2.0 PROJECT OVERVIEW AND APPROACH

This section provides an overview of the RIRP and Black & Veatch's approach to the completion of this study.

2.1 Project Overview

In response to a directive from the Alaska Legislature, the AEA was the lead agency for the development of this RIRP for the Railbelt region. This region is defined as the service areas of six regulated public utilities that comprise the region, including: Anchorage ML&P, Chugach, GVEA, HEA, MEA, and SES.

The goal of this project is to minimize future power supply costs and maintain or improve on current levels of power supply reliability through the development of a single comprehensive RIRP for the Railbelt region. The intent of the RIRP project is to provide:

- An up-to-date model that the utilities and AEA can use as a common database and model for future planning studies and analysis.
- An assessment of loads and demands for the Railbelt electrical grid for a time horizon of 50 years including new potential industrial demands.
- Projections for Railbelt electrical capacity and energy growth, fuel prices, and resource options.
- An analysis of the range of potential generation resources available, including costs, construction schedule, and long-term operating costs.
- A schedule for existing generating unit retirement, new generation construction, and construction of backbone redundant transmission lines that will allow the future Railbelt electrical grid to operate reliably under a transmission tariff which allows access by all potential power producers, and with a postage-stamp rate for electric energy and demand for the entire Railbelt as a whole.
- A long-term schedule for developing new fuel supplies that will provide for reliable, stable priced electrical energy for a 50-year planning horizon.
- A short-term schedule that coordinates immediate network needs (i.e., increasing penetration level of non-dispatchable generation, such as wind) within the first 10 years of the planning horizon with the long-term goals.
- A short-term plan addressing the transition from the present decentralized ownership and control to a unified G&T entity that identifies unified actions between utilities that must occur during this transition period.
- A diverse portfolio of power supply that includes, in appropriate portions, renewable and alternative energy projects and fossil fuel projects, some or all of which could be provided by IPPs.
- A comprehensive list of current and future generation, transmission and electric power infrastructure projects.

Black & Veatch conducted the REGA study for the AEA, which evaluated the feasibility of the Railbelt utilities forming an organization to provide coordinated unit commitment and economic dispatch of the region's generation resources, generation and transmission system planning, and project development for the Railbelt. As a result of that study, legislation was proposed to create GRETC, with a 10-year transition period in to achieve these goals. This RIRP is based on the GRETC concept being implemented from the beginning of the study's time horizon.

Black & Veatch had primary responsibility for conducting this Railbelt RIRP. In addition to Black & Veatch, three other AEA contractors (HDR, EPS, and SNW) played important roles in the development of the RIRP.

HDR updated work from the mid-1980s on the Susitna Hydroelectric Project and developed the capital and operating costs, as well as the generating characteristics, for several smaller sized Susitna options. HDR's work was used by Black & Veatch in the Strategist® and PROMOD® modeling discussed below. HDR's report summarizing the results of its work is provided in Appendix A.

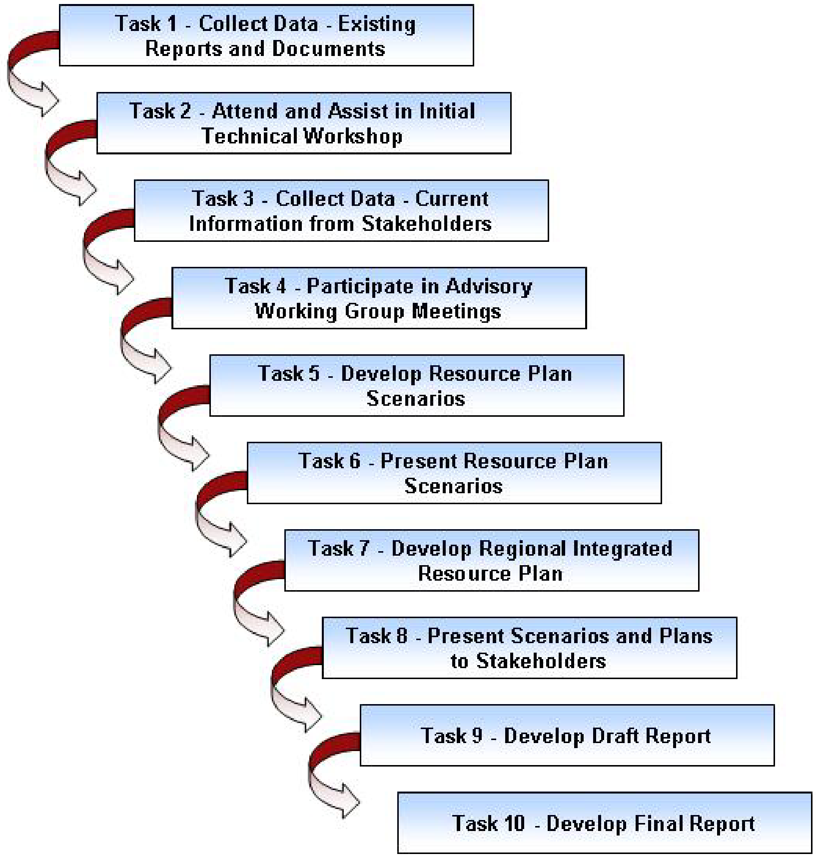
EPS assisted in the evaluation of the region's transmission system.

SNW developed the financial model used to determine the overall financing costs for the portfolios of generation and transmission projects developed as part of this project, and evaluated the impact of some financial options that could be used to address financing issues and mitigating related rate impacts. The results of SNW's analysis are provided in Appendix B.

2.2 Project Approach

The RIRP study process for the Railbelt system consisted of three key stages: data collection, optimal generation expansion along with integrated transmission expansion planning and production cost modeling, and report writing and documentation. Throughout this process, data related to alternative demand-side, supply-side, and transmission resource options were compiled, reviewed, screened for appropriateness, and modeled using Ventyx's Strategist® and PROMOD® optimal generation expansion and production cost models. Model inputs and assumptions take into consideration possible sensitivity cases and any considerations unique to the six utilities to derive the least-cost plan for the Railbelt region's electric system. To complete this study, the Black & Veatch project team, in collaboration with the other aforementioned AEA contractors, completed the tasks shown in Figure 2-1.

Figure 2-1
Project Approach Overview



Task 1 – Collect Data – Existing Reports and Documents
Black & Veatch issued data requests to the six Railbelt utilities to update and add to the data previously obtained in the REGA study. These data included existing generating resources and operating data, load and energy requirements, transmission characteristics, purchase power transactions, and DSM/EE programs.

Task 2 – Attend and Assist in Initial Technical Workshop
Black & Veatch worked with the AEA to sponsor a Technical Workshop near the beginning of the project to obtain information and input from the various regional stakeholders and to enable the development of scenarios for evaluation which provided the basis for the assessment of future fuel supply, generation, and transmission resource alternatives for the Railbelt.

Task 3 – Collect Data – Current Information From Stakeholders
Black & Veatch collected additional information from other regional stakeholders, including producers, ratepayer groups, and representatives from project developers, as well as the DSM/EE, environmental and renewables communities.

Task 4 – Participate in Advisory Working Group Meetings

Black & Veatch participated in five meetings with the Advisory Working Group that was formed for the project. The role of this Advisory Working Group is described later in this section.

Task 5 – Develop Resource Plan Scenarios

This task involved the following activities:

Subtask 5.1 – Development of Economic Parameters
Subtask 5.2 – Development of Regional Load Forecast
Subtask 5.3 – Development of Fuel Price Forecasts
Subtask 5.4 – Development of Reserve Criteria
Subtask 5.5 – Evaluation of Conventional Supply-Side Alternatives
Subtask 5.6 – Evaluation of Hydro Projects
Subtask 5.7 – Evaluation of Wind and Other Renewable Projects
Subtask 5.8 – Evaluation of Transmission System Expansions
Subtask 5.9 – Evaluation of Generation Unit Retirements
Subtask 5.10 – Evaluation of DSM/EE Measures
Subtask 5.11 – Scenario Mapping
Subtask 5.12 – Benchmarking Analysis

Task 6 – Present Resource Plan Scenarios

Black & Veatch made a presentation to the RIRP Advisory Working Group and AEA explaining the resource scenarios and describing the recommended Evaluation Scenarios.

Task 7 – Develop Regional Integrated Resource Plan

Black & Veatch then developed alternative resource plans for each of the four Evaluation Scenarios, based upon the results of Task 5.

Task 8 – Present Scenarios and Plans to Stakeholders

Black & Veatch presented its preliminary results, conclusions and recommendations to interested parties at a second Technical Conference that was held in December.

Task 9 – Develop Draft Report

Black & Veatch prepared a Draft Report that was provided to the AEA and made available to interested parties for review and comment.

Task 10 – Develop Final Report

Black & Veatch prepared a Final Report that incorporated comments received on the Draft Report.

2.3 Modeling Methodology

2.3.1 Study Period and Considerations

The evaluation timeframe consists of a 50-year study period from 2011 through 2060. Evaluations were conducted in nominal dollars with the annual costs discounted to 2011 dollars for comparison using the present worth discount rate discussed in Section 5. After evaluating the seasonal month definitions of the utilities, Black & Veatch defined the summer season as May 1 through October 31, and the winter season as November 1 through April 30.

The 50-year planning period presented challenges to reduce the running time for the Strategist® model to acceptable levels. Several techniques were used including bracketing years and pre-screening alternatives to reduce the number of alternatives included in the Strategist® runs to reduce run time to a target level of approximately 24 hours per run.

For comparison purposes, existing project capital costs are not carried forward. Only new generation, transmission, and DSM/EE costs, as well as system fuel, O&M and emission allowance costs, are considered when comparing the various expansion plan scenarios.

2.3.2 Strategist® and PROMOD® Overview

For the RIRP Study, Black & Veatch used Ventyx's Strategist® optimal generation expansion model to evaluate the various alternatives and scenarios. The Strategist® model is capable of evaluating a large number of plans with generating, transmission, and DSM/EE alternatives by using probabilistic dispatch, dynamic programming, and elimination of factors that typically are not taken into account when comparing thousands (or millions) of plans, such as ramp-up and ramp-down rates and start-up energy and start-up fuel costs.

The model utilizes a typical week methodology and evaluates the relative economics between all possible plans within a given set of criteria and minimizes utility costs through optimization. The model checks all feasible combinations in every year of the study period using dynamic programming. At the end of the study period, the model traces back through the matrix of feasible states to find the plans with the best financial or other operational criteria (cumulative present worth cost in this case) and ranks these plans according to this criteria. The plans that are shown to be most promising from an economic standpoint are then input into Ventyx's hourly chronological model, PROMOD®, for additional analysis with this more detailed production costing model.

PROMOD® performs unit commitment and economic dispatch under a wide array of operation constraints along with detailed transmission simulation. The model develops hourly generation, production costs, and fuel consumption for generating units utilizing detailed operating characteristic inputs. Hours on-line and start-up hours are also calculated. Transmission line information such as hourly flow and constraints are available for output along with unserved energy. Debt service (i.e., return on investment and depreciation) for capital additions are added externally to the operating costs developed by PROMOD®.

2.3.3 Benchmarking

With the uniqueness of the Railbelt electric system, it was important that Black & Veatch benchmark the models' production costing against an actual year in order to validate the models' abilities to appropriately model the characteristics of the Railbelt. The benchmarking exercise was based on 2008 actual data as that was the most recent year with complete generation, transmission, and purchases and sales data to benchmark against. Actual 2008 data was gathered from the utilities regarding generating unit performance, outages, and costs, as well as information on purchases and sales of economy energy and corresponding costs.

The goal of the benchmarking effort was to model system inputs and validate the outputs against actual values for 2008 for each utility. Outputs to be validated were generating unit capacity factors, hydroelectric generation amounts, generation costs, economy energy purchases and sales, and resulting costs. Wheeling rates, fuel costs, operations and maintenance (O&M) costs, and other costs were input on a per unit basis. Scheduled and forced outages were input directly to reflect actual unit availability.

Accurately benchmarking the Railbelt's hydroelectric generation was important to validate the models. Much of the Railbelt system in 2008 was powered by combined cycle and simple cycle turbines. With most of the scheduled maintenance on combined cycles occurring in the summer months due to high electric demand in the winter, less-efficient, more costly combustion turbines must be used for generation. When total system costs begin to rise, hydroelectric storage units can be used to generate a portion of the Railbelt's requirements. The fact that storage water for hydro is finite must also be taken into account. Water levels in hydroelectric reservoirs have minimums and maximums. The model was set up to limit the amount of generation available in each month to avoid exhausting all of the available water in one month and not having enough remaining in other months.

Overall, the benchmarking process verified that the models adequately reflect operation in the Railbelt for purposes of the RIRP. While the models have limitations in their modeling of the Railbelt system, they also have other benefits for their use in this study.

2.3.4 Hydroelectric Methodology

Strategist® treats hydroelectric generation as a load modifier, while PROMOD® offers the option of treating hydroelectric as a load modifier or dispatching it. In Strategist® hydroelectric generating units are dispatched one at a time. Each unit has a maximum and minimum capacity level at which it operates. Each unit can also be given a monthly total energy that is available. The utility's overall load is reduced by the minimum hydro generation available in each hour. The difference between the total hydroelectric energy in the month and the minimum hydro energy is the energy available for peak shaving. Capacity available for peak shaving is the difference between the maximum and minimum capacities of the unit. The resulting load shape is then met by unit dispatch of other available resources.

Black & Veatch provided the model with the monthly energy limits for hydroelectric units and allowed the model to perform the load modifications. These limits were calculated from the average monthly historical generation of the units provided by the utilities. Providing monthly energy limits for each hydroelectric unit prevents the model from taking an unrealistic amount of water from the reservoirs, but still allows for variance throughout the year. The amount of baseload energy to be met will be reduced, thereby allowing some units to be shut down, or run minimally. This methodology will also lower the amount of load to be met by less-efficient thermal units and lowers production costs. Peak load reduction will also work to reduce the amount of units that need to be started to handle peak times.

There are several factors that drive hydroelectric generation in the Railbelt system. Summer maintenance outages on other generating units can increase the amount of hydroelectric generation necessary to reduce system costs. Limitations on the deliverability of natural gas in the winter for thermal generating units can also drive the use of hydroelectric generation in the region. As the system ages, the correlation between higher system costs and generating unit maintenance will be reduced as less efficient units will be retired and replaced. With multiple factors influencing hydroelectric generation in the Railbelt region, Black & Veatch believes that the load modification technique is an appropriate method to model hydroelectric generation in the Railbelt. Modeling assumptions specific to each hydroelectric unit are presented in Section 4.

PROMOD® offers the additional modeling feature that, on a weekly basis, PROMOD® will dispatch available hydro energy at the times when avoided thermal unit costs are greatest. This feature was used in the PROMOD® modeling.

2.3.5 Evaluation Scenarios

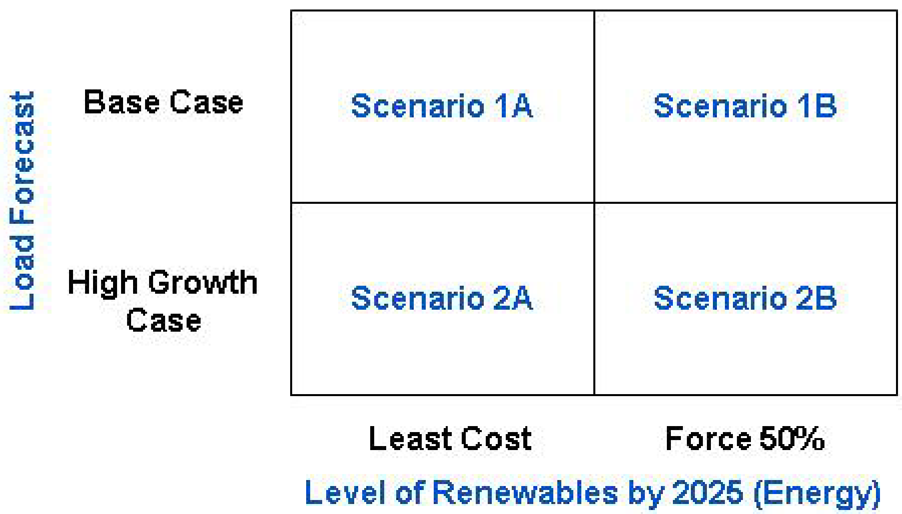
Black & Veatch, in collaboration with the Advisory Working Group, developed four Evaluation Scenarios for this project. Black & Veatch then developed a 50-year resource plan for each of these Evaluation Scenarios.

The primary objective of these Evaluation Scenarios was to evaluate two key drivers. The first driver was to look at what the impacts would be if the demand in the region was significantly greater than it is today; of primary interest was to see if higher demands would result in greater reliance on large generation resource options and allow for more aggressive expansions of the region's transmission network.

The second driver was to determine the impact associated with the pursuit of a significant amount of renewable resources over the 50-year time horizon.

As a result, Black & Veatch evaluated the four Evaluation Scenarios shown on Figure 2-2.

Figure 2-2
Evaluation Scenarios



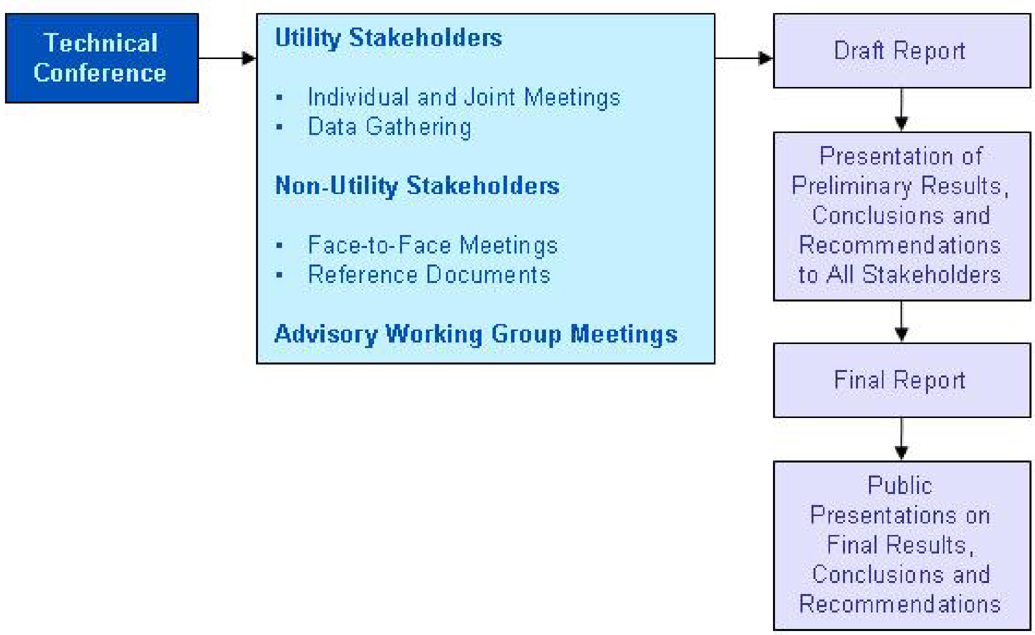
The key assumptions underlying each Evaluation Scenario include:

- **Scenario 1 – Base Case Load Forecast**
  - Current regional loads with projected growth
  - All available resources – fossil fuel, renewables, and DSM/EE
  - Probabilistic estimate of gas supply availability and prices
  - Deterministic price forecasts for other fossil fuels
  - Emissions including CO_2 costs
  - Transmission system investments required to support selected resources
  - **Scenario 1A – Least Cost Plan**
  - **Scenario 1B – Force 50% Renewables**
- **Scenario 2 – Large Growth Load Forecast**
  - Significant growth in regional loads due to economic development efforts or large scale electrification (e.g., economic development loads, space and water heating fuel switching, and electric vehicles)
  - Base case resources, fuel availability/price forecasts and CO_2 costs
  - Transmission system investments required to support selected resources
  - **Scenario 2A – Least Cost Plan**
  - **Scenario 2B – Force 50% Renewables**

2.4 Stakeholder Input Process

One of the AEA's directives to Black & Veatch, related to the completion of this project, was to proactively solicit input from a broad cross-section of the Railbelt region's stakeholders. Elements of the stakeholder involvement process are summarized in Figure 2-3.

