

Final Report

Railbelt Energy Study

Ater Wynne LLP

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R. W. BECK Railbelt Energy Study

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EXECUTIVE SUMMARY

During June 2003, five of the six Railbelt utilities¹ agreed to jointly undertake a Railbelt Energy Study (RES). At the request of the utilities, the law firm Ater Wynne LLP contracted with the economic/engineering consulting firm R. W. Beck in August 2003 to perform the study. This report is a summary of the activities completed during the study, and the results of these activities.

Background and Objective

The participating utilities have several motives for conducting the RES:

- All of the thermal generating capacity in the Railbelt is more than 20 years old, and much of it is more than 30 years old. The utilities need to determine during the next several years whether to retire these units or make the investments in them required to extend their lives. If they decide to retire the units, they also need to decide what new generating capacity, if any, they should build to replace the units.
- During the next few years, several of the utilities may need to build new capacity to satisfy load growth.
- The utilities recognize that it may be both less costly and less risky to develop and operate new generating units jointly or collectively than to undertake these efforts separately.
- The utilities have several opportunities, such as restarting the Healy Clean Coal Project, constructing the Southern Intertie, and developing the Emma Creek Coal Project, that would provide benefits to (and impose costs on) more than one utility. As a result, the utilities recognize that decisions about these opportunities should reflect the joint or collective interests of the Railbelt utilities.

The objective of the RES is to identify the combination of generation and transmission (G&T) capital investments in the Railbelt through 2033 that 1) minimize future power supply costs and 2) maintain current levels of power supply reliability. The investments are to be identified taking into account uncertainty about future loads, fuel prices, and resource options, and assuming that the six Railbelt utilities act collectively. There are three important points to make about this objective:

- The RES is a *study*, not an Integrated Resource Plan (IRP). Each utility will still need to perform an IRP or Power Supply Plan, in order to identify appropriate

¹ The five participating utilities are Anchorage Municipal Light & Power (ML&P), Chugach Electric Association (Chugach), Golden Valley Electric Association (GVEA), Homer Electric Association (HEA), and Seward Electric System (SES). Matanuska Electric Association (MEA) was invited to participate but declined. Although MEA did not participate in the study, data for it has been included in the study, and the identified G&T capital investments reflect the need to serve its load.

G&T investment decisions for that utility. R. W. Beck believes that it is not possible in an analysis such as this, performed for a collection of utilities, to appropriately reflect all of the utility-specific issues that a utility needs to address in making G&T capital investment decisions. For example, it was not possible in this analysis to collect and appropriately analyze all of the information required to make decisions regarding retirements of existing generating units.

- The RES assumes the utilities act *collectively* to invest in new G&T assets and dispatch both new and existing generating resources. For the purposes of the study, *collectively* means that investments were identified *as if* a single entity makes all G&T investment and dispatch decisions; that this entity makes these decisions in order to minimize expected power supply costs for the collection of all six Railbelt utilities; and that in making these decisions it takes into account the operational limitations of existing and potential new generating units and transmission facilities, but not the ownership of these assets. R. W. Beck believes that the Railbelt utilities can achieve the benefits of collective action identified in this study under the current set of institutional arrangements, as well as under other sets of institutional arrangements, such as a power pool or a single G&T organization. The study did not investigate the benefits or costs of changing the set of institutional arrangements that are in place in the Railbelt.
- The RES is a study of both generation *and* transmission investments. However, the detailed information required to analyze transmission investments was only available for one potential transmission investment, the Southern Intertie Project, which is described in the section titled “G&T Investments in Unique Investment Opportunity and Sensitivity Cases.” It was beyond the scope of the study to develop the required information for other potential transmission investments, such as a second line from Anchorage to Healy. As a result, the only transmission investment the study considered was the Southern Intertie Project. A wide variety of generation investments were also considered, which are discussed in the same section.

Methodology and Data

The approach employed in the RES has two major components:

- **Model Development** – R. W. Beck developed a state-of-the-art G&T investment model tailored to the unique circumstances of the Railbelt. The model consists of four modules:
 - **Retirement Module** – For each existing unit, the utilities and R. W. Beck agreed on a “Retirement Evaluation Date,” the date at which either the unit would be retired or an investment would need to be made to extend its life. The module calculates the annual cost of continuing to operate each existing generating unit beyond the Retirement Evaluation Date, including the increase in fixed operations and maintenance (O&M) expense associated with life extension; as well as the annual cost of operating the most similar (size and type) potential new unit, which includes the amortization of the capital

cost of the unit. These two annual costs are estimated under a combination of three fuel price scenarios and three capacity factor scenarios. The module retires existing units whose annual cost is higher than the annual cost of the most similar potential new unit.

- **Reliability Module** – The module calculates the loss of load probability (LOLP) for each transmission area in each year, under various load growth scenarios and combinations of new resources, and the reserve margins required to maintain specified LOLP levels. In calculating the LOLP, the module takes into account the forced outage rates of generating resources, the contribution of the transmission system to reliability, and the forced outage rates of transmission facilities.
- **Production Cost Module** – This module comprises a state-of-the-art stochastic multi-area hourly dispatch sub-module and a cost regression sub-module to distill the dispatch results into a usable form. The dispatch sub-module works in the following manner. For each possible combination of new resources, for each of 30 years, 60 blocks of hours, and 50 random draws of the key uncertain variables (loads in each of the three transmission areas with loads, fuel prices, and output of each of the three hydroelectric resources), the algorithm dispatches the available hydroelectric and thermal generating units to minimize the annual Railbelt-wide production cost required to satisfy the hourly loads in the three areas. In determining this dispatch, the module takes into account the capacity and production cost of each individual generating unit, the transfer capabilities of each transmission facility, spinning reserve requirements, quadratic transmission losses, and generating unit maintenance schedules. The cost regression sub-module takes the results from the dispatch sub-module, and estimates regression equations relating the cost for a portfolio in a year to the values of the uncertain variables. These regression estimates are then input to the Investment Module.
- **Investment Module** – This module comprises a state-of-the-art stochastic dynamic programming algorithm. At the beginning of each year, the module selects the optimal capacity additions four years hence (reflecting the development/construction lead time for new generating resources), based on loads and fuel prices in the previous year and expectations about load and fuel price growth (and their volatility) during the ensuing four years. For example, at the beginning of 2029 the module selects the optimal capacity additions to be placed in service during 2033, based only on the loads and fuel prices experienced in 2028, and expected growth rates of loads and fuel prices between 2028 and 2033.

The module selects the optimal capacity additions for each year, for each possible prior decision, and for each combination of values of the uncertain variables (loads and fuel prices). To select the optimal capacity additions for a year, the module calculates the expected cost associated with each possible decision that can be made at that point, using production cost estimates from

the Dispatch Algorithm as well as estimates of capital costs and fixed O&M expenses. In selecting the optimal capacity additions for a year, the module takes into account the irreversibility of each investment decision, i.e., that the selected capacity will remain in place in future years.

- **Data Development** – The participating utilities and R. W. Beck collaborated to develop the extensive data base required in the analysis. The utilities led the assembly of data regarding the characteristics of existing generating resources, including planned additions and retirements; the characteristics of unique Alaska-specific potential new resources; the characteristics of the existing transmission system, and potential upgrades; forecasts of expected load growth; and historical data on loads, hydroelectric output, and fuel prices, as well as fuel contracts. R. W. Beck verified these data.

R. W. Beck led the development of forecasts of expected fuel availability, prices, and price volatility; characteristics of potential new generic generating resources; forecasts of load shapes and volatility of load growth; and estimates of expected annual hydroelectric output and variability. The participating utilities verified these data.

An important outcome of the data development process is the representation of the Railbelt transmission system that was used throughout the remainder of the analysis, which consists of four transmission areas, which are connected by transmission “lines”:

- **Fairbanks** – Includes the GVEA loads and resources, except Healy
- **Healy** – Includes the Healy unit(s), and no loads
- **Anchorage** – Includes the loads and resources of ML&P, Chugach, and MEA, except Chugach resources assigned to Kenai
- **Kenai** – Includes the HEA and SES loads and resources, as well as Bernice Lake, Bradley Lake, Cooper Lake, and Nikiski generating units

Results

The study generated the following results:

- **Fuel Availability and Pricing** – The analysis indicates that natural gas will remain available in the Anchorage and Kenai transmission areas throughout the study period, at prices that are approximately equal to the Henry Hub price (the lower-48 benchmark). Forecasts of future Henry Hub prices are approximately double current Cook Inlet natural gas prices, in real terms.
- **Generating Unit Retirements** – ML&P intends to retire all units at its Plant 1 by 2008 (all dates are January 1), and the contract GVEA has for the output of Aurora Chena expires in 2017. In addition, the analysis indicates that it would be cost-effective to retire the Chugach Beluga 6/8 combined cycle (CC) unit in 2020, the Chugach Beluga 7/8 combined cycle unit in 2021, and the ML&P Plant 2 7/6 combined cycle unit in 2024.

- **Reliability** – R. W. Beck estimates that the LOLP was approximately 8 percent in the Fairbanks area in 2002, and below 1 percent in the Anchorage and Kenai areas. This compares to an industry standard of 10 percent. Maintaining a 10 percent LOLP requires an approximate 22 percent reserve margin in each of the three areas. These area-level reserve margins correspond, approximately, to utility-level reserve margins of 37 percent for GVEA and 40 percent for ML&P and Chugach². The latter estimates are slightly higher than the 30 percent utility-level reserve margins the utilities are required to maintain under the Alaska Intertie Agreement.
- **Base Case G&T Capital Investments** – The Base Case assumes that natural gas is available in Anchorage and Kenai but not Fairbanks or Healy, no new transmission facilities are constructed³, and none of several “unique investment opportunities”⁴ are constructed. In the Base Case, the analysis indicates that a new 85 MW simple-cycle combustion turbine (CT) should be installed in the Fairbanks area by 2008. Beyond that, the timing, size, type, and location of all other additions depends on 1) the resolution of uncertainty about loads and fuel prices between now and the time the associated decision must be made (i.e., four years prior to completion of the new unit) as well as 2) all previous investment decisions. For example, if the 2005 Fairbanks load is in the upper 80 percent of possible values, a new 60 MW combined cycle (CC) should be built in Fairbanks in 2010. If the 2005 Fairbanks load is not this high, but the 2006 Fairbanks load is in the upper 80 percent of the possible values, the new 60 MW CC should be built in 2011.

The analysis indicates that a wide variety of decisions could be made in January 2008 for additions to be completed in 2012. These decisions are summarized in Table ES-1, which shows the following:

- If 2007 loads and/or natural gas prices are low enough, no capacity should be added in 2012. For example, the first row of the table indicates that if the 2007 Fairbanks load is low (i.e., 0 – 20th percentiles of all possible values), the Anchorage load is expected (40 – 60th percentiles), the Kenai load is low or moderately low (0 – 40th percentiles), then for all possible 2007 natural gas prices no new capacity should be built in 2012.
- A 130 MW CC should be built in Anchorage if particular combinations of high enough Anchorage load, low enough Fairbanks load, high enough Kenai load, and high enough natural gas price occur in 2007.

² The reserve margin for a transmission area is the ratio of resources in the area to load in the same area. The reserve margin for a utility is the ratio of resources owned and contracted for by the utility (including its allocation of Bradley Lake capacity) to the utility’s load.

³ In particular, the Base Case assumes the Southern Intertie is not constructed.

⁴ The unique investment opportunities include the Healy Clean Coal Project (HCCP), the Emma Creek Coal project, a steam turbine at the existing Nikiski generating unit, the Fire Island Wind project, and generic coal units.

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- A 130 MW CC should be built in Fairbanks if the Fairbanks load is high and particular combinations of low enough Anchorage load and high enough natural gas price occur in 2007.

Table ES-1
Base Case Possible 2012 Capacity Additions
No Additions Are Made in 2010 and 2011

2012 Additions	2007 Values of Uncertain Variables (Percentile)			
	Load by Area			Henry Hub Gas Price
	Fairbanks	Anchorage	Kenai	
No Additions	0 - 20	40 - 60	0 - 40	0 - 100
	0 - 20	40 - 60	40 - 100	0 - 80
	0 - 20	60 - 80	0 - 100	0 - 80
	0 - 40	0 - 40	0 - 100	0 - 100
	20 - 60	40 - 80	0 - 100	0 - 80
	40 - 60	0 - 20	0 - 100	0 - 100
	40 - 60	20 - 40	80 - 100	0 - 80
	40 - 60	20 - 40	0 - 80	0 - 100
130 MW CC in Anchorage	0 - 20	40 - 60	40 - 100	80 - 100
	0 - 20	60 - 80	0 - 100	80 - 100
	0 - 60	80 - 100	0 - 100	0 - 100
	20 - 60	40 - 80	0 - 100	80 - 100
	40 - 60	20 - 40	80 - 100	80 - 100
130 MW CC in Fairbanks	80 - 100	0 - 20	0 - 20	0 - 100
	80 - 100	0 - 20	20 - 100	20 - 100
	80 - 100	20 - 60	0 - 100	20 - 100
	80 - 100	60 - 80	0 - 100	20 - 80
	80 - 100	60 - 80	0 - 20	80 - 100
130 MW CCs in Anchorage and Fairbanks	80 - 100	60 - 80	20 - 100	80 - 100
	80 - 100	80 - 100	0 - 60	20 - 100
	80 - 100	80 - 100	60 - 100	40 - 100
60 MW CC in Fairbanks	60 - 80	0 - 60	0 - 100	0 - 100
	60 - 80	60 - 80	0 - 100	0 - 80
	80 - 100	0 - 20	20 - 100	0 - 20
	80 - 100	20 - 80	0 - 100	0 - 20
60 MW CC in Fairbanks and 130 MW CC in Anchorage	60 - 80	60 - 80	0 - 100	80 - 100
	60 - 80	80 - 100	0 - 100	0 - 100
	80 - 100	80 - 100	0 - 100	0 - 20
	80 - 100	80 - 100	60 - 100	20 - 40

- 130 MW CCs should be built in both Fairbanks and Anchorage if the Fairbanks load is high and particular combinations of high enough Anchorage load and high enough natural gas price occur in 2007.
- A 60 MW CC should be built in Fairbanks if particular combinations of high enough Fairbanks load, low enough Anchorage load, and low enough natural gas price occur in 2007.

- A 60 MW CC should be built in Fairbanks and a 130 MW CC should be built in Anchorage if particular combinations of high enough Fairbanks load, Anchorage load, Kenai load, and natural gas prices occur in 2007.

In addition, the Base Case analysis indicates that over the 2008 – 2030 period, a significant amount of new generating capacity may need to be built in the Railbelt:

- If expected loads and natural gas prices happen to occur in every year, a total of 725 MW of new generating capacity should be built in the Railbelt between 2008 and 2030 – 205 MW in the Fairbanks area, 520 MW in the Anchorage area. Approximately 355 MW of this new capacity will replace existing capacity that will or should be retired between 2020 and 2024. The 370 MW of net new capacity is equal to approximately 30 percent of the 1,200 MW of current dispatchable capacity in the Railbelt.
- If low (i.e., 10th percentile) loads and natural gas prices happen to occur in every year, a total of 535 MW should be built in the Railbelt between 2008 and 2030 – 85 MW in the Fairbanks area, 450 MW in the Anchorage area.
- If high (i.e., 90th percentile) loads and natural gas prices happen to occur in every year, a total of 985 MW should be built between 2008 and 2030 – 335 MW in the Fairbanks area, 650 MW in the Anchorage area.
- The present value (as of January 2008) of total expected 2008 – 2033 system costs is \$5.04 billion. The average levelized cost is \$53.3 / MWh (real 2008 dollars). This compares to an estimated expected value for 2004 of \$34.6 / MWh (also in real 2008 dollars). More than half of the increase in the average levelized cost is due to an increase in fuel prices; the remainder of the increase is due to incremental fixed O&M expenses associated with extending the life of existing units and the capital costs of new units that will be constructed.
- **G&T Investments With Risk Aversion** – In the Risk Aversion Case, capacity decisions are made at each decision point to minimize the 90 percent confidence level present value of total system costs from that point forward, instead of the present value of expected total system costs from that point forward (as in the Base Case). Incorporating risk aversion into the decision making process in this manner results generally in the construction of more capacity. For example, in contrast to the Base Case:
 - If actual Fairbanks load in 2005 is in the highest 20 percent of possible values, either a 130 MW CC or a 60 MW CC should be built in 2010 in the Fairbanks area, depending on fuel prices and loads in other areas in 2005; in the Base Case, a 60 MW CC would be built. If a unit is not built to begin operation in 2010, but the Fairbanks 2006 load is in the highest 20 percent of possible values, a 130 MW CC should be built in Fairbanks in 2011; in the Base Case, under similar circumstances a 60 MW CC would be built.
 - If expected loads and fuel prices happen to occur in every year, 865 MW of new capacity would be built in the Risk Aversion Case during the 2008 –

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2033 period, compared to 725 MW in the Base Case. If high loads and fuel prices happen to occur in every year, 1,055 MW of new capacity would be built in the Risk Aversion Case, compared to 985 MW in the Base Case.

