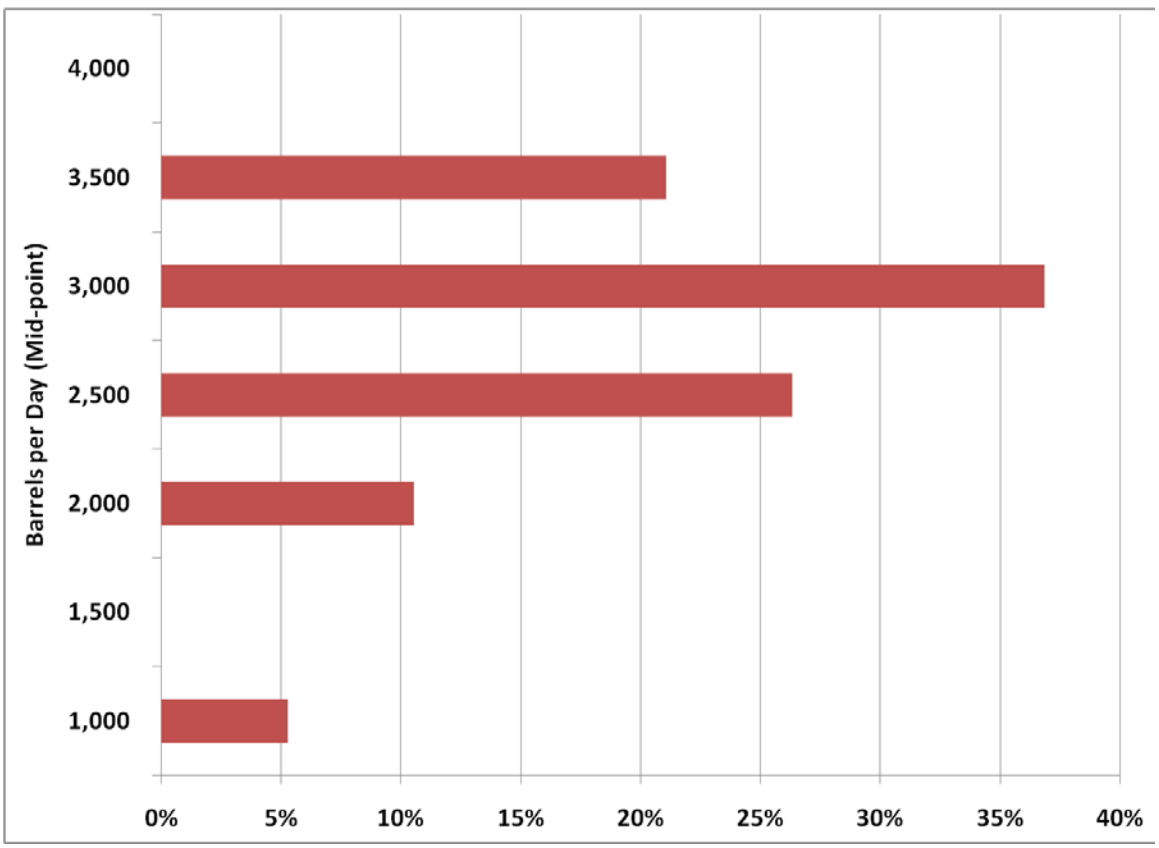
The results presented here anticipate that propane extraction facilities would be built in the Fairbanks area and in either Cook Inlet or Valdez, depending on the ultimate route. The capital cost for small propane extraction plants is very large compared to the throughput and a comparison of the potential tariff of such a plant with trucking costs indicate that it would be less expensive to truck propane from Fairbanks to small communities on the road system.

A propane extraction facility is proposed to be built at Prudhoe Bay with the propane sold into the Fairbanks area. Such a facility could facilitate an earlier conversion to propane in Fairbanks and communities along the road system and increase the demand in the earlier years of the pipeline project. The Prudhoe Bay facility could have lower transportation costs to parts of western and Arctic Alaska which could result in additional propane demand in those areas.

A competing project to provide LNG to Fairbanks has also been proposed. This LNG project would not have the same effect on propane conversion and since there is substantial uncertainty regarding which project might move forward we have not modeled future demand with a North Slope propane extraction facility.

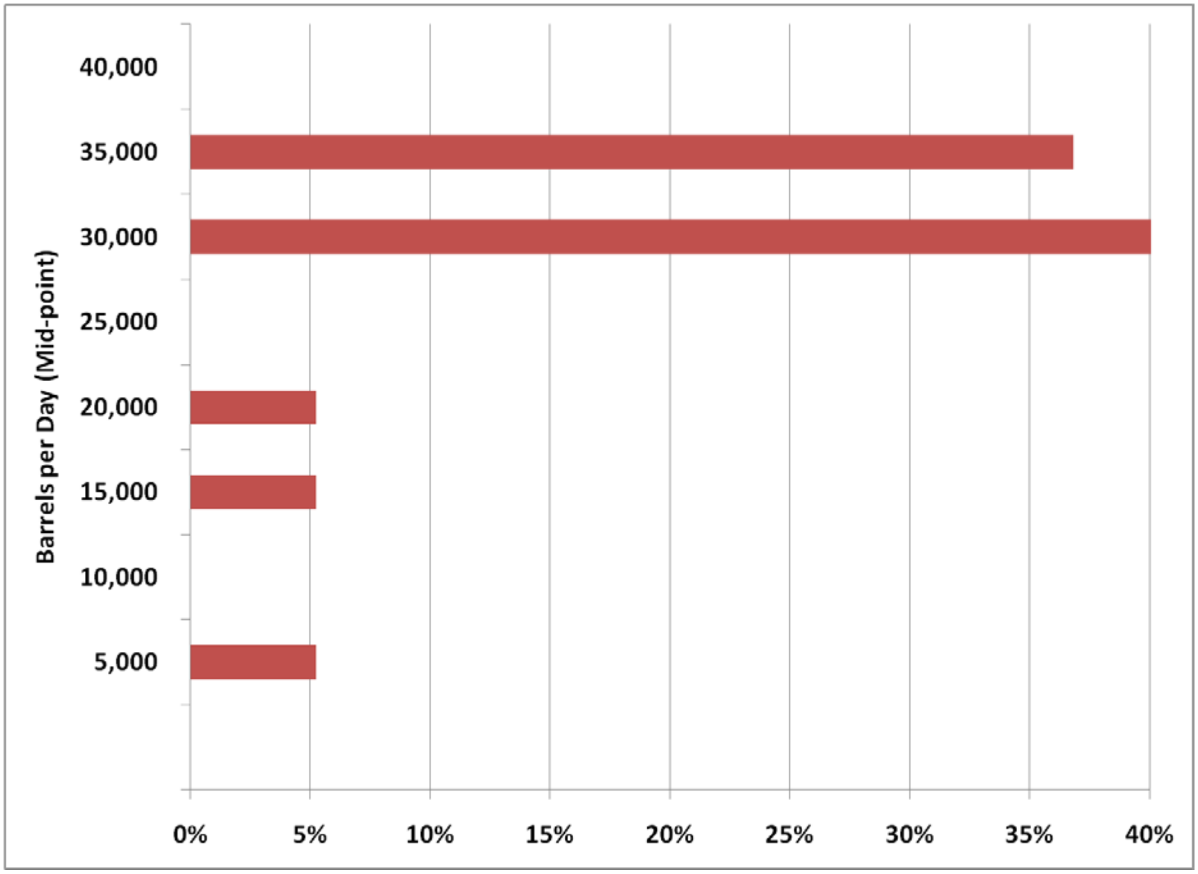
Figure 24 and Figure 25 show the percent probability that demand will fall within one of the demand categories shown on the vertical axis. For example, Figure 24 shows that there is a 37 percent chance that the actual demand will fall within 2,751 to 3,250 barrels of propane per day, and a 26 percent chance that demand will be within 2,251 to 2,750 bpd. In Years 10 to 15 the probability model indicates that there is a 40 percent chance that demand will fall within 27,501 to 32,500 bpd.