Figure 2-3
Elements of Stakeholder Involvement Process



As the first element of this public participation process, the AEA held a two-day Technical Conference near the beginning of the project. The purpose of this conference was to enable a number of industry participants to provide their views regarding the broad array of issues confronting the Railbelt utilities and to provide comments specific to the completion of this study. Approximately 100 individuals, including Black & Veatch project team members, participated in this conference.

Additionally, Black & Veatch met with a number of non-utility stakeholders to provide them with the opportunity to present their input directly to the Black & Veatch project team members. These meetings were in addition to the meetings that Black & Veatch held with Railbelt utility representatives.

Black & Veatch and the AEA also held several meetings with the Advisory Working Group that was assembled for this project. The role and membership of this Advisory Working Group is discussed in the next subsection.

Additionally, the AEA held a second Technical Conference during which the Black & Veatch project team presented our preliminary results, conclusions and recommendations. Subsequent to that presentation, all stakeholders were provided the opportunity to review and comment on our Draft Report.

2.5 Role of Advisory Working Group and Membership

Another important element of this project's stakeholder input process was the formation of an Advisory Working Group, assembled by the AEA, which provided input to the Black & Veatch/AEA project team throughout the study. This Group, which met five times during the course of the project, included the following members:

- Norman Rokeberg, Retired State of Alaska Representative, Chairman
- Chris Rose, Renewable Energy Alaska Project
- Brad Janorschke, Homer Electric Association
- Carri Lockhart, Marathon Oil Company
- Colleen Starring, Enstar Natural Gas Company
- Debra Schnebel, Scott Balice Strategies
- Jan Wilson, Regulatory Commission of Alaska
- Jim Sykes, Alaska Public Interest Group
- Lois Lester, AARP
- Marilyn Leland, Alaska Power Association
- Mark Foster, Mark A. Foster & Associates
- Nick Goodman, TDX Power, Inc.
- Pat Lavin, National Wildlife Federation - Alaska
- Steve Denton, Usibelli Coal Mine, Inc.
- Tony Izzo, TMI Consulting

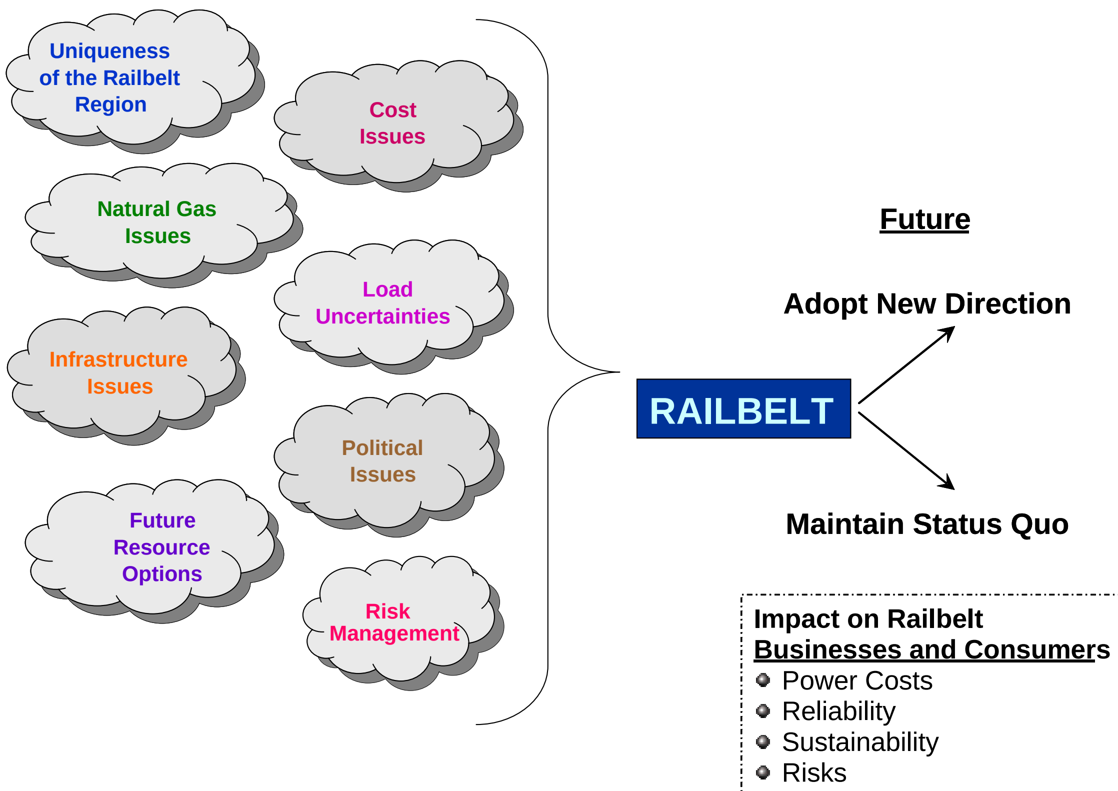
The Advisory Working Group provided input on a number of project-related issues, including the following:

- Project objectives, scope, and approach
- Evaluation Scenarios to be considered
- Input assumptions for each Evaluation Scenario
- Tax and legal issues
- Preliminary results, conclusions and recommendations
- Draft Report

3.0 SITUATIONAL ASSESSMENT

The purpose of this section is to discuss the myriad of issues facing the Railbelt electric utilities; the major categories of issues are shown on Figure 3-1. This discussion is largely drawn from the REGA study that was completed by Black & Veatch.

Figure 3-1
Summary of Issues Facing the Railbelt Region



Each of these issue categories is discussed below.

3.1 Uniqueness of the Railbelt Region

In comparison to the business and operating environment of the utility industry in the lower-48 states, the Railbelt region is unique. The following presents a summary of the more significant issues that cause the uniqueness of the Railbelt region:

Issue	Description
Size and Geographic Expanse	First, the overall size of the Railbelt region is small when compared to other utilities or areas. The total combined peak load of all six utilities is approximately 870 MW. When compared to the peak loads of other utilities throughout the U.S., a combined "Railbelt utility" would still be relatively small. As an example, many electric utilities have single coal or nuclear plants that exceed 900 MW of capacity (based on Energy Information Administration plant data, there are 100 generating units in the U.S. with nameplate capacity greater than 900 MW). This relative size, coupled with the geographic expanse and diversity of the Railbelt region, creates certain issues and affects the solutions available to the Railbelt utilities.
Limited Interconnections and Redundancies	The Railbelt electric transmission grid has been described as a long straw, as opposed to the integrated, interconnected, and redundant grid that is in place throughout the lower-48 states. This characterization reflects the fact that the Railbelt electric transmission grid is an isolated grid with no external interconnections to other areas and that it is essentially a single transmission line running from Fairbanks to the Kenai Peninsula, with limited total transfer capabilities and redundancies. As a consequence, each Railbelt utility is required to maintain much higher generation reserve margins than elsewhere in order to ensure reliability in the case of a transmission grid outage. Furthermore, the lack of interconnections and redundancies exacerbates a number of the other issues facing the Railbelt region.

3.2 Cost Issues

The following issues relate to the current cost structure of the Railbelt utilities.

Issue	Description
Relative Costs – Railbelt Region Versus Other States	Alaska has the seventh highest cost of any state based on the total cost per kWh, as shown in Table 3-1. Alaska's average retail rate was 13.3 cents per kWh; in comparison, Hawaii was the highest ranked state at 21.3 cents per kWh and Idaho was the lowest at 5.1 cents per kWh. The U.S. average was 9.1 cents per kWh.

Issue	Description
Relative Costs – Among Railbelt Utilities	ML&P's customers pay the lowest monthly electric bills in the region; GVEA's residential customers pay the highest monthly bills. Chugach, MEA, Seward and Homer are in the middle. Table 3-2 provides a comparison of the monthly electric bills paid by the residential, small commercial and large commercial customers of each of the six Railbelt utilities. Monthly bills are shown for residential customers assuming average monthly usage of 750 kWh based upon the rates of each Railbelt utility. Also shown are the monthly bills paid by small commercial (10,000 kWh average monthly usage) and large commercial (150,000 kWh average monthly usage) customers.
Economies of Scale	The Railbelt utilities have not been able to take full advantage of economies of scale and scope. With respect to scale economies, there are several reasons that the region has been limited by scale constraints. First, as previously noted, the combined peak load of the six Railbelt utilities is still relatively small. Second, the Railbelt transmission grid's lack of redundancies and interconnections with other regions has placed reliability-driven limits on the size of generation facilities that could be integrated into the Railbelt region. Third, the fact that each utility has developed their own long-term resource plans has led to less optimal results (from a regional perspective) relative to what could be accomplished through a rational, fully coordinated regional planning process. Finally, the existence of six separate utilities, and their small size on an individual utility basis, has restricted their ability to take advantage of economies of scale with regards to staffing and their skill sets. For example, the development of six separate programs to develop and deliver DSM and energy efficiency programs is a considerably more difficult challenge than would be the case if there was one regional entity responsible for developing and delivering DSM and energy efficiency programs to residential and commercial customers throughout the Railbelt region.

Table 3-1
Relative Cost per kWh (Alaska Versus Other States) - 2007

Name	Average Retail Price (cents/kWh)	Name	Average Retail Price (cents/kWh)
Hawaii	21.29	North Carolina	7.83
Connecticut	16.45	Colorado	7.76
New York	15.22	Alabama	7.57
Massachusetts	15.16	Minnesota	7.44
Maine	14.59	New Mexico	7.44
New Hampshire	13.98	Oklahoma	7.29
Alaska	13.28	South Carolina	7.18
Rhode Island	13.12	Montana	7.13
New Jersey	13.01	Virginia	7.12
California	12.80	Tennessee	7.07
Vermont	12.04	Oregon	7.02
District of Columbia	11.79	Arkansas	6.96
Maryland	11.50	South Dakota	6.89
Delaware	11.35	Kansas	6.84
Florida	10.33	Iowa	6.83
Texas	10.11	Missouri	6.56
Nevada	9.99	Indiana	6.50
Pennsylvania	9.08	North Dakota	6.42
Arizona	8.54	Utah	6.41
Michigan	8.53	Washington	6.37
Wisconsin	8.48	Nebraska	6.28
Illinois	8.46	Kentucky	5.84
Louisiana	8.39	West Virginia	5.34
Mississippi	8.03	Wyoming	5.29
Ohio	7.91	Idaho	5.07
Georgia	7.86	**US Average**	**9.13**

Source: Energy Information Administration, "State Electricity Profiles," DOE/EIA-0348, April 2009.

Table 3-2
Relative Monthly Electric Bills Among Alaska Railbelt Utilities

RESIDENTIAL	Fuel Adjustment	Regulatory Cost Charge	Energy Charge	Total Energy Charge	Customer Charge	Usage Factor (kWh)	Typical Bill		
GVEA	0.05903	0.000274	0.11153	0.170834	15	750	$143.13		
Chugach	0.02478	0.000274	0.09282	0.117874	8.42	750	$96.83		
MEA	0.03084	0.000274	0.09447	0.125584	5.65	750	$99.84		
ML&P	-0.00655	0.000274	0.09476	0.088484	6.56	750	$72.92		
Homer (North of Kachemak Bay)	0.00078	0.000274	0.12718	0.128234	11	750	$107.18		
Homer (South of Kachemak Bay)	0.00078	0.000274	0.13056	0.131614	11	750	$109.71		
City of Seward	NA	NA	NA	NA	NA	NA	NA		
Average							**$104.93**		
SMALL COMMERCIAL	**Fuel Adjustment**	**Regulatory Cost Charge**	**Energy Charge**	**Total Energy Charge**	**Customer Charge**	**Usage Factor (kWh)**	**Typical Bill**		
GVEA	0.05903	0.000274	0.10957	0.168874	20	10,000	$1,708.74		
Chugach	0.02478	0.000274	0.08001	0.105064	18.26	10,000	$1,068.90		
MEA	0.03084	0.000274	0.07677	0.107884	5.65	10,000	$1,084.49		
ML&P	-0.00655	0.000274	0.09182	0.085544	12.88	10,000	$868.32		
Homer (North of Kachemak Bay)	0.00078	0.000274	0.1181	0.119154	24	10,000	$1,215.54		
Homer (South of Kachemak Bay)	0.00078	0.000274	0.11479	0.115844	40	10,000	$1,198.44		
City of Seward	NA	NA	NA	NA	NA	NA	NA		
Average							**$1,190.74**		
LARGE COMMERCIAL	**Fuel Adjustment**	**Regulatory Cost Charge**	**Energy Charge**	**Total Energy Charge**	**Customer Charge**	**Demand Charge**	**Usage Factor (kWh)**	**Demand Usage (kW)**	**Typical Bill**
GVEA	0.05903	0.000274	0.7835	0.137654	50	8.55	150,000	500	$24,973.10
Chugach	0.02478	0.000274	0.0462	0.071254	58.85	11.65	150,000	500	$16,571.95
MEA	0.03084	0.000274	0.06004	0.091154	13.37	4.85	150,000	500	$16,111.47
ML&P	-0.00655	0.000274	0.05351	0.047234	44.15	11.85	150,000	500	$13,054.25
Homer (South of Kachemak Bay)	0.00078	0.000274	0.11479	0.115844	40	6.73	150,000	500	$20,781.60
City of Seward	NA	NA	NA	NA	NA	NA	NA	NA	NA
Average									**$18,298.47**

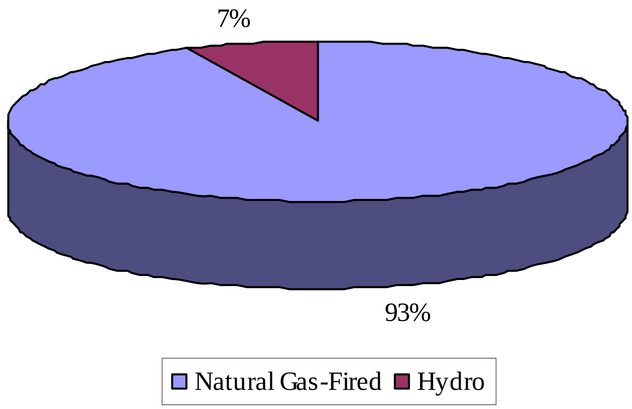
3.3 Natural Gas Issues

The Railbelt utilities use Cook Inlet natural gas as a significant generation fuel source and have done so for decades; the future ability of the Railbelt region to continue to rely on natural gas is in question.

Issue	Description
Historical Dependence	Natural gas has been the predominant source of fuel for electric generation used by the customers of ML&P, Chugach, MEA, Homer and Seward. Additionally, customers in Fairbanks have benefited from natural gas-generated economy energy sales in recent years. For example, Figure 3-2 shows the current dependence that Chugach (as well as MEA, Homer and Seward as a result of their full requirements contracts with Chugach) has on natural gas-fired generation, based on 2007 statistics. ML&P has a similar level of dependence on natural gas.
Expiring Contracts	There are a number of inherent risks whenever a utility or region is so dependent upon one fuel source; risks with regard to prices, availability and deliverability. An additional risk faced by Chugach is the fact that its current gas supply contracts are expected to expire in the 2010-2012 timeframe. Chugach is currently working with its natural gas suppliers to renegotiate these contracts. Although those negotiations are have not all been finalized, it is expected that future natural gas prices paid by Chugach will increase once the existing contracts expire.
Declining Developed Reserves and Deliverability	An additional problem faced by the Railbelt utilities, due to their dependence on natural gas, is the fact that existing developed reserves in the Cook Inlet are declining as well as the current deliverability of that gas. This is shown in Figure 3-3. As can be seen in Figure 3-3, the population of the Anchorage, Mat-Su, and Kenai Peninsula areas has increased 170% from 1970 to 2005. At the same time, known reserves in the Cook Inlet have declined by 80%. As a result, one prediction is that gas supplies from known reserves will meet less than one-half of the residential and commercial demand for heating and electricity by 2017. This will have a significant impact on all Railbelt utilities, including ML&P as its owned gas supply is experiencing the same dynamics. Related to the decline in reserves is the decline in deliverability. Historically, deliverability of natural gas to electric generation facilities, and to residential and commercial customers in the Railbelt region for heating, was not a problem. However, deliverability is increasingly becoming an issue as the Cook Inlet gas fields age, reserves decline, and pressures drop. Consequently, the Railbelt region will not be able to continue its dependence upon natural gas in the future unless additional reserves are discovered in the Cook Inlet, new sources of supply become available from the North Slope, or a liquefied natural gas (LNG) import terminal is developed to supplement Cook Inlet supplies.

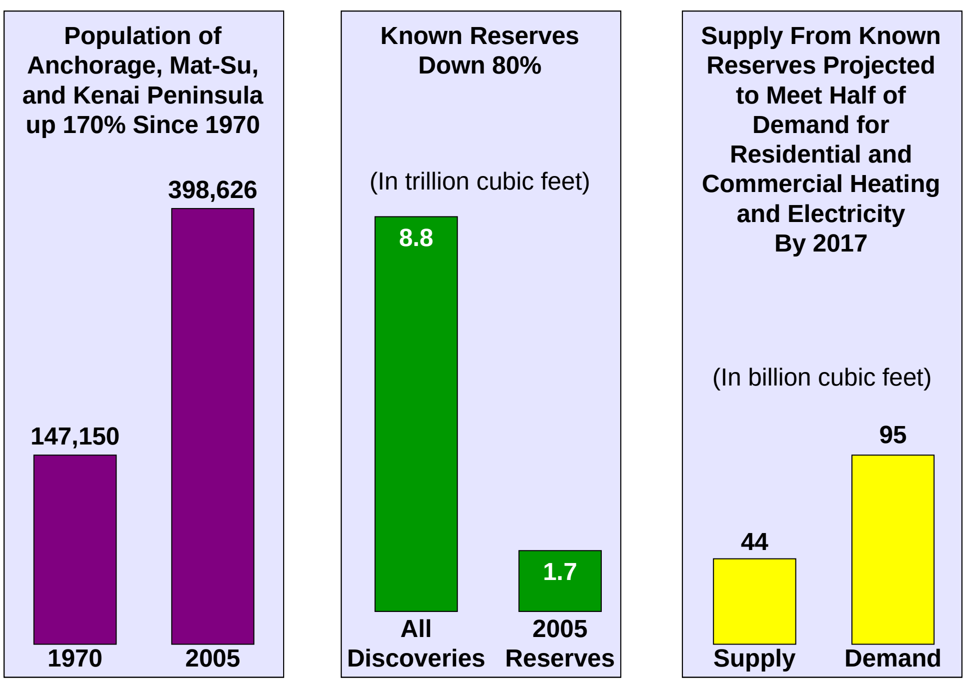
Issue	Description
Historical Increase in Gas Prices	Railbelt residential and commercial customers are directly feeling the rise in natural gas prices that have occurred in recent years. These price increases are shown in Figure 3-4, which shows historical gas prices paid by Chugach. Figure 3-5 shows the resulting rise in Chugach's residential bills from 1994 to 2007. As can be seen, the fuel component of the customer's bill has increased significantly in recent years while the base rate component has remained roughly the same until very recently. With natural gas prices expected to continue increasing, Railbelt consumers and businesses will experience even greater electric prices in the future.
Potential Gas Supplies and Prices	Regardless of the future source of additional natural gas supplies (whether new gas supplies from the Cook Inlet, gas from the North Slope, or imported LNG supplies), one reality can not be escaped: future gas supply prices will be higher. For additional gas supplies in the Cook Inlet to become available, prices will need to increase to encourage exploration and development. This results from the fact that oil and gas producers make investment decisions based upon expected returns relative to investment opportunities available elsewhere in the world. In the case of North Slope gas supplies, the cost, probability and timing of potential gas flows to the Railbelt region are unknown at this time. Nevertheless, given the construction lead times for a potential gas pipeline to provide gas from the North Slope, gas from that region is unlikely to be available for a number of years. Furthermore, if gas from the North Slope becomes available in the Railbelt region through either the Bullet Line or Spur Line, prices will be tied to market prices since potential natural gas flows to the Railbelt region will be just one of the competing demands for the available gas. Additionally, the pipeline transmission rates that will be paid to move gas to the Railbelt region will be significantly higher than the transportation rates that are imbedded in the delivered cost of gas from Cook Inlet suppliers under existing contracts.