- **G&T Investments in Unique Investment Opportunity and Sensitivity Cases** – Several unique investment opportunities and sensitivity cases were also analyzed:
 - **Pseudo-Healy Clean Coal Project** – The HCCP as it currently exists was not analyzed. Instead, HCCP was modeled as if it had the same operating characteristics (i.e., heat rate, unit variable O&M, maintenance rate, and forced outage rate) as a generic 50 MW coal unit, assumed to be “built” in the Healy transmission area in 2008. Excluding the capital costs required to transform the existing HCCP facility into the modeled facility, and the annual fixed O&M associated with the transformed facility, the estimated present value (as of January 2008) of expected 2008 – 2033 total system costs with the pseudo-HCCP operating is \$4.82 billion. This represents a savings of \$220 million compared to the Base Case. Thus, if the present value of the sum of capital expenditures and fixed O&M associated with transforming the existing facility into the modeled unit is less than \$220 million, customers of the Railbelt would be better off if the transformation is made than if the plant is allowed to remain idle.
 - **Southern Intertie** – Construction of the Southern Intertie would increase the transfer capability between the Anchorage and Kenai areas by 50 MW (in each direction), and reduce transmission losses. Excluding capital costs and fixed O&M, construction of the Intertie results in an estimated present value of 2008 – 2033 total system costs of \$5.01 billion, a savings of \$28 million compared to the Base Case. The present value of the estimated capital and fixed O&M costs of the project is \$141 million (in real 2008 dollars), so net savings attributable to construction of the project are estimated to be negative \$113 million (real 2008 dollars), i.e., customers of the Railbelt would be worse off by \$113 million during the 2008 – 2033 period if the project is completed.
 - **Fire Island Wind Project** – The Fire Island Wind Project was modeled as a 50 MW facility in the Anchorage area that would begin operation in 2008. Excluding capital costs and fixed O&M, construction of the project results in an estimated present value of 2008 – 2033 total system costs of \$4.94 billion, a savings of \$104 million compared to the Base Case. The present value of the estimated capital and fixed O&M costs of the project is \$101 million (in real 2008 dollars), so net savings attributable to construction of the project are estimated to be \$3 million (real 2008 dollars), i.e., customers of the Railbelt would be better off by \$3 million during the 2008 – 2033 period if the project is completed.
 - **Nikiski Repowering Project** – The Nikiski Repowering Project was modeled as a 25 MW steam turbine added to the 42 MW gas turbine (and steam generator) at the existing Nikiski plant in the Kenai area, which would begin operation in 2008. Excluding capital costs and fixed O&M,

construction of the project results in an estimated present value of 2008 – 2033 total system costs of \$4.95 billion, a savings of \$94 million compared to the Base Case. The present value of the estimated capital and fixed O&M costs of the project is \$29 million (in real 2008 dollars), so net savings attributable to construction of the project are estimated to be \$65 million (real 2008 dollars), i.e., customers of the Railbelt would be better off by \$65 million during the 2008 – 2033 period if the project is completed.

- **Emma Creek Coal Project** – The Emma Creek Project was modeled as two 100 MW coal-fired units in the Healy transmission area, which begin operation in 2012. Excluding capital and fixed O&M costs, the estimated present value of 2008 – 2033 total system costs is \$4.56 billion, which represents a gross savings of \$477 million compared to the Base Case. The present value of estimated capital and fixed O&M costs for the project is \$504 million, so net savings attributable to construction of the project are estimated to be negative \$27 million (real 2008 \$), i.e., the customers of the Railbelt would be worse off by approximately \$27 million during the 2008 – 2033 period if the project is constructed.
- **Generic Coal** – This sensitivity case investigated how the optimal investment strategy would change if coal could be delivered to power plants in the Fairbanks and Anchorage transmission areas, beginning in 2015, at the same price that GVEA’s existing Healy 1 plant pays; and that a site could be identified in each area at which a coal plant could be permitted and cost-effectively constructed and operated. Based on the results of a screening analysis, the sensitivity case was constructed so that either a 150 MW coal plant would be built in Anchorage in 2015, a 150 MW coal plant would be built in Fairbanks in 2015, or both; and if a unit was built in only one area in 2015, the unit in the other area could be built at a later date. The important results from this sensitivity case are as follows:
 - Construction of the coal plant(s) produces net savings in the present value of 2008 – 2033 total system costs of \$420 million compared to the Base Case, and a significant reduction in the level of risk of the strategy (i.e., a standard deviation of these costs of \$475 million, compared to \$760 million in the Base Case).
 - In nearly all circumstances, the optimal strategy is to build coal units in both Fairbanks and Anchorage to begin operation in 2015. In a few circumstances, the optimal strategy is to wait up to five years to build the Fairbanks unit, and in a very limited set of circumstances the Fairbanks unit never gets built.
 - Construction of the coal plant(s) in 2015 modifies the short-term investment strategy significantly. Instead of building a 60 MW CC in Fairbanks in either 2010 or 2011 (if the 2005 or 2006 Fairbanks load is high), an 85 MW CT, which has lower total capital costs, should be built in these circumstances. In 2012, a 130 MW CC should be built in Anchorage only if the 2007 Anchorage load is in

the highest 20 percent of possible values, and an 85 MW CT (and not either a 60 MW CC or 130 MW CC, as in the Base Case) should be built in Fairbanks only if the 2007 Fairbanks load is in the highest 40 percent of possible values. The range of 2007 loads and natural gas prices under which no capacity additions should be made in 2012 is substantially broader than in the Base Case (as portrayed in Table ES-1).

- The effects of construction of the coal plant(s) on the long-term investment strategy are fairly predictable. If expected loads and natural gas prices occur in all years, the coal plant built in Anchorage in 2015 displaces the 130 MW CC that would have been built there in 2015. In Fairbanks, the coal plant built in 2015 replaces the 60 MW CCs that would have been built there in 2015 and 2029.
- Natural Gas to Fairbanks – This sensitivity case investigated how the optimal investment strategy would change if natural gas was made available to power plants in the Fairbanks area, beginning in 2015, at the same prices as natural gas is sold to power plants in the Anchorage and Kenai areas. The results of this case are as follows:
 - The short-term investment decisions are very similar to those in the Base Case. The primary difference is that in some circumstances, a 130 MW CC should be built in Fairbanks in 2010, 2011, or 2012 that in the Base Case would lead to construction of a 60 MW CC.
 - The long-term investment strategy is also very similar to the strategy for the Base Case. The primary difference is, again, that a 130 MW CC is more likely to be built in Fairbanks in the 2015 – 2020 period than the 60 MW CC that is built under similar circumstances in the Base Case.
 - Interestingly, although expected natural gas prices are lower than expected refined fuel oil prices, the present value of total expected 2008 – 2033 system costs is higher in this sensitivity case by \$110 million (\$5.15 billion versus \$5.04 billion). The reason for this is that natural gas prices are so much more volatile than refined fuel oil prices that in the event that fuel prices happen to be in the highest 40 percent of possible values, the total system costs in the sensitivity case are significantly higher than in the Base Case, more than offsetting the savings if fuel prices happen to be in the lowest 60 percent of possible values.

Section 1

INTRODUCTION

During June 2003, five of the six Railbelt utilities⁵ agreed to jointly undertake a Railbelt Energy Study (RES). At the request of the utilities, the law firm Ater Wynne LLP contracted with the economic/engineering consulting firm R. W. Beck in August 2003 to perform the study. This report is a summary of the activities completed during the study, and the results of these activities.

Background

The participating utilities have several motives for conducting the RES:

- All of the thermal generating capacity in the Railbelt is more than 20 years old, and much of it is more than 30 years old. The utilities need to determine during the next several years whether to retire these units or make the investments in them required to extend their lives. If they decide to retire the units, they also need to decide what new generating capacity, if any, they should build to replace the units.
- During the next few years, several of the utilities may need to build new capacity to satisfy load growth.
- The utilities recognize that it may be both less costly and less risky to develop and operate new generating units jointly or collectively than to undertake these efforts separately.
- The utilities have several opportunities, such as restarting the Healy Clean Coal Project, constructing the Southern Intertie, and developing the Emma Creek Coal Project, that would provide benefits to (and impose costs on) more than one utility. As a result, the utilities recognize that decisions about these opportunities should reflect the joint or collective interests of the Railbelt utilities.

Objective

The objective of the RES is to identify the combination of generation and transmission (G&T) capital investments in the Railbelt between 2004 and 2033 that:

- Minimize future power supply costs, and

⁵ The five participating utilities are Anchorage Municipal Light & Power (ML&P), Chugach Electric Association (Chugach), Golden Valley Electric Association (GVEA), Homer Electric Association (HEA), and Seward Electric System (SES). Matanuska Electric Association (MEA) was invited to participate but declined. Although MEA did not participate in the study, data for it has been included in the study, and the identified G&T capital investments reflect the need to serve its load.

Section 1

- Maintain current levels of power supply reliability.

The investments are to be identified taking into account uncertainty about future loads, fuel prices, and resource options, and assuming that the six Railbelt utilities act collectively.

There are three important points to make about this objective:

- The RES is a *study*, not an Integrated Resource Plan (IRP). Each utility will still need to perform an IRP or Power Supply Plan, in order to identify appropriate G&T investment decisions for that utility. R. W. Beck believes that it is not possible in an analysis such as this, performed for a collection of utilities, to appropriately reflect all of the utility-specific issues that a utility needs to address in making G&T capital investment decisions. For example, it was not possible in this analysis to collect and appropriately analyze all of the information required to make decisions regarding retirements of existing generating units.
- The RES assumes the utilities act *collectively* to invest in new G&T assets and dispatch both new and existing generating resources. For the purposes of the study, *collectively* means that:
 - Investments were identified *as if* a single entity makes all G&T investment and dispatch decisions.
 - This entity makes these decisions in order to minimize expected power supply costs for the collection of all six Railbelt utilities.
 - That in making these decisions it takes into account the operational limitations of existing and potential new generating units and transmission facilities, but not the ownership of these assets.

R. W. Beck believes that the Railbelt utilities can achieve the benefits of collective action identified in this study under the current set of institutional arrangements, as well as under other sets of institutional arrangements, such as a power pool or a single G&T organization. The study did not investigate the benefits or costs of changing the set of institutional arrangements that are in place in the Railbelt.

- The RES is a study of both generation *and* transmission investments. However, the detailed information required to analyze transmission investments was only available for one potential transmission investment, the Southern Intertie Project. It was beyond the scope of the study to develop the required information for other potential transmission investments, such as a second line from Anchorage to Healy. As a result, the only transmission investment the study considered was the Southern Intertie Project. A wide variety of generation investments were also considered.

Report Overview

The remainder of this report is organized as follows:

- The methodology developed for and executed in the RES is summarized in Section 2.
- The data that were developed for and utilized in the RES are presented in Section 3.
- The results of the study are summarized in Section 4.
- More detailed and comprehensive descriptions of the methodology, data, and results are provided in the Appendix, which is bound separately.

Section 2 METHODOLOGY

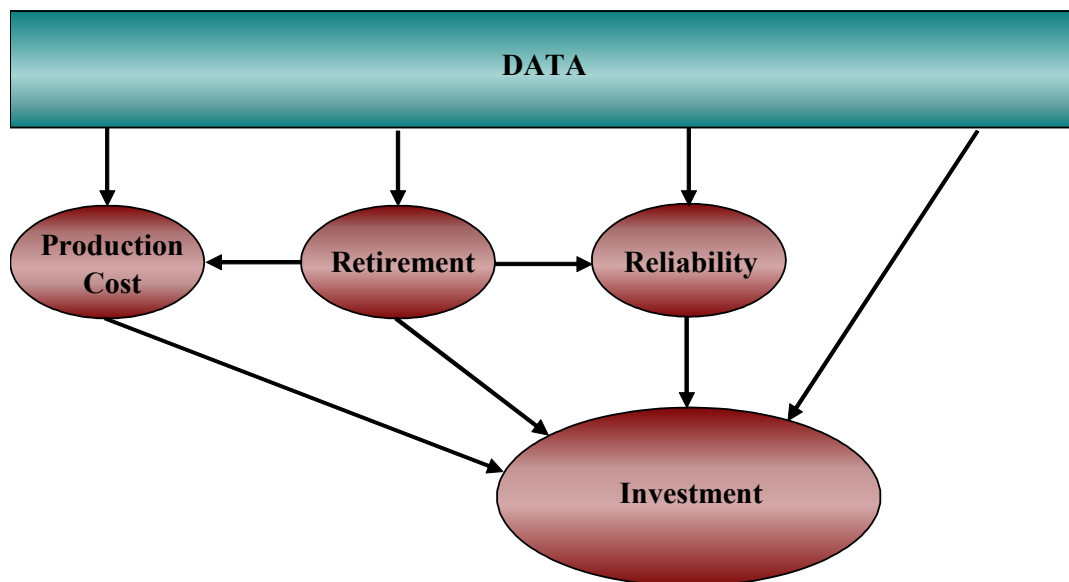
To complete the RES, R. W. Beck developed an Excel-based model of the Railbelt system. This section summarizes the most important features of the RES model, including each of the four modules that comprise the model. This section is divided into the following sub-sections:

- Model Overview
- Retirement Module
- Reliability Module
- Production Cost Module
- Investment Module

Model Overview

An overview of the RES model is provided in Figure 2-1, and the following bullets:

Figure 2-1
Overview of Railbelt Energy Study Model



- The data that form the inputs to all four modules are described in Section 3.
- The Retirement Module is executed first. The module determines the existing generating units 1) definitely to be retired and 2) to be considered for retirement in the Investment Module. This list, which includes the associated dates, is provided as input to the three other modules.
- The Reliability Module is executed next. For each year, the module calculates the LOLP and ELOE in each of the three transmission areas with load,⁶ for various combinations of existing and potential new generating units and transmission facilities. It also calculates the reserve margins required in each area to achieve specified LOLP levels. These reserve margins are provided as input to the Investment Module.
- The Production Cost Module is executed in parallel to the Reliability Module. For each potential combination of existing and new generating units (called a “portfolio”), the module generates, for each year, a specified number of random draws of the uncertain variables. The module then calculates the annual production costs (i.e., fuel plus variable O&M expenses) that would be incurred to satisfy the load, based on the draw. These calculated costs are summarized in a set of parameters that can be used to predict the annual production costs that would be incurred if the portfolio were selected, for any set of values of the uncertain variables. These parameters are provided as input to the Investment Module.
- The Investment Module determines the optimal generating and transmission capacity investment strategy. For each year, for each possible combination of values of the uncertain variables, and for each possible prior decision, the module selects the portfolio that best achieves the decision making criterion from that point forward, taking into account uncertainty about the future, the irreversibility of investment decisions, and the ability to make additional decisions in the future.

Retirement Module

The Retirement Module is the simplest module of the RES Model, comprising a single Excel spreadsheet. The spreadsheet incorporates the following principles:

- The participating utilities identified a Retirement Evaluation Date for each generating unit. At this date, the unit would either be retired or an investment would have to be made in it to extend its life.
- The criterion for deciding to retire or extend the life of a unit at its Retirement Evaluation Date is fairly simple:
 - The most similar unit among the list of potential new generating units was selected. This unit is called the “potential replacement unit.” For this purpose, “most similar” means the same technology (e.g., existing simple

⁶ The concept of transmission areas is defined in Section 3.

cycle combustion turbines were compared to potential new simple cycle combustion turbines, existing combined cycles to potential new combined cycles, etc.) and the nearest in size (e.g., an existing 30 MW simple cycle was compared to the potential 40 new MW simple cycle)⁷.

- The annual cost (per kW of capacity) in the first year following the Retirement Evaluation Date was calculated for both the existing unit and its potential replacement unit, under three different capacity factors (Low, Medium, and High) and three different fuel prices (Low, Medium, and High).
- The annual cost for both the existing unit and the potential replacement unit include fuel cost (assumed capacity factor multiplied by 8760 hours multiplied by heat rate multiplied by assumed fuel price), variable O&M (assumed capacity factor multiplied by 8760 hours multiplied by unit variable O&M), and fixed O&M (unit amount). For the potential replacement unit, the annual cost also included the annual amortization of the capital cost for the unit, using a 30-year life and 7 percent discount factor. For the existing unit, the annual cost also included the incremental investment required to extend its life. This was assumed to be 6.7 percent (i.e., one-fifteenth) of the capital cost of the potential replacement unit.
- If an existing unit is projected to have lower first-year costs than its potential replacement unit in all nine capacity factor-fuel price scenarios, it is definitely not retired; if an existing unit is projected to have higher first-year costs in all nine scenarios, it definitely is retired; and if an existing unit is projected to have lower costs in some scenarios and higher costs in other scenarios, the decision to retire or extend the life of the unit is made in the Investment Module⁸.

Reliability Module

The Reliability Module calculates the LOLP and ELOE in each area associated with a particular combination of 1) annual loads in the three areas and 2) a specific set of generating units. LOLP for an area is the probability that the load in that area is not satisfied during one or more hours during the year, and ELOE is the expected number of MWh of load not served during these hours. Both measures consider load that is not served because enough generating capacity (and, potentially, transmission capacity) is out of service due to maintenance or forced outages such that there is not enough generating capacity available to serve the load. These are the standard

⁷ Representing the retirement decision as based only on a comparison of the existing unit's first-year costs to those of the most similar unit is a simplification of the process that the Railbelt utilities actually employ. In fact, R. W. Beck believes that this simplification is the primary difference between this study and a comprehensive IRP.

⁸ The Retirement Module does not consider environmental issues generally, and emission limit issues specifically. For each existing unit analyzed, it was assumed that the potential replacement unit could be constructed at a location and in a manner such that no environmental-related limits on annual production would be established. Comprehensive consideration of these issues was beyond the scope of this study.

Section 2

measures for incorporating reliability into a resource planning or capacity expansion study, as they reflect the aspects of electric system reliability that can be improved by constructing additional generating units or transmission lines⁹.