Figure 24. Chances of Propane Demand, Alberta Route, Years 1-5



Source: Northern Economics, Inc.

Figure 25. Chances of Propane Demand, Alberta Route, Years 10-15

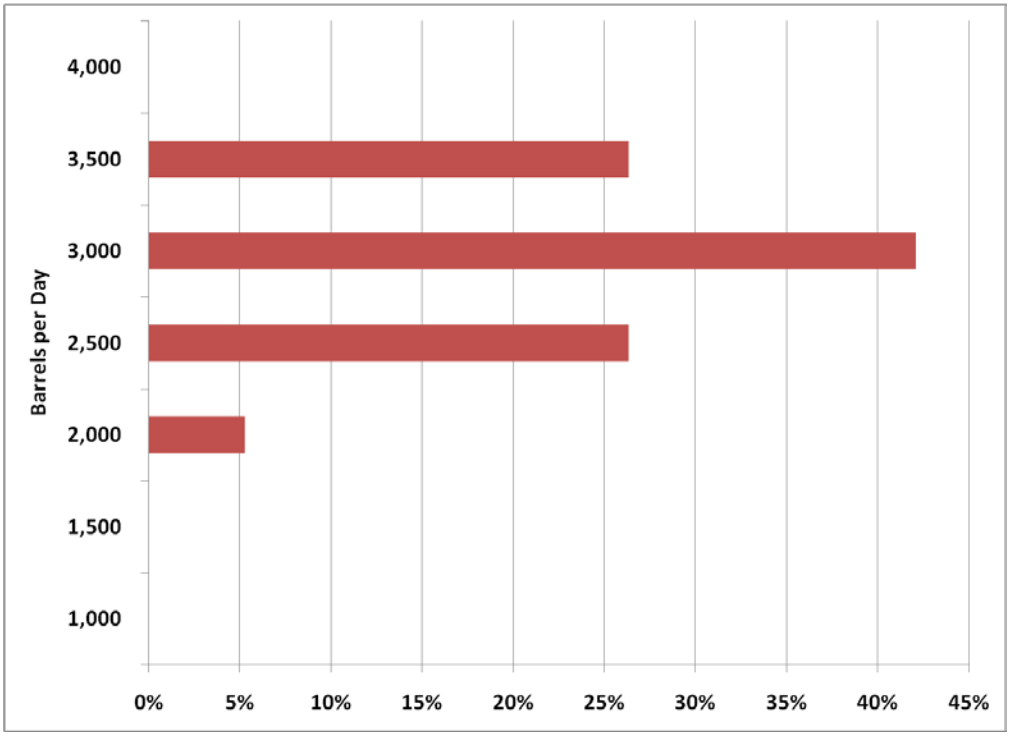


Source: Northern Economics, Inc.

The demand estimates presented in Figure 26 are similar to those shown earlier for the Alberta route, although the range is much narrower. The percent of total demand in Figure 27 vary from the Alberta route in that the range is much narrower and there is a higher probability of demand being greater than 22,500 bpd.

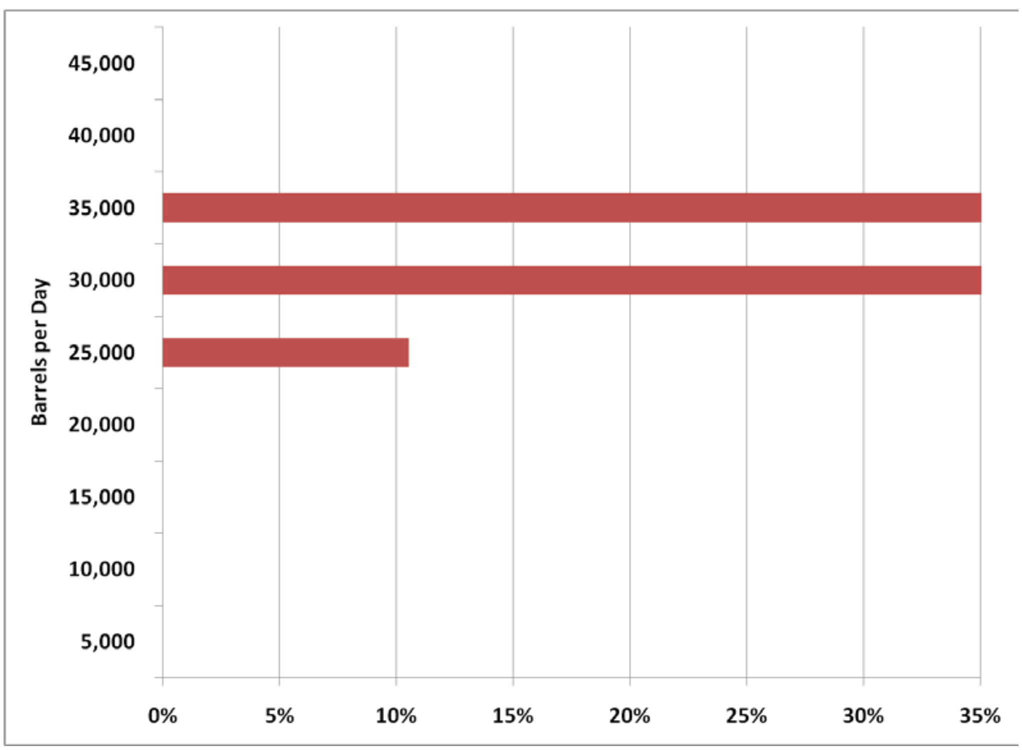
The propane composition of the North Slope gas could range from 1.7 to 3.6 percent per volume. A pipeline with 4.5Bcf per day of North Slope gas would be transporting about 21,000 to 47,000 bpd so the propane demand in years 1-5 could readily be met with the anticipated propane volumes. Demand in years 10-15 would exceed the propane volumes if the lean gas composition (1.7 percent) occurs but demand would be met with the rich gas composition. Much of the demand in the later years arises with potential demand from large mines that begin operations. Such operations may not have access to the volumes of propane they might desire and as a result would need to use distillate fuels.

Figure 26. Chances of Propane Demand, Valdez Route, Years 1-5



Source: Northern Economics, Inc.

Figure 27. Chances of Propane Demand, Valdez Route, Years 10-15



Source: Northern Economics, Inc., 2009.

Table 26 shows the projected demand generated by the probability analysis of demand for propane throughout the State of Alaska. The table results represent the mean (average) estimate for the analysis that developed the probability estimates presented in Figure 24 and Figure 25. The estimates show the growth in demand over time as people and firms convert to propane over time or as new industrial users emerge in the future. In the Year 1 to 5 timeframe for the Alberta Route, expected propane demand could be about 2,700 bpd with a range of about 500 bpd to 3,750 bpd (Figure 24). In the Year 10 to 15 timeframe expected propane demand is about 28,400 bpd with a range of about 5,000 to 37,000 bpd (Figure 25).