Figure 3-2
Chugach's Reliance on Natural Gas



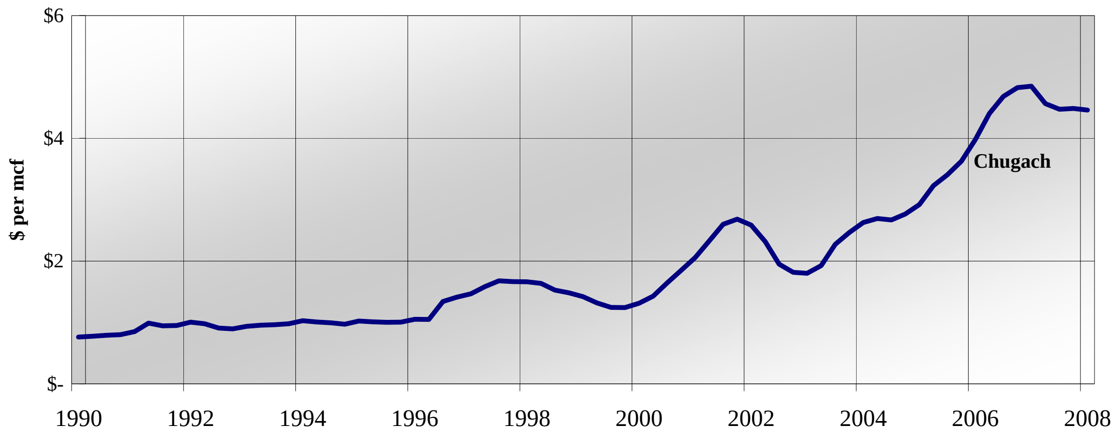
Total Power Produced in 2007: 2,628 gWh
Source: Chugach Electric Association.

Figure 3-3
Overview of Cook Inlet Gas Situation



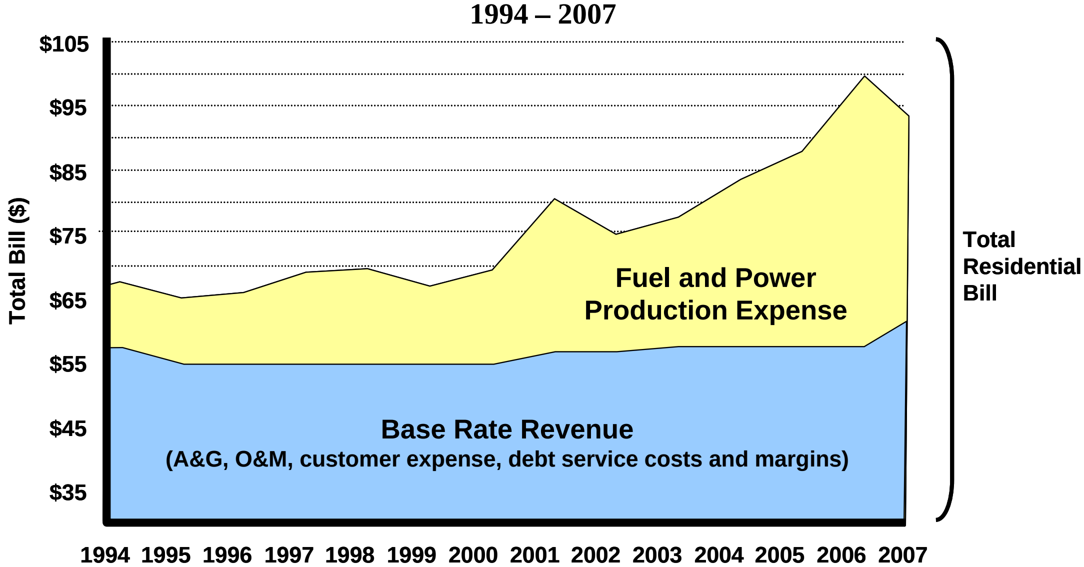
Source: Alaska Department of Labor, Alaska Division of Oil and Gas, and Science Applications International Corporation.

Figure 3-4
Historical Chugach Natural Gas Prices Paid



Source: Chugach Electric Association.

Figure 3-5
Chugach Residential Bills Based on 700 kWh Consumption
1994 – 2007



Source: Chugach Electric Association.

3.4 Load Uncertainties

Load uncertainties are always an issue of concern for electric utilities as they make investment decisions regarding which generation resources to add to their system.

Issue	Description
Stable Native Growth	With regard to native load growth (e.g., normal load growth resulting from residential and commercial customers), Railbelt utilities have experienced stable growth in recent years. This stable native load growth is expected to continue in the years ahead, absent significant economic development gains in the region.
Potential Major New Loads	There are, however, a number of potential significant load additions that could result from economic development efforts. These potential load additions could result from the development of new, or expansion of existing, mines (e.g., Pebble and Donlin Creek), continued military base realignment, and other economic development efforts or the enactment of policies that would result in increased electric loads (e.g., gas to electric fuel switching, electric vehicles, etc.). Additionally, there will likely be a significant increase in Railbelt population if the proposed North Slope natural gas pipeline, and or the Spur Line or Bullet Line, is built. Any significant growth in Railbelt electric loads will lead to increased stress on the ability of the region's utilities to meet demand, particularly if this demand has to be met by one utility. This is particularly true given the fact that a significant portion of the Railbelt's electric generation facilities are approaching their planned retirement dates.

3.5 Infrastructure Issues

The challenges faced by the Railbelt utilities are magnified by the aging nature of existing generation facilities in the region.

Issue	Description
Aging Generation Infrastructure	Approximately 67 percent of the existing generation capability within the Railbelt region is scheduled to be retired within 15 years. During this period, decisions relative to retirement, refurbishment, and life extension must be made. Replacing this capacity with more efficient capacity requires substantial new capital investment, which is offset by the lower cost of generation with better heat rates or when plants incorporate lower fuel cost resources.
Baseload Usage of Inefficient Generation Facilities	Another issue that is directly related to the aging nature of the existing Railbelt generation fleet is the fact that certain older, inefficient generation units are being used as baseload, or near-baseload, generation facilities, raising regional operating costs. Since the cost of energy production is a combination of fuel costs and heat rate, the combination of rising energy costs and more production from high heat rate units causes large increases in the cost of energy. As more high heat rate units operate more hours, the average cost of power increases even without a fuel cost increase. In addition, it is typical that as generation units mature past the mid-point of their average life there is a strong likelihood that heat rates will rise the further their age goes beyond the mid-point of the expected life.

Issue	Description
Operating and Spinning Reserve Requirements	Railbelt reliability criteria require spinning reserves equal to the largest operating unit and an operating reserve level of an additional 50% of the largest unit. In addition, the region's system target reserve margin is set at 30%. These reserve levels reflect the absence of interconnections, the relative operating impacts of limited resources and the necessity of maintaining reliability with the existing size of the system. Such high reserve margins affect total fuel and maintenance costs.

3.6 Future Resource Options

There are several issues regarding the future resource options that will be available to meet demand within the Railbelt region.

Issue	Description
Acceptability of Large Hydro and Coal	Much discussion has occurred in recent years about the future role that large hydroelectric and coal projects might play in meeting the electricity needs of the Railbelt region. Like other parts of the country and the world, the acceptability and economics of large hydroelectric and coal facilities are uncertain. Resolving the acceptability issues, and other related economic and environmental issues, associated with large hydro and coal will require the active involvement of the Governor and Legislature, as well as the Railbelt utilities and other stakeholders.
Carbon Tax and Other Environmental Restrictions	Another uncertainty facing the Railbelt utilities relates to the restrictions on carbon emissions, and the related economic impact, that might be imposed by Federal and/or State legislation, as well as other environmental restrictions (e.g., mercury limits) that will impact the technical and economic feasibility of various generation technologies. In the case of the imposition of carbon taxes, bills are currently working their way through the Federal legislative process, and additional bills may be introduced in the future. These bills each have different targets for the reduction of carbon emissions, and each will result in different levels of carbon taxes and/or different costs for the capturing and sequestering of carbon emissions. Depending upon the form of Federal and/or State carbon legislation ultimately enacted, the economics of fossil-fueled generation technologies could be significantly impacted.
Optimal Size and Location of New Generation and Transmission Facilities	Given the need to replace existing generation facilities and meet expected load growth, significant investments in new generation resources will be required. A very important issue that needs to be addressed by the Railbelt utilities is the optimal size and location of new generation and transmission facilities. This is, in fact, one of the factors driving the interest in the formation of a regional generation and transmission entity, and one of the primary reasons why this RIRP project was commissioned. When individual utilities make resource decisions that optimize the future resource mix for their own needs, the resulting regional resource mix will simply not be as optimal relative to the resource mix that result from a regional planning process. Additionally, decisions that will be made with regard to improving and expanding the Railbelt electric transmission grid will have a direct bearing of determining the optimal size and location of future generation resources.

Issue	Description
Limited Development – Renewables	Renewable generation technologies represent a significant opportunity for the Railbelt utilities relative to replacing aging generation facilities and meeting future load growth. To date, the Railbelt utilities have developed renewable resource technologies to a very limited degree, relative to the technical potential of these resources as well as relative to the level of deployment of these technologies in other regions of the country. While this limited use of renewable resources reflects, to a certain degree, the challenges of integrating such resources into a transmission-constrained grid and managing the power fluctuations on an individual utility basis, enhanced transmission infrastructure and regional coordination will create additional opportunities for renewables as part of the portfolio of resources. The issue of integrating technologies having variable outputs (i.e., non-dispatchable resources), such as wind and solar, into a fossil-fueled grid presents substantial operational challenges including the determination of the optimal level of these resources. Additionally, an important issue related to the implementation of renewables that needs to be addressed is whether the development of renewable resources should be accomplished by the individual Railbelt utilities or whether a regional approach would result in the more efficient and cost-effective deployment of these resources.
Limited Development – DSM/EE Programs	Similar to the comments above related to renewable resource technologies, the Railbelt utilities have limited experience with the planning, developing and delivering of DSM/EE programs. To date, the majority of efforts in the Railbelt region and the State as a whole have been focused on the implementation of home weatherization programs. These programs can significantly reduce the energy consumption within individual homes; however, given the limited saturation of electric space heating equipment and the general lack of air conditioning loads, the potential for DSM/EE programs are limited from the perspective of the Railbelt electric utilities. Notwithstanding this, additional opportunities do exist in this area. An implementation issue that needs to be addressed is whether the development and deployment of DSM/EE programs throughout the Railbelt region should be accomplished by the individual Railbelt utilities or whether a regional approach would result in more efficient and cost-effective deployment of these resources. Additionally, given the fact that the total monthly energy bills paid by residential and commercial customers in the Railbelt have increased significantly in recent years and given that natural gas is the predominant form of space heating within the majority of the Railbelt region, it may be appropriate for the electric utilities to work jointly with Enstar to develop DSM/EE programs that would be beneficial to both. This would create economies of scope for the region and reduce the delivery costs of DSM/EE programs.

3.7 Political Issues

The following political issues impact the current situation in the Railbelt region.

Issue	Description
Historical Dependence on State Funding	The Railbelt utilities have been dependent upon State funding for certain portions of the regional generation and transmission infrastructure, as well as for certain local infrastructure investments. Some of these investments have been made through the Railbelt Energy Fund; others have been direct appropriations by the Legislature. Regional State-funded infrastructure investments include the Alaska Intertie and Bradley Lake Hydroelectric Plant.
Proper Role for State	Historical State infrastructure-related investments have provided significant benefits to the residential and commercial customers in the Railbelt. Going forward, one question that needs to be answered is what the proper role of the State should be relative to the further development of the Railbelt region's generation and transmission infrastructure.

3.8 Risk Management Issues

The following issues relate to risk management, which has become increasingly important for all utilities.

Issue	Description
Need to Maintain Flexibility	As previously discussed, the recent increase in natural gas prices highlights the dangers inherent with an over-reliance on one fuel source or generation technology. Just as investors rely on a portfolio of assets, it is important for utilities to develop a portfolio of assets to ensure safe, reliable and cost-effective service to customers. It also demonstrates the importance of maintaining flexibility.
Future Fuel Diversity	Fuel supply diversity inherently has value in terms of risk management. Simply stated, the greater a region's dependence upon one fuel source, the less flexibility the region will have to react to future price and availability problems.
Aging Infrastructure	The fact that the generation and transmission infrastructure in the Railbelt region is aging, and that a significant percentage of the region's generation units are approaching the end of their expected lives, adds to the challenges facing utility managers. That represents the "half empty" view of the situation. The "half full" views leads one to a more positive perspective that the region has an unprecedented opportunity to diversify its resource mix and improve the overall efficiency of its generation fleet.
Ability to Spread Regional Risks	The level of uncertainty facing the Railbelt region continues to grow, as do the risks attendant to utility operations. One important approach to risk management is to spread the risk to a greater base of investors and consumers so that the impact of those risks on individuals is reduced. Simply stated, the ability of the region to absorb the risks facing it is greater on a regional basis than it is on an individual utility basis.

4.0 DESCRIPTION OF EXISTING SYSTEM

This section contains a general description of the generation and transmission resources currently in use in the Railbelt region. The existing system data was provided by the Railbelt utilities in response to data requests by Black & Veatch. Black & Veatch reviewed the data and, where necessary, applied judgment to the data to obtain a consistent set of existing system data for planning purposes. Detailed information on each existing generating unit is presented in Appendix C.

4.1 Existing Generating Resources

4.1.1 Anchorage Municipal Light & Power

ML&P operates seven combustion turbines (Units 1-5, 7, and 8) between two power plants, which operate on natural gas, and one steam turbine (Unit 6), which derives its steam from un-fired heat recovery steam generators (HRSGs). Units 1 and 2 are not available for normal dispatch, but are available if needed in an emergency. Unit 4 is dispatched on a normal, but infrequent basis. For this study, Units 1, 2, and 4 were not modeled. ML&P's other units provide approximately 280 MW of generating capability. Combustion turbines 5 and 7 have HRSGs, which allow them to operate in a combined cycle mode with the Unit 6 steam turbine. Unit 5 is frequently cycled when used in combined cycle or simple cycle mode. Unit 5 or Unit 7 may be operated in simple cycle mode when the steam turbine is unavailable. ML&P's existing thermal units are shown in Table 4-1.

Table 4-1
ML&P Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Anchorage ML&P – Plant 1	1[(1)]	Natural Gas	16.2	N/A
Anchorage ML&P – Plant 1	2[(1)]	Natural Gas	16.2	N/A
Anchorage ML&P – Plant 1	3	Natural Gas	32	2037
Anchorage ML&P – Plant 1	4[(1)]	Natural Gas	34.1	N/A
Anchorage ML&P – Plant 2	5	Natural Gas	37.4	2020
Anchorage ML&P – Plant 2	5/6	Natural Gas	49.2	2020
Anchorage ML&P – Plant 2	7	Natural Gas	81.8	2030
Anchorage ML&P – Plant 2	7/6	Natural Gas	109.5	2020
Anchorage ML&P – Plant 2	8	Natural Gas	87.6	2030
Anchorage ML&P – Plant 2	6	N/A	N/A	2030

[(1)]Denotes units not included in modeling for this study.

4.1.2 Chugach Electric Association

Chugach operates 13 combustion turbines between three power plants (Bernice 2-4, Beluga 1-7, and International 1-3) which operate on natural gas and one steam turbine (Beluga 8) which derives its steam from HRSGs. Chugach has approximately 500 MW of generating capability. Chugach's existing thermal units are shown in Table 4-2.

Table 4-2
Chugach Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Bernice	2	Natural Gas	19	2014
Bernice	3	Natural Gas	25.5	2014
Bernice	4	Natural Gas	25.5	2014
Beluga	1	Natural Gas	17.5	2011
Beluga	2	Natural Gas	17.5	2011
Beluga	3	Natural Gas	66.5	2014
Beluga	5	Natural Gas	65	2017
Beluga	6	Natural Gas	82	2020
Beluga	6/8	Natural Gas	108.5	2014
Beluga	7	Natural Gas	82	2021
Beluga	7/8	Natural Gas	108.5	2014
International	1	Natural Gas	14	2011
International	2	Natural Gas	14	2011
International	3	Natural Gas	19	2012

4.1.3 Golden Valley Electric Association

GVEA's generating capability of 278 MW is supplied by four generating facilities. The Healy Power Plant is a 27 MW coal-fired unit located adjacent to the Usibelli Coal Mine. GVEA's 187 MW North Pole Power Plant is oil-fired and built next to the Flint Hills refinery. The oil-fired Zehnder Power Plant in Fairbanks can provide 39 MW. The Delta Power Plant (DPP), formerly the Chena 6 Power Plant, can produce 26 MW. GVEA's existing thermal units are shown in Table 4-3.

Table 4-3
GVEA Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Zehnder	GT1	HAGO	19.2	2030
Zehnder	GT2	HAGO	19.6	2030
North Pole	GT1	HAGO	62.6	2017
North Pole	GT2	HAGO	60.6	2018
North Pole	GT3	NAPHTHA	51.3	2042
North Pole	ST4	STEAM	12	2042
Healy	ST1	COAL	27	2022
DPP	1	HAGO	25.8	2030

4.1.4 Homer Electric Association

HEA owns the natural gas Nikiski combustion turbine. During the summer months it can produce a maximum of 35 MW, whereas in the winter it provides 42 MW. This unit is shown in Table 4-4.

Table 4-4
HEA Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Nikiski	1	Natural Gas	42.0	2026

4.1.5 Matanuska Electric Association

MEA does not have any existing thermal units.

4.1.6 Seward Electric System

The City of Seward currently has three diesel generators in operation, each with capacities of 2.5 MW, and one diesel generator with a capacity of 2.9 MW. In this study, these small existing diesel generators are not included since the City of Seward is a full requirements customer of Chugach and the existing diesels are mainly used for back-up.

4.1.7 Hydroelectric Resources

Currently, each of the utilities in the Railbelt region has full or partial ownership in existing hydroelectric generation facilities. The hydroelectric generation plants include Bradley Lake (a 120 MW hydroelectric plant that under normal conditions dispatches up to 90 MW and provides an additional 27 MW of spinning reserves), Eklutna Lake hydroelectric facility (maximum capacity of 40 MW), and Cooper Lake hydroelectric facility (20 MW of capacity). Table 4-5 gives the percent ownership, average annual energy, and capacity for each utility for each of the existing hydroelectric plants. In the existing system, hydroelectric capacity and energy allocations are based on percent ownership, but in the RIRP modeling runs, all hydroelectric generation is placed geographically such that capacity and energy enter the Railbelt system from the areas in which the projects are physically located. The annual and monthly energy is based on the average historical energy generated at each plant for the previous 9-10 years (depending on historical plant data provided) and is presented in Table 4-6.

Table 4-5
Railbelt Hydroelectric Generation Plants

Utility	Bradley Lake[1]				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity (MW)	Spinning Reserves (MW)	Percent Allocation	Annual Energy (MWh)	Capacity (MW)	Percent Allocation	Annual Energy (MWh)	Capacity (MW)
MEA	13.8	54,383	12.4	3.7	16.7	26,056	6.7	0	0	0
HEA	12	47,289	10.8	3.2	0	0	0	0	0	0
CEA	30.4	119,800	27.4	8.2	30	46,806	12	100	41,342	20
GVEA	16.9	66,599	15.2	4.6	0	0	0	0	0	0
ML&P	25.9	102,066	23.3	7	53.3	83,159	21.3	0	0	0
SES	1	3,941	0.9	0.3	0	0	0	0	0	0
Total	**100**	**394,078**	**90**	**27**	**100**	**156,021**	**40**	**100**	**41,342**	**20**

[1]The values for capacity and spinning reserves represent normal operation. The plant has a nameplate capacity of 126 MW with a nominal rating of 120 MW.

Table 4-6
Hydroelectric Monthly and Annual Energy (MWh)

Month	Bradley Lake	Eklutna Lake	Cooper Lake
January	28,688	11,153	3,696
February	29,448	10,653	3,421
March	31,737	12,374	3,967
April	28,829	12,039	3,687
May	28,643	10,094	3,854
June	31,586	13,425	4,072
July	35,372	14,547	4,361
August	37,881	17,954	3,328
September	37,728	17,494	3,388
October	37,654	14,102	2,421
November	34,152	11,452	2,198
December	32,360	10,734	2,951
Total	**394,078**	**156,021**	**41,342**

4.1.8 Railbelt System

Table 4-7 shows the resulting total capacity for each utility within the Railbelt region.