The module consists of a single Excel workbook, with a Visual Basic for Applications (VBA) macro. For a specified combination of annual loads in the three areas and set of generating units, the module calculates the LOLP and ELOE in the following manner:

- Within Excel, the module calculates the load in each area in each of the 60 blocks of hours corresponding to the annual loads, in the same manner as in the Dispatch Sub-Module
- For each of the 60 blocks of hours, the VBA macro calculates the probability that the load in each area will not be fully served, and the expected magnitude of any unserved load. This calculation is performed by looping through all possible permutations of outages of generating units and transmission lines. For each permutation, the macro:
 - Calculates the probability of the permutation occurring, the amount of generating capacity available in each area, and the amount of transmission capacity available between each area.
 - Dispatches the available generating capacity to try to satisfy the load in each area, using available transmission capacity to transfer excess capacity in one area to areas with shortages (if any).
 - Determines if all of the load in each area can be satisfied and, if not, the difference between total load and served load (i.e., unserved load).
- For each area, the macro accumulates probabilities and expected unserved load across permutations within a block of hours, and across blocks of hours to generate an estimate of the annual LOLP and ELOE for each area for the year.
- The macro also calculates the reserve margin for each area, given the specified annual load and specified set of generating units.

Production Cost Module

The Production Cost Module consists of two sub-modules:

- The Dispatch Sub-Module
- The Cost Regression Sub-Module

Dispatch Sub-Module

The Dispatch Sub-Module calculates the annual production cost (i.e., fuel plus variable O&M expenses) required to satisfy the specified load for each combination of

⁹ These measures do not, however, reflect aspects of electric system reliability that cannot be improved simply by adding G&T capacity, in particular, transmission system instability and operating inertia.

potential portfolio, year, and random draw of uncertain variables. The uncertain variables are the year-to-year percentage change in the average annual load in each of the three areas with loads, the year-to-year percentage change in the annual average Henry Hub natural gas price, the annual average world oil price, and the annual output of each of the three hydroelectric generating units.

In this context, a “portfolio” is the set of existing generating units and transmission facilities, and a specified set of potential new generating units and transmission facilities. For example, one portfolio (i.e., the “BASE” portfolio) comprises just the set of existing generating units and transmission facilities, and no new generating units or transmission facilities; another portfolio includes existing generating units and transmission facilities plus a single 85 MW simple cycle combustion turbine located in the Fairbanks area; and still another portfolio consists of existing generating units and transmission facilities, a single 85 MW simple cycle combustion turbine in the Fairbanks area, and two 130 MW combined cycle units in the Anchorage area. More than 30,000 such portfolios were analyzed as part of this study.

The sub-module is an Excel workbook that invokes both the Crystal Ball[®] (CB) Monte Carlo random number generator add-in and several VBA macros. The sub-module works in the following manner:

- CB is invoked to generate a specified number (in the final RES, 50) of random draws of the uncertain variables
- For each random draw, the values of several variables that depend on these random variables, including the unit production cost (i.e., fuel plus variable O&M expense per MWh of output) for each generating unit and loads in each area in each of 60 blocks of hours, are calculated in Excel worksheets
- For each random draw, a VBA macro is executed that loops through specified portfolios and years. For each portfolio and year, the macro performs the following steps:
 - Reads the load and generating unit characteristic data from the appropriate Excel sheets.
 - Schedules maintenance for all generating units.
 - Schedules the three hydroelectric generating units (i.e., determines the output of each facility in each of the 60 blocks of hours) in a manner that 1) utilizes all of the available output for the unit for the year/draw combination and 2) is consistent with the way that Railbelt system operators actually schedule these resources.
 - For each of the 60 blocks of hours, performs an initial dispatch of the available thermal generating units in order to minimize the total production cost in that block. In performing this dispatch, the algorithm takes into account the maximum generating capacity and unit production cost of every generating unit, the ability to transfer energy between areas over transmission facilities, the limits on these transfers, and transmission losses, which increase according to the square of the transferred quantity.

- Identifies the largest contingency in each of the three areas with loads, determines the amount of spinning reserves required in each area from thermal generating units, and adjusts the initial dispatch to accommodate these spinning reserve requirements¹⁰.
- Calculates the total production cost for the block of hours, multiplies the production cost by the number of hours in the block, and accumulates these costs across all of the blocks of hours that comprise the year.

Cost Regression Sub-Module

The Cost Regression Sub-Module distills all of the output of the Dispatch Sub-Module into a form that the Investment Module can use. It does this by estimating a separate regression equation for each potential portfolio and each year. The dependent variable in the regression is the annual production cost calculated by the dispatch cost sub-module, for which there are 50 values, one for each of the 50 random draws. The independent or explanatory variables are the corresponding values of average annual load in each of the three load areas, the world oil and Henry Hub natural gas price, and total hydroelectric output of the three facilities (aggregated across facilities, not individually). The parameters of each regression equation are estimated using ordinary least squares. The output of this sub-module is a set of parameters that can be combined with any set of values of the six explanatory variables to predict the annual production cost that would occur given that set of values, as well as the standard deviation of the annual production cost.

Investment Module

The Investment Module comprises a set of Excel workbooks (one containing VBA code and control parameters, one containing input data, and three containing results) and a VBA macro. The module utilizes a Stochastic Dynamic Programming algorithm, which works in the following manner:

- For the purpose of making investment decisions, four of the uncertain variables were considered to be stochastic: annual average load in each of the three areas, and the annual Henry Hub natural gas price. The other uncertain variables (i.e., annual world oil price, annual output at each of the three hydroelectric units) were considered to be probabilistic¹¹. For each of the years 2004 – 2028, the probability distribution of each of these four variables was determined, and the

¹⁰ The largest contingency in an area is the maximum of a) the capacity of the largest generating unit running or b) the largest import. The spinning reserve requirement in an area is the contingency, less spinning reserves provided a) automatically by hydroelectric generating units and b) special spinning resources (e.g., GVEA has a 25 MW battery installed specifically to provide spinning reserves, and also can shed up to 70 percent of its load to meet its spinning requirements). The requirement in an area can be satisfied by a) reducing the output of already dispatched units or b) if the largest contingency is not an import, importing excess spinning reserves produced in other areas.

¹¹ For the purpose of the RES, a stochastic variable is one whose expected value in n years depends on the current value, where n is the development/construction period plus one (i.e., five years in the RES). A probabilistic variable is one whose expected value in n years is independent of the current value.

value of each variable at a specified number of percentiles (in the final analysis, five) was calculated. For example, given the actual 2003 annual average Fairbanks load, the expected 2003 – 2004 load growth, and the assumed volatility of load growth, the five values of annual average 2004 load growth that correspond to the 10th, 30th, 50th, 70th, and 90th percentiles were calculated¹².

- For each pair of consecutive years, the probability of moving from a particular Evaluation Point in the first year to a particular Evaluation Point in the second year was calculated for each of the four stochastic variables and all combinations of Evaluation Points in the two years.
- The algorithm works backward, making the January 2029 decisions for 2033 capacity additions first, then the January 2028 decisions for 2032 additions, and so on, making the January 2004 decisions for 2008 additions last. With the exception of the January 2004 decision, the algorithm makes a separate decision for 1) each of the 625 possible combinations of Evaluation Points in the preceding year (5 Fairbanks load values x 5 Anchorage load values x 5 Kenai load values x 5 Henry Hub natural gas price values) and 2) each possible prior investment decision¹³. For example, in January 2029, the algorithm makes a decision for every combination of 1) all 625 combinations of possible values of the 2028 loads and fuel prices and 2) all 4950 portfolios that could have been selected in January 2028 for operation in 2032.
- In January 2029, the algorithm performs the following steps:
 - For each of the 625 combinations of 2028 loads and natural gas prices, the algorithm calculates the expected 2033 value of each of the four stochastic variables, as well the variance of each. For each possible 2033 portfolio, the algorithm combines these expected values and variances with the parameters estimated for the portfolio in the Cost Regression Sub-Module described above to calculate the expected value and variance of 2033 production costs if the portfolio were selected. To the expected value, the algorithm adds the annual fixed O&M expenses and annual amortized capital costs for the portfolio to yield the expected value of 2033 total system cost for the specified portfolio, given the specified combination of 2028 values of the four stochastic variables.
 - For each of the 3,093,750 combinations of 2028 loads and natural gas prices and 4,950 prior decisions, the algorithm identifies the portfolio that in 2033 both 1) is feasible and 2) best satisfies the decision criterion. Feasibility has two aspects. First, for a specific previously selected portfolio A, potential

¹² In the remainder of this section these five values (and their analogues for other variables and years) are referred to as “Evaluation Points.”

¹³ For the January 2004 decision, it is necessary to make the decision for only one combination of Evaluation Points (i.e., the one associated with actual 2003 loads and natural gas price) and prior decisions point (i.e., because no new capacity has been added prior to the January 2004 decision). In the final RES analysis, 4,950 portfolios were considered, each a unique combination of potential new generating unit additions. At each decision point except January 2004, any one of these 4,950 portfolios could have already been selected, so it is necessary to make 3,093,750 (625 x 4,950) decisions at each decision point.

portfolio B is feasible only if either A and B are the same or A is a subset of B, i.e., B contains all of the generating units that A does, and possibly (but not necessarily) others. Second, portfolio B is feasible only if it satisfies the reserve margin requirement in each area, i.e., the ratio of the portfolio's capacity in each area to the expected 2033 peak load in the area (given the 2028 load and expected load growth between 2028 and 2033), minus one, exceeds the reserve margin requirement (e.g., 22 percent).

At each decision point, the algorithm can use either of two decision criteria: select the portfolio with the lowest expected value of future total system costs, or select the portfolio with the lowest future total system cost at the α percent (e.g., 90 percent) confidence level. These two decision criteria are explained further below.

- Moving backward, the algorithm then addresses the decision to be made in January 2028 regarding capacity additions to be made in 2032. This decision is more complicated than the January 2029 decision, and making it involves the following steps:
 - Analogous to the January 2029 decision, for each of the 625 combinations of 2027 values of the four stochastic variables and for each potential 2032 portfolio, the algorithm calculates the expected value and variance of 2032 total system costs if the portfolio were selected.
 - In addition, for each of the 625 combinations of 2027 values of the four stochastic variables and for each potential portfolio, the algorithm calculates the expected value and variance of 2033 total system costs if the portfolio were selected for operation in 2032.

In calculating these expected values and variances, the algorithm takes into account that in January 2029 another decision will be made that will directly determine the expected value and variance of 2033, but that by affecting the portfolios that are feasible to select in January 2029 the January 2028 decision indirectly affects the 2033 costs.

For each of the 625 combinations of 2027 values of the stochastic variables, and each of the 4,950 potential 2032 portfolios, the algorithm calculates the expected value and variance of the 2033 costs by looping through all 625 combinations of 2028 values of the stochastic variables. For each of these 625 2028 Evaluation Points, the algorithm calculates the probability of moving from the 2027 Evaluation Point of interest to the 2028 Evaluation Point, and the expected value and variance of the 2033 total system cost if 1) the indicated 2028 Evaluation Point occurs and 2) the indicated portfolio is selected in January 2028, thereby becoming the “previously selected portfolio” for the January 2029 decision. Multiplying the probability of moving to the 2028 Evaluation Point by the expected value (and variance) of 2033 costs if that point is reached, and summing across possible 2028 Evaluation Points, yields the expected value (and variance) of 2033 total system costs if the portfolio is selected in January 2028 for operation in 2032.

For example, consider the costs in 2033 if the 2027 Evaluation Point is #1 and portfolio A is selected in January 2028. Suppose the probability of moving from 2027 Evaluation Point #1 to 2028 Evaluation Point #1 is 60 percent, and that the probability of moving to 2028 Evaluation Point #2 is 40 percent¹⁴. Further suppose that if the 2028 Evaluation Point is #1, and if the previous decision is A, in January 2029 portfolio B will be selected for 2033, and the expected value of 2033 costs (ignore variances for the purpose of the example) in this situation is \$300 million; while if the 2028 Evaluation Point is #2, and the expected value of 2033 costs in this situation is \$350 million. Then the expected value of 2033 costs if the 2027 Evaluation Point is #1 and portfolio A is selected in January 2028 is \$320 million ($.6 \times 300 + .4 \times 350$).

- Once the 2033 costs are estimated, their present values are calculated, and the resulting value is added to the 2032 costs. The resulting amount represents the expected value and variance of the present value (as of January 2032) of 2032 – 2033 costs if 1) the specified 2027 Evaluation Point occurred and 2) the specified portfolio is selected in January 2028.
- For each of the 625 combinations of 2027 values of the stochastic variables, the algorithm selects the portfolio for operation in 2032 that is both feasible and best achieves the decision criterion, in the same fashion as it selects the best portfolio for operation in 2033. In testing feasibility, the algorithm only considers feasibility in 2032. However, in applying the decision criterion, the algorithm considers the expected value and variance of the present value of 2032 – 2033 total system costs, not just costs in 2032.
- Continuing to move backward, the algorithm then addresses the decision to be made in January 2027 regarding capacity additions to be made in 2031. It makes this decision in nearly the same way as it makes the January 2028 decision. First, the algorithm calculates the expected value and variance of 2031 costs. Then it calculates the expected value and variance of the present value (as of January 2032) of 2032 – 2033 costs. The present value of 2032 – 2033 costs are discounted one year (so that they represent the present value of 2032 – 2033 costs as of January 2031), then added to the expected 2031 costs to yield the expected value and variance of the present value (as of January 2031) of 2031 – 2033 total system costs. Feasibility is tested, and the decision criterion applied, in exactly the same manner as for the January 2028 decision.
- Continuing to move backward, the algorithm addresses the decisions to be made in January 2026, 2025, etc, all the way to 2005 in exactly the same manner.
- The decision to be made in January 2004 is less complicated. The 2003 values of each of the four stochastic variables are known (or treated as if they were known). As a result, a separate decision does not need to be made for 625 combinations of possible values of the stochastic variables, just the one actual value. In addition, a

¹⁴ This is an extreme simplification, provided only to illustrate how the algorithm works. In implementing the model for the RES, there was a non-zero probability of moving from each of the 625 2027 Evaluation Points to all 625 of the 2028 Evaluation Points.

Section 2

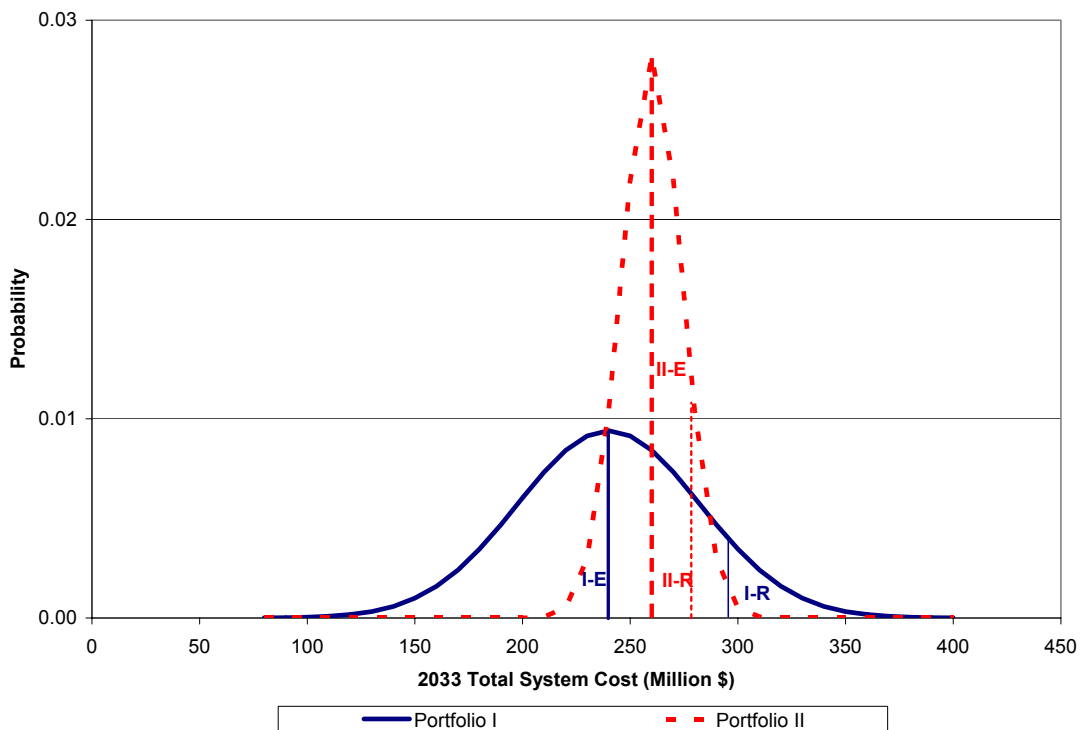
separate decision does not need to be made for all 4,950 possible previous decisions, just the one actual previous decision.

Alternative Decision Criteria

As indicated above, the algorithm can use either of two decision criteria: minimize expected future total system cost or minimize the future total system cost at the α percent confidence level, which we call the risk aversion criterion. The following example describes the difference between these two criteria:

- Suppose it is January 1, 2029, and the algorithm is selecting capacity additions to begin operation in January 2033. At each decision point, the algorithm knows what the 2028 loads in the three areas were, as well as 2028 natural gas prices. For convenience, suppose the algorithm is deciding between just two portfolios, labeled I and II. The 2033 total system costs (i.e., production costs plus capital and fixed O&M) for each portfolio are uncertain, but the algorithm knows how they are distributed statistically. In Figure 2-2, the probability distribution of 2033 portfolio I system costs are portrayed with the solid blue curve, and the probability distribution 2033 portfolio II system costs are represented by the dashed red curve.