Table 26. Projected Annual Average Daily Propane Demand by Sector, in Two Future Time Frames for the Alberta Route (in Barrels per day)

Sector	Year 1 to 5 of Pipeline Operations	Year 10 to 15 of Pipeline Operations
Residential & Commercial	477	6,133
Electric Power	337	4,248
Industrial	2,484	22,326
Total	3,298	32,707

Source: Northern Economics, Inc.

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9 Cook Inlet Supply

The Alaska Department of Natural Resources, Division of Oil and Gas (DOG) recently issued a report that evaluated the remaining Cook Inlet natural gas reserves (Hartz, J.D., et al, 2009). As noted in the report, the issue of "whether the existing system of natural gas production and delivery in Cook Inlet can continue to meet the energy demands of south-central Alaska" depends on two separate sets of information. The first includes the geologic and engineering estimates of the gas remaining to be recovered from Cook Inlet fields, and the steps to access the gas. The second set deals with the complex commercial and infrastructure issues that affect the provision of gas to the end user. The DOG report only addresses the geologic and engineering issues regarding natural gas resources and reserves.

Table 27 presents the DOG estimates for natural gas volumes in Cook Inlet. The more conservative estimates are based on engineering analyses using decline curve and material balance techniques. According to DOG, the geologic analysis for the four major fields in Cook Inlet is strong enough to classify these volumes as reserves that have the potential, if developed, to meet the local demand well into and possibly beyond the next decade. Finally, there are potential exploration targets throughout the basin that could provide additional gas resources though there is less certainty for this estimate compared to the gas reserves estimate.

Table 27. Remaining Cook Inlet Natural Gas Volumes by Type of Reserves and Resources

Location/Type of Reserve	Derivation of Estimate	Volume
All Fields		**(Bcf)**
Proved, developed, producing	Decline Curve Analysis (DCA)	863
Probable	Material Balance (MB)-DCA (1,142-863)	279
Four Fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River)		
High-confidence pay intervals	Geologic PAY (GP)-MB for 4 fields (1,213-860)	353
Lower-confidence pay intervals	GP+50%-risked Potential Pay-GP (1,856-1,213)	643
Total Estimated Reserves		**2,138**
All Fields		
Higher risk contingent resources	Exploration Leads, Basin-wide	300
Total Estimated Reserves and Resources		**2,438**

Source: Values shown in the table are from, Hartz, J.D., et al, 2009. Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves. Alaska Department of Natural Resources.

DOG assumes that "either a significant amount of gas is found by explorers to meet industrial use, or that export of gas out of the basin will stop at the end of the current license period" (2011) for the LNG plant. DOG further assumes that no new demand will occur until reserves are developed to satisfy the market, which requires that sufficient risk-capital be available to explore and develop the higher risk contingent and prospective gas resources.

Figure 28 is a schematic production forecast from the DOG report that shows the incremental reserves identified by the various methods used in their analysis.

Figure 28. Schematic Cook Inlet Production Forecast,

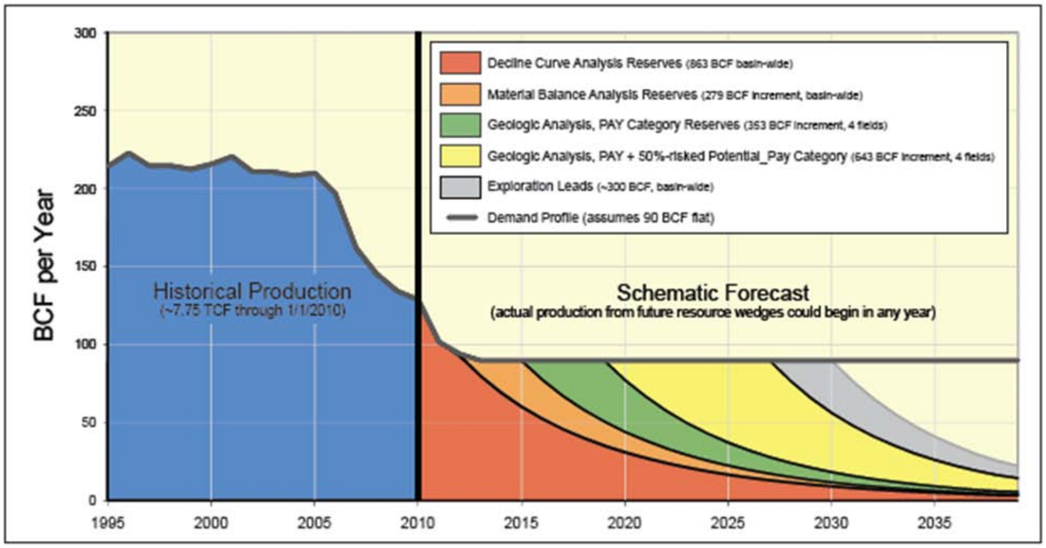

Figure 14. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses discussed in text. This schematic diagram assumes that near-term production will come from gas volumes documented by the most conservative estimation techniques. Successive wedges are introduced with progressively lower certainty regarding commerciality, volume, and timing of first production. Production from future resource wedges could begin in any year, resulting in a more complex forecast, and extending the production lifespan of previous wedges. On the other hand, we are unable to predict the commercial thresholds at which volumes from future wedges become economic to recover. Wedges show gas volume increments from basin-wide decline curve analyses (red), basin-wide material balance analyses (orange), deterministic geologic mapping of PAY (green), and 50 percent-risked Potential_Pay (yellow) in four large gas fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands). The last wedge (gray) is a more speculative estimate of aggregated gas volumes that may be recoverable from the exploration leads discussed in text. See text for additional discussion.

Source: Hartz, J.D., et al, 2009. Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves. Alaska Department of Natural Resources.

The DOG report states that "infill drilling, perforating undeveloped sands, and targeting marginal reservoirs are effective ways to add reserves to replace production." However, these costs will need to be absorbed into a market that requires relatively small volumes which will likely place upward pressure on gas prices.

As noted earlier in Section 2, Cook Inlet produces enough gas to meet annual average demand. However, supplying the required volumes during spikes in demand on very cold days in the winter is challenging for the current system. This indicates that it is difficult for producers to justify the investment to meet short-duration peak deliverability requirements when such projects must compete with other projects on a global basis. Wells are being drilled and storage facilities are being developed which indicates that investment is being made to address the issue but projects to address deliverability will continue to be marginal investments in many instances.

After the proposed spur line to Southcentral Alaska is completed, natural gas prices from both Cook Inlet and the North Slope will begin to converge. Local utilities, as expressed in the Railbelt Integrated Resource Plan (RIRP) (Black & Veatch, 2009), have indicated a desire to reduce their dependence on natural gas with increased demand side management and energy efficiency, increased use of renewable energy sources, and expanded transmission systems. However, even with such diversification and new facilities, natural gas remains a major energy source for the Railbelt, even 50 years into the future. Given this long time frame, utilities would seek to diversify their supplies of natural gas and would consider gas from the North Slope, coal bed methane, landfill gas, underground coal gasification, and other sources. The utilities have indicated that Cook Inlet sources would remain as a very large percentage of their natural gas supplies even if North Slope gas is less expensive.