Table 4-7
Railbelt Installed Capacity

Utility	Thermal Existing Capacity	Bradley Lake Capacity(1)	Eklutna Lake Capacity	Cooper Lake Capacity	Total
MEA	0	16.1	6.7	0	22.8
HEA	42	14.0	0	0	56.0
CEA	500.5	35.6	12	20	568.1
GVEA	278.1	19.8	0	0	297.9
ML&P	278.3	30.3	21.3	0	329.9
SES	0	1.2	0	0	1.2
Total	**1,098.9**	**117**	**40**	**20**	**1,275.9**

(1)The nameplate rating for Bradley Lake is 126 MW with 90 MW dispatchable and 27 MW available for spinning reserves under normal conditions.

4.2 Committed Generating Resources

Committed generating resources are generating units planned by the individual Railbelt utilities and which are considered committed for installation by the individual Railbelt utilities. Table 4-8 summarizes the cost and performance estimates for the committed units. The cost and performance information was either provided by the individual Railbelt utilities or estimated by Black & Veatch. Cost information is presented in 2009 dollars. The following subsections briefly describe each of the committed units. The committed units are not included in the Reference Case Scenarios; this is discussed further in Section 13.

4.2.1 Southcentral Power Project

The Southcentral Power Project, previously known as the South Central Alaska Power Project, is a 3x1 natural gas fired, combined cycle project that utilizes GE LM6000 combustion turbines for a total capacity of approximately 180 MW. Currently, the project is to be jointly owned by Chugach and ML&P with 70 percent of the capacity owned by Chugach and the remaining 30 percent to be owned by ML&P. For modeling purposes, the entire 180 MW is included in the Anchorage area, which is comprised of both Chugach's and ML&P's service areas. The capital cost for the Southcentral Power Project is approximately $370 million with an estimated 2013 commercial operation date. A significant portion of the cost of this unit has already been spent.

4.2.2 ML&P Units

ML&P plans to add two units to its system by 2014. The addition of these units will allow ML&P to retire some of its older, less efficient units. In 2012, ML&P plans to install a GE LM2500 simple cycle combustion turbine with an estimated output of 30 MW. The capital cost associated with this unit is estimated to be $43 million in 2009 dollars. ML&P also plans to construct a GE LM6000 combined cycle plant for commercial operation by 2014. The output of this plant is estimated at 58 MW. The capital cost associated with this project is approximately $95 million in 2009 dollars.

Table 4-8
Railbelt Committed Generating Resources[1]

Plant Name	Area	Capital Cost ($000)	Maximum Winter Capacity (MW)	Full Load Heat Rate (Btu/kWh)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Commercial Online Date
Southcentral Power Project	Anchorage	370,000	180	7,091	4.29	15.38	2013
ML&P 2500 Simple Cycle	Anchorage	43,200	30	9,960	2.32	28.72	2012
MLP LM6000 Combined Cycle	Anchorage	95,200	58	7,091	2.32	26.45	2014
Healy Clean Coal Project	GVEA	95,000	50	11,090	8.44	79.53	2011/2014
HEA Aeroderivative	HEA	[2]	34	8,800	3.85	64.42	2014
HEA Frame	HEA	[2]	42	11,500	3.08	79.07	2014
Nikiski Upgrade	HEA	[2]	77 (34 incremental)	10,000	2.91	4.83	2012
Eklutna Generation Station	MEA	356,000	187	8,500	4.29	15.38	2015
Seward Diesel #N1	City of Seward	7,200	2.9	9,200	11.41	31.93	2010
Seward Diesel #N2	City of Seward	1,100	2.5	9,200	11.41	31.93	2011

[1] 2009 dollars
[2] HEA has requested that their cost estimates remain confidential while they are obtaining their bids.

4.2.3 Healy Clean Coal Project

The Healy Clean Coal Project (HCCP) resulted from a nationwide competition held by the Department of Energy (DOE) to address the issues surrounding acid rain. The project is located adjacent to Golden Valley's current Healy 1 coal-fired power plant. HCCP utilizes a staged combustion process and other methods to minimize the formation of nitrogen and sulfur oxides. Construction and testing of the project was completed in December 1999, but issues were raised concerning the operations and maintenance cost, reliability, and safety of the project[1].

After several years of legal disputes, an agreement was reached for the sale of HCCP to GVEA. GVEA will pay $50 million for the plant "as is" and will have a line of credit up to $45 million to get the unit operating up to GVEA's standards and to integrate the plant into its system. For the RIRP, Black & Veatch has assumed the entire $95 million will be paid by GVEA. The project has an assumed commercial on-line date of 2011, but is expected to have poor reliability initially. GVEA will back up 100 percent of the plant's output with spinning reserve and its battery energy storage system (BESS) until plant reliability improves and settles by 2014. For modeling purposes, Black & Veatch has assumed a 50 percent forced outage rate for HCCP beginning in 2011 and decreasing linearly to the steady state forced outage rate of 3 percent in 2014. Because the HCCP is currently built, it is considered as an alternative in all the model runs except for the committed units case, where it is forced in along with the other committed units in this section.

4.2.4 HEA Units

Currently, HEA is an all requirements customer of Chugach in that they receive all of their electric needs from Chugach. The existing agreement expires in 2014 at which time HEA plans to supply its own load. In order to reliably serve its customers at that time, HEA must have generation built or supply contracts to support its service area. HEA has indicated plans to upgrade one of its existing units and build two new units before becoming independent. In 2012, HEA plans to complete an upgrade of its existing Nikiski unit from simple cycle to a combined cycle configuration. The upgrade would add 34 MW to the power plant and bring the plant's capacity from 43 MW to 77 MW. HEA is also planning to construct a new simple cycle aeroderivative unit in 2014 with approximately 34 MW of capacity. HEA may purchase reserves instead of installing the aeroderivative. Also in 2014, HEA plans to build a simple cycle frame unit with approximately 42 MW of capacity.

4.2.5 MEA Units

In a situation similar to that of HEA, MEA is currently an all requirements customer of Chugach and plans to be responsible for supplying their own load by 2015. In order to provide reliable service to MEA's customers, it must plan to build generation at that time. Currently, MEA's only source of power generation is the Eklutna hydroelectric power plant. MEA plans to build the Eklutna Generation Station in 2015 with an estimated 180 MW of natural gas fired capacity. Since the project is in the early stages of conceptualization, much of the unit's performance and cost information have been estimated by Black & Veatch and is similar to that of the Southcentral Power Project. The capital cost for this project was developed using the same $/kW amount as the Southcentral Power Project and is estimated at $370 million in 2009 dollars.

4.2.6 City of Seward Diesels

The City of Seward currently has four diesel generators in operation totaling approximately 10 MW. Although these four generators have not been included in the existing RIRP modeling, the City of Seward's future diesel generators are being included in the committed units sensitivity case. The existing diesels were not included because Seward is a full requirements customer of Chugach and the existing diesels are primarily used for back-up. Seward plans to install two more diesel generators in 2010 and 2011. Generator #N1 is

[1] http://www.aidea.org/PDF%20files/HCCP/HCCPFactSheet.pdf.

scheduled to be installed in the spring 2010 with an output of 2.9 MW. The capital cost for #N1 is estimated at $7.2 million in 2009 dollars. Generator #N2 is scheduled to be installed in the spring 2011 with an output of 2.5 MW. Generator #N2 currently exists, but is not connected to the City of Seward's electrical system. The estimated cost for bringing #N2 to operation and for interconnection is $1.0 million in 2009 dollars.

4.3 Existing Transmission Grid

For purposes of the RIRP study, the Railbelt transmission system is separated into four main load centers: GVEA or the interior, MEA, Anchorage comprised of Chugach's and ML&P's service areas, and the Kenai comprised of HEA and the City of Seward. Within each load center, energy is assumed to flow freely without transmission constraints. The existing transmission system of the Railbelt may be characterized as weak and in need of development. Power transfer between areas of the system is currently constrained by weak transmission links and stability constraints. Generating reserves cannot be readily shared between areas and project development activities are seriously affected.

GVEA's service area is connected with 138 kV lines that supply Delta Junction, Fairbanks, and Healy.

The interior and MEA load centers are interconnected via the Alaska Intertie and the Healy-Fairbanks and Teeland-Douglas transmission lines. The Alaska Intertie is a 345 kV (operated at 138 kV), 170-mile transmission line that is owned by the AEA connecting the Douglas and Healy substations. The Healy-Fairbanks transmission line is a 230 kV, 90-mile transmission line, operated at 138 kV, and runs from the Healy to the Wilson substations which deliver power from the Alaska Intertie directly into the city of Fairbanks. Another 138 kV transmission line also runs from Healy to Nenana to Goldhill and delivers power to Fairbanks. The 138 kV, 20-mile Douglas-Teeland transmission line stretches between the Douglas and Teeland substations and connects the southern portion of the Alaska Intertie to the MEA load center. The current transfer capability of the Alaska Intertie and Healy-Fairbanks transmission lines is assumed to be 75 MW and 140 MW, respectively.

MEA serves customers down the southern half of the intertie and south of the intertie through the towns of Wasilla and Palmer.

The Anchorage load center consists of ML&P's, and Chugach's service territories. ML&P serves the load of the residents and businesses in the central core of Anchorage. Chugach also serves residents and businesses in Anchorage along with the area south of Anchorage, the City of Seward, and into the southern portion of the Kenai Peninsula. For modeling purposes, the City of Seward's load and generation have been placed in the Kenai peninsula to allow economic commitment and dispatch in accordance with GRETC.

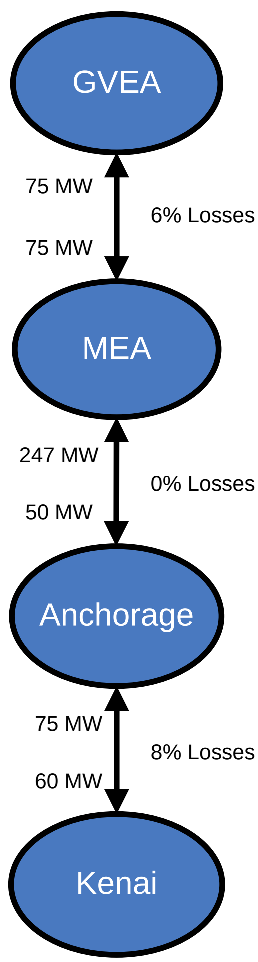
The MEA and Anchorage load centers are connected via two transmission lines. A 230 kV transmission line connects the Teeland substation to Chugach's Beluga plant in the western portion of the Anchorage load center. A 115 kV transmission line connects the Eklutna Hydro Project and runs through ML&P's area, continuing into Chugach's service territory. The current total transfer capability of these lines is assumed to be 250 MW when power is flowing north into MEA and 50 MW when power is flowing south into Anchorage.

The Anchorage and Kenai load centers are connected via a 135-mile, 115 kV transmission line, referred to as the "Southern Intertie," which connects the Chugach system to that of the Kenai Peninsula. The current transfer capability of the Southern Intertie is assumed to be 75 MW when power is flowing north to Anchorage, and 60 MW when the flow is south into the Kenai.

The Kenai load center consists of HEA's and the City of Seward's service territories. The HEA service area includes the cities of Homer and Soldotna.

Figure 4-1 shows the current Railbelt transmission transfer paths, four load centers, and existing transfer capability as modeled. Transfer capability varies depending on generating unit availability and performance as well as on direction of power flow between the areas. The transfer capabilities shown in Figure 4-1 represent the total MW transferable between the respective areas in the indicated direction with no transmission criteria violated. Major generating project additions requiring interconnection to the system are modeled as specific additional areas to appropriately account for transmission losses. Projects that require such areas are Susitna and Chakachamna hydroelectric, Mt. Spurr geothermal, and Turnagain Arm tidal. As transmission lines are added to the system throughout the planning period, transfer capabilities and transmission losses are modeled.

Figure 4-1
Railbelt Existing Transmission System as Modeled



4.3.1 Alaska Intertie

The Alaska Intertie is a 170-mile long, 345 KV transmission line between Willow and Healy that is owned by the AEA. The Intertie was built in the mid-1980s with State of Alaska appropriations totaling $124 million. There is no outstanding debt associated with this asset.

The Intertie is one of a number of transmission segments that, when connected together, can move power throughout the network from Delta, through Fairbanks to Anchorage down to Seldovia in the south. This interconnected system of utilities, tied together with the Intertie is collectively termed the "Railbelt Electric Grid System."

The operation of the Intertie is governed by an agreement that was negotiated in 1985 between the predecessor of AEA, the Alaska Power Authority (APA), and four utility participants: ML&P, Chugach, GVEA, and AEG&T Cooperative, Inc., which is comprised of HEA and MEA. All of the utility participants are connected to the Intertie and can move power on and off the Intertie.

For example, GVEA uses the Intertie to purchase non-firm economy energy from ML&P and Chugach. As another example, the Railbelt Electric Grid System is used to transfer power from the Bradley Lake Hydroelectric Plant, which is located east of Homer just below the glacier-fed Bradley Lake. Each of the Railbelt utilities has rights for a specified percentage of the power output from Bradley Lake as shown in Table 4-5. GVEA owns a portion of the capacity and energy available from Bradley Lake, and it transmits this power north to its service area over the AEA Intertie. In practice, however, the GVEA's power from Bradley Lake is displaced by power sold by Chugach to HEA and Seward.

Both functional operation of the transmission line, as well as arrangements for the collection of and expenditure of annual operations and maintenance funds, are a part of the agreement. The agreement also specifies a governance structure that consists of representatives from the participating utilities and AEA.

The agreement specifies, through interconnection terms and conditions, how utilities are allowed access to the Intertie. Each utility is required to maintain spinning reserve to preserve the reliability of electrical supply throughout the network.

4.3.2 Southern Intertie

The Southern Intertie consists of approximately 130 miles of 115 kV transmission line constructed some 50 years ago that connects the Anchorage area operated by the Chugach, and the Kenai peninsula operated by HEA. The Southern Intertie connects the Soldotna substation and the University substation by way of Quartz Creek, Daves Creek and several other load serving taps between Daves Creek and the University substation. The section from Soldotna to Quartz Creek is owned and operated by HEA while the section from Daves Creek to the University substation is owned and operated by Chugach.

The HEA section of the Southern Intertie is in poor condition, routed through swampy terrain, and is consequently affected by frost jacking which pushes the poles out of the ground. The Chugach section of the intertie runs through areas susceptible to frequent avalanches. Several sections have been rebuilt; however, over 60 percent of the line's structures are in need of repairs. Although the thermal limit of the 115 kV line is considered to be approximately 145 MW, this intertie is limited to a transfer limit of approximately 75 MW by stability considerations. The intertie is currently used to transfer power from the jointly owned Bradley Lake Hydro Units to utilities in the Anchorage area. This line is considered essential to the development and operation of an integrated Railbelt transmission system.

4.3.3 Transmission Losses

Existing transmission losses have been modeled between the four major load centers. The percentage of losses varies with the load on the transmission lines. Losses for each of the connections between the four load centers that are included in the models are illustrated in Figure 4-1 and represent a percentage of the total flow along the lines. The losses shown represent the losses applied to power flowing both north and south.

4.4 Must Run Capacity

Must run capacity are units that are run to maintain the reliability of the Railbelt system regardless of whether they are the most economical generation available. Must run capacity can also result from purchase power contracts which require the utility to purchase the power at all times. Additionally, must run capacity can result from a generating unit not having the capability to be shutdown and started up in response to economic commitment and dispatch. Units are also required to run to maintain voltage and stability. The Railbelt Utilities have indicated the following three units are current must run capacity units and have been modeled as such.

- Nikiski through 2013
- Healy 1
- Aurora Purchase Power

5.0 ECONOMIC PARAMETERS

The economic parameters are those necessary for developing the expansion plans using Strategist® and determining the costs associated with those expansion plans. They include inflation, escalation, financing, present worth discount rate, interest during construction interest rate, and development of fixed charge rates.

5.1 Inflation and Escalation Rates

Escalation rates have been developed for capital and O&M costs and are consistent with the general inflation rate. The same general inflation rate and escalation rates were used for all Railbelt utilities. For evaluation purposes, 2.5 percent was used for annual general inflation and escalation.

5.2 Financing Rates

The cost of capital was assumed to be 7 percent.

5.3 Present Worth Discount Rate

The present worth discount rate was assumed to be equal to the cost of capital, of 7 percent.

5.4 Interest During Construction Interest Rate

The interest during construction interest rate was assumed to be 7 percent.

5.5 Fixed Charge Rates

Fixed charge rates were developed for new capital additions based on the cost of capital. The fixed charge rates were based on the assumption of using taxable financing, and further assumed 100 percent debt. In developing financing assumptions, Seattle Northwest Securities Corporation was consulted and a general consensus developed for purposes of estimating the cost of capital for evaluation purposes.

The fixed charge rates include the following components in addition to debt amortization:

- Issuance costs for debt - 2 percent
- Property insurance - 0.5 percent
- Property taxes - 0.5 percent
- Debt service reserve funds - 1 year
- Earnings on reserve funds - 7 percent

Levelized fixed charge rates were developed for the following financing terms as appropriate. Table 5-1 summarizes these terms as modeled for the GRETC system:

- Simple Cycle Combustion Turbines - 25 years
- Combined Cycle Units - 30 years
- Coal Units - 30 years
- Hydro Units - 100 years
- Wind - 20 years
- Municipal Solid Waste – 30 years
- Tidal - 20 years
- Geothermal - 25 years
- Generic Greenfield Nuclear - 30 years

Table 5-1
Cost of Capital and Fixed Charge Rates for the GRETC System

Cost of Capital (%)	Levelized Fixed Charge Rates (%) Financing Terms (Years)			
	20	25	30	100
7.0	10.543	9.536	8.925	8.163

The fixed charge rates were used for Strategist® to ensure that all alternatives for expansion plans were selected on a consistent basis. The 100-year term for hydro units, while longer than traditional financing, was selected based on the long life span of hydro units so that hydro units would be considered on this consistent basis by Strategist®.

6.0 FORECAST OF ELECTRICAL DEMAND AND CONSUMPTION

6.1 Load Forecasts

Load forecasts were provided by the utilities in response to a Black & Veatch data request. Since the RIRP Study has a 50-year planning horizon, load forecast data was extrapolated through 2060. The load forecast does not include incremental DSM/EE programs not inherently included in the utilities' forecasts.

6.2 Load Forecasting Methodology

Each of the utilities provided load forecasts spanning different lengths of time that required extrapolation to develop annual peak and energy requirements for the GRETC electrical system over the 50-year study period. Typically, simple extrapolation of load forecasts is based on exponential growth by using the average annual percentage growth rate for the last 5 or 10 years. This potentially can lead to over forecasting when these percentage growth rates are applied over long periods of time. To compensate for this potential over forecasting, Black & Veatch extrapolated the load forecasts in two different ways and took the average of the two extrapolated forecasts as the forecast used in the RIRP. The first method of extrapolation was the typical approach of extrapolating at the average annual percentage load growth over the last 10 years of the forecast. The second method extrapolated the average annual increase in load over the last 10 years of the forecast. In addition to peak load forecasts, annual minimum load, or valley, forecasts were also developed for the GRETC system. The peak and valley demand and net energy for load requirements forecasts are provided in the following subsection; it should be noted that demand and energy forecasts do not include transmission losses between utilities.

6.3 Peak Demand and Net Energy for Load Requirements

Tables 6-1 and 6-2 present the winter and summer peak demand forecasts for each utility as well as the coincident winter and summer peak demands for the GRETC system. The coincident peak demand forecasts were developed by combining all of the utilities' hourly load profiles for 2008 and calculating the 2008 coincident peak demands. The resulting coincident peak demands were compared to the 2008 non-coincident peak demands to develop coincident factors. These factors were applied seasonally to the noncoincident peak demand for both winter and summer months of the study period to develop the resulting coincident peak demand forecasts for the GRETC system.