Figure 2-2
Decision-Making Using Alternative Decision Criteria



- Using the expected value criterion, the algorithm calculates the expected value of 2033 total system costs for each portfolio, and selects the one with the lowest

expected cost. These expected costs are represented in Figure 2-2 by the heavy vertical lines labeled I-E (for Portfolio I) and II-E (for Portfolio II). In the example, I-E is less than II-E (\$240 million vs. \$260 million), so Portfolio I would be selected over Portfolio II.

- Using the risk aversion criterion, and assuming that a 90 percent confidence level is specified, the algorithm calculates the value of 2033 total system costs for each portfolio that has only a 10 percent (i.e., 100 percent minus the 90 percent confidence level that was specified) chance of being exceeded. This value is called the 90 percent confidence level value for the portfolio. The algorithm then selects the portfolio with the lowest 90 percent confidence level value. The 90 percent confidence level values are represented in Figure 2-2 by the lighter vertical lines labeled I-R (for Portfolio I) and II-R (for Portfolio II). In the example, II-R is less than I-R (\$278 million vs. \$294 million), so Portfolio II would be selected over Portfolio I.

In the example, Portfolio II has higher expected total system costs than Portfolio I, but a much lower standard deviation of these costs (i.e., degree of uncertainty). Several factors could cause this phenomenon:

- Portfolio II could include more new capacity in 2033 than Portfolio I. If the 2033 loads and prices are less than or equal to the values that were expected in January 2029, when the decision was made, Portfolio II would have higher 2033 total system costs, because the capital and fixed O&M costs attributable to the additional capacity are larger than the production cost savings attributable to this capacity. However, if the 2033 loads and prices are higher than the values that were expected in January 2029, the production cost savings would outweigh the capital and fixed O&M costs attributable to the additional capacity, and Portfolio II's total system costs would be less than the Portfolio I costs. The additional capacity serves as a hedge, or insurance, against higher-than-expected loads and/or fuel prices.
- Portfolio II could include the same amount of capacity in 2033 as Portfolio I, but more combined cycle capacity (and therefore less simple cycle capacity) than Portfolio I. With lower-than-expected or expected 2033 loads and fuel prices, the combined cycle unit's higher capital and fixed O&M costs outweigh the production cost savings, but at higher-than-expected loads and/or fuel prices, the converse is true.
- Portfolio II could include the same amount of capacity in 2033 as Portfolio I, but the two portfolios have different fuel mixes. For example, both coal and refined fuel-oil prices are less volatile than natural gas prices. As a result, the greater the share of coal- or refined fuel oil-fired (e.g., diesel) capacity in a portfolio, the lower the standard deviation of total system costs for that portfolio.
- Portfolio II could have a more diversified fuel mix than Portfolio I. Even if refined fuel oil prices were as volatile as natural gas prices, if the two fuel prices are not perfectly correlated, a portfolio that includes both natural gas-fired and refined fuel oil-fired capacity would have a lower standard deviation of total system costs than a portfolio that used just one fuel.

Section 3

DATA DEVELOPMENT

The model described in Section 2 requires a substantial amount of data, including:

- Characteristics of the existing transmission system and potential upgrades to the system
- Characteristics of existing generating units
- Characteristics of potential new generating units
- Forecasts of future hourly loads
- Forecasts of future fuel prices
- Economic and financial parameters

The remainder of this section describes how these data were developed, and provides a high-level summary of the developed data. A more detailed and comprehensive presentation of the data is provided in Appendix B.

Transmission System Characteristics

One of the underlying premises of the RES model is that:

- The Railbelt is divided electrically (as opposed to legally or economically) into a number of areas.
- Each of these areas has generating resources and/or load.
- Electric energy can be transferred from one area to an adjacent area over transmission lines.
- These lines have limited capacity, which constrains the amount of electric energy than can be transferred between areas.
- A portion of the electric energy that is exported from one area to another is “lost,” so that the imported amount is less than the exported amount.

The RES model therefore requires the following information about the existing transmission system:

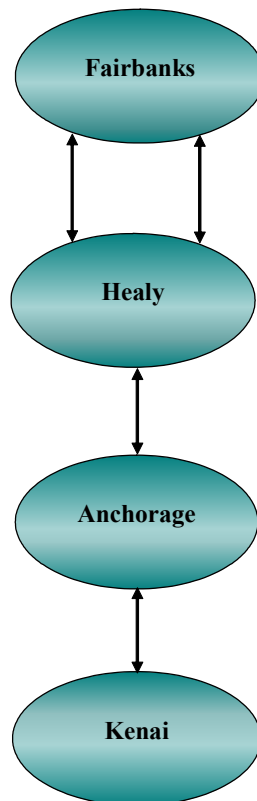
- Definitions of transmission areas, particularly the existing generating units to be assigned to each and the portions of each utility’s loads to be assigned to each
 - The limits on transfers between adjacent areas
 - The forced outage rate of the various transmission lines
 - The loss factors for the various lines
-

Section 3

In addition, for each potential transmission system upgrade project, the model requires data on the effects that the project would have on the characteristics listed above.

Utility staff led the effort to develop these data, with frequent interaction between R. W. Beck and utility staff. The results of the effort are summarized in Figure 3-1, which displays the transmission system representation used in the Base Case.

Figure 3-1
Railbelt Transmission System



The transmission system was modeled as consisting of four transmission areas, which were defined as follows:

- Fairbanks area—GVEA loads and resources, except Healy unit(s)
- Healy area—No load, Healy unit(s)
- Anchorage—Chugach, ML&P, and MEA loads and resources, except Chugach resources located in the Kenai area
- Kenai—HEA and SES loads and resources, plus Bernice Lake, Cooper Lake and Nikiski units

Note that two lines between the Fairbanks and Healy areas were modeled. The transfer limits between the areas are (all limits are the same in both directions):

- Fairbanks - Healy – 125 MW
- Healy - Anchorage – 75 MW
- Anchorage – Kenai – 75 MW

Forced outage rates and loss factors for these facilities are provided in Appendix B.1.

One of the “unique investment opportunities” that was modeled was construction of the Southern Intertie. This was modeled as a second line between the Kenai and Anchorage areas. Construction of this project would increase the transfer capability between the Anchorage and Kenai areas by 50 MW, to 125 MW (in each direction). Construction of this second line would also reduce losses on exports from one area to the other, and would increase the reliability of transfers between the two areas. Forced outage rates and loss factors for the Southern Intertie project are provided in Appendix B.1¹⁵.

Existing Generating Unit Characteristics

The RES model requires the following information for each of the existing thermal generating units:

- Maximum dispatchable capacity by month
- Full-load heat rate (Btu/kWh)
- Unit variable O&M (year 2003 \$ per MWh)
- Unit fixed O&M (year 2003 \$ per kW-year)
- Maintenance rate (%)
- Forced outage rate (%)
- Retirement Evaluation Date (defined in Section 2)
- Fuel type burned and technology type

Utility staff also led the effort to develop these data. R. W. Beck staff verified each value. A summary of the data is provided in Table 3-1¹⁶, and more detailed information is presented in Appendix B.2.

¹⁵ The Railbelt utilities are also considering a number of other transmission upgrade projects, such as the Eklutna transmission line upgrade and the Douglas bypass. These projects improve the ability to transmit power within a transmission area, but do not affect transfers between areas (i.e., limits or loss factors), the need for new generating capacity, or the cost-effectiveness of various generation alternatives. As a result, analysis of these projects was beyond the scope of this study.

¹⁶ Table 3-1 excludes twelve generating units, with a combined capacity of 84 MW. The Railbelt utilities use these units only in emergencies. These units were not included in the production cost analysis (i.e., in the Dispatch Cost Module), because it was determined that they would not dispatch under any of the circumstances contemplated in that module. They were, however, included in the reliability analysis, and were determined to contribute significantly to the reliability of the Railbelt system. These units include Seward 1 – 6, Zehnder GT 1 – 2 and 5 – 6, Chena 6, and Healy Diesel 1.

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In addition, the model requires information about the characteristics of the three existing hydroelectric generating units in the Railbelt. Extensive discussion between utility staff and R. W. Beck indicated that:

- The annual production at each facility varies considerably across years, due almost entirely to variations in flows into the reservoir at each facility.

**Table 3-1
Characteristics of Existing Thermal Generating Units**

Name	Area*	Technology / Fuel**	Maximum Capacity (MW)	Heat Rate (Btu / kWh)	Variable O&M (2003 \$ / MWh)	Fixed O&M (2003 \$ / kW-year)	Maintenance Rate	Forced Outage Rate
Aurora Chena	F	ST/Coal	16	0	37.0	0.0	14%	1%
North Pole 1	F	CT/HAGO	63	10,370	3.3	10.6	1%	2%
North Pole 2	F	CT/HAGO	65	9,869	3.3	10.6	1%	2%
Healy 1	H	ST/Coal	27	13,360	8.4	168.1	4%	2%
Beluga Unit 1	A	CT/NG	20	17,283	4.6	13.1	3%	2%
Beluga Unit 2	A	CT/NG	20	17,918	4.6	13.1	3%	2%
Beluga Unit 3	A	CT/NG	69	12,288	4.6	9.9	5%	2%
Beluga Unit 5	A	CT/NG	73	12,538	4.6	9.8	5%	2%
Beluga Unit 6/8	A	CC/NG	109	9,620	4.6	12.2	10%	4%
Beluga Unit 7/8	A	CC/NG	109	9,884	4.6	12.3	10%	4%
International 1	A	CT/NG	15	16,121	4.6	8.6	3%	2%
International 2	A	CT/NG	15	17,388	4.6	8.6	3%	2%
International 3	A	CT/NG	19	15,127	4.6	7.9	5%	2%
ML&P Plant1 Unit 1	A	CT/NG	17	15,413	4.8	19.0	0%	0%
ML&P Plant1 Unit 2	A	CT/NG	17	14,286	4.8	19.0	2%	2%
ML&P Plant1 Unit 3	A	CT/NG	20	14,280	4.8	19.0	6%	6%
ML&P Plant1 Unit 4	A	CT/NG	35	14,082	4.8	12.0	6%	1%
ML&P Plant2 Unit 5/6	A	CC/NG	49	10,256	4.8	47.0	8%	12%
ML&P Plant2 Unit 7/6	A	CC/NG	110	9,010	4.8	28.0	8%	2%
ML&P Plant2 Unit 8	A	CT/NG	88	11,768	4.8	10.0	4%	2%
Bernice Lake 2	K	CT/NG	19	14,655	4.6	8.9	5%	2%
Bernice Lake 3	K	CT/NG	28	13,460	4.6	8.2	3%	2%
Bernice Lake 4	K	CT/NG	23	13,639	4.6	8.5	3%	2%
Nikiski	K	CT/NG	42	11,600	4.6	7.5	0%	2%

*F=Fairbanks, H=Healy, A=Anchorage, K=Kenai

** ST=Steam, CT=Simple Cycle Combustion Turbine, CC=Combined Cycle Combustion Turbine, HAGO=High Atmospheric Gas Oil, NG=Natural Gas

- The production at each facility varies considerably across months of the year, and across hours of a month, due almost entirely to operator decisions.
- Each facility has a defined maximum rating. Eklutna and Cooper Lake can be dispatched to this rating, and the difference between the rating and the dispatched amount can be treated as spinning reserve. For Bradley Lake, the rating is 117 MW but the facility is dispatched under normal circumstances to no more than 90 MW. Bradley Lake's contribution to spinning reserves is the smaller of 27 MW and 117 MW minus the dispatched amount.
- It is appropriate to model each facility by inputting an expected value and variance of the annual generation that can be produced at the facility, use Crystal Ball[®] to generate random draws of these values, and use the Dispatch Sub-Module to allocate the annual output to each of the months and hours of the year.

In order to implement this approach, the model requires estimates of the expected value and variance of the annual generation at each facility, as well as the correlations between these values (across facilities) and the maximum dispatchable output at each.

Utility staff provided R. W. Beck historical data on production at each of the facilities. R. W. Beck statistically analyzed these data to generate the required estimates of annual expected values, variances, and correlations. Utility staff provided the maximum dispatchable output for each facility and R. W. Beck checked these data.

The results of this effort are summarized in Table 3-2.

**Table 3-2
Characteristics of Existing Hydroelectric Generating Units**

Name	Maximum Dispatchable Capacity (MW)		Annual Generation (GWh)	
	Emergency	Normal	Average	Standard Deviation
Bradley Lake	117	90	392	52
Cooper Lake	20	20	52	14
Eklutna	40	40	164	12

Potential New Generating Unit Characteristics

With one exception, the model requires the same information about new generating units that could be built as the information required for existing thermal generating units. The exception is that the capital cost (in real year 2003 dollars per kW of capacity) is required for new units, but the Retirement Evaluation Date is not (because all new units have an expected useful life of 30 years, so the Retirement Evaluation Date for any constructed unit extends past the end of the study period).

Utility staff and R. W. Beck worked collaboratively to develop a list of “generic” units (i.e., not associated with a “unique investment opportunity”) to be considered. R. W. Beck then led the effort to develop the required data about these units, and utility staff reviewed the data.

The results of this effort are summarized in Table 3-3. More detailed information is provided in Appendix B.3.

Following data development, but before the full-scale modeling, the Dispatch Sub-Module was used to screen the list of units. This screening analysis indicated that the following generic units were extremely unlikely to be selected and, in the interest of streamlining the analysis, were not included in the full-scale modeling effort:

- 25 MW and 172 MW simple cycle combustion turbines
- 30 MW and 260 MW combined cycle combustion turbines
- 50 MW coal-fired unit

Within each unit type (e.g., CT), small units have much higher capital and operating costs (per kW installed or MWh generated) than similar larger units. As a result, even

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though building three 25 MW CTs provides much more investment and operational flexibility than building a single 85 MW CT, a single 85 MW CT is always preferred because of the cost advantage.

Table 3-3
Characteristics of Potential New Generic Generating Units

Name/Technology*	Fuel Type**	Maximum Capacity (MW)	Heat Rate (Btu / kWh)	Variable O&M (2003 \$ / MWh)	Fixed O&M (2003 \$ / kW-year)	Main-tenance Rate	Forced Outage Rate	Capital Cost (2003 \$ / kW)
LM2500 CCCT	NG/FO	30	7,400	6	80	6%	3%	1,400
LM6000PC CCCT	NG/FO	60	7,200	5	47	6%	3%	1,100
6B CCCT	NG/FO	65	7,800	5	47	6%	3%	1,150
7EA CCCT	NG/FO	130	7,500	4	28	6%	3%	1,000
7FA CCCT	NG/FO	260	6,800	4	15	6%	3%	900
LM2500 SCCT	NG/FO	25	10,900	6	19	4%	4%	1,100
LM6000PC SCCT	NG/FO	40	9,600	6	12	4%	4%	1,100
6B SCCT	NG/FO	42	11,900	5	12	4%	4%	1,150
7EA SCCT	NG/FO	85	11,700	5	10	4%	4%	800
7FA SCCT	NG/FO	172	10,500	5	8	4%	4%	750
Stoker Coal Boiler	Coal	50	12,000	8	80	6%	4%	4,000
PC Coal Boiler	Coal	100	11,000	7	60	8%	4%	3,000
PC Reheat Coal Boiler	Coal	150	10,000	6	45	8%	4%	2,420

*CCCT=Combined Cycle Combustion Turbine, SCCT=Simple Cycle Combustion Turbine, PC=Pulverized Coal.

Names LM2500, 6B, etc. are model names.

**NG/FO=Natural Gas/Fuel Oil

Similarly, large units (e.g., 170 MW and larger) have lower capital and operating costs than similar mid-sized units (e.g., between 50 MW and 150 MW). However, operation of such a large unit significantly increases the spinning reserve requirements of the system. The resulting cost is equivalent to an increase in the operating cost of the large unit. As a result of this increase, it is more cost-effective in the Railbelt to construct and operate a mid-sized unit than a large unit.

In addition to the generic potential new units discussed above, three “unique investment opportunities” involving construction of new generating units were analyzed:

- **Pseudo-Healy Clean Coal Project**—The Healy Clean Coal Project is a coal-fired generating unit in the Healy transmission area with approximately 50 MW of capacity. It is currently idle, due to past performance problems. The State of Alaska and the Railbelt utilities are discussing the possibility of upgrading the project to correct these performance problems.

For modeling purposes, it was assumed that the upgrades to be performed would transform the existing unit into a unit with the same operating and performance characteristics as the 50 MW generic coal unit discussed above. In particular, the unit was assumed to have a heat rate of 12,000 Btu/kWh, variable O&M expense of \$8.40 / MWh (real 2003 dollars), require an average of three weeks of maintenance every year, and have a 3.5 percent forced outage rate. Because these characteristics are not the same as those of the existing HCCP, the case analyzed in this study is called the “Pseudo-HCCP” case, not the HCCP case.

For two reasons, the Pseudo-HCCP unit was modeled with zero capital costs and fixed O&M expense:

- It was outside of the scope of the RES for R. W. Beck to develop estimates of the capital costs required to transform the existing HCCP unit into the pseudo-HCCP unit that was modeled.
- As is the case with the other unique investment opportunities, in order to determine the value of the project to the Railbelt region, it is appropriate to set capital costs and fixed O&M expense to zero for the modeling, and then use the modeling results to determine the maximum value that the capital costs could be and still provide value to the Railbelt customers.
- **Fire Island Wind Project**—Several of the Railbelt utilities are investigating the possibility of developing wind projects in the region. Chugach has assembled substantial data on a possible wind project on Fire Island in the Anchorage transmission area. Although the potential Fire Island project would have performance characteristics unique to its location, the project was considered as a proxy for generic wind projects throughout the region.