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10 Integration

This section integrates the modeling results of the probability analyses for all the components of in-state natural gas demand. Sections 4, 5, and 6 discussed the preliminary probability analyses completed for the residential and commercial sector, electric power sector, and the industrial sector, respectively. Military demand (as discussed in Section 7) and the potential demand from the yet-to-be developed gold mine at Livengood in the Yukon-Koyukuk region (as noted in Section 8.2.4.1), were combined with Industrial demand. The outputs from these sector models were then integrated into a combined demand model to allow a simultaneous probability analysis of all the sectors using the variables specific to each probability model[9]. Appendix B provides a summary of the estimated demand ranges by sector for both the Alberta and the Valdez routes.

The first few sub-sections below discuss the demand scenarios for the Alberta and the Valdez projects, demand uncertainty, and a summary of the current industry scenario. Finally, the last section, provides a discussion of net North Slope gas demand.

10.1 Demand Scenarios

Historically, Alaskan demand for natural gas has been greater for gas-intensive industries than for all other sectors combined. As for the future, it is anticipated that the total in-state demand for natural gas would also be largely driven by the volume of natural gas requirements of future Alaska gas-intensive industries. There is great uncertainty, however, as to what industrial prospects will come to pass as North Slope gas becomes accessible through the gas pipeline.

The Industrial Sector analysis in Section 6 discussed several possible future demand scenarios. Three of these have been selected to define demand scenarios categorized as “no industry”, “current industry”, and “growth industry”. Recognizing that no in-state gas-intensive industrial load is very certain, the No Industry case represents in-state demand without a gas-intensive industrial load. The Current Industry case represents a continuation of current trends, with a facility representative of the demand required by the Nikiski LNG terminal operating at full capacity. Finally, the Growth Industry case represents a scenario in which a facility with a demand similar to double the capacity of the existing LNG facility is built, but no greenfield projects will be built in years 1 to 5. Greenfield (or new) industrial projects are not assumed to be built at the same time as the pipeline because the joint demand for labor and materials could significantly increase the capital costs for a new facility, causing it to be uneconomic. Furthermore, unless owners of the greenfield industrial projects are to secure gas supply and commit to pipeline capacity in the early open seasons, it is unlikely that they would have sufficient gas to support the greenfield projects in the initial years of pipeline operation. In years 10 to 15, greenfield projects with reasonably likely economic feasibility are included under the Growth Industry case.

Table 28 and Table 29 summarize the total in-state demand for the three scenarios for both the Alberta Project and the Valdez Project. The tables also show the percent chance that each case will occur. The “no industry” case is more likely in the first years of pipeline operation than in later years.

Under the Alberta project, the “current industry” case is the most likely of the assessed scenarios. A summary of the current industry case for the Alberta Project is discussed in more detail in Section 10.3.

[9] In this situation, each model was subject to the same random number generation and the outputs would be consistent across all of the models. Simulations were run with 10,000 iterations and results have very little differences between subsequent runs (e.g., variances of less than 2 percent of the mean).

Not counting demand from a new Valdez LNG facility, the Valdez Project is estimated to have a higher gas demand than the Alberta Project for the three demand scenarios. This is due to the additional industrial demands in the Valdez area with the availability of natural gas. For the first five years of pipeline operations, the projected demand for the No Industry case, Current Industry case, and Growth Industry case, are 270, 500, and 750 MMcfd respectively; and the percent chance of these scenarios happening are 61 percent, 30 percent, and 9 percent respectively.

Table 28. Total In-State Natural Gas Demand Estimates for Three Scenarios, Alberta Project (MMcfd)

	Year 1 to 5 of Pipeline Operation			Year 10 to 15 of Pipeline Operation		
Demand Scenarios	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level
No Industry	260	29	71	290	14	86
Current Industry	490	38	26	520	18	65
Growth Industry	740	12	3	1,120	6	2

Source: Northern Economics, Inc. and SAIC, Inc., 2009.
Note: MMcfd is million cubic feet per day.

Table 29. Total In-State Natural Gas Demand Estimates for Three Scenarios, Valdez Project (MMcfd)

	Year 1 to 5 of Pipeline Operation			Year 10 to 15 of Pipeline Operation		
Demand Scenarios	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level	Demand	% Chance of this scenario	% Chance Demand will Exceed this Level
No Industry	270	61%	39%	300	36%	64%
Current Industry	500	30%	9%	530	18%	46%
Growth Industry	750	9%	<1%	1,130	4%	5%

Source: Northern Economics, Inc. and SAIC, Inc., 2009.
Note: MMcfd is million cubic feet per day.

10.2 Demand Uncertainty

The demand forecast is best expressed as a range due to uncertainty in the actual future demand. Furthermore, the demand forecast for each sector (residential/commercial, power, and industrial) has a different level of uncertainty. The amount of uncertainty is greatest for large industrial demand because as noted earlier, there is no certain gas-intensive industry in Alaska after 2011, when the Nikiski LNG terminal export license expires. Furthermore, a single large industrial project can have a demand that exceeds all the other sectors' in-state demand combined.

Figure 29, Figure 30, Figure 31, and Figure 32 show the range of likely in-state demand for natural gas by sector in the two future timeframes for the Alberta and the Valdez pipeline project, respectively. In these figures, certain demand is defined as demand that has at least a 90 percent chance of realization. Uncertain demand is potential demand that has a lower chance of realization. In Year 1 to 5, for the Alberta Project, 17 percent of the potential demand from the residential/commercial sector is uncertain, and roughly 30 percent of the potential demand from the power sector is uncertain. In contrast, 95 percent of industrial demand (i.e., all the gas-intensive industrial demand) is categorized as uncertain.

Figure 29. Projected Annual Average Daily Demand by Sector, Year 1 to5, Alberta Project

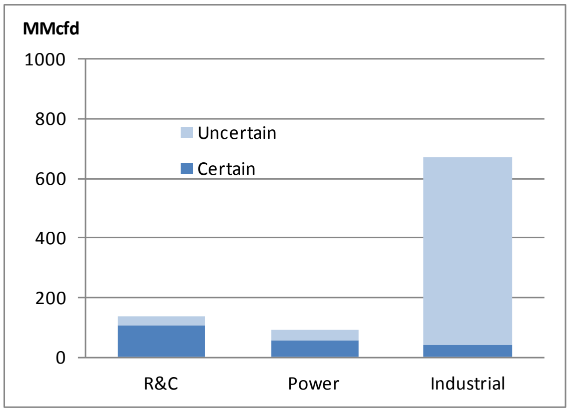
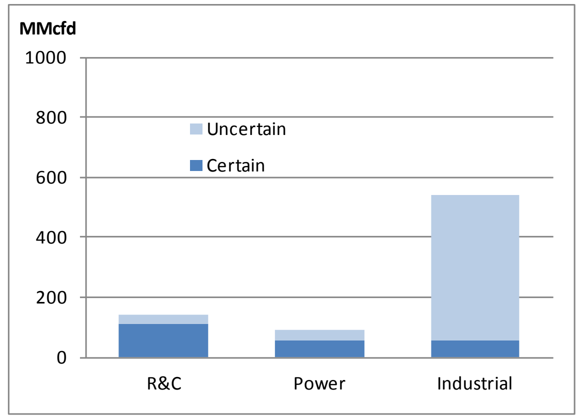


Figure 30. Projected Annual Average Daily Demand by Sector, Year 1 to5, Valdez Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