Table 6-3 presents the annual valley demand forecasts for each utility and the coincident valley demands for the GRETC system. The valley demand forecasts for each utility were developed by taking the minimum load for each utility from the provided hourly load information for 2008. Valley demand forecasts for 2011 and beyond were calculated for each utility by applying the annual increase in peak demands to the valleys. A non-coincident value was calculated by summing up the minimum load for each utility and the result was compared to the coincident minimum load value for the GRETC system that was developed by taking the minimum load from the GRETC hourly profile to develop a valley coincident factor. The resulting valley coincident factor was applied to the annual non-coincident valley load for the GRETC system to develop a coincident valley demand forecast through 2060.

The net energy for load requirements for the GRETC system were developed by taking the sum of all the utilities' individual energy requirements. The resulting net energy for load forecast is provided in Table 6-4.

Table 6-1
GRETC's Winter Peak Load Forecast for Evaluation (MW)
2011 - 2060

Year	Winter Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	233.9	238.1	87.0	146.0	188.0	9.5	869.3
2015	234.5	217.5	89.0	157.0	192.0	10.4	867.8
2020	238.1	226.0	92.0	167.0	197.0	10.4	896.3
2025	242.2	234.3	96.0	178.0	202.0	10.4	927.5
2030	246.9	242.8	100.0	188.0	207.0	10.4	959.0
2035	251.6	251.5	104.0	199.0	212.1	10.4	991.2
2040	256.3	260.3	108.1	210.4	217.2	10.4	1,024.1
2045	261.1	269.2	112.3	222.1	222.5	10.4	1,057.7
2050	265.9	278.4	116.5	234.2	227.7	10.4	1,092.0
2055	270.7	287.7	120.9	246.8	233.1	10.4	1,127.1
2060	275.7	297.3	125.4	259.7	238.5	10.4	1,163.0

Table 6-2
GRETC's Summer Peak Load Forecast for Evaluation (MW)
2011 - 2060

Year	Summer Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	160.6	191.4	75.1	91.1	167.2	10.0	668.0
2015	161.3	174.8	76.8	95.5	170.8	11.0	666.8
2020	163.4	181.6	79.4	95.0	175.2	11.0	688.7
2025	166.3	188.3	82.8	99.9	179.7	11.0	712.7
2030	169.9	195.2	86.3	105.9	184.1	11.0	736.9
2035	173.1	202.1	89.7	112.5	188.7	11.0	761.6
2040	176.3	209.2	93.3	119.3	193.2	11.3	786.9
2045	179.6	216.4	96.9	126.4	197.9	11.6	812.7
2050	182.9	223.8	100.5	133.7	202.6	11.9	839.1
2055	186.3	231.3	104.3	141.3	207.3	12.2	866.0
2060	189.6	238.9	108.2	149.1	212.2	12.5	893.6

Table 6-3
GRETC's Annual Valley Load Forecast for Evaluation (MW)
2011 - 2060

Year	Annual Valley Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	95.4	88.6	44.4	53.2	91.0	4.4	413.5
2015	95.8	81.0	45.5	57.2	92.9	4.8	413.7
2020	97.1	84.1	47.0	60.9	95.3	4.8	426.9
2025	98.8	87.2	49.0	64.9	97.7	4.8	441.4
2030	100.9	90.4	51.1	68.5	100.2	4.8	456.1
2035	102.8	93.6	53.1	72.6	102.6	4.8	471.1
2040	104.8	96.9	55.2	76.7	105.1	4.8	486.4
2045	106.7	100.2	57.3	81.0	107.6	4.8	502.0
2050	108.7	103.6	59.5	85.4	110.2	4.8	517.9
2055	110.7	107.1	61.7	90.0	112.8	4.8	534.2
2060	112.7	110.7	64.0	94.7	115.4	4.8	550.9

Table 6-4
GRETC's Net Energy for Load Forecast for Evaluation (GWh)
2011 - 2060

Year	Utility Net Energy for Load Forecast (GWh)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	1,302.0	1,522.7	554.5	771.2	1,162.8	64.6	5,377.8
2015	1,311.4	1,333.5	568.1	831.9	1,184.9	65.6	5,295.3
2020	1,334.5	1,373.4	591.2	888.3	1,213.0	67.4	5,467.8
2025	1,359.2	1,403.8	615.5	946.4	1,241.7	69.3	5,636.0
2030	1,384.5	1,434.7	640.0	1,004.7	1,271.2	71.2	5,806.3
2035	1,409.9	1,465.7	665.1	1,065.4	1,300.9	73.1	5,980.1
2040	1,435.5	1,497.1	690.7	1,128.1	1,330.9	75.1	6,157.4
2045	1,461.4	1,528.9	716.8	1,192.9	1,361.3	77.1	6,338.4
2050	1,487.5	1,561.1	743.5	1,259.9	1,392.1	79.1	6,523.2
2055	1,513.9	1,593.6	770.8	1,329.4	1,423.2	81.1	6,712.0
2060	1,540.5	1,626.5	798.7	1,401.4	1,454.7	83.2	6,905.0

The GRETC peak demand is projected to increase at an average annual rate of 0.6 percent and average annual GRETC system energy is projected to increase at 0.5 percent.

Appendix D presents the annual forecasts for winter and summer peak demand, system valley, and net energy for load.

6.4 Significant Opportunities for Increased Loads

As discussed in Section 2, a scenario representing a significant increase in load was evaluated in addition to the base case load forecast. This section evaluates some potential increases in load that could lead to the large increase in load scenario; Black & Veatch is not predicting that these additional loads will occur (such prediction is outside of the scope of this project) but, rather, offers this discussion to illustrate some of the ways that the regional load could increase significantly.

6.4.1 Plug-In Hybrid Vehicles

Energy security and climate change issues are driving change in the transportation sector now more than ever. With the potential of carbon legislation and the possibility of high gasoline prices returning , there is an increased need to consider new advanced technology vehicles that hold the promise of considerably improving fleet energy efficiency and reducing fleet carbon footprint, such as plug-in hybrid vehicles (PHEV).

According to a recent study conducted by the Transportation Research Institute at University of Michigan (UMTRI)[1], fleet penetration of PHEVs is expected to reach 1 percent of the national market by 2015, 2 percent by 2020, and 16 percent by 2040 (Table 6-5). Since these vehicles cost a lot more than their conventional counterparts, especially in the near term, their market viability depends heavily on government subsidies and incentives. This study assumes that appropriate government policy initiatives were instituted to enable successful market penetration. Market penetration estimates from an ORNL study[2] predict that nationwide penetration will not surpass 25 percent (Table 6-5).

Table 6-5
Projected PHEV Penetration in the American Auto Market

Year	PHEV Penetration (%)
2015	1
2020	2
2040	16
2060	25

[1] "PHEV Marketplace Penetration: An Agent Based Simulation;" Sullivan, Salmeen, and Simon; July 2009.
[2] "Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation;" Hadley and Tsvetkova; January 2008.

Given that the Alaska Railbelt region had 53 percent of all vehicles in the state in 2008 (338,943)[3], that the average daily personal vehicle travel in the Alaska Railbelt area is 32 miles/day[4], and that the average PHEV33 (a vehicle capable of running 33 miles on a single charge) requires 0.35 kWh of energy per mile[5] (Table 6-6), it is assumed the Alaska Railbelt region could experience an increase in annual energy as shown in Table 6-7.

Table 6-6
Electric Consumption for a PHEV33 PNNL Kinter-Meyer

Vehicle Class	Specific Energy Requirements (kWh/mile)
Compact Sedan	0.26
Mid-size Sedan	0.30
Mid-size SUV	0.38
Full-size SUV	0.46
Average	**0.35**

Table 6-7
Additional Annual Energy Required in the Alaska Railbelt Region from PHEVs

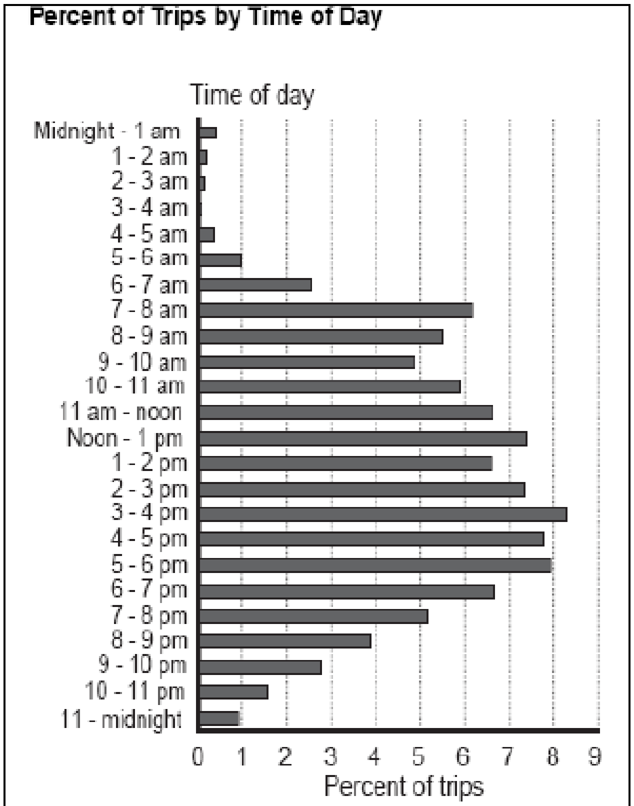
Year	Additional Load from PHEVs (MWh/year)
2015	14,736
2020	31,242
2040	327,489
2060	679,391

PHEVs can be plugged in and recharged when they are not on the road, which according to Figure 6-1 occurs in the late evening or early morning.

Consistent with the previous observation, a study conducted by EPRI/NRDC assumed that 70 percent of the charging would occur "off-peak," when electric demand is relatively low (Figure 6-2). Rate designs, such as night rates, and time-of-use rates, could provide electric customers with incentives to utilize "off-peak" charging.

[3] Registered vehicles in 2008, including only pickups and passenger vehicles. Division of Motor Vehicles from the Alaska Department of Administration.
[4] From interviews to local car insurance companies conducted by NORECON.
[5] Pacific Northwest National Laboratory (PNNL). Kinter-Meyer.

Figure 6-1
US Daily Driving Patterns



SOURCE: The 2001 National Household Travel Survey, daily trip file, U.S. Department of Transportation.

Figure 6-2
PHEV Daily Charging Availability Profile

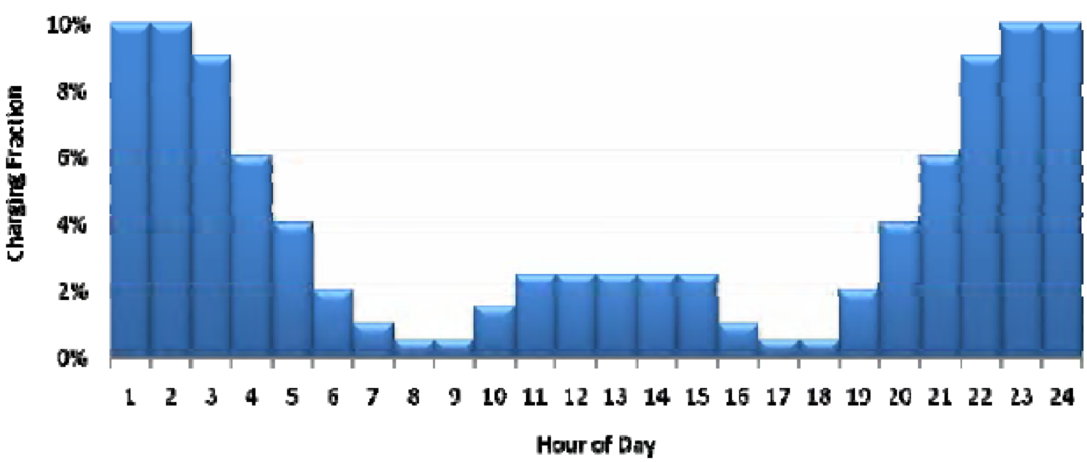


Table 6-8 and Figure 6-3 show how the extra load from PHEVs would likely be distributed on a typical day.

This high penetration of PHEVs scenario has the potential to increase the energy requirement of the Alaska Railbelt system by as much as 9.8 percent in 2060. Figure 6-4 and Table 6-9 illustrate these impacts.

This high penetration of PHEVs scenario has the potential to increase the peak demand of the Alaska Railbelt system by as much as 5.5 percent in 2060. There would also be a shift in the peak hour from the 18th hour to the 22nd hour of the peak day by 2060. Figure 6-5 and Table 6-10 illustrate these impacts.

Table 6-8
Hourly Distribution of PHEV Load on a Typical Day – Alaska Railbelt Region

Hour of Day	Charging Fraction (%)	Typical Day Hourly Load (MW)				
		2010	2015	2020	2040	2060
1	10	0	4.0	8.6	89.7	186.1
2	10	0	4.0	8.6	89.7	186.1
3	9	0	3.6	7.7	80.8	167.5
4	6	0	2.4	5.1	53.8	111.7
5	4	0	1.6	3.4	35.9	74.5
6	2	0	0.8	1.7	17.9	37.2
7	1	0	0.4	0.9	9.0	18.6
8	0.5	0	0.2	0.4	4.5	9.3
9	0.5	0	0.2	0.4	4.5	9.3
10	1.5	0	0.6	1.3	13.5	27.9
11	2.5	0	1.0	2.1	22.4	46.5
12	2.5	0	1.0	2.1	22.4	46.5
13	2.5	0	1.0	2.1	22.4	46.5
14	2.5	0	1.0	2.1	22.4	46.5
15	2.5	0	1.0	2.1	22.4	46.5
16	1	0	0.4	0.9	9.0	18.6
17	0.5	0	0.2	0.4	4.5	9.3
18	0.5	0	0.2	0.4	4.5	9.3
19	2	0	0.8	1.7	17.9	37.2
20	4	0	1.6	3.4	35.9	74.5
21	6	0	2.4	5.1	53.8	111.7
22	9	0	3.6	7.7	80.8	167.5
23	10	0	4.0	8.6	89.7	186.1
24	10	0	4.0	8.6	89.7	186.1
Total	**100**	**0**	**40**	**86**	**897**	**1,861**

Figure 6-3
Hourly Distribution of PHEV Load on a Typical Day – Alaska Railbelt Region

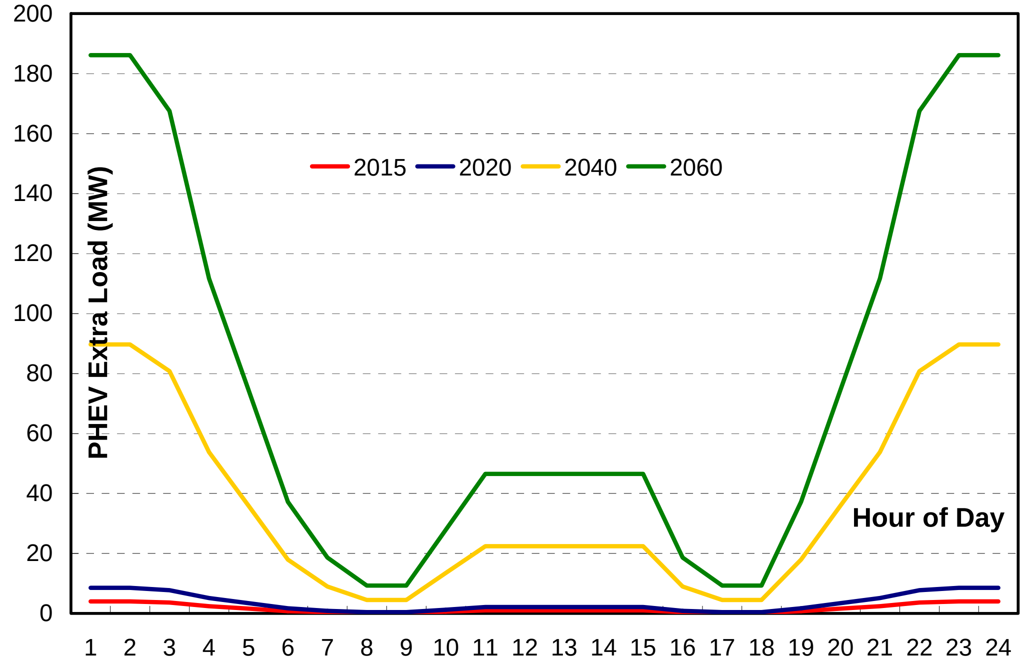


Figure 6-4
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Energy Requirement

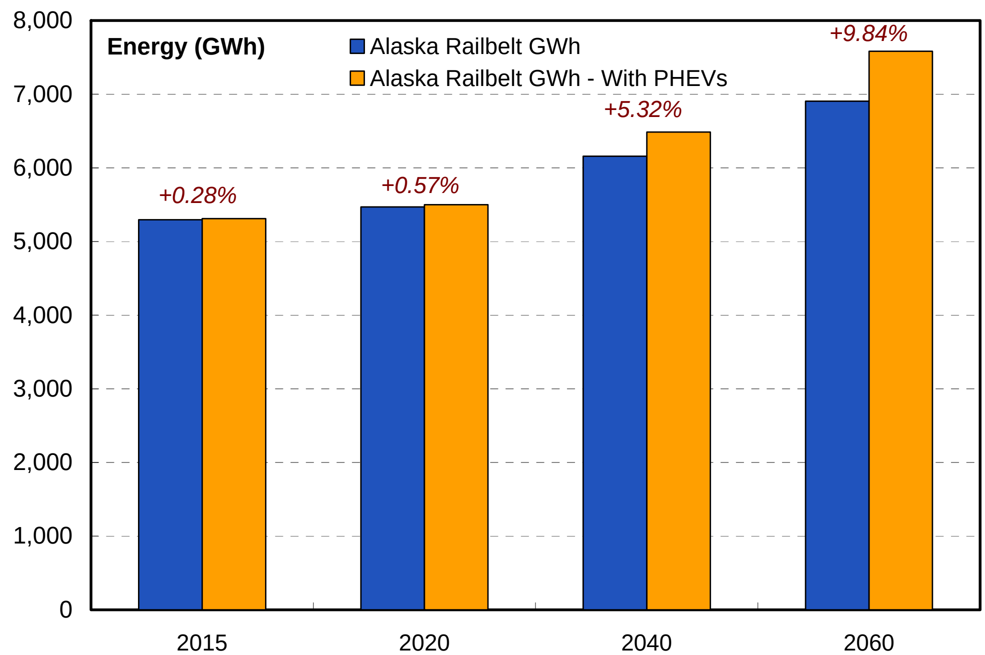


Table 6-9
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Energy Requirement

	2015	2020	2040	2060
Alaska Railbelt GWh	5,295	5,468	6,157	6,905
Alaska Railbelt GWh - With PHEVs	5,310	5,499	6,484	7,584
Percent Increase	0.28	0.57	5.32	9.84

Figure 6-5
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Peak Demand

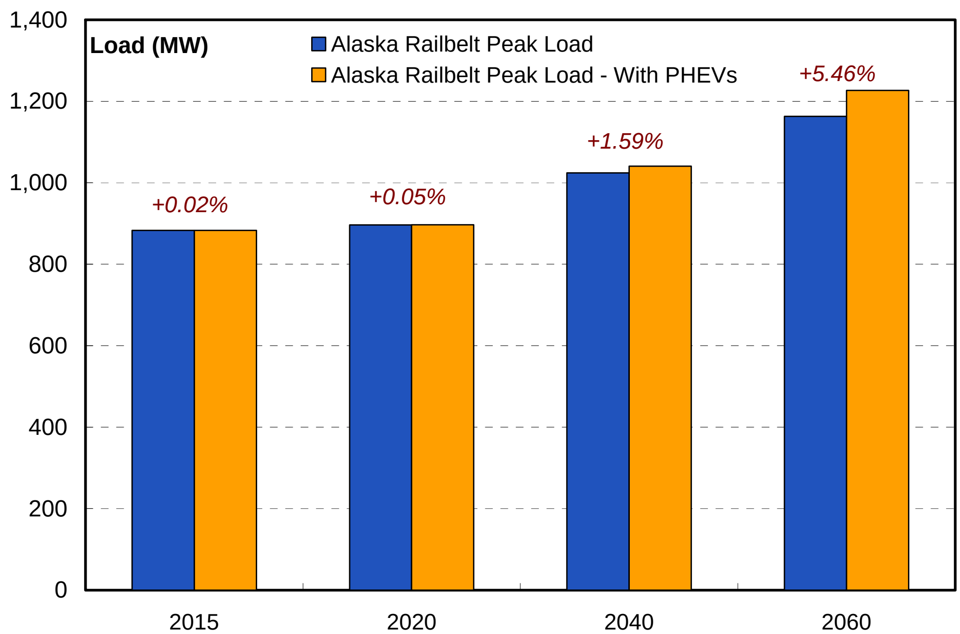


Table 6-10
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Peak Demand

	2015	2020	2040	2060
Alaska Railbelt Peak Load	882.70	896.30	1,024.10	1,163.00
Alaska Railbelt Peak Load - With PHEVs	882.90	896.73	1,040.36	1,226.45
Percent Increase	0.02	0.05	1.59	5.46
Peak Hour	18	18	20	22

6.4.2 Electric Space and Water Heating Load

Another means of significantly increasing electric demand within the region would to encourage increased penetration of electric space and water heating. ENSTAR Natural Gas is the primary supplier of natural gas within the State of Alaska along with Barrow Utilities Electric Coop and Fairbanks Natural Gas. Natural gas consumption within the State is almost evenly distributed between residential, commercial and industrial customers. The Energy Information Administration (EIA) publishes statistics on natural gas on an annual basis. Table 6-11 provides a summary of 2007 data for the state of Alaska.