For modeling purposes, it was assumed that a project with 50 MW of capacity was built. The variable O&M is estimated to be \$2.70 per MWh (real 2003 dollars). In order to determine the value of the project to the region, the unit was modeled with zero capital costs and fixed O&M expense.

Chugach provided data for 2001 and 2002 on the hourly generation that would have occurred if the project had been in place during these years. R. W. Beck analyzed these data and determined that:

- The annual average capacity factor is approximately 32 percent.
- The capacity factor varies across the months of the year in a systematic fashion, as shown in Appendix B.3.
- The generation varies substantially across the hours of a month, from 0 MWh per hour in many hours to 50 MWh per Hour in many others. There is no discernable pattern to these variations. In particular, there appears to be no correlation between hourly output and the hourly load in either the Anchorage transmission area or the Railbelt region as a whole.

Based on this analysis, the unit was modeled as producing a constant number of MWh in every hour of a month (e.g., 19.9 MWh per hour in every hour of January), with the amount produced in every hour of a month varying across months of the year as indicated by the capacity factors provided in Appendix B.3¹⁷.

- **Nikiski Repowering Project**—The existing Nikiski generating unit is a 42 MW simple cycle combustion turbine, plus a steam generator attached to the unit that

¹⁷ It is important to note that the output of a wind project is not, in fact, schedulable, and especially not constant across the hours of a month as assumed here. As a result, additional thermal units will have to be dispatched, and one or more of the dispatched thermal units will have to operate at less than full capacity, so that their output can be increased quickly when the wind project output falls. This is equivalent to an increase in the system's spinning reserve requirements. The Dispatch Cost Module was not designed to consider such issues, so they are ignored in the analysis. As a result, the RES Model overstates the benefits to the system of the Fire Island Project, by an unknown amount.

provides steam to an industrial customer. In the event that the industrial customer would no longer require steam, it would be possible to “repower” the unit by adding a steam turbine. The repowered unit would generate an additional 25 MWh every hour without burning any additional fuel. The unit variable O&M expense is estimated to be \$4.60 / MWh (real 2003 dollars). In order to determine the value of the project to the Railbelt region, the unit was modeled with zero capital costs and fixed O&M expense; the estimates of the actual values of these two variables are discussed in Section 4.

- **Emma Creek Coal Project**—Usibelli Coal Mine, Inc. has proposed to construct and operate a coal plant in the Healy transmission area that would have approximately 200 MW of capacity. The proposed plant was modeled as if it were two 100 MW generic coal units, with the characteristics described above for such units. In order to determine the value of the project to the Railbelt region, the unit was modeled with zero capital costs and fixed O&M expense; the estimates of the actual values of these two variables are discussed in Section 4.

Load Forecasts

The participating utilities provided R. W. Beck with historical data for all six Railbelt utilities on annual and monthly energy requirements for the 1993 – 2002 period and hourly loads for 2001 and 2002; as well as forecasts of annual energy requirements for the 2003 – 2033 period. R. W. Beck aggregated these data to the transmission-area level (e.g., the loads for Chugach retail, ML&P, and MEA were added together to create the Anchorage loads), and analyzed the aggregated historical data statistically. Based on this analysis, it was determined that:

- Annual energy requirements in each of the three transmission areas with load are highly uncertain. Future annual energy requirements can best be represented as a stochastic process, with an expected year-to-year percentage increase (or decrease) and a standard deviation that represents the degree of uncertainty. The forecasts of annual energy requirements provided by the utilities were used to calculate the expected growth rate in each area and each year. These expected growth rates are displayed in Table 3-4. Note that the expected percentage changes in several area/year combinations are very large, due to the expected gain of one or more major loads in that area/year; and negative in several other area/year combinations, due to the expected loss of one or more major loads in that year.

The standard deviations of annual growth rates (i.e., volatilities) were estimated from the historical data provided by the utilities. The estimates used in the model are:

- Fairbanks area – 6.2 percent
- Anchorage area – 2.2 percent
- Kenai area – 2.7 percent

Table 3-4
Expected Annual Load Changes by Transmission Area

Year	Fairbanks	Anchorage	Kenai
2004	9.2%	5.8%	-3.0%
2005	1.0%	1.5%	1.2%
2006	2.6%	6.9%	-5.9%
2007	2.7%	1.2%	1.2%
2008	1.2%	1.5%	-0.9%
2009	1.2%	1.3%	0.0%
2010	2.1%	0.9%	1.1%
2011	2.1%	1.2%	1.2%
2012	2.1%	1.1%	1.3%
2013	2.1%	1.3%	1.5%
2014	2.1%	1.6%	1.7%
2015	2.1%	1.8%	0.8%
2016	2.1%	1.8%	0.8%
2017	-18.8%	1.5%	1.1%
2018	2.6%	1.5%	1.7%
2019	2.6%	1.5%	0.5%
2020	2.6%	1.4%	0.5%
2021	2.5%	1.5%	0.5%
2022	2.5%	1.5%	0.5%
2023	2.5%	1.5%	0.5%
2024	2.5%	1.5%	0.5%
2025	2.5%	1.5%	0.5%
2026	2.5%	1.4%	0.5%
2027	2.5%	1.4%	0.5%
2028	2.5%	1.4%	0.5%
2029	2.5%	1.4%	0.5%
2030	2.5%	1.4%	0.5%
2031	2.4%	1.4%	0.5%
2032	2.4%	1.4%	0.5%
2033	2.4%	1.4%	0.5%

These volatilities can be interpreted in the following manner. Given the expected 2004 growth in the Anchorage area of 5.8 percent, and the volatility of 2.2 percent, there is a 90 percent probability that the actual 2004 growth in the Anchorage area will be greater than 3.0 percent (5.8 percent minus 1.28 times 2.2 percent, where 1.28 is the critical value from the normal distribution associated with the 90 percent confidence level), and a 90 percent probability that the actual growth will be less than 8.6 percent (5.8 percent plus 1.28 times 2.2 percent). The volatility estimates reflect randomness in annual energy requirements due to all sources of uncertainty, including year-to-year variations in both weather and economic growth.

The RES model also requires estimates of the correlations between annual growth rates in the three areas. Statistical analysis of the historical data indicated that these correlations were all insignificantly different from zero. As a result, for modeling purposes the correlations were assumed to be zero.

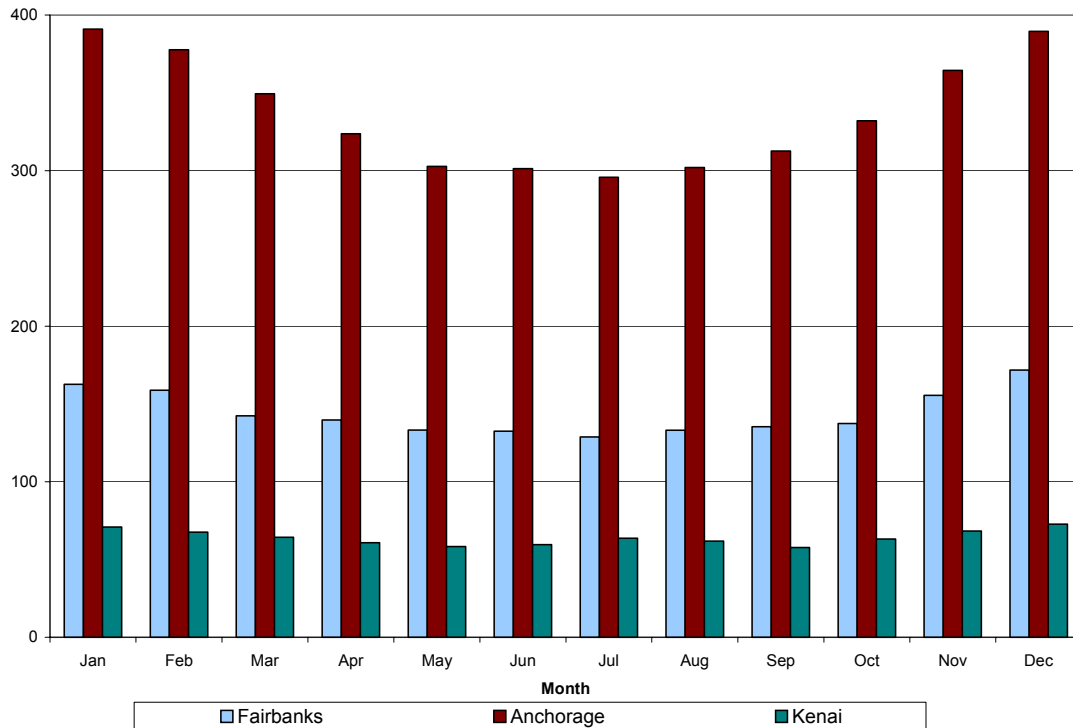
- In each area, loads vary considerably across the months of the year in a fairly systematic fashion. Although the share of annual energy that occurs in any particular month varies from one year to another, it was determined these variations are small enough that incorporating them into the model would not significantly affect the results. The historical monthly energy requirements data were used to estimate a monthly load shape for each area, which was used in a deterministic manner (i.e., the shape was assumed to be known with certainty) in the model. The monthly shapes for the three transmission areas with load are displayed in Figure 3-2 (for 2004, with expected annual energy requirements).
- In each area, loads vary considerably across the hours of each month in a fairly systematic fashion. Statistical analysis of the hourly load data for 2001 and 2002 indicated that it was appropriate to represent the hourly loads in each area/month combination with a block load duration curve (BLDC). In a BLDC, hourly loads in a particular area/month combination are assumed to take on n different values, with n_1 hours having the value l_1 , n_2 hours having the value l_2 , etc. It was further determined that it was appropriate to represent the loads in every area/month with a five-block BLDC (i.e., hourly loads in each area/month were assumed to take on five different values), with the number of hours assigned to each block varying across months. The BLDC for January is provided in Figure 3-3 (for 2004, with expected annual energy requirements). BLDCs for all twelve months are presented in Appendix B.4.

It is important to note that in addition to the systematic variation of hourly loads that is reflected in the BLDCs, hourly loads also vary considerably due to random, non-deterministic factors. Randomness of hourly loads was not incorporated into the RES model, because it was determined that doing so 1) was unlikely to significantly affect the results and 2) would significantly increase the time required to complete the study.

Fuel Price Forecasts

The model described in Section 2 requires estimates of the expected annual percentage change in the price of the following listed fuels, as well as the standard deviation of these changes (i.e., the volatility) and the correlations (across fuels) between the changes. The required parameters refer in all cases to fuel delivered to power plants in the Railbelt region. The fuels are:

Figure 3-2
Monthly Load Shapes by Area
With 2004 Expected Annual Energy Requirements (aMW)



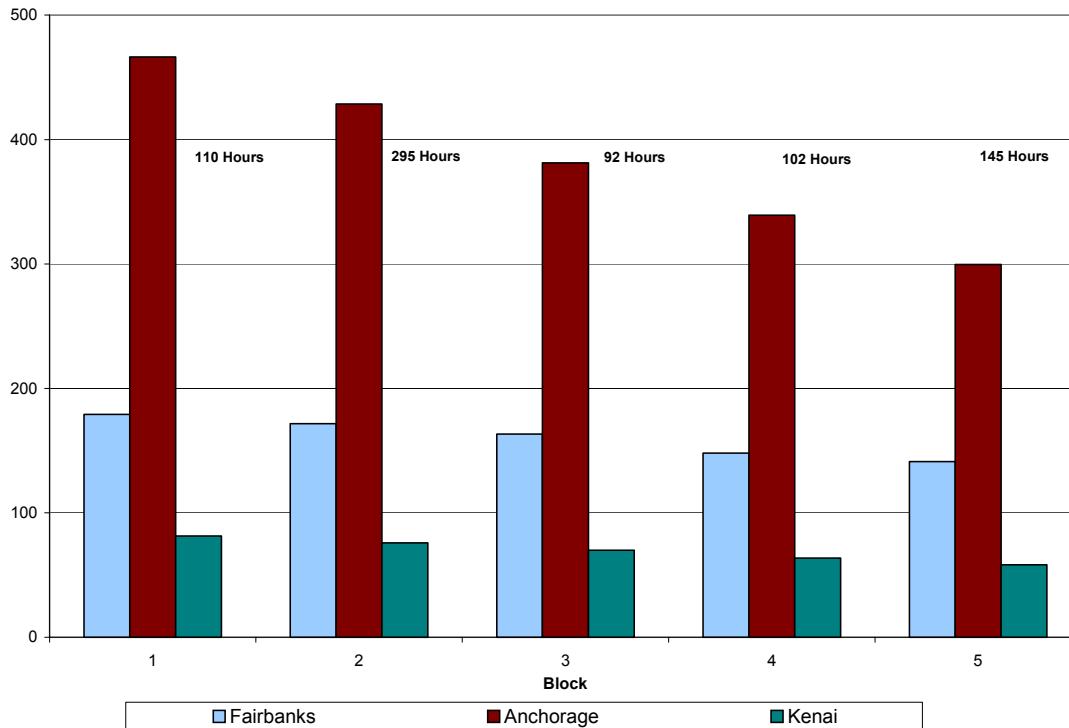
- Natural gas
- Diesel
- HAGO (Fairbanks area only)
- Naptha (Fairbanks area only)
- Coal

The activities to develop the required parameters, and the results of those activities, are summarized in the following paragraphs.

Natural Gas

Future availability and pricing of natural gas is one of the most important issues affecting the Railbelt utilities. To address this issue, R. W. Beck obtained and reviewed copies of natural gas contracts the utilities have with fuel suppliers, reviewed documents prepared by agencies of the Alaska and Federal governments, held discussions with senior managers of both the utilities and several natural gas production companies, and analyzed historical natural gas price data for both Alaska and the lower-48. Based on these activities, it was determined that:

**Figure 3-3
January Hourly Load Shapes by Area
With 2004 Expected Annual Energy Requirements (aMW)**



- ML&P owns gas reserves in the Cook Inlet, which it expects to last until at least 2020. ML&P “charges” itself a price for this gas, which is designed to recover the cost of purchasing the reserves.
- Chugach has contracts in place to purchase natural gas from three different suppliers. The term of these contracts is defined according to the cumulative amount of gas purchased. At current rates of use, Chugach expects these contracts to last until approximately 2014. Pricing in these contracts is set by a formula that depends on lower-48 prices of natural gas and refined fuel oil products.
- Discussions with production companies and a review of available documents indicate that there is a sufficient amount of natural gas in the Cook Inlet area to fuel power plants in the Anchorage and Kenai areas through at least the end of the study period (i.e., 2033). These discussions also indicated that producers would be willing to develop these reserves, and sell natural gas to the utilities, at a price approximately equal to the price they would receive from producing natural gas in the lower-48. The standard lower-48 price benchmark is the price of natural gas traded for delivery at the Henry Hub in Louisiana.
- Natural gas is currently not available in the Fairbanks transmission area. Several proposals have been made to construct a pipeline from the North Slope to Fairbanks area. In the RES Base Case, it was assumed that natural gas would not

become available in the Fairbanks area during the study period (i.e., through 2033). A sensitivity case was analyzed, in which natural gas became available in Fairbanks in 2015, at the same prices as in the Anchorage and Kenai transmission areas.

- For modeling purposes, it was assumed that the price in the Anchorage and Kenai transmission areas would be equal to the Chugach contract price through 2008. Between 2008 and 2014, the price would transition toward the Henry Hub price (e.g., in 2009, it would be 86 percent of the Chugach contract price plus 14 percent of the Henry Hub price; in 2010 72 percent of the Chugach contract price plus 28 percent of the Henry Hub price, etc.) and from 2015 on it would be equal to the Henry Hub price.
- The Henry Hub price was modeled as a stochastic process. Expected year-to-year changes in the price, as well as the volatility, were taken from R. W. Beck's proprietary natural gas price forecast, which was developed using an econometric analysis of historical data. Forecasts of the fuel oil variables required to calculate the Chugach contract price were developed using the world oil price forecast discussed below.

The second column of Table 3-5 provides the expected natural gas prices (measured in real 2003 dollars per million Btus) used in the RES. More detailed and comprehensive data are provided in Appendix B.5. The Henry Hub price volatility used in the model was 20 percent.

Refined Fuel Oil Prices

Price forecasts for diesel, HAGO, and naptha developed in the same manner:

- A forecast of world oil prices was obtained from the U.S. Department of Energy's Energy Information Administration's 2003 "Annual Energy Outlook."
- A statistical analysis of historical world oil prices was performed. This analysis indicated that the world oil price should be modeled as a probabilistic variable, as opposed to a stochastic variable¹⁸. Furthermore, the standard deviation of the price (not the percentage change in the price) was determined to be approximately \$3.80 (real 2003 dollars per barrel).
- Equations relating the prices of naptha and HAGO delivered to Railbelt utilities to the world oil price were developed based on discussions with participating utility staff, a review of fuel supply contracts, and a review of historical data.
- An equation relating the price of diesel delivered to Railbelt utilities was developed by performing a regression analysis of historical data. Similarly, regression equations relating the fuel oil price variables that determine the Chugach natural gas contract price to the world oil price were estimated.

¹⁸ The distinction is discussed in Section 2.