Figure 31. Projected Annual Average Daily Demand by Sector, Year 10 to15, Alberta Project

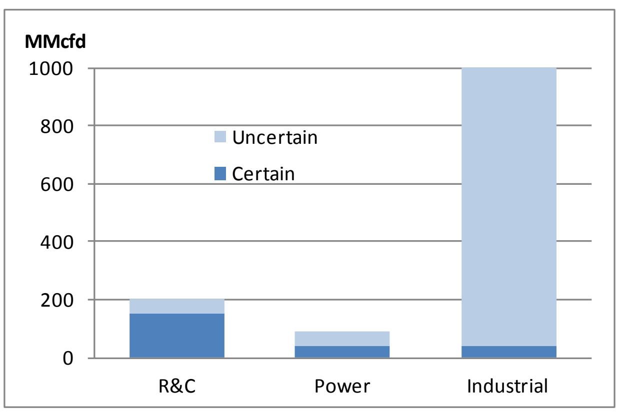
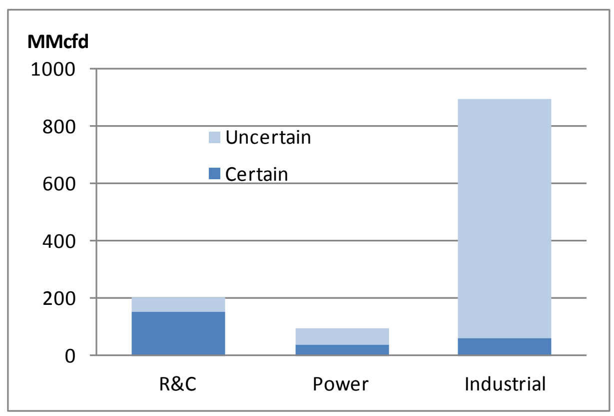


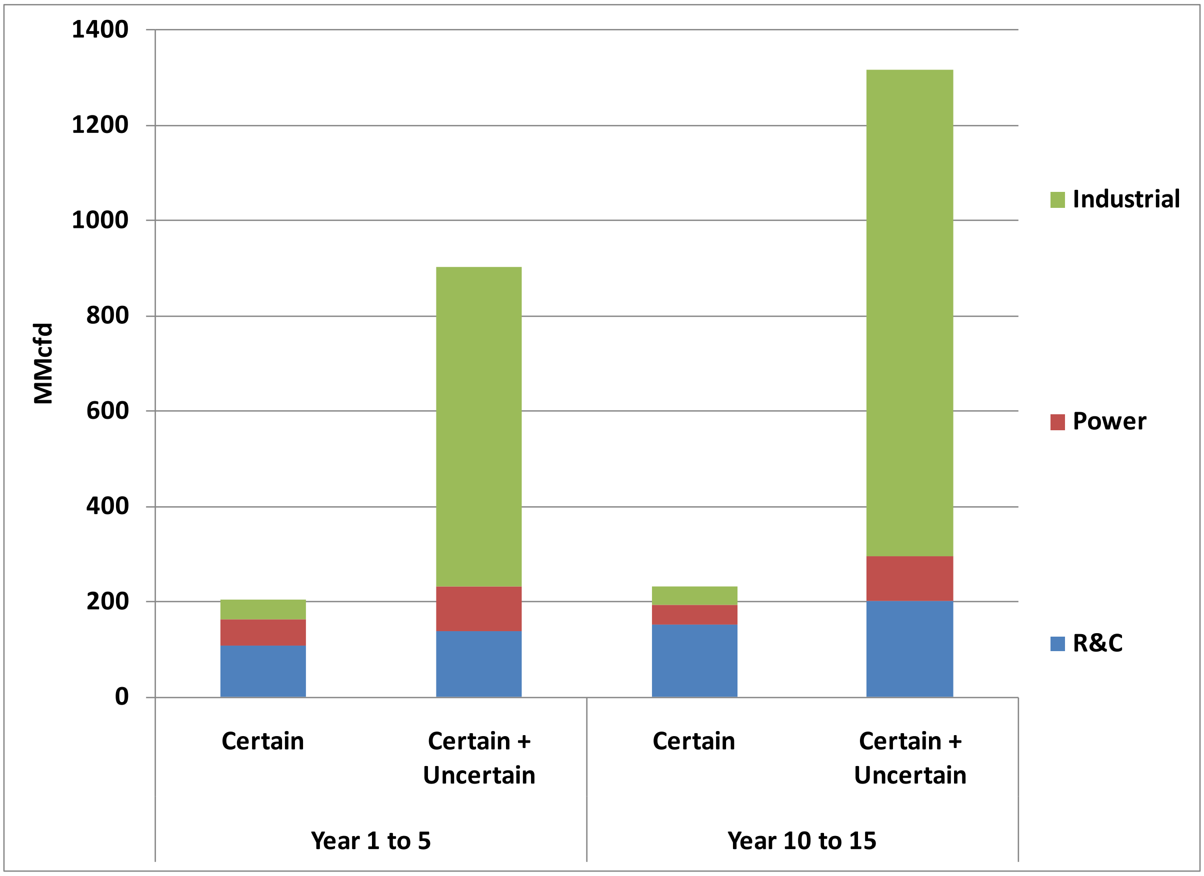
Figure 32. Projected Annual Average Daily Demand by Sector, Year 10 to15, Valdez Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

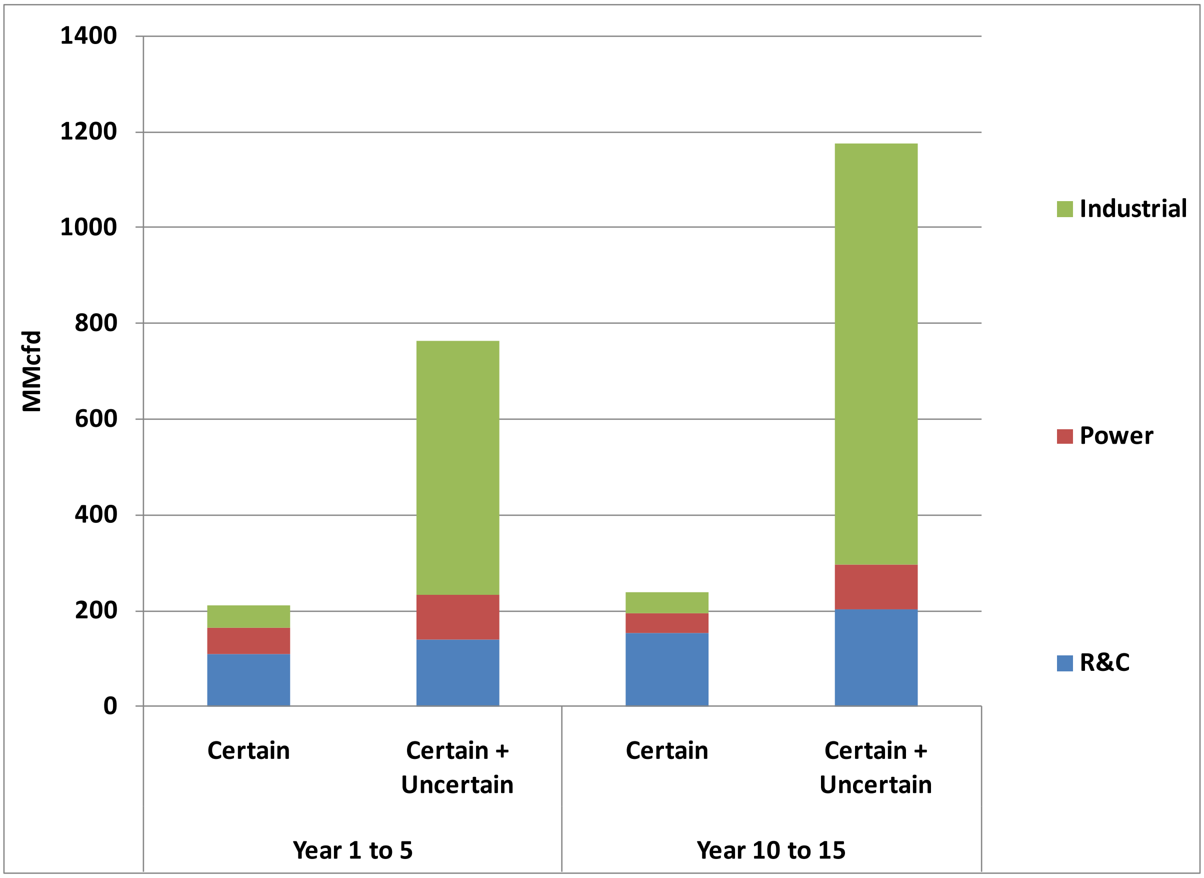
Figure 33 and Figure 34 present the range of certain and uncertain demand by sector in a different manner as the figures above, for both the Alberta and Valdez projects.