Table 6-11
2007 Natural Gas Consumption for the State of Alaska (Source: EIA)

	Residential Customers	Commercial Customers	Industrial Customers
Natural Gas Delivered (MMcf)	19,840	18,760	19,750

For purposes of this discussion, it is assumed that 100 percent of the gas consumption within the State of Alaska applies to the Railbelt region, given that an estimated 97 percent or more of natural gas is consumed within the region. According to the American Gas Association, space and water heating accounts for approximately 85 percent of the natural gas application in the New England region for residential customers. It is assumed that a similar proportion is applicable to commercial customers. The percentage of industrial consumption related to space and water heating is negligible compared to other applications and, therefore, is not included in this study. Table 6-12 contains the calculated energy and demand if all residential and commercial space and water heating requirements were met through electricity, based on a 2007 heating value of 1,005 Btu/cf, published by the EIA for the State of Alaska. The energy and demand calculations assume that natural gas space and water heating are 85 percent efficient. Peak demand is based on the residential natural gas load factor for the state of 39 percent.

Table 6-12
Calculated Railbelt System Energy and Demand by Customer Type for Electric Space and Water Heating

	Residential Customers	Commercial Customers
Calculated Space and Water Heating Energy, MWh	4,222,640	3,991,324
Calculated Space and Water Heating Demand, MW	1,243	1,174

6.4.3 Economic Development Loads

Another opportunity for increased loads in the Railbelt is from large new industrial loads. Black &Veatch obtained a list of potential economic development projects from the Alaska Industrial Development & Export Authority (AIDEA) presented in Table 6-13, as well as possible areas in which they might be located. For purposes of this study, Chugach's and ML&P's service areas have been combined as the Anchorage area. For purposes of load forecasting, Interior loads were assumed to be in GVEA's service area. Loads in the Kenai area were assumed as occurring in HEA's area.

Table 6-13
Potential Economic Development Projects

Potential Project	Area Location	Size (MW)
Ore Processing Facility	Anchorage	300
Internet Server Facility	Anchorage	300
Coal Mine	Anchorage	50
Subtotal – Anchorage Area		**650**
Gold Mine	Interior	150
Mine	Interior	200
Subtotal - Interior		**350**
Nitrogen/Urea Facility	Kenai	50
Total		**1,050**

In addition to the loads identified in Table 6-13, the Pebble Mine is another potential large load estimated to be approximately 300 MW. While it appears likely that if it is developed, it will develop on-site power, there has been some consideration that it could be supplied by the Railbelt through HEA's system. Other potential large loads could be from electric compressors for the proposed natural gas pipelines from the North Slope. Many of these compressors, however, would likely be remotely located.

It appears conceivable that a 1,000 MW of new load could potentially be developed in the Railbelt within the time frame of this study. Such new load would likely require specific policies to be implemented whether if from fuel switching or large industrial loads. For the purposes of creating a load forecast for the large load scenarios, new loads of 500 MW will be added in both 2025 and 2040, with 350 MW of each addition of new load being assumed in the Anchorage area and 150 MW of the new load being assumed in the Interior. For load forecasting purposes, the new load was assumed to have a 75 percent load factor. Tables 6-14 and 6-15 present the winter peak demand and net energy for load forecasts for the large load scenarios. Annual forecasts for the large load scenario are presented in Appendix D.

Table 6-14
GRETC's Winter Peak Large Load Forecast for Evaluation (MW)
2011 - 2060

Year	Large Load Winter Peak Demand (MW)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2011	238.1	412.2	146.0	96.3	869.3
2015	217.5	417.1	157.0	99.2	867.8
2020	226.0	425.1	167.0	102.2	896.3
2025	384.3	734.0	178.0	156.2	1,398.3
2030	392.8	744.0	188.0	160.1	1,429.5
2035	401.5	753.5	199.0	164.1	1,461.4
2040	560.3	1063.2	210.4	218.5	1,975.7
2045	569.2	1072.9	222.1	222.9	2,009.3
2050	578.4	1082.8	234.2	227.4	2,043.6
2055	587.7	1092.8	246.8	232.1	2,078.8
2060	597.3	1102.9	259.7	236.8	2,114.7

Table 6-15
GRETC's Large Load Net Energy for Load Forecast for Evaluation (GWh)
2011 - 2060

Year	Utility Large Load Net Energy for Load Forecast (GWh)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2011	1522.7	2464.8	771.2	619.1	5,377.8
2015	1333.5	2496.2	831.9	633.7	5,295.3
2020	1373.4	2547.4	888.3	658.6	5,467.8
2025	2389.3	4572.0	946.4	1013.3	8,921.0
2030	2420.2	4626.7	1,004.7	1039.7	9,091.3
2035	2451.2	4681.8	1,065.4	1066.7	9,265.1
2040	3473.5	6719.2	1,128.1	1424.6	12,745.4
2045	3499.9	6764.7	1,192.9	1450.9	12,908.4
2050	3532.1	6821.6	1,259.9	1479.6	13,093.2
2055	3564.6	6879.1	1,329.4	1508.9	13,282.0
2060	3602.9	6948.0	1,401.4	1540.7	13,493.0

7.0 FUEL AND EMISSIONS ALLOWANCE PRICE PROJECTIONS

7.1 Fuel Price Forecasts

7.1.1 Natural Gas Availability and Price Forecasts

7.1.1.1 Description of Risk-Based Assessment Methodology

Risk-based forecasts differ from other types of forecasts by acknowledging the element of chance in the way that multiple factors can combine to produce a range of outcomes. For example, there might be a 60 percent chance that a gas field will produce 150 million cubic feet per day (MMcf/d) in a given year but only a 20 percent chance that it will produce 200 MMcf/d. Likewise, a new gas pipeline might be 25 percent likely to begin flowing gas at 200 MMcf/d in a given year but 55 percent likely to begin flowing at 250 MMcf/d two years later. In both cases, an analysis is required to convert the best estimates of chance into a mathematical formula that will support a risk-based forecast of what the total gas supply might be in a given year if the gas field and pipeline were considered together in the range of possible outcomes.

For development of the RIRP, Black & Veatch's risk-based natural gas supply forecasts employed a model that considered performance prospects of each of several prospective gas sources and their variations over the 50-year planning horizon. The model was constructed using Palisade DecisionTools Professional 5.0 software. A decision-tree architecture was employed where each gas supply node was supported by a mathematical probability distribution function that described the node's annualized performance over the 50-year period. Monte Carlo methods were used to run gas supply simulations using alternative sets of assumptions about performance of each supply node. The purpose of the model was to run "what if" types of scenarios that would provide information about the aggregate supplies of gas in a specified year. The main gas sources included production from the Cook Inlet basin, importation of LNG from outside Alaska, and delivery of gas from the Alaska North Slope to the Railbelt by means of an instate pipeline. Variations among the model runs featured different sets of assumptions about the future capacity of Cook Inlet production, including possible enhancements, as well as the timing and volume throughput of LNG imports and the instate pipeline, respectively.

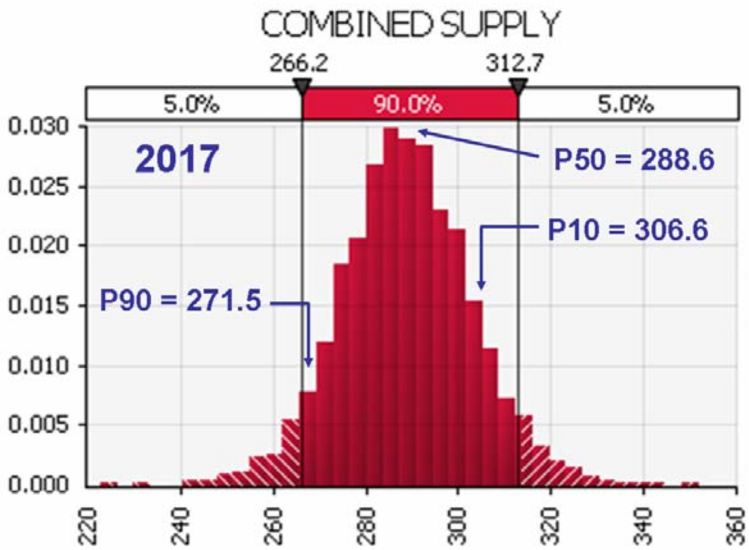
Model runs analyzed individual years for the decade of 2010-2019. For the years 2020-2060, model runs were made by five-year intervals (for example, 2020-2024, 2025-2029, etc.).

In evaluating results, attention was focused on probabilities for attainment of gas supplies at three benchmark levels:

- P90: Gas capacity achievable with 90% probability
- P50: Gas capacity achievable with 50% probability
- P10: Gas capacity achievable with 10% probability

Figure 7-1 illustrates the P90, P50 and P10 metrics from an actual gas supply model simulation. Clearly, as the gas capacity goes up, the probability for attaining that capacity goes down. Although conservatism might argue for using P90 values (the lowest of the three capacities) for all planning purposes, the P50 value is a reasonable choice for two primary reasons. First, P50 is easier to intuitively reference and visualize because it always falls near the middle of the range of possibilities. Second, P50 is the metric most comparable to "average expectation" forecasts that can be made with assumptions about average performance of gas sources where probabilities are ignored. Indeed, P50 supply was the metric chosen for the reference price forecast.

Figure 7-1
Results of a Risk-Based Gas Supply Model Simulation for the Year 2017



Results from the risk-based model forecasts comprised gas volumes, in annualized units of MMcf/d, that served as inputs into separate price forecasts. The price forecasts employed conventional methods from energy market analysis that used the interplay of supply and demand to predict a commodity value for gas that would be delivered at the Cook Inlet as if from the historical Cook Inlet gas production. Black & Veatch developed mathematical relationships for the commodity value using historical Alaska gas supply, gas demand and gas price data published by the U. S. Energy Information Administration as well as from additional research.

To that commodity value, estimated transportation costs were added for any volume of gas that was obtained from a non-local source; namely, LNG imports or the instate pipeline. Black & Veatch conducted research to estimate reasonable transportation costs. LNG costs were based on market knowledge of the Asia-Pacific Basin LNG markets. Pipeline costs were based on previously published studies of instate gas pipelines, both for stand-alone direct lines from the North Slope to the Anchorage area and for lateral lines from a large pipeline that might carry gas from the North Slope to Alberta, Canada.

The final price estimate, consisting of the commodity value and transportation adders, is equivalent to a “city gate” price that would be available to a high-volume buyer such as an electric utility or a gas distribution company. As used by the U. S. Energy Information Administration, a “city gate” price is the first point of sale for gas before it enters the wholesale markets. Ownership of gas beyond the “city gate” typically changes several times before it reaches residential consumers, with price increases at each change of ownership. Therefore, “city gate” prices are substantially lower that residential retail prices. Because the price forecasts used risk-based model gas supplies as input, separate prices were associated with P90, P50 and P10 supplies, respectively.

7.1.1.2 Gas Stakeholder Input Process

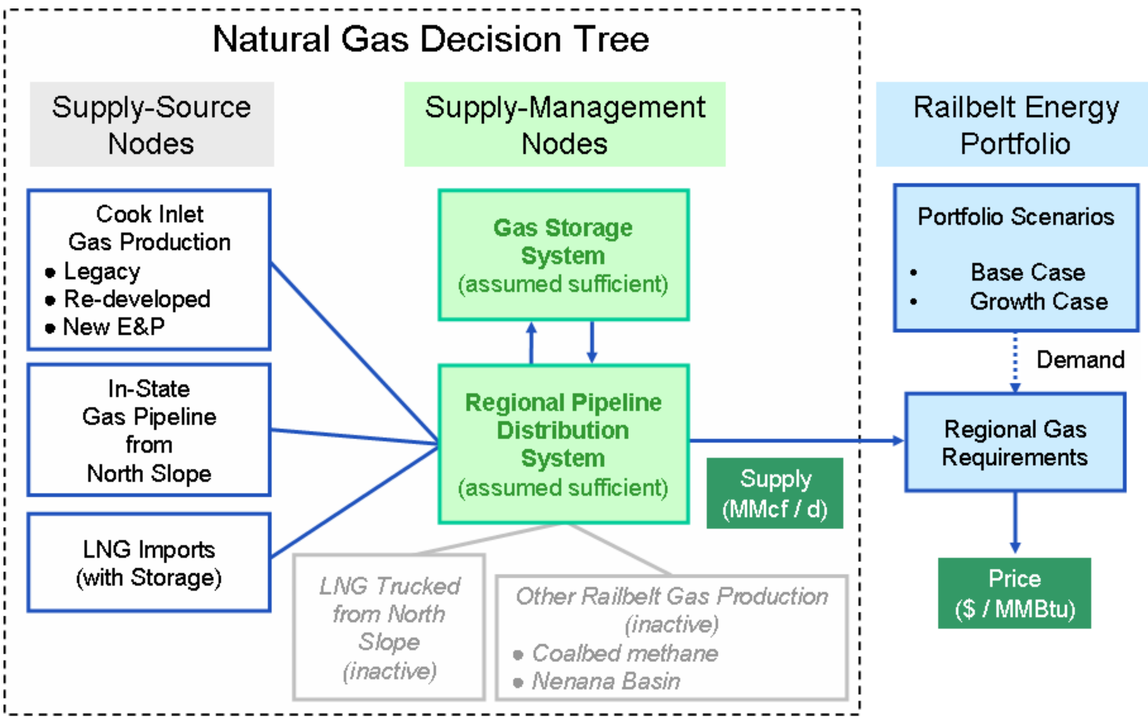
Black & Veatch conducted multiple rounds of reviews with numerous stakeholders to discuss the construction of the gas supply forecast model, as well as preliminary results for supply and price forecasts. These stakeholders included State of Alaska officials; technical specialists and executives from the Railbelt electric utilities; technical specialists and executives from Enstar; producers; and independent, Alaska-based energy consultants.

The gas stakeholder meetings were conducted over a three-month period and involved four different editions of the Black & Veatch gas supply forecast model. After each round of stakeholder meetings, Black & Veatch made changes to the gas supply forecast model in response to stakeholder feedback. The fourth version of the model was used to produce the results reported in this report.

7.1.1.3 Structure of the Natural Gas Decision Tree

The gas supply and price forecasts considered a variety of possibilities but utilized only those that could be supported quantitatively with the necessary degree of mathematical precision. Specifically, model attributes were separated into factors that were modeled and factors that were not modeled as summarized in Figure 7-2 and discussed below.

Figure 7-2
Schematic Summary of the Probabilistic Gas Supply Forecast Model



7.1.1.4 Decision Tree Input Assumptions

7.1.1.4.1 Gas Demand

Black & Veatch reviewed publicly-available data on historical consumption of natural gas in the Railbelt region and re-calculated those data into mathematical functions that were compatible with the risk-based, gas supply forecast model. Sources included the U.S. Energy Information Administration, State of Alaska and Enstar. As shown in Table 7-1, adjustments were made for the fact that traditional consumers of gas are changing as the decade of 2000-2009 gives way to the decades of 2010-2019 and forward. For example, the decade of 2000-2009 included major use of gas by the Agrium fertilizer plant and by the Nikiski LNG plant (as exports to Japan). But the Agrium fertilizer plant ceased operations in 2007 and the Nikiski LNG exports are expected to end by March 2011. So going forward, the main consumers of gas are expected to be electric-utilities, and gas pipeline users (including space heating) plus oilfield operations. Accordingly, the P90, P50 and P10 metrics for gas demand reflect a significant downturn in risk-based demand in 2010-2019 followed by slow growth in the expected use of gas for power, heating and field operations.

Table 7-1
Representative Risk-Based Metrics for Railbelt Natural Gas Demand
Based on Historical Data and Known Changes in Gas Consumption

Risk-Based Demand Metric	Annualized Gas Demand (MMcf /d)		
	2000-2009	2010-2019	2020-2029
P90 (90% likely that this demand will occur)	415	216	252
P50 (50% likely that this demand will occur)	524	245	257
P10 (10% likely that this demand will occur)	632	275	262

It should be noted that the 2006-2009 decade was one of rapid change, both in gas demand and gas production. The curve-fitting approach needed to render demand data into a probability curve, as required for the probabilistic supply forecasts, displayed large spreads in key percentages in the decadal curve as a consequence of large year-to-year changes in the historical data there were used as input.

7.1.1.4.2 Gas Supplies

7.1.1.4.2.1 Cook Inlet Gas Production

Prospects included a "legacy" component based on the expected future performance of historically known, producing gas reservoirs. A "re-developed" component represented additional performance that might be possible from "legacy" reservoirs through new or re-worked gas wells. Finally, a "New E&P" component represented geoscience-based estimates of discoverable, new gas reservoirs within the greater Cook Inlet region. After consulting subject matter experts among the Railbelt gas stakeholders, and reviewing previously published reports about gas resources and reserves, Black & Veatch concluded that enhanced Cook Inlet gas production could be made to meet P50 gas demand through 2016 with plausible assumptions about re-working and re-investment. Enhanced Cook Inlet production was retained as a source in the gas supply model through 2039 but with significant performance decline after 2017.

7.1.1.4.2.2 Instate Gas Pipeline

This supply node was predicated upon construction of a pipeline to deliver gas from the Alaska North Slope (Prudhoe Bay, Point Thomson) to the Anchorage area. Prospects included a stand-alone, direct line as well as a lateral from a larger pipeline that might carry gas into Canada and the USA Lower-48 states. After consulting subject matter experts among the Railbelt gas stakeholders, and reviewing previously published reports about possible instate pipeline projects, Black & Veatch concluded that an instate pipeline was plausible after 2018 and with a maximum capacity of 350 MMcf/d. Such an instate pipeline source was included in the gas supply model with ramp-up from 2018 through 2022 and maximum capacity thereafter. No attempt was made to analyze the economics of building smaller or larger pipelines. Although published descriptions of possible pipeline projects cover the range of about 50-500 MMcf/d capacities, the limit of 350 MMcf/d was chosen as the largest capacity likely to be built given the demand outlook (Table 7-1).

7.1.1.4.2.3 LNG Imports (With Storage)

This supply node was premised on bringing LNG to the Cook Inlet through ocean tankers supplied from sources within the Asia-Pacific basin. Prospects included re-engineering the Nikiski export plant to become a receiving and storage facility or building a new receiving facility with associated storage.

For a re-developed (i.e., brownfield) Nikiski facility, storage capacity would be limited to the liquid equivalent of about 2,300 MMcf of gas. Although re-developed Nikiski could provide peak deliverability of 100 MMcf/d for short durations, total storage volume translated to annualized deliverability would be only about 6 MMcf/d. Black & Veatch research found that a plausible design for a new (i.e., greenfield) LNG facility with tank storage might increase the total available storage to a liquid equivalent of 5,700 MMcf which would have an annualized deliverability equivalent of about 15 MMcf/d. But the latter facility likely would require a capital investment at least several times that of the re-developed Nikiski facility.