Table 3-5
Expected Annual Fuel Prices (2003 \$ / MMBtu)

Year	Natural Gas	Diesel	HAGO	Naptha	Coal
2004	2.36	7.38	4.27	5.28	1.14
2005	2.12	7.27	4.13	5.12	1.14
2006	1.99	7.29	4.16	5.15	1.13
2007	2.02	7.31	4.18	5.18	1.12
2008	2.04	7.33	4.21	5.21	1.12
2009	2.24	7.35	4.23	5.24	1.11
2010	2.63	7.37	4.26	5.27	1.10
2011	3.01	7.40	4.28	5.30	1.10
2012	3.38	7.42	4.30	5.33	1.09
2013	3.74	7.44	4.33	5.36	1.08
2014	4.10	7.46	4.35	5.39	1.08
2015	4.45	7.48	4.38	5.42	1.07
2016	4.36	7.50	4.40	5.45	1.06
2017	4.31	7.53	4.43	5.48	1.06
2018	4.28	7.55	4.46	5.51	1.05
2019	4.27	7.57	4.48	5.55	1.04
2020	4.26	7.59	4.51	5.58	1.04
2021	4.26	7.63	4.54	5.62	1.03
2022	4.26	7.66	4.58	5.67	1.03
2023	4.26	7.69	4.62	5.71	1.02
2024	4.26	7.72	4.65	5.76	1.01
2025	4.26	7.75	4.69	5.80	1.01
2026	4.26	7.79	4.73	5.85	1.00
2027	4.26	7.82	4.76	5.89	1.00
2028	4.26	7.85	4.80	5.94	0.99
2029	4.26	7.88	4.83	5.98	0.98
2030	4.26	7.91	4.87	6.03	0.98
2031	4.26	7.95	4.91	6.07	0.97
2032	4.26	7.98	4.95	6.12	0.97
2033	4.26	8.01	4.98	6.17	0.96

- Within the model, the world oil price is determined through a CB random draw, and the drawn value is then combined with the equations described above to calculate the price of naptha, HAGO, and diesel.

Columns 3 – 5 of Table 3-5 display the expected prices of these three fuels used in the model. More detailed and comprehensive data are provided in Appendix B.5.

Coal

Future coal pricing for the existing coal unit (i.e., Healy 1) was determined through conversations with participating utility staff, review of contracts, and analysis of historical data. Based on these activities, it was determined that the coal price could be modeled as a deterministic variable (i.e., known with certainty). Although there obviously is some uncertainty in future coal prices in the Railbelt, it was determined that incorporating this uncertainty into the model was unlikely to significantly affect the results.

The prices used in the model are provided in the last column of Table 3-5. In nominal terms, coal prices were assumed to increase from their current levels at a rate equal to 75 percent of the rate of inflation. This results in the decreasing real prices shown in Table 3-5.

As discussed above, two “unique investment opportunities” involve coal units. The pricing of coal for these two opportunities is not presently known. It was determined that it would be appropriate to use the same price forecast to evaluate these opportunities as the price used for Healy 1.

Finally, there is a possibility that coal generating units could be constructed in the Fairbanks, Anchorage, or Kenai areas. The feasibility of constructing such units depends on development of coal mines in or near the associated transmission area. It was outside of the scope of the RES to definitively determine whether such development of one or more mines would be economically feasible, and therefore whether construction of coal generating units would be feasible. The RES Base Case therefore does not include generic coal units.

However, in order to determine whether construction of coal units is an alternative that the Railbelt utilities should consider further, a sensitivity case was analyzed. The case assumed that coal would be available in all three transmission areas beginning in 2015, and that the price of the coal would be the same as the forecast price for the Healy 1 unit.

Economic and Financial Parameters

The model described in Section 2 also requires estimates of the economic and financial parameters listed below. R. W. Beck developed values for these parameters, which are also listed, based on our experience, analysis of recent historical data, and discussions with the participating utilities. The parameters include:

- Inflation rate—2.5 percent per year
- Discount rate (weighted average cost of capital)—7 percent per year
- Useful life/financial recovery period of new generating units—30 years

Section 4 RESULTS

The results of the analysis are described in detail in this section, which is divided into the following segments:

- Retirements
- Reliability
- Load-Resource Balances
- Base Case Investment Strategies
- Effects of Risk Aversion on Investment Decisions
- Analysis of Unique Investment Opportunities and Sensitivity Cases

Retirements

The results of the Retirements analysis, which was performed in the manner described in Section 2, are summarized in Table 4-1. Details about the calculations are provided in Appendix C3.

For each existing unit¹⁹, Table 4-1 indicates the Fuel and Technology of the unit, as well as the Capacity and Heat Rate of the unit. The table also displays the Retirement Evaluation Date for each existing unit, the year in which a decision would have to be made to either retire the unit or make the investment required to extend its life. In addition, the table displays the Total Fixed Cost, measured in dollars per kilowatt-year, for each existing unit. This fixed cost includes both the current fixed O&M, escalated to the Retirement Evaluation Date year, and the additional investment required to extend the life of the unit. As discussed in Section 2, this amount was assumed to equal 6.7 percent of the capital cost (on a \$ per kW basis) of the most similar new unit²⁰.

For each existing unit, Table 4-1 also displays the Heat Rate and Total Fixed Cost of the most similar potential new unit. For example, for Bernice Lake 2, the most similar new unit was a 25 MW simple-cycle combustion turbine (CT). The assumed heat rate for this new unit is 10,900 Btu per kWh, and the Total Fixed Cost is \$113 per kW-year, the sum of the assumed fixed O&M and the amortized capital cost for such a unit.

¹⁹ Except the units that comprise ML&P Plant 1, which ML&P intends to retire prior to the beginning of 2008; the Aurora Chena unit, whose contract with GVEA expires in 2017; and ML&P Plant 2 units 8/6 and 9, whose Retirement Evaluation Dates were after 2033, the last year of the analysis.

²⁰ This equals the capital cost of the most similar new unit, spread over a 15-year period.

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**Table 4-1
Retirements Analysis**

Unit Name	Unit Characteristics							First-Year Cost Savings by Replacing Existing Unit with Similar New Unit (\$ / kW-year)								
	Existing Unit					New Unit		Low Capacity Factor			Medium Capacity Factor			High Capacity Factor		
	Fuel / Technology	Retirement Evaluation Year	Capacity (MW)	Heat Rate (Btu / kWh)	Total Fixed Cost (\$ / kW-yr)	Heat Rate (Btu / kWh)	Total Fixed Cost (\$ / kW-yr)	Low Fuel Price	Medium Fuel Price	High Fuel Price	Low Fuel Price	Medium Fuel Price	High Fuel Price	Low Fuel Price	Medium Fuel Price	High Fuel Price
Bernice Lake 2	Gas CT	2004	19	14,655	65	10,900	113	-39	-38	-37	-31	-28	-26	-23	-19	-15
International 1	Gas CT	2008	15	16,121	72	10,900	124	-45	-42	-38	-37	-32	-23	-29	-22	-8
International 2	Gas CT	2008	15	17,388	72	10,900	124	-43	-40	-34	-33	-27	-15	-23	-14	4
Beluga Unit 1	Gas CT	2009	20	17,283	79	10,900	128	-40	-37	-30	-32	-25	-11	-23	-13	7
Beluga Unit 2	Gas CT	2009	20	17,918	79	10,900	128	-39	-35	-28	-30	-22	-8	-21	-9	13
Bernice Lake 3	Gas CT	2010	28	13,460	75	10,900	131	-53	-50	-48	-50	-45	-39	-47	-40	-31
Bernice Lake 4	Gas CT	2012	23	13,639	79	10,900	137	-55	-52	-49	-51	-47	-39	-48	-41	-29
International 3	Gas CT	2012	19	15,127	79	10,900	137	-53	-50	-44	-48	-40	-28	-42	-31	-13
Beluga Unit 3	Gas CT	2014	69	12,288	65	11,700	98	-28	-25	-19	-27	-23	-15	-26	-20	-10
Beluga Unit 5	Gas CT	2017	73	12,538	70	11,700	107	-30	-26	-15	-28	-22	-8	-26	-18	-1
Beluga Unit 6/8	Gas CC	2020	109	9,620	95	7,500	155	-6	29	83	2	42	103	10	54	124
Beluga Unit 7/8	Gas CC	2021	109	9,884	97	7,500	158	-3	42	121	5	57	147	14	71	173
Healy 1	Coal Steam	2024	27	13,360	618	12,000	693		-61			-59			-57	
Unit 7&6 CC	Gas CC	2024	110	9,010	131	7,500	182	-5	24	81	1	35	100	8	45	118
Nikiski	Gas CT	2024	42	11,600	105	10,900	185	-80	-79	-77	-79	-78	-74	-79	-76	-71
North Pole 1	HAGO CT	2030	63	10,370	99	11,700	145		-53			-61			-68	
North Pole 2	HAGO CT	2030	65	9,869	99	11,700	145		-56			-65			-74	

Finally, for each existing unit Table 4-1 presents estimates of the first-year cost savings, measured in dollars per kilowatt of capacity, of retiring the existing unit and replacing it with the most similar potential new unit. Estimates are provided for three different capacity factors and three different fuel prices.²¹ The capacity factors that were used were developed through preliminary analysis using the Dispatch Cost Sub-Module, and vary by unit type:

- For the Beluga 3 and 5 CT units, the capacity factors are 30 percent (Low), 40 percent (Medium), and 50 percent (High)
- For all the other CTs, the capacity factors are 5 percent, 10 percent, and 15 percent
- For all the other units (i.e., CCs and steam units), the capacity factors are 70 percent, 80 percent, and 90 percent.

The fuel prices correspond to the 25th (Low) 50th (Medium) and 75th (High) percentile of the probability distribution of the associated prices during the year of the Retirement Evaluation Date. A positive number in a cell indicates that there would be savings by retiring the existing unit and replacing it with the most similar new unit, given the specified capacity factor and fuel price.

The table shows that for all but the three shaded units (Beluga 6/8, Beluga 7/8, and ML&P Plant 2 Unit 7/6), it would be more expensive under all combinations of capacity factors and fuel prices to retire the unit and replace it with a new similar unit than to make the investment to keep the existing unit operating²². For the three shaded units, it would be less expensive to keep the existing unit operating if both the low capacity factor and the low fuel price occurred; in all other circumstances, it would be less expensive to retire the existing unit and replace it with a new unit.

All three retired units are combined cycle units, with heat rates above 9,000 Btu per kWh. The potential replacement unit for all three is a 130 MW combined cycle unit, which has a heat rate of 7,500 Btu per kWh. This heat rate improvement, combined with capacity factors of 70 percent (in the Low capacity factor case) or higher, generates enough fuel savings per year to more than offset the additional capital cost (i.e., the difference between the amortized capital cost of the new unit and the life extension cost for the existing unit) associated with development of the new unit. For example, in the Medium capacity factor and fuel price case, the savings for the three units are \$42 per kW-year for Beluga 6/8, \$57 per kW-year for Beluga 7/8, and \$35 per kW-year for ML&P Plant 2 7/6.

²¹ Estimates for the Low and High fuel prices are only provided for units that burn natural gas, because uncertainty about coal and fuel oil prices was not considered in the investment analysis, into which the retirement analysis feeds.

²² Note that with a combination of High capacity factor and High fuel prices, small positive first-year savings would be obtained from retiring both Beluga 1 and Beluga 2. Given the magnitude of the savings and the fact that positive savings only occur in the one combination, it was decided to not retire these two units, i.e., to treat these two units as if the savings were negative in all combinations.

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In contrast, the heat rate improvements that could be achieved by retiring the simple cycle units is even greater, for example, from 14,655 Btu per kWh to 10,900 Btu per kWh for Bernice Lake 2. However, with capacity factors between 5 percent (Low) and 15 percent (High), the fuel savings per year are not large enough to offset the additional capital cost associated with development of the new unit.

Healy 1, the only existing coal steam unit, is an anomaly. For this unit, the improvement in the heat rate is fairly small (13,360 Btu per kWh versus 12,000 Btu per kWh), which does not generate enough fuel cost savings to justify the incremental capital cost of a new unit (693 \$ per kW-year for a new unit versus 618 \$ per kW-year to extend the life of the existing unit).

Reliability

As discussed in Section 2, several types of reliability analysis were performed. First, estimates of the LOLP and ELOE were developed for 2002 for each of the three areas with loads. The estimates are as follows:

- Fairbanks – 8 percent LOLP, 80 kWh ELOE
- Anchorage – less than 0.5 percent LOLP, less than 10 kWh ELOE
- Kenai – less than 0.5 percent LOLP, less than 10 kWh ELOE²³

The industry standard LOLP in the lower-48 is 10 percent. Given that the current LOLP in all three areas is less than this standard, after consulting with the participating utilities R. W. Beck determined that it would be appropriate to use 10 percent as the LOLP standard for generation- and transmission-related reliability in the analysis of capacity additions.

Second, an analysis was performed to determine the reserve margin required in each transmission area to achieve a LOLP of 10 percent or less. For each year, the analysis involved estimating the LOLP for each area assuming expected loads and existing generating resources. If one or more of the areas had an LOLP above 10 percent, new capacity was added (in 10 MW increments) until all three areas had an LOLP below 10 percent.

Table 4-2 reports the results of this analysis assuming expected loads for the Base Case, which excludes the Southern Intertie, Pseudo-Healy Clean Coal, and Emma Creek investment opportunities²⁴. The first (shaded) row of the table shows results for 2008 if no new capacity is constructed. The LOLPs for the Anchorage and Kenai

²³ As discussed above, LOLP and ELOE measure the aspects of electric system reliability that can be improved by adding G&T capacity. According to these measures, the Kenai area has very high reliability. However, in other aspects of system reliability, the Kenai area is not nearly so reliable. In particular, due to the size (relative to the load in the area) and instability of the Bradley Lake Project, the Kenai power system is fairly unstable, resulting in more frequent outages than suggested by the LOLP and ELOE estimates.

²⁴ All of the capacities and peak loads reported in Table 4-2 are multiples of 10. The reason for this is that in order to reduce the number of permutations that it must iterate through, the Reliability Module rounds the available capacity and load for each combination of hour, area, and outage permutation down to the nearest multiple of 10.

areas are well below the 10 percent standard, due to their relatively high reserve margins of 35 and 225 percent, respectively. However, without any capacity additions, the Fairbanks area reserve margin is 0 percent, and the LOLP is 78 percent. The second row of the table shows that 40 MW of new capacity needs to be added in the Fairbanks area by 2008 to achieve the 10 percent LOLP standard. With this new capacity, the reserve margin is 19 percent.

The table also shows that in order to maintain the 10 percent (or lower) LOLP, a total of 50 additional MW would have to be built in the Fairbanks area between 2009 and 2016. As discussed in Section 3, Fairbanks loads are expected to decrease substantially in 2017, so there is surplus capacity there between 2017 and 2019. Capacity additions are required in Anchorage in 2016, 2018, and 2019 to maintain the 10 percent LOLP. No capacity additions are required for reliability purposes in the Kenai area.

For the purpose of determining the reserve margins required to achieve the 10 percent LOLP standard, the years 2016 and 2020 are crucial. The year 2016 is the first year in which both the Fairbanks and Anchorage areas simultaneously need to add capacity to achieve the 10 percent LOLP standard. The reserve margins in the two areas in that year are 20 and 23 percent, respectively, and the average is 22 percent. The year 2020 is the first year in which both the Fairbanks and Anchorage areas simultaneously have just enough capacity to achieve the 10 percent LOLP standard, i.e., the LOLP in both areas is above 9 percent, and reducing the capacity in either area by just 1 MW would cause the LOLP in both areas to increase above the 10 percent standard. The reserve margin in both areas is 22 percent in that year.

After 2020, the reserve margins required to maintain the 10 percent LOLP standard in the two areas declines steadily, reaching levels of 13 percent in the Fairbanks area and 18 percent in the Anchorage area in 2033. These declines are due to the fact that over time new (i.e., post-2007) capacity represents a growing proportion of total capacity, especially after the retirements in the Anchorage area in the 2020 – 2024 period; and that the assumed forced outage rates for new units are lower than the assumed rates for the existing units.

For the purpose of the investment model, a single reserve margin standard was required for each area. The 22 percent level was selected because this level appears to be required during at least the next 15 – 20 years. In 15 years, the Railbelt utilities should consider using a lower reserve margin for making capacity decisions.