Figure 33. Projected Annual Average Daily Demand showing Certain and Uncertain Demand Range by Sector for Years 1 to 5 and Years 10 to 15, Alberta Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

Figure 34. Projected Annual Average Daily Demand showing Certain and Uncertain Demand Range by Sector for Years 1 to 5 and Years 10 to 15, Valdez Project



Source: Northern Economics, Inc. and SAIC, Inc., 2009.

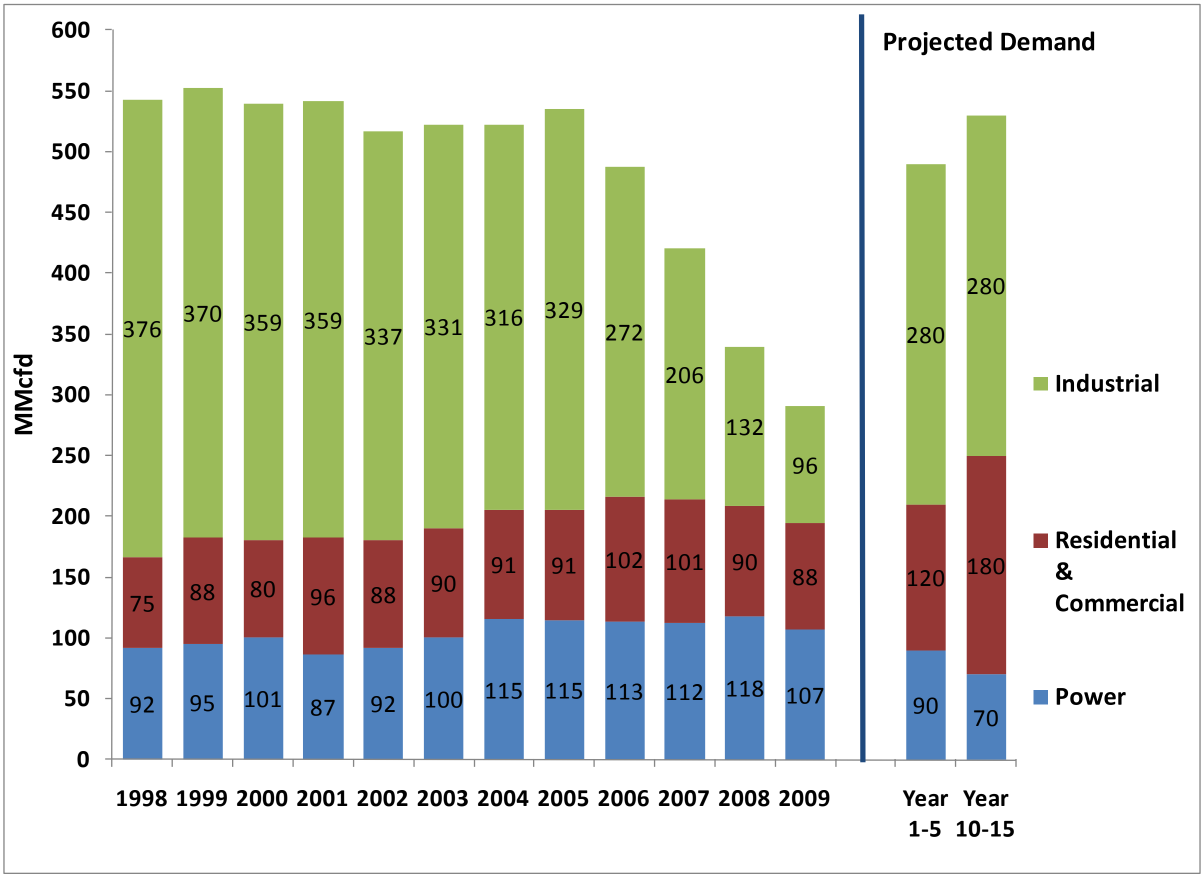
10.3 Summary of Projected Demand in the Current Industry Case

As described earlier, the current industry case represents a continuation of current trends with reasonable growth in demand in the power and residential and commercial sector, and one large gas-intensive industry—such as the existing LNG facility. Since this demand scenario has the greatest chance of occurrence among the three summary cases, the projected demand under the current industry case is used for analysis of potential off-take locations and volumes.

Figure 35 illustrates both the historic and the projected natural gas demand by sector. The projected demand totals represent the Current Industry Case for the Alberta Project for Year 1 to 5 and Year 10 to 15 of pipeline operations.

For the period 1998 to 2009, the total annual daily demand averaged about 480 million cubic feet. In the Current Industry scenario, this annual average daily demand is expected to stay at about the same level in the first five years of pipeline operations. While there is a projected increase in residential and commercial sector demand, the power sector and industrial sector demand are anticipated to decrease. Efficiency and demand side management programs implemented prior to pipeline operation are expected to decrease natural gas requirements for power generation. Projected industrial demand for the Current Industry scenario, assumes only one major gas-intensive industrial user. Demand is projected to increase to 520 MMcfd in the later years of pipeline operations due primarily to population growth.

Figure 35. Historic and Projected Total Annual Average Daily Demand for Natural Gas, Current Industry Scenario, Alberta Project



Source: Historical data are from the Division of Oil and Gas, Alaska Department of Natural Resources. Projected demand in Year 1 to 5 and Year 10 to 15 of pipeline operations are based on the results of this study.

Notes: Historical values for industrial sector include gas consumption for the LNG facility, the Ammonia-Urea plant from 1998 to 2007, and for other small operations such as for military bases in Anchorage, the GTL facility, Tesoro refinery, the small liquefaction facility that transports LNG to Fairbanks Natural Gas, etc. Gas consumed in field operations is not included in the values shown above. The sum of the projected values for Year 10-15 in this figure does not match the total Current Industry case demand in Table 28 due to rounding.