A new receiving facility built with associated underground geologic storage (depleted oil or gas reservoir), in principle, could be made more scalable than for tank storage based on phased expansion of storage capacity through successive re-commissioning of depleted reservoirs. Because geologic-based storage typically scales in multiples of one billion cubic feet (1 Bcf = 1,000 MMcf), the two limiting factors for the Cook Inlet would be how fast depleted reservoirs could be re-developed into storage (Bcf per unit time) and what practical limits would apply to ocean tanker-based deliveries (tanker deliveries per unit time). After consulting subject matter experts among the Railbelt stakeholders, researching performance characteristics of LNG ocean tankers, and reviewing previously published reports about possible gas storage projects, Black & Veatch arrived at a plausible order of magnitude for LNG imports with associated geologic-based storage. A reasonable lower-end estimate would be five (5) deliveries per year, by a tanker with 138,000 cubic meter (liquid) capacity, and as supported by an available (working gas) storage capacity of at least 15-20 Bcf to produce the equivalent of an annualized gas supply of 42 MMcf/d. A reasonable upper-end limit would be 12 deliveries per year, by a tanker with 150,900 cubic meter (liquid) capacity, and as supported by an available (working gas) storage capacity of at least 40-45 Bcf to produce the equivalent of an annualized gas supply of 106 MMcf/d. For the gas supply model, Black & Veatch used the 41 MMcf/d capacity limit, beginning imports and ramp-up in 2013, for the base case. But alternative simulations also were made using the 106 MMcf/d capacity limit.

7.1.1.4.3 Other Considerations

Regional pipeline distribution systems, and gas storage not affiliated with LNG imports, were considered not to be performance bottlenecks so they were treated as non-issues in the gas supply model (Figure 7-2). Black & Veatch interviews with stakeholders led to the conclusion that the gas pipeline distribution system, at least in the Cook Inlet region, has sufficient capacity to handle new gas supplies without requiring significant capital investments. Also, published reports on geologic gas-storage prospects identified suitable volumes of reservoirs that could, in principle, be re-commissioned before the instate pipeline appeared in 2018 and ramped-up to maximum capacity in 2022. Gas storage required for earlier imports of LNG was treated as storage implicit in the import project and scaled as discussed above.

Stakeholders suggested other possible sources of gas that Black & Veatch did not include in the gas supply model for lack of the necessary quantitative supporting information. Although such sources might become viable in the future, the performance data required to model their probabilities for performance were not available either through published or unpublished sources.

First, overland trucking of LNG from the North Slope to Fairbanks was proposed. Although such a supply could be significant for residential space heating, the plausible scale of such deliveries is virtually immaterial to gas-fired power plants. Specifically, a 10,000-gallon LNG tanker truck delivered five (5) times per week for every week of the year provides a gas equivalent of less than 1 MMcf/d whereas a continuously-run, 100 MW gas-fired power plant would need about 20-30 MMcf/d. So given the emphasis of the current report on power generation, overland LNG trucking was not selected as a gas source in the supply simulations.

Second, gas production from Railbelt geologic sources other than Cook Inlet has not been confirmed in publicly-available reports. The Nenana Basin was mentioned specifically by several stakeholders but Black & Veatch was not able to confirm whether gas had been proven or resources estimated through ongoing exploratory drilling activities.

Third, gas production from coalbed methane was mentioned by a few stakeholders who did not provide supporting data. Black & Veatch researched available reports but could not confirm plausible projects that would deliver significant amounts of gas within the same timeframe as LNG imports or an instate gas pipeline.

7.1.1.5 Natural Gas Price Forecasts

Black & Veatch approached the price forecast as:

$$\text{Price} = \text{Commodity Value (supply, demand)} + \text{Delivery Cost}$$

using the following main premises:

- Metric is a single, pooled Railbelt price as if for a single, unified consumer
- Focus on “city gate” price that would be a proxy for fuel procurement plans by electric utilities – not retail consumer prices
- Commodity value estimated from historical-empirical data regressions
- A premium adder included for Cook Inlet enhanced production
- All-in delivery and storage costs for imported LNG
- Tariffs for instate pipeline, North Slope to Anchorage

For the commodity value, Black & Veatch analyzed historical supply, demand and price data for Alaska to develop five empirical relationships, each with an individual strength of correlation. Those five model relationships were combined using weighting factors proportional to the strengths of the respective correlation coefficients.

For the delivery cost, Black & Veatch reviewed publicly-available information on LNG ocean-tanker transportation and alternative proposals for Alaska instate pipeline projects. Although LNG transportation costs are well-established, Alaska pipeline projects remain incompletely defined and, therefore, carry larger associated uncertainties. Both for LNG and instate pipeline, anticipated costs fell within the range of $1.50-$2.00/MMBtu. In addition, Black & Veatch estimated that investments to realize the postulated enhancement to Cook Inlet production would require additional costs in the range of $0.25-$1.00/MMBtu.

To develop the price forecast for a given year, Black & Veatch applied the P50 supply output from the risk-based gas supply forecast to the commodity value model. Then delivery adders were applied for all of the supply sources that were presumed to be operational in that year. The result effectively was a weighted-average cost of gas involving the various gas sources.

7.1.1.6 Summary of Results

Black & Veatch selected two sets of gas supply simulations to illustrate the challenges that exist in providing suitable volumes of natural gas to Railbelt users, as follows:

Base Case (used for Scenario 1A in the RIRP model)

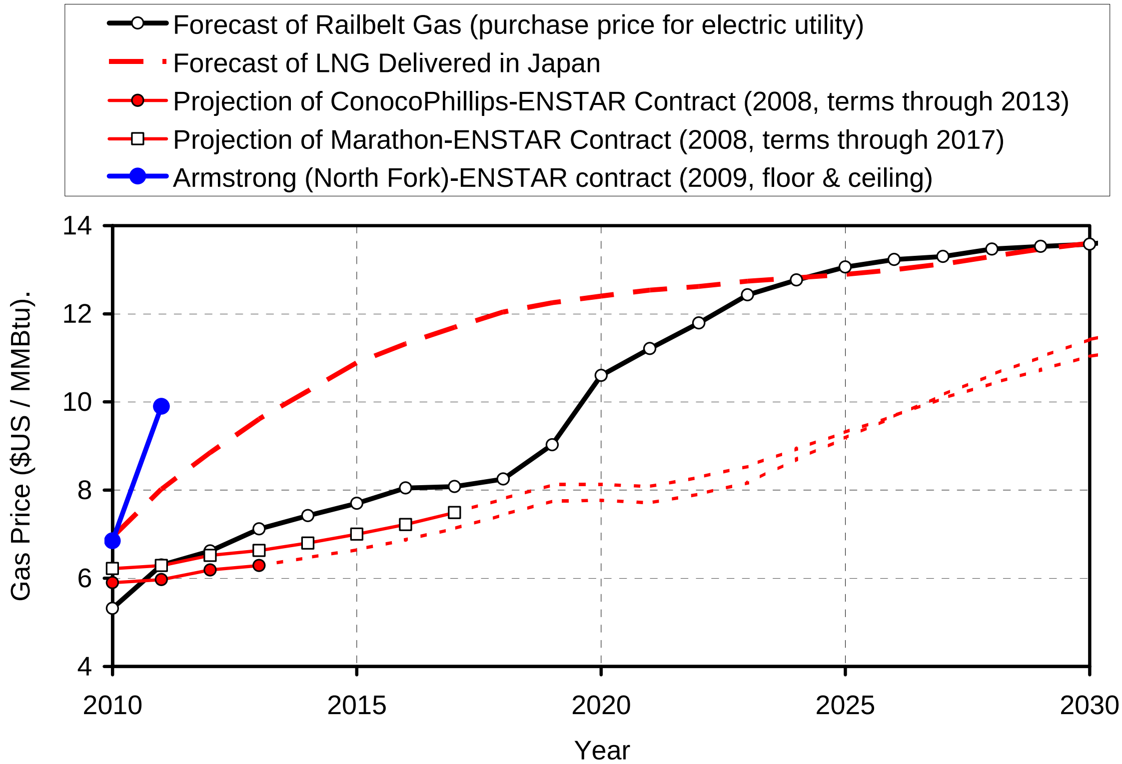
- Expanded Cook Inlet production, beginning in 2012, matched P50 demand but with decline toward a supply-demand deficit beginning in 2017 and with end of production as of 2039
- LNG imports began in 2013, and ramped-up to annualized equivalent of 41 MMcf/d, before ending in 2018 (when the instate pipeline appeared)
- Instate pipeline began in 2018, with ramp-up to maximum capacity of 350 MMcf/d by 2022, and continued operation thereafter
- Met anticipated P50 demand (with P90 to P50 supplies) through 2060
- Performance sensitivities during 2018-2024 related to uncertainties in appearance and ramp-up of the instate pipeline

Sensitivity Case (for comparison and contrast with Base Case)

- Expanded Cook Inlet production as in Base Case
- LNG imports began in 2013, with ramp-up to annualized equivalent of 106 MMcf/d, and continuous operation thereafter
- No instate pipeline was available
- Failed to meet anticipated P50 gas demand after 2018
- Performance sensitivities during 2017-2024 related to uncertainties in ramp-up of LNG imports

Railbelt gas price forecasts derived from the P50 supply simulated in the Base Case are shown in Figure 7-3 along with alternative forecasts for comparison. Before 2018, the Railbelt forecast resembles projections of bi-lateral contracts executed in the Cook Inlet in 2008. But the Railbelt forecasts are higher than the subject contracts because of additional costs associated with importation of non-Alaska LNG as well as enhanced Cook Inlet production. After 2018, the Railbelt forecasts trend much higher under heavy influence of the transportation costs assumed for the instate gas pipeline. It should be noted that the bi-lateral contracts referenced have terms only through 2013 and 2017, respectively, and are predicated on Cook Inlet production as the sole source of gas. Also, the prices projected from those contract terms pertain to the “base tier” or “base load” price that is the lowest price available; both contracts provide for multipliers up to 130 percent of the base price for gas sold under peak-demand conditions. Finally, the price for “LNG Delivered in Japan” is considered an upper limit for the Railbelt price, including the supply-starved Sensitivity Case.

Figure 7-3
Comparison of Natural Gas Price Forecasts Relevant to Railbelt Resource Plans



Gas pricing in the bi-lateral sales contracts referenced in Figure 7-3 utilize formulas that reference an assortment of non-Alaska price points with various provisions for floor and ceiling pricing. For the two contracts collectively, the reference price points include Alberta, Canada; the border of British Columbia, Canada with Washington state; the Oregon-California border; northern California; southern California; and Chicago, Illinois. Therefore, the Black & Veatch projections of those contract prices are based on forecasts of annualized prices at each of those reference price points.

Black & Veatch used conventional market analysis methods to correlate historical prices at reference price points with historical prices at the Henry Hub, LA price point. Based on those correlations, individual forecast models were developed for each reference price point in order to accomplish the individualized price forecast for each reference point, based on Black & Veatch selection of a forecast for Henry Hub.

From the price curves depicted in Figure 7-3, representative prices are summarized in Table 7-2. For reasons discussed above, the Railbelt forecast prices fall between the Cook Inlet bi-lateral contracts from 2008 and the anticipated forward price in Japan.

The "Forecast of Railbelt Gas" curve is the price corresponding to the P50 supply output from the Base Case described above. Projections for the ConocoPhillips and Marathon contracts were made by Black & Veatch using the price terms in the 2008 contracts which end in 2013 and 2017, respectively.

Table 7-2
Representative Forecasts of Railbelt Natural Gas Price According to Different Benchmarks

Price Reference	Natural Gas "City Gate" Price ($US / MMBtu) as Delivered at Cook Inlet AK (unless noted otherwise)						
	2011	2013	2015	2017	2019	2021	2023
LNG Delivered in Japan	8.02	9.61	10.89	11.69	12.25	12.54	12.74
Forecast for Railbelt	6.30	7.12	7.70	8.08	9.03	11.21	12.43
Projection of ConocoPhillips-Enstar Contract (Base Tier)	5.97	6.29	N/A	N/A	N/A	N/A	N/A
Projection of Marathon-Enstar Contract (Base Load)	6.29	6.63	7.00	7.49	N/A	N/A	N/A

The main conclusions from these gas supply analyses are as follows:

- There are plausible scenarios for long-term supplies of natural gas in the Alaska Railbelt but they will require new capital investments that include enhanced production from the Cook Inlet, as well as importation of LNG from non-Alaska sources and or North Slope gas through an instate pipeline.
- LNG imports are a useful supplement to Cook Inlet production but are not likely to supplant the higher capacity provided by an instate pipeline.
- Both LNG imports and instate gas pipeline supplies will be more costly than historical production from the Cook Inlet and will necessitate significantly higher gas prices than in historical experience.

7.1.2 Methodology for Other Fuel Price Forecasts

7.1.2.1 Coal

The price forecast for the RIRP study represents the EIA AEO2009[1] delivered industrial price (dollars per short ton) but with an energy conversion factor of 20.169 MMBtu/ton and with the low end of possible transportation costs. The energy conversion factor was chosen to resemble available assays of Alaska coal.

In addition to the delivered price of coal, a minemouth coal price estimate was developed for the Healy plant and for a coal sensitivity analysis. The minemouth price is based on the delivered price less an estimate for delivery costs.

7.1.2.2 HAGO

High Atmospheric Gas Oil (HAGO) was treated as materially equivalent to a sub-grade of Fuel Oil No. 4. The price forecast adopted here represents a 75 percent multiplier applied to the EIA AEO2009[2] forecast for distillate fuel oil delivered for electric power and using an energy conversion factor of 0.139 MMBtu/gallon.

[1] EIA AEO2009. U. S. Energy Information Administration, Annual Energy Outlook 2009, March 2009. Available online at http://www.eia.doe.gov/oiaf/aeo/index.html.
[2] EIA AEO2009 (previously referenced).

7.1.2.3 Naphtha

Naphtha was treated as materially equivalent to a sub-grade of jet fuel. The price forecast adopted here represents a 75 percent multiplier applied to the EIA AEO2009[3] forecast for jet fuel delivered for aviation and using an energy conversion factor of 0.139 MMBtu/gallon.

7.1.2.4 Propane

Propane is not currently used as a fuel for electric power generation in the Railbelt region. However, in response to a stakeholder request, propane was added for comparison as an alternative fuel. The price forecast reported here utilized an historical-empirical relationship developed for propane and natural gas in the Lower-48 states as applied to the natural gas price predicted for the Railbelt.

7.1.3 Resulting Fuel Price Forecasts

Table 7-3 summarizes the resulting annualized prices predicted for hydrocarbon fuels from 2011 to 2060. Although seasonal variation of price can be expected to occur in response to demand swings, the prices represented here reflect a single average price for a given year.

7.2 Emission Allowance Price Projections

7.2.1 Existing Legislation

Currently, there is no existing legislation in place that subjects electric generating units in Alaska to an emission allowance trading program for NO_x, SO_2, CO_2, or Hg emissions. As a result, no emission allowance costs are included in the economic evaluations other than for CO_2 as discussed in the next subsection. Capital and operating costs are included for generating units in order for the units to meet expected emission limitations under the Environmental Protection Agency's Prevention of Significant Deterioration Program.

7.2.2 Proposed Legislation

Currently, there is no proposed federal or state legislation that would subject electric generating units in Alaska to an emission allowance trading program for NO_x, SO_2, or Hg. There have been a number of bills introduced in the U.S. Congress that would create an emission allowance trading program and corresponding emission reductions for CO_2. The only bill that has passed either House of Congress is H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA), which was passed in the House of Representatives in 2009. While it is unknown if H.R. 2454 will ultimately be passed into law, after vetting the issue with numerous stakeholders in the RIRP process, it was decided that CO_2 allowance costs would be included in the economic evaluations for the RIRP. The development of those allowance costs is presented in the following subsection.

7.2.3 Development of CO_2 Emission Price Projection

The CO_2 emission price projection used in this analysis is based upon price projections developed by the Energy Information Administration (EIA) and by the Environmental Protection Agency (EPA). The base price projection is presented in EIA report number SR-OIAF/2009-05, entitled *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA)*, dated August 4, 2009. The EIA report considered the energy-related provisions in ACESA that could be analyzed using EIA's National Energy Modeling System. The ACESA basic case was used for the CO_2 emission price projection for the years 2012 through 2030.

[3] EIA AEO2009 (previously referenced).

Table 7-3
Nominal Fuel Price Forecasts ($/MMBtu)

Year	Natural Gas	Delivered Coal	Minemouth Coal	HAGO	Naphtha	Propane
2011	6.30	2.94	2.18	12.98	13.77	9.05
2012	6.62	2.99	2.21	14.52	15.24	9.45
2013	7.12	3.02	2.24	15.26	16.16	10.08
2014	7.42	3.08	2.28	16.31	17.24	10.46
2015	7.70	3.19	2.36	17.23	18.11	10.81
2016	8.05	3.23	2.39	17.79	18.71	11.25
2017	8.08	3.29	2.44	18.23	19.25	11.29
2018	8.25	3.36	2.49	18.71	19.79	11.50
2019	9.03	3.43	2.54	19.29	20.45	12.49
2020	10.60	3.50	2.59	19.77	20.85	14.46
2021	11.21	3.55	2.63	20.26	21.33	15.23
2022	11.79	3.61	2.67	20.78	21.86	15.96
2023	12.43	3.67	2.72	20.98	22.09	16.76
2024	12.77	3.73	2.76	21.50	22.56	17.19
2025	13.06	3.80	2.81	21.98	23.09	17.56
2026	13.23	3.86	2.86	22.43	23.57	17.77
2027	13.30	3.93	2.91	22.98	24.03	17.86
2028	13.47	4.00	2.96	23.76	24.83	18.07
2029	13.53	4.07	3.01	24.38	25.50	18.15
2030	13.58	4.11	3.04	25.07	26.01	18.21
2031	13.72	4.24	3.14	25.82	26.79	18.39
2032	13.92	4.36	3.23	26.60	27.59	18.64
2033	14.00	4.49	3.33	27.40	28.42	18.74
2034	14.08	4.63	3.43	28.22	29.27	18.84
2035	14.21	4.77	3.53	29.07	30.15	19.00
2036	14.11	4.91	3.64	29.94	31.06	18.88
2037	13.93	5.06	3.75	30.84	31.99	18.65
2038	13.84	5.21	3.86	31.76	32.95	18.54
2039	13.59	5.37	3.98	32.72	33.93	18.22
2040	13.91	5.53	4.10	33.70	34.95	18.63
2041	13.96	5.69	4.21	34.71	36.00	18.69

Table 7-3 (Continued)
Nominal Fuel Price Forecasts ($/MMBtu)

Year	Natural Gas	Delivered Coal	Minemouth Coal	HAGO	Naphtha	Propane
2042	14.17	5.86	4.34	35.75	37.08	18.95
2043	14.30	6.04	4.47	36.82	38.19	19.12
2044	14.59	6.22	4.61	37.93	39.34	19.48
2045	14.73	6.41	4.75	39.06	40.52	19.66
2046	14.94	6.60	4.89	40.24	41.73	19.92
2047	15.07	6.80	5.04	41.45	42.98	20.08
2048	15.37	7.00	5.19	42.68	44.27	20.46
2049	15.50	7.21	5.34	43.97	45.60	20.63
2050	15.64	7.43	5.50	45.29	46.97	20.80
2051	15.77	7.65	5.67	46.64	48.38	20.97
2052	16.08	7.88	5.84	48.05	49.83	21.36
2053	16.21	8.12	6.01	49.49	51.33	21.52
2054	16.34	8.36	6.19	50.97	52.87	21.68
2055	16.57	8.61	6.38	52.50	54.45	21.97
2056	16.80	8.87	6.57	54.08	56.09	22.26
2057	16.93	9.14	6.77	55.70	57.77	22.43
2058	17.17	9.41	6.97	57.37	59.51	22.73
2059	17.30	9.69	7.18	59.09	61.29	22.89
2060	17.75	9.98	7.39	60.86	63.13	23.46

The EPA has also made an analysis of ACESA. EPA's CO_2 emission price projection is presented in a presentation, entitled *EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress*, dated June 23, 2009. The EPA report provides CO_2 emission prices for the years 2015, 2030, and 2050. The EPA analysis was used to develop CO_2 emission price projections for 2030 through 2050. Emission price projections from 2050 through 2060 were escalated at the general inflation rate of 2.5 percent annually. The CO_2 emission allowance price projections are presented in Table 7-4.