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**Table 4-2
Base Case Reliability Results**

Year	Loss of Load Probability by Area (%)			Capacity by Area (MW)				Expected Peak Load by Area (MW)			Reserve Margin by Area (%)				Reserve Margin by Utility (%)	
	Fairbanks	Anchorage	Kenai	Fairbanks	Healy	Anchorage	Kenai	Fairbanks	Anchorage	Kenai	Fairbanks	Anchorage	Kenai	Total	GVEA	Chugach / ML&P
2008	78%	5%	0%	210	20	730	260	210	540	80	0%	35%	225%	47%	17%	57%
2008	9%	1%	0%	250	20	730	260	210	540	80	19%	35%	225%	52%	36%	57%
2009	6%	1%	0%	260	20	730	260	210	550	80	24%	33%	225%	51%	41%	55%
2010	8%	1%	0%	260	20	730	260	220	550	80	18%	33%	225%	49%	34%	55%
2011	7%	2%	0%	270	20	730	260	220	560	80	23%	30%	225%	49%	39%	52%
2012	10%	3%	0%	270	20	730	260	230	570	80	17%	28%	225%	45%	33%	50%
2013	7%	4%	0%	280	20	730	260	230	570	80	22%	28%	225%	47%	37%	50%
2014	9%	7%	0%	280	20	730	260	240	580	90	17%	26%	189%	42%	31%	45%
2015	8%	9%	0%	290	20	730	260	240	590	90	21%	24%	189%	41%	36%	43%
2016	7%	8%	0%	300	20	740	260	250	600	90	20%	23%	189%	40%	34%	43%
2017	1%	8%	0%	300	20	740	260	220	610	90	36%	21%	189%	43%	52%	41%
2018	4%	9%	0%	280	20	750	260	220	620	90	27%	21%	189%	41%	43%	40%
2019	7%	9%	0%	280	20	760	260	230	630	90	22%	21%	189%	39%	37%	40%
2020	9%	9%	0%	280	20	780	260	230	640	90	22%	22%	189%	40%	37%	40%
2021	5%	9%	0%	280	20	790	260	240	650	90	17%	22%	189%	38%	31%	40%
2022	10%	9%	0%	280	20	810	260	240	660	90	17%	23%	189%	38%	31%	41%
2023	5%	8%	0%	290	20	820	260	250	670	90	16%	22%	189%	38%	30%	40%
2024	6%	8%	0%	300	20	830	260	260	680	90	15%	22%	189%	37%	29%	40%
2025	6%	8%	0%	300	20	830	260	260	690	90	15%	20%	189%	36%	29%	38%
2026	6%	8%	0%	310	20	840	260	270	700	90	15%	20%	189%	35%	28%	37%
2027	5%	7%	0%	320	20	850	260	280	710	90	14%	20%	189%	34%	27%	37%
2028	7%	9%	0%	320	20	860	260	280	720	100	14%	19%	160%	33%	27%	35%
2029	6%	9%	0%	330	20	870	260	290	730	100	14%	19%	160%	32%	26%	34%
2030	10%	7%	0%	330	20	890	260	300	740	100	10%	20%	160%	32%	22%	35%
2031	8%	10%	0%	340	20	890	260	300	750	100	13%	19%	160%	31%	25%	34%
2032	7%	10%	0%	350	20	900	260	310	760	100	13%	18%	160%	31%	24%	33%
2033	8%	9%	0%	360	20	910	260	320	770	100	13%	18%	160%	30%	24%	33%

The Alaska Intertie Agreement (AIA) requires the utilities to maintain a 30 percent reserve margin. This requirement currently applies to GVEA, ML&P, and Chugach. The last two columns of Table 4-2 provide Utility Reserve Margins. In 2020, the GVEA reserve margin is 37 percent and the combined ML&P/Chugach reserve margin is 40 percent²⁵. The 30 percent reserve margin requirement specified in the AIA may therefore be too low to achieve a 10 percent LOLP.

Tables similar to Table 4-2 for the Southern Intertie, Pseudo-Healy Clean Coal Project, and Emma Creek cases are provided in Appendix C.4. Construction of the Southern Intertie will delay the need to build new generating capacity in the Anchorage area for reliability purposes until 2020, from 2016 in the Base Case. In 2020, the total capacity required in the Anchorage area to maintain the 10 percent LOLP is 730 MW with the Southern Intertie, compared to 780 MW in the Base Case, a difference of 50 MW. In other years, this difference varies between 40 and 60 MW. For the purpose of calculating reserve margins in the investment analysis, adding the Southern Intertie to the very large capacity surplus in the Kenai area was deemed to be equivalent to adding 50 MW of new generating capacity in the Anchorage area.

Similarly, completion of the HCCP delays the need to build new generating capacity in the Fairbanks area until 2009. In 2020, the total capacity required in the Fairbanks area to maintain the 10 percent LOLP is 250 MW, compared to 280 MW in the Base Case, a difference of 30 MW. In other years, this difference varies between 30 and 50 MW. In 2020 and later years, the presence of this unit also increases the need for new generating capacity in the Anchorage area by 10 MW. For the purpose of calculating reserve margins in the investment analysis, adding the 50 MW HCCP unit was deemed to be equivalent to adding 40 MW of new generating capacity in the Fairbanks area and 10 MW of new generating capacity in the Anchorage area.

Finally, if the Emma Creek project (2x100 MW) could be completed in time (i.e., by 2008), it would delay the need to build new generating capacity in the Fairbanks area until 2014. However, construction completion is not expected until at least 2012. More importantly, in 2020 its presence reduces the need for generating capacity in the Fairbanks areas by 60 MW and in the Anchorage area by 20 MW. Although these differences also vary across the years analyzed, for the purpose of calculating reserve margins in the investment analysis, adding the two units was deemed to be equivalent to adding 60 MW of new generating capacity in the Fairbanks area and 20 MW of new generating capacity in the Anchorage area.

Load – Resource Balances

Figures 4-1 – 4-3 display load resource balances for each of the three areas. The broad, solid line in each figure represents existing capacity in the area, net of retirements. The five thin lines represent capacity requirements with a 22 percent

²⁵ Assuming that GVEA owns or controls all of its existing units plus all units added in the Fairbanks area, and ML&P/Chugach own or control all of their existing units and all units added in the Anchorage area. It is not possible in the analysis to separate ML&P from Chugach.

reserve margin, under five different load conditions – the 10th, 30th, 50th, 70th, and 90th percentiles of the probability distribution of loads in each year²⁶. The solid thin line, representing the 50th percentile, roughly corresponds to the expected load scenario, while the two extreme dashed/dotted lines correspond to low and high scenarios.

Figure 4-1 indicates that Fairbanks has an immediate (i.e., in 2008) need for approximately 50 MW of new capacity²⁷, based on actual 2003 loads and expected load growth between 2003 and 2008. Through 2016, this net requirement increases in all but the low load scenarios, to as much as 175 MW in the high load scenario. Loads are expected to fall in 2017, reducing the new capacity requirement substantially, but by 2033 between 60 MW and 370 MW (cumulative) will be required to maintain the 22 percent reserve margin.

Figure 4-2 shows that capacity requirements in Anchorage are also erratic, but driven by unit retirements as opposed to load decreases. New capacity is not needed in the high load case until 2012, and not until 2020, when the first of the unit retirements occurs, in the low load case. Given the retirement of the three combined cycle units (each approximately 110 MW), cumulative capacity additions required by 2033 to maintain the 22 percent reserve margin range between 420 MW and 685 MW.

In contrast, Figure 4-3 indicates that no new capacity will be required during the study period in the Kenai area for reliability purposes. In 2008 the area has approximately 165 MW of excess capacity. By 2033 this surplus ranges from 60 MW to 120 MW.

Base Case Investment Strategies

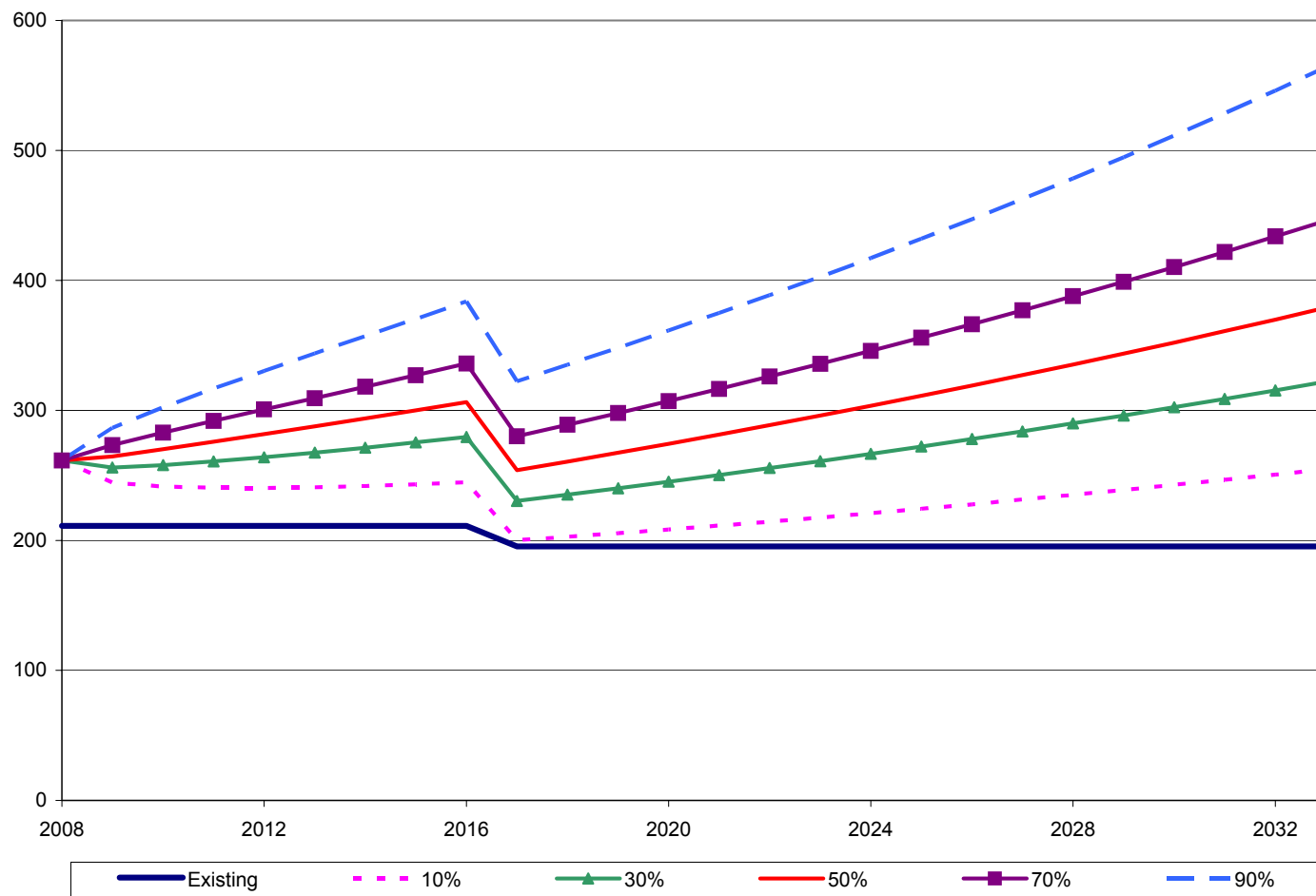
The results of the investment analysis of the Base Case can be grouped into three categories:

- Short-term investment decisions
- Long-term investment decisions
- Expected system costs

²⁶ For the purpose of capacity decisions, the load that matters is the load five years prior to the year the addition will take place, not the load during the year of the addition. Therefore, the capacity requirements displayed in all three figures are the corresponding load five years previous, escalated by the expected load growth during the intervening five years, escalated by the 22 percent reserve requirement.

²⁷ This amount is higher than the 40 MW discussed in the Reliability section above, due to a) the rounding that was done in the reliability analysis; and b) the use here of the 22 percent reserve margin standard, which is slightly higher than the 19 percent reserve that the reliability analysis indicated would be sufficient in 2008 to achieve the 10 percent LOLP standard.

Figure 4-1
Fairbanks Area Existing and Required Capacity, by Load Scenario (MW)



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Figure 4-2
Anchorage Area Existing and Required Capacity, by Load Scenario (MW)

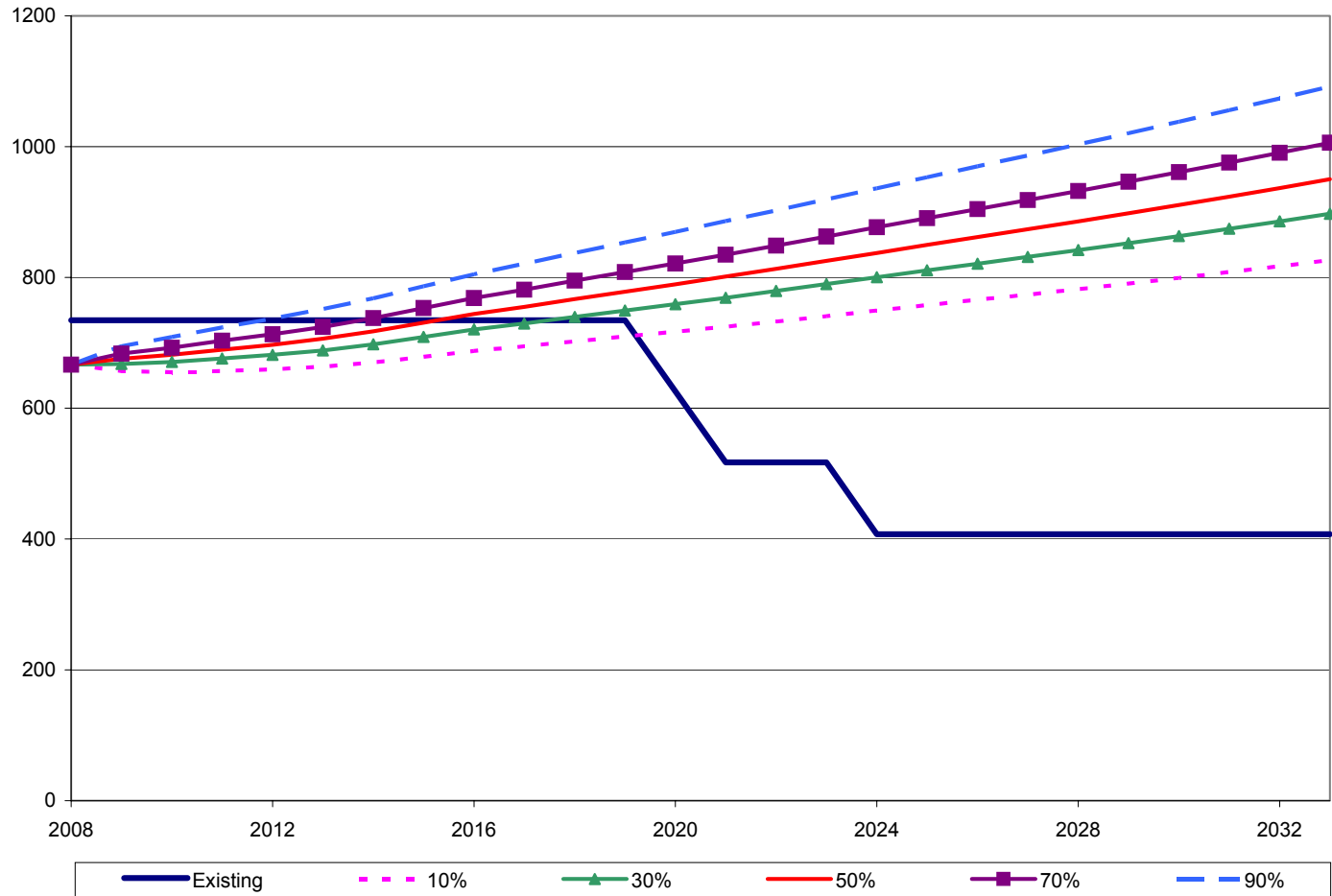
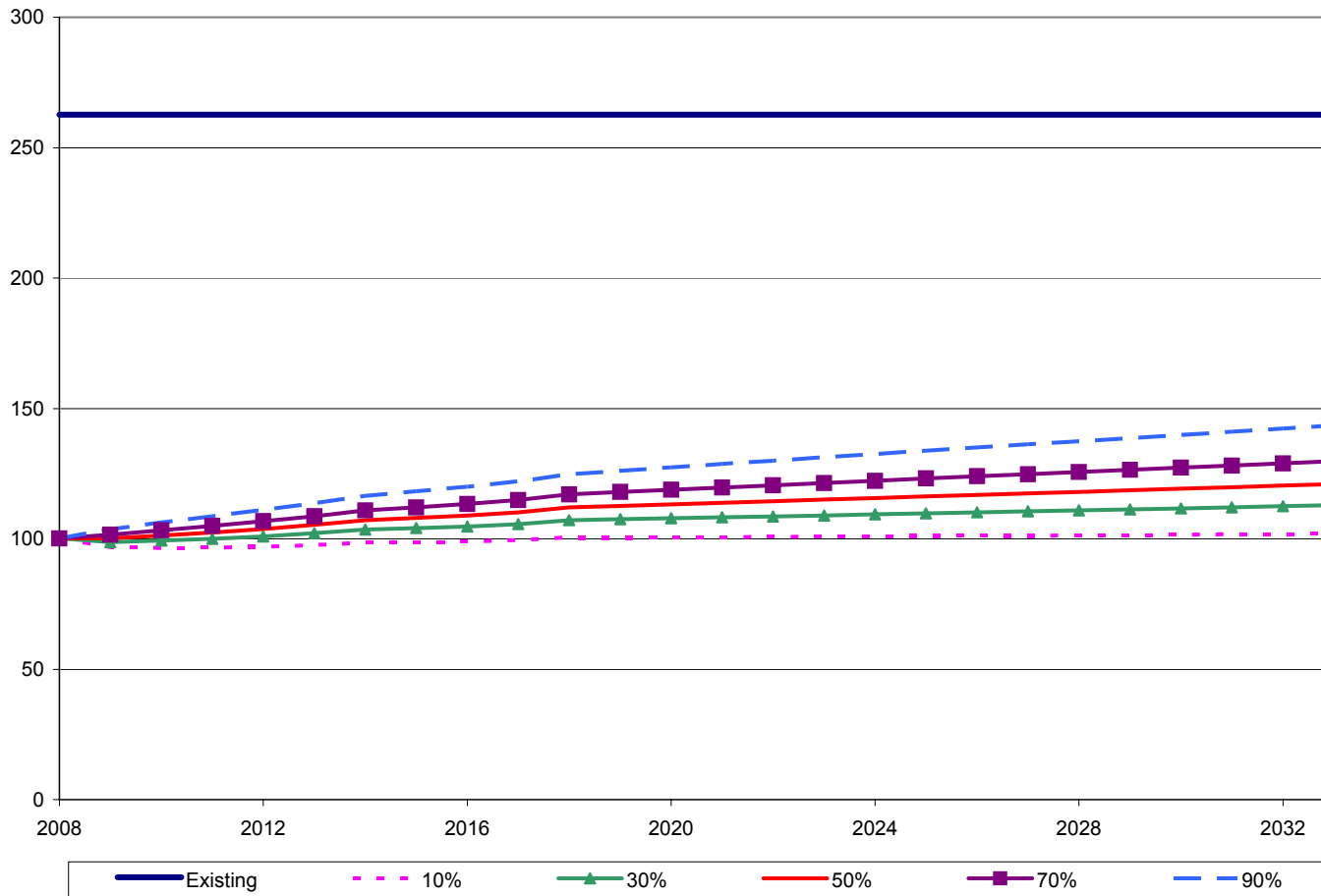


Figure 4-3
Kenai Area Existing and Required Capacity, by Load Scenario (MW)



Short-Term Investment Decisions

As indicated above, given actual 2003 loads and expected load growth between 2004 and 2008, the Fairbanks area has an immediate need (i.e., in 2008) for 50 MW of capacity. Depending on load growth (or possible decreases) between now and 2007, the amount of capacity required in 2012 to achieve the 22 percent reserve margin may decrease by 20 MW or increase by 40 MW.