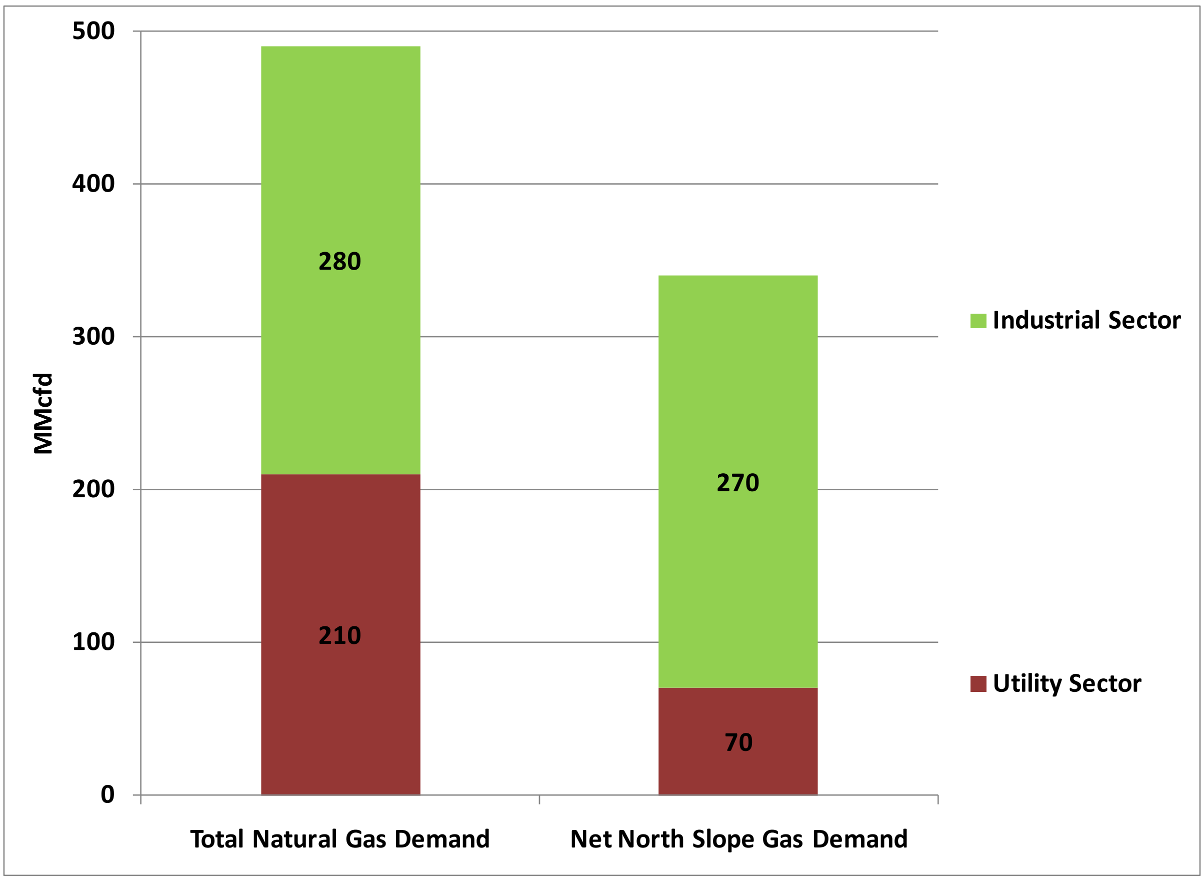
10.4 Net North Slope Natural Gas Demand

After the spur line is completed, natural gas prices from both Cook Inlet and the North Slope will begin to converge. Local utilities, as expressed in the Railbelt Integrated Resource Plan (RIRP) (Black & Veatch, 2009), have indicated a desire to reduce their dependence on natural gas with increased demand side management and energy efficiency, increased use of renewable energy sources, and expanded transmission systems. However, even with such diversification and new facilities, natural gas remains a major energy source for the Railbelt, even 50 years into the future. Given this long time frame, utilities would seek to diversify their supplies of natural gas and would consider gas from the North Slope, coal bed methane, landfill gas, underground coal gasification, and other sources. Utilities have indicated that Cook Inlet sources would remain as a very large percentage of their natural gas supplies even if North Slope gas is less expensive.

Discussions with several Southcentral utilities indicated that they might look to source 5 to 50 percent of their total gas demand from the North Slope. These percent estimates, when aggregated, suggest an average daily utility demand of about 40 MMcfd of North Slope Gas in the Southern Railbelt region in Years 1 to 5. In addition, industrial demand in the Southern Railbelt region for the current industry case is assumed to be met solely by North Slope gas. Therefore, under the Current Industry case for the Alberta Project, about 270 MMcfd of the total Southern Railbelt demand is projected to be supplied by North Slope gas, and about 160 MMcfd is assumed to be supplied by Cook Inlet gas.

As shown in Figure 36, for the Alberta Project, the total net demand for North Slope gas (including demand in the Northern Railbelt region) is projected to be about 340 MMcfd in Years 1 to 5 of pipeline operations.

Figure 36. Total Natural Gas Demand versus Total North Slope Natural Gas Demand, Current Industry Case, Year 1 to 5 of Pipeline Operations, Alberta Project



Source: Northern Economics, Inc., and SAIC, Inc., 2009.

For the Valdez Project, the total net demand for North Slope gas under the Current Industry case is projected to be about 350 MMcfd in Years 1 to 5 of pipeline operations.

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11 Potential Demand along the Pipeline Corridor

This section presents potential energy demand expressed as demand for natural gas of communities along the two pipeline routes under consideration, including the net effect of Cook Inlet production on the demand for North Slope gas.

Figure 37 shows the potential demand along the pipeline corridor in the first few years of pipeline operation. This figure shows the demand by community, as well as potential off-take points at Delta Junction or Glennallen, assuming a Richardson Highway or Glenn Highway spur line were built. If a Parks Highway spur were built instead of a Richardson Highway or Glenn Highway spur, similar demand would exist at a Parks Highway off-take location.

The demand shown for communities includes industrial demand as well as residential and commercial, and demand by the electric utilities. The demand at Livengood includes a proposed gold mine and the Fairbanks area demand includes demand by the two military bases in the community and the North Pole refineries, as well as power and residential and commercial demand.