Both the EIA and EPA analyses of H.R 2454 consider the development and deployment of carbon capture and sequestration (CCS).

Table 7-4
CO_2 Allowance Price Projections

Year	$/ton
2012	18.41
2020	39.70
2030	103.78
2040	213.91
2050	440.89
2060	564.38

8.0 RELIABILITY CRITERIA

The purpose of this section is to discuss the reliability criteria that were used in this study.

8.1 Planning Reserve Margin Requirements

Currently, the Railbelt utilities maintain a 30 percent reserve margin. For planning purposes, GRETC is assumed to be required to maintain a 30 percent reserve margin. As the GRETC transmission projects are implemented and experience is gained in the Railbelt with a more robust transmission system, it may be possible to reduce the 30 percent planning reserve margin which would further increase benefits under GRETC. This potential additional savings, however, is not modeled in this study.

8.2 Operating Reserve Margin Requirements

8.2.1 Spinning Reserves

Spinning reserve requirements for the Railbelt system are based on the largest unit on-line. Currently, Chugach, GVEA, HEA, and ML&P share that spinning reserve requirement in relation to their largest units on-line. Table 8-1 presents the largest unit for each of the Railbelt utilities and shows their share of the largest unit.

Table 8-1
Railbelt Spinning Reserve Requirements

Utility	Largest Unit	Capacity (MW)	Percentage of Largest Unit	Spinning Reserve Requirement (MW)
CEA	Beluga 7/8	108.6	33.6	36.9
GVEA	North Pole 2	62.6	19.4	21.2
HEA	Nikiski	42.0	13.0	14.3
ML&P	Plant 2 Units 7/6	109.6	34.0	37.2
Total		319.5	100.0	109.6

Spinning reserve requirements vary continuously based on the largest unit operating. Throughout the study period, the spinning reserve requirements increase when new units become the largest unit on the system.

Generally, any unit operating below its maximum load can contribute to the spinning reserve requirement. In addition, Bradley Lake can provide up to 27 MW of spinning reserves as shown in Table 4-5.

GVEA also has a Battery Energy Storage System (BESS) which provides 27 MW of equivalent spinning reserves. GVEA currently employs Shed in Lieu of Spin (SILOS) for a portion of GVEA's spinning reserve responsibility. In this RIRP, SILOS is not considered for spinning reserve.

8.2.2 Non-Spinning Operating Reserves

The Railbelt currently requires total operating reserves to be 150 percent of the spinning requirement. This results in an amount of non-spinning reserves up to 50 percent of spinning reserve capacity that may be provided by quick-start capacity in order to meet the operating reserve requirement. This non-spinning operating reserve is proportioned between the Railbelt utilities in the same proportions as spinning reserves. The units that qualify as quick-start units for meeting operating reserves are presented in Table 8-2.

8.3 Renewable Considerations

Wind, solar, and tidal renewable technologies are not dispatchable; consequently, they are not counted toward planning or operating reserves.

8.4 Regulation

Resources that are not dispatchable and subject to varying output due to factors that cannot be controlled such as weather (e.g., variations in wind speed that result in variable wind power output), require additional regulating capacity in order to maintain system reliability when the wind does not blow or the sun does not shine. For evaluation purposes, it is assumed that 50 percent of the nameplate capacity of wind and solar resources will be required to be maintained as additional regulating capacity. Tidal resources, while not dispatchable, are more predictable, and for evaluation purposes, additional regulating capacity is not included.

Table 8-2
Quick-Start Units

Name	Unit	Winter Rating (MW)
Anchorage ML&P – Plant 1	3	32
Anchorage ML&P – Plant 1	4	34.1
Anchorage ML&P – Plant 2	5	37.4
Anchorage ML&P – Plant 2	7	81.8
Anchorage ML&P – Plant 2	8	87.6
Beluga	1	17.5
Beluga	2	17.5
Beluga	3	66.5
Beluga	5	65
Beluga	6	82
Beluga	7	82
Bernice	2	19
Bernice	3	25.5
Bernice	4	25.5
DPP	1	25.8
International	1	14
International	2	14
International	3	19
Nikiski	1	42
North Pole	GT1	62.6
North Pole	GT2	60.6
Zehnder	GT1	19.2
Zehnder	GT2	19.6

9.0 CAPACITY REQUIREMENTS

When the 30 percent planning reserve criteria described in Section 8 is applied to the load forecasts presented in Section 6, the capacity requirements for the Railbelt are established. Comparing those capacity requirements to the existing generating units and their expected retirement dates results in the capacity addition requirements for the Railbelt. Figures 9-1 through 9-6 present the capacity requirements for the following cases.

- Figure 9-1 - Scenario 1A Capacity Requirements Without DSM/EE
- Figure 9-2 - Scenario 1A Capacity Requirements With DSM/EE
- Figure 9-3 - Scenario 2A Capacity Requirements Without DSM/EE
- Figure 9-4 - Scenario 2A Capacity Requirements With DSM/EE
- Figure 9-5 - Scenario 1A Capacity Requirements Including Committed Units Without DSM/EE
- Figure 9-6 - Scenario 1A Capacity Requirements Including Committed Units With DSM/EE

Figure 9-1
Scenario 1A Capacity Requirements Without DSM/EE

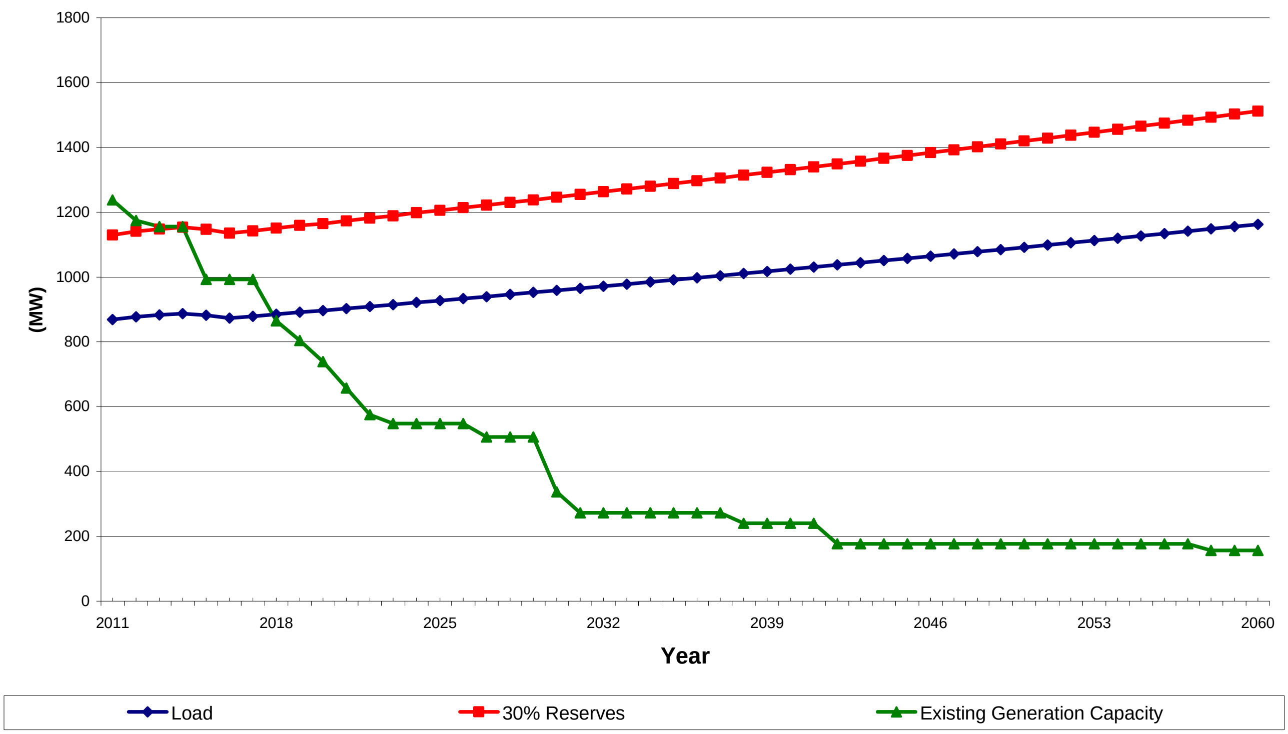


Figure 9-2
Scenario 1A Capacity Requirements With DSM/EE

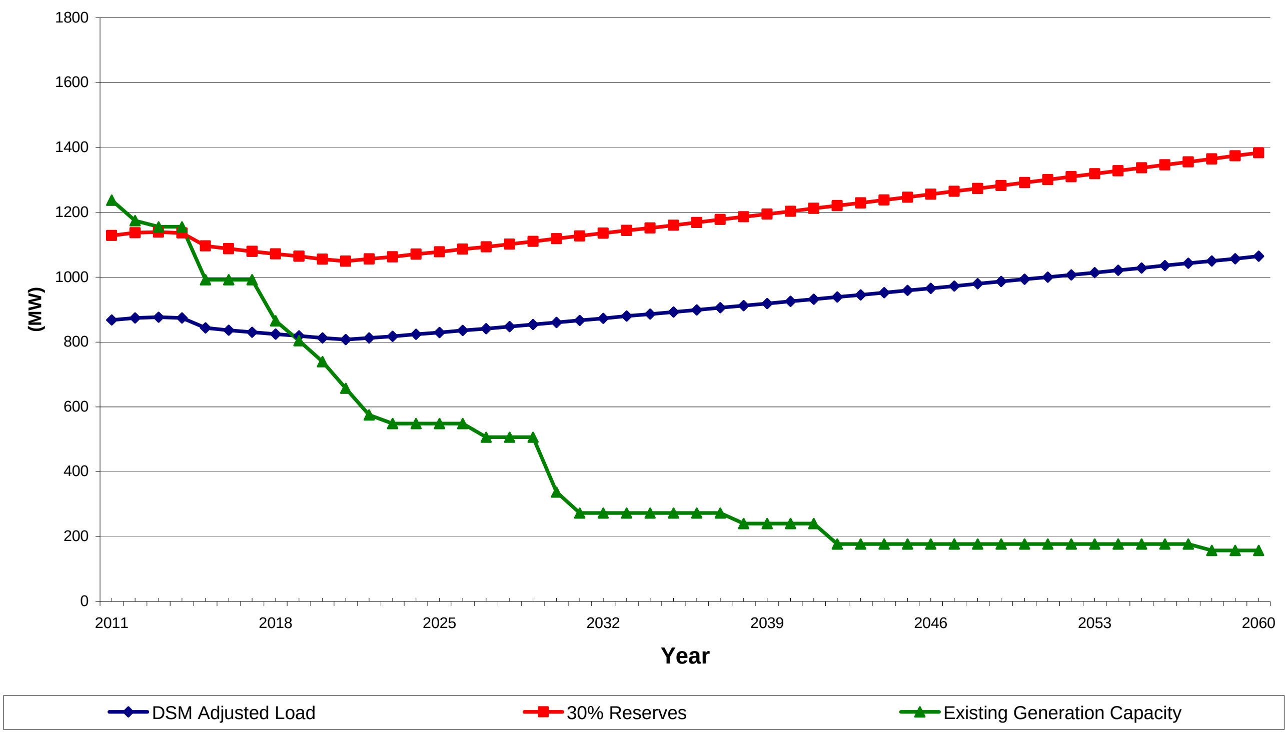


Figure 9-3
Scenario 2A Capacity Requirements Without DSM/EE

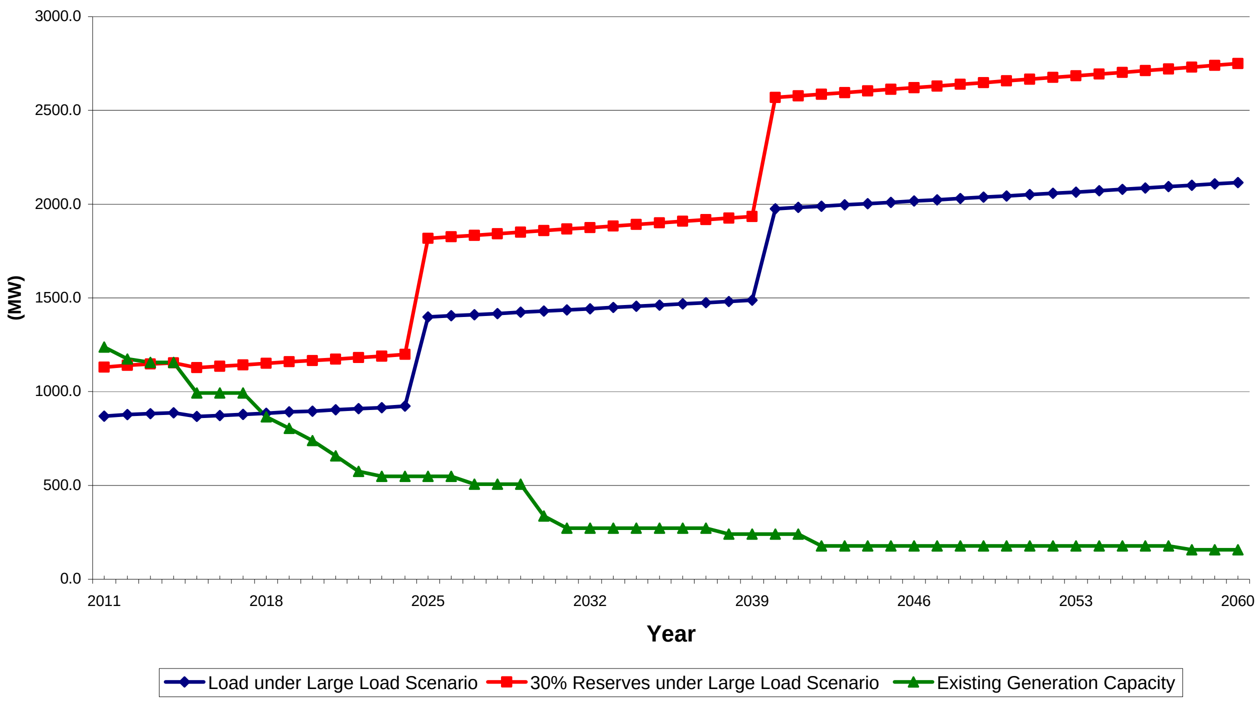


Figure 9-4
Scenario 2A Capacity Requirements With DSM/EE

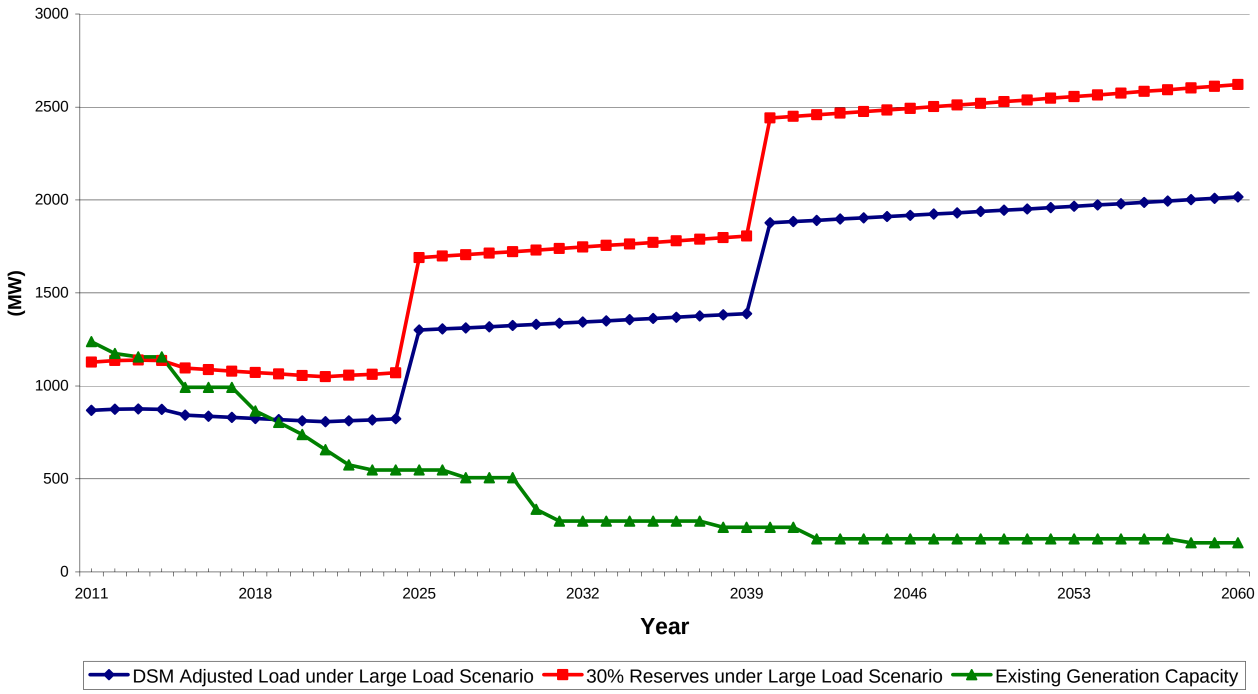


Figure 9-5
Scenario 1A Capacity Requirements Including Committed Units Without DSM/EE

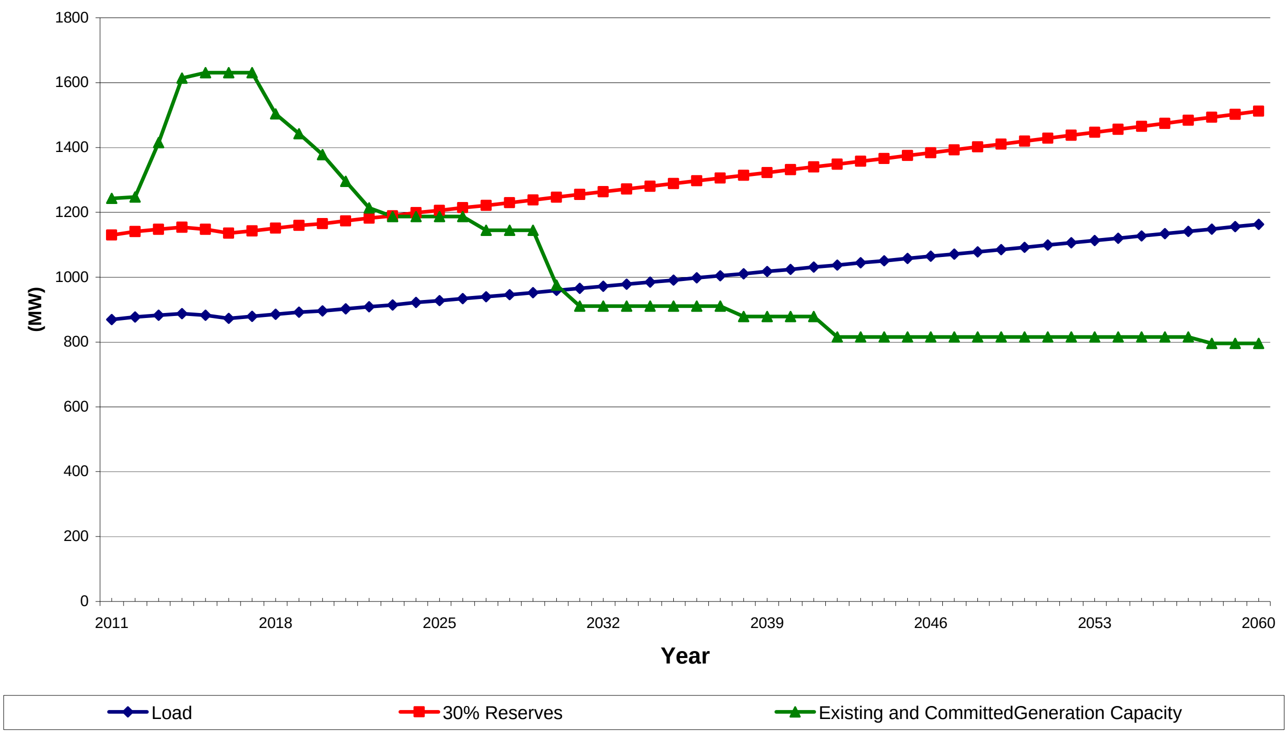


Figure 9-6
Scenario 1A Capacity Requirements Including Committed Units With DSM/EE