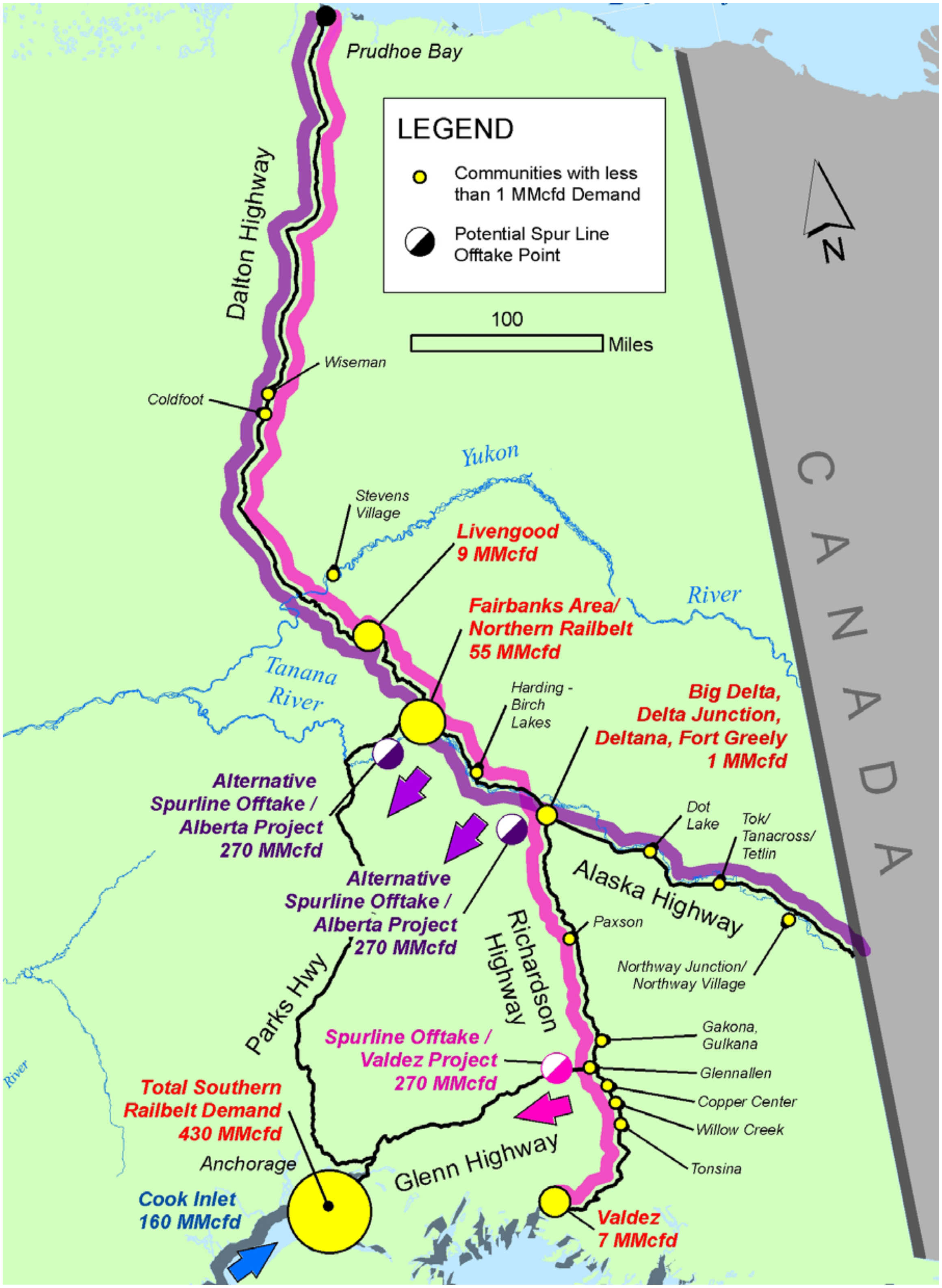
The projected demand (for the take-off volumes) for the Southern Railbelt and Valdez represent the results of the Current Industry demand scenario in the Year 1 to 5 timeframe as modeled in the combined demand probability analysis described in the previous section.

Table 30 and Table 31 show the results of the estimated potential annual average daily demand by location in more detail. The tables also show the net effect on demand for North Slope gas of the availability of Cook Inlet supplies. Projected Cook Inlet gas production is based on a study conducted by the Alaska Department of Natural Resources and with input from Southcentral utilities. The potential North Slope gas demand in the Southern Railbelt is reduced by Cook Inlet production.

Many of the communities along the pipeline routes have very small populations and typically have relatively small demand for natural gas or propane. As noted in Section 8, the capital cost for taking natural gas or propane off of the gas pipeline is very high per unit of energy, and for most small communities, it would be more cost-effective to truck propane from Fairbanks or another location to meet their energy requirements.

At the compressor stations along the pipeline, it is necessary to reduce the pressure to obtain gas for the compressor turbines, and propane could be produced at each compressor station with this pressure drop. No decision has been made regarding the potential for making propane available at any compressor stations, and the location of these stations is not yet confirmed. To the extent that propane was available at a compressor station and the station was closer to the community than Fairbanks or another large demand center, the cost of propane would be reduced for the community.

Figure 37. Potential Net Demand along the Pipeline Corridor, Current Industry Case, Year 1 to 5 of Pipeline Operations



Source: Alaska Map Company, 2009.

Table 30. Potential Annual Average Daily Demand along the Pipeline, Alberta Project (MMcfd)

Community	Total North Slope Demand
Spur Line off-take/ Southern Railbelt	270.0
Fairbanks Area/Northern Railbelt	55.0
Livengood	8.9
Big Delta, Delta Junction, Deltana, Fort Greely	1.4
Tok/Tanacross/Tetlin	0.4
Northway Junction/Northway Village	<0.1
Stevens Village	<0.1
Dot Lake	<0.1
Coldfoot	<0.1
Wiseman	<0.1

Source: Northern Economics estimates, 2009.

Table 31. Potential Annual Average Daily Demand along the Pipeline, Valdez Project (MMcfd)

Community	Total North Slope Demand
Spur Line off-take/ Southern Railbelt	270.0
Fairbanks Area/Northern Railbelt	55.0
Valdez	7.0
Livengood	8.9
Big Delta, Delta Junction, Deltana/Fort Greely	1.4
Copper Center	0.2
Glennallen	0.2
Gakona, Gulkana	0.2
Harding-Birch Lakes	<0.1
Willow Creek	<0.1
Tonsina	<0.1
Stevens Village	<0.1
Paxson	<0.1
Coldfoot	<0.1
Wiseman	<0.1

Source: Northern Economics estimates, 2009.

The demand estimates along each route suggest that potential off-take points should be considered for each potential spur line location and two or more may be required in the Fairbanks area, depending on the main gas pipeline alignment.

Table 32 shows the most likely off-take points based on the analysis conducted for this report. A proposed gold mine at Livengood is a likely candidate for a delivery point, one or more off-take points may be required in the Fairbanks area, and another one to provide for a Parks highway spur line to Southcentral Alaska, or for future growth along the Parks Highway. The communities in the Delta Junction area plus Fort Greely are a likely location for an off-take point, which could be on the main gas pipeline or on a proposed spur line that would generally parallel the Richardson and Glenn highways to the Cook Inlet region. The communities in the vicinity of Tok may not have sufficient demand at present to justify an off-take point, but there is the potential for future mineral development and associated demand in the region around Tok. Glennallen and Valdez would be obvious off-take points for the Valdez project since Glennallen would be the location of a spur line to Southcentral Alaska, and Valdez has community demand plus demand from the Alyeska marine terminal.

Table 32. Potential Off-Take Locations along the Alberta Line and the Valdez Line

	Route	
Location	**Alberta**	**Valdez**
Livengood	1	1
Fairbanks	1-2	1-2
Parks Highway spur	1	1
Delta Junction area/ Richardson Highway spur	1	1
Tok	1	NA
Glennallen	NA	1
Valdez	NA	1
Total	**5-6**	**6-7**

Source: Northern Economics, Inc.

At this time, ten years prior to the planned commencement of the TransCanada Alaska pipeline operation, the pro forma in-state gas tariff for the upcoming open season will be an estimate based on the demand for North Slope gas net of projected Cook Inlet supply as noted in this study. The actual tariff for the pipeline will be highly dependent on the actual contracted volume of the pipeline, which will be determined in the initial open season and subsequent open seasons.

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