Given the uncertainty about future loads, the immediate decision that yields the lowest expected system costs is to build an 85 MW CT in Fairbanks in 2008 (i.e., to begin commercial operation in January 2008). There are two important attributes of this decision:

- The decision is to build a simple cycle unit, not a combined cycle unit. In the Base Case, natural gas is assumed to not be available in the Fairbanks area. Until at least 2012, the Anchorage area has excess combined cycle capacity, and in most hours of the year the transmission lines between the Anchorage and Fairbanks areas are not completely full. As a result, it is less expensive in the near term to meet capacity requirements in the Fairbanks area with a CT and import additional energy from the Anchorage area than to construct (and operate) a new combined cycle unit in the Fairbanks area. Over time usage of the transmission lines between the two areas approaches their operating limits. As a result, the incentive to meet post-2008 reliability-related capacity requirements in the Fairbanks area with a combination of CTs and energy imports declines.
- The selected unit is larger than the immediate requirement. Part of this is due to the size of the units considered in the analysis (i.e., the only smaller units the model could have selected were a 40 MW CT or a 60 MW CC). However, more important reasons are the capital cost advantage that the 85 MW CT has over the 40 MW CT and the 60 MW CC (on a per kW basis) and the likelihood (though not certainty) that additional capacity will be required during the immediately following years.

The model indicates that no capital additions should be made in 2009. However, if the 2005 Fairbanks load is high (i.e., in the highest 20 percent of possible values), a 60 MW CC should be built in Fairbanks in 2010. If this decision is not made (i.e., if the 2005 Fairbanks load is not high), but the 2006 Fairbanks load is high, this 60 MW CC should be built in 2011. In either situation, less than 40 MW of new capacity is required to achieve the 22 percent reserve margin, so that the 40 MW CT could have been selected; the additional capacity and energy cost savings associated with the 60 MW CC make the larger unit less expensive.

The decisions to be made in January 2008 regarding January 2012 capacity additions are very interesting, as there are several possibilities. The best choice depends on the resolution of uncertainty about loads in all three areas and fuel prices between now and the end of 2007, and whether or not the decision to build the 60 MW CC in Fairbanks in 2010 or 2011 has been made. Table 4-3 summarizes these decisions for

the case in which the 60 MW CC Fairbanks has not been selected already. The table indicates:

- If 2007 loads and/or natural gas prices are low enough, no capacity should be added in 2012. For example, the first row of the table indicates that if the 2007 Fairbanks load is low (i.e., 0 – 20th percentiles of all possible values), the Anchorage load is expected (40 – 60th percentiles), the Kenai load is low or moderately low (0 – 40th percentiles), then for all possible 2007 natural gas prices no new capacity should be built in 2012.
- A 130 MW CC should be built in Anchorage if particular combinations of high enough Anchorage load, low enough Fairbanks load, high enough Kenai load, and high enough natural gas price occur in 2007.
- A 130 MW CC should be built in Fairbanks if the Fairbanks load is high and particular combinations of low enough Anchorage load and high enough natural gas price occur in 2007.
- 130 MW CCs should be built in both Fairbanks and Anchorage if the Fairbanks load is high and particular combinations of high enough Anchorage load and high enough natural gas price occur in 2007.
- A 60 MW CC should be built in Fairbanks if particular combinations of high enough high Fairbanks load, low enough Anchorage load, and low enough natural gas price occur in 2007.
- A 60 MW CC should be built in Fairbanks and a 130 MW CC should be built in Anchorage if particular combinations of high enough Fairbanks load, Anchorage load, Kenai load, and natural gas prices occur in 2007.

It is important to note that the actual 2007 natural gas price, which determines (together with the expected price growth) the expected 2012 and later natural gas prices, affects the capacity decisions in a significant manner. For example, if the 2007 Anchorage load is the expected level (i.e., 40 – 60th percentiles), a new unit will be built in Anchorage only if the 2007 natural gas price is high (i.e., in the 80 – 100th percentiles). In addition, actual 2007 loads (and therefore expected 2012 and later values) in one area affect decisions about capacity additions in other areas. For example, the combination of expected 2007 load in Anchorage and high 2007 load in the Kenai area typically leads to the same decision as moderately high load in Anchorage and less-than-high load in Kenai. Both of these phenomena occur for economic reasons, as opposed to reliability reasons.

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**Table 4-3
Base Case Possible 2012 Capacity Additions
No Additions Are Made in 2010 and 2011**

2012 Additions	2007 Values of Uncertain Variables (Percentile)			
	Load by Area			Henry Hub Gas Price
	Fairbanks	Anchorage	Kenai	
No Additions	0 - 20	40 - 60	0 - 40	0 - 100
	0 - 20	40 - 60	40 - 100	0 - 80
	0 - 20	60 - 80	0 - 100	0 - 80
	0 - 40	0 - 40	0 - 100	0 - 100
	20 - 60	40 - 80	0 - 100	0 - 80
	40 - 60	0 - 20	0 - 100	0 - 100
	40 - 60	20 - 40	80 - 100	0 - 80
	40 - 60	20 - 40	0 - 80	0 - 100
130 MW CC in Anchorage	0 - 20	40 - 60	40 - 100	80 - 100
	0 - 20	60 - 80	0 - 100	80 - 100
	0 - 60	80 - 100	0 - 100	0 - 100
	20 - 60	40 - 80	0 - 100	80 - 100
	40 - 60	20 - 40	80 - 100	80 - 100
130 MW CC in Fairbanks	80 - 100	0 - 20	0 - 20	0 - 100
	80 - 100	0 - 20	20 - 100	20 - 100
	80 - 100	20 - 60	0 - 100	20 - 100
	80 - 100	60 - 80	0 - 100	20 - 80
	80 - 100	60 - 80	0 - 20	80 - 100
130 MW CCs in Anchorage and Fairbanks	80 - 100	60 - 80	20 - 100	80 - 100
	80 - 100	80 - 100	0 - 60	20 - 100
	80 - 100	80 - 100	60 - 100	40 - 100
60 MW CC in Fairbanks	60 - 80	0 - 60	0 - 100	0 - 100
	60 - 80	60 - 80	0 - 100	0 - 80
	80 - 100	0 - 20	20 - 100	0 - 20
	80 - 100	20 - 80	0 - 100	0 - 20
60 MW CC in Fairbanks and 130 MW CC in Anchorage	60 - 80	60 - 80	0 - 100	80 - 100
	60 - 80	80 - 100	0 - 100	0 - 100
	80 - 100	80 - 100	0 - 100	0 - 20
	80 - 100	80 - 100	60 - 100	20 - 40

If it has already been decided to construct a 60 MW CC in Fairbanks in 2010 or 2011, the decision criteria are different. As one would expect, if the 2007 Anchorage load is high, a 130 MW CC should be built in Anchorage in 2012, regardless of 2007 loads in the other two areas or the natural gas price. This is also the optimal decision if the 2007 Anchorage load is moderately high (i.e., 60 – 80th percentiles), the Fairbanks load is expected or higher (i.e., the 40 – 100th percentile) and the natural gas price is high. However, the other combinations that are shown in Table 4-3 to lead to selection of a 130 MW CC in Anchorage, in particular, those with lower than expected 2007 load in Fairbanks and less-than-high Anchorage load, lead to no new units in 2012 if the 60 MW CC is already under construction for completion in 2010 or 2011. The reason for this is that in these situations, there would be excess energy-producing

capacity in Fairbanks by 2012, reducing the economic benefits of building the new 130 MW CC in Anchorage in that year.

The possible capacity additions in 2013 are similar to those shown in Table 4-3 for 2012, so a table similar to Table 4-3 is not provided. However, the circumstances under which a new unit should be built in 2013 are more likely than in 2012, whether or not the 60 MW CC is already under construction. For example, if the 60 MW CC is not under construction, a new 130 MW CC should be built in Anchorage in 2013 even if the 2008 load in all three areas is low (i.e., in the 0 – 20th percentile of all possible values), as long as the natural gas price is high.

Long-Term Investment Decisions

The investment decisions to be made between 2010 (for operation in 2014) and 2029 (for operation in 2033) are difficult to summarize. There are literally thousands of combinations of new units that the model selects, and for some decision literally millions of permutations of actual loads and natural gas prices that lead to the decision.

Tables 4-4 – 4-6 summarize the decisions that would be made through 2026 (for operation in 2030) under three very specific patterns of uncertainty resolution²⁸. Table 4-4 displays the decisions that would be made if the expected loads and natural gas prices happen to occur in every year²⁹. In this situation, the 85 MW CT would be built in Fairbanks in 2008, followed by a 60 MW CC in 2015 and another 60 MW CC in 2029. A 130 MW CC would be built in Anchorage in 2015, followed by additional 130 MW CCs in 2020, 2021, and 2024. The three CCs built in Anchorage between 2020 and 2024 essentially replace the three existing units that are retired there during that period. A total of 725 MW of new capacity (375 MW net of post-2008 retirements) would be installed under these circumstances between 2008 and 2030.

In contrast, Table 4-5 displays the additions that would be made if the low values of both loads (in all three areas) and natural gas prices happened to occur in all years. In this situation, only 535 MW of new capacity would be built between 2008 and 2030, 185 MW net of post-2008 retirements. Moreover, after the 85 MW CT built in 2008, the next unit to be built is not until 2021.

²⁸ The table only reports additions through 2030 because there are so many possible combinations after that date that it is not possible to print them to a file for further analysis.

²⁹ These results are not the same results that would be generated by performing a deterministic analysis that ignores uncertainty. These results correspond to the situation that the decision maker knows that the expected loads and natural gas price occurred in each prior year, but does not know that the expected values will occur in future years, and takes uncertainty into account in making the decisions regarding the future.

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**Table 4-4
Base Case Capacity Additions
If Expected Loads and Natural Gas Prices Occur**

Year	Fairbanks			Cumulative Additions (MW)	Anchorage			Cumulative Additions (MW)	Railbelt
	# Units				# Units				Total
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		Cumulative Additions (MW)
2008	1			85				0	85
2009				85				0	85
2010				85				0	85
2011				85				0	85
2012				85				0	85
2013				85				0	85
2014				85				0	85
2015		1		145			1	130	275
2016				145				130	275
2017				145				130	275
2018				145				130	275
2019				145				130	275
2020				145			1	260	405
2021				145			1	390	535
2022				145				390	535
2023				145				390	535
2024				145			1	520	665
2025				145				520	665
2026				145				520	665
2027				145				520	665
2028				145				520	665
2029		1		205				520	725
2030				205				520	725

Finally, Table 4-6 displays the additions that would be made if the high values of both loads (again, in all three areas) and natural gas prices happen to occur in all years. In this situation, 985 MW of new capacity would be built by 2030, 635 MW net of post-2008 retirements. As indicated above, new units would be required in this situation in 2010 in Fairbanks and 2012 in Anchorage.

Table 4-5
Base Case Capacity Additions
If Low (10th Percentile) Loads and Natural Gas Prices Occur

Year	Fairbanks				Anchorage				Railbelt Total Cumulative Additions (MW)
	# Units			Cumulative Additions (MW)	# Units			Cumulative Additions (MW)	
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		
2008	1			85				0	85
2009				85				0	85
2010				85				0	85
2011				85				0	85
2012				85				0	85
2013				85				0	85
2014				85				0	85
2015				85				0	85
2016				85				0	85
2017				85				0	85
2018				85				0	85
2019				85				0	85
2020				85			1	130	215
2021				85			1	260	345
2022				85				260	345
2023				85				260	345
2024				85			1	390	475
2025				85				390	475
2026				85				390	475
2027				85				390	475
2028				85				390	475
2029				85				390	475
2030				85		1		450	535

Expected System Costs

The present value (as of January 2008) of total expected 2008 – 2033 system costs is \$5.04 billion. This cost estimate includes all fuel, variable O&M, and fixed O&M expenses at both existing and newly constructed generating units, as well as the incremental fixed O&M expenses associated with extending the life of existing generating units past their Retirement Evaluation Dates and the amortized capital costs of new generating units. It does not include the amortization of capital costs of existing generating units, or any O&M (variable or fixed) or capital costs associated with existing transmission facilities³⁰. On a levelized basis, this is equal to \$53.3 per MWh (real 2008 dollars).

³⁰ And in the Base Case no new transmission facilities are constructed.

**Table 4-6
Base Case Capacity Additions
If High (90th Percentile) Loads and Natural Gas Prices Occur**

Year	Fairbanks			Cumulative Additions (MW)	Anchorage			Cumulative Additions (MW)	Railbelt
	# Units				# Units				Total
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		Cumulative Additions (MW)
2008	1			85				0	85
2009				85				0	85
2010		1		145				0	145
2011				145				0	145
2012				145			1	130	275
2013				145				130	275
2014		1		205			1	260	465
2015				205				260	465
2016				205				260	465
2017				205			1	390	595
2018				205				390	595
2019				205				390	595
2020				205				390	595
2021				205			1	520	725
2022				205				520	725
2023			1	335				520	855
2024				335			1	650	985
2025				335				650	985
2026				335				650	985
2027				335				650	985
2028				335				650	985
2029				335				650	985
2030				335				650	985

For reference purposes, the model generates an equivalent expected value for 2004 of \$34.6 per MWh (again, in real 2008 dollars). If the 2004 expected value were realized throughout the 2008 – 2033 period, the present value of total expected 2008 – 2033 system costs would be \$3.28 billion, a reduction of \$1.77 billion.

There are three primary reasons for the approximate 54 percent increase in the levelized cost between 2004 and the entire 2008 – 2033 period:

- Increases in fixed O&M at existing generating units, associated with extending the lives of these units past their retirement evaluation dates
- Increases in fuel prices
- Cost of building new generating capacity

The present value in 2008 of the incremental fixed O&M associated with life extension is approximately \$260 million, 15 percent of the total of \$1.77 billion. It is not possible, given the manner in which the Investment Module performs its calculations, to determine the relative contributions of the two other factors. However, the present value of the amortized capital costs of the capacity additions shows in Tables 4-4 and 4-6 should provide lower- and upper-bound estimates of the amount due to the capital cost of capacity additions. The amounts calculated from Table 4-4

approximately \$375 million, and from Table 4-6, \$635 million, represent approximately 20 and 35 percent, respectively of the total. This suggests that the expected increase in fuel prices accounts for between 50 and 65 percent of the expected increase in levelized power costs.

Effects of Risk Aversion on Investment Decisions

In the Base Case, at each decision point the Investment Module calculates the expected total system costs from that point forward for each feasible portfolio, and selects the portfolio with the lowest expected total system cost. As discussed above, the Investment Module can also utilize a different decision criterion, which reflects risk aversion by decision makers. With this criterion, at each decision point and for each feasible portfolio, the module calculates the probability distribution of future total system cost and, particularly, the future total system cost that would only be exceeded with χ (e.g., 10) percent probability. This value is called the $100 - \chi$ percent confidence level expected total system cost. At each decision point the module then selects the portfolio with the lowest $100 - \chi$ confidence level expected total system cost.

To determine the effects that decision-maker's risk aversion would have on investment decisions, the Investment Module was re-run, using the same assumptions as the in the Base Case, except using a 90 percent confidence level decision criterion instead of the expected value criterion. The key finding of this analysis is that incorporation of risk aversion generally leads to construction of more capacity. The reason for this is that there is much more risk associated with either loads or fuel prices turning out higher than expected at the time of a decision than that they turn out lower than expected. Building additional capacity (over and above that indicated in the Base Case) provides a "hedge" against the risks of higher loads or fuel prices.

For example, in the Base Case, if the 2005 Fairbanks load is in the highest 20 percent of possible values, the decision should be made at the beginning of 2006 to build a 60 MW CC in Fairbanks to begin operation in 2010. Even with this 60 MW CC, if either 1) loads in Fairbanks (or, to a lesser extent, the other areas) or 2) fuel prices turn out to be higher in 2010 (and, to a lesser extent, later years) than they were expected to be at the time of the decision (even given the high 2005 Fairbanks load), production costs in 2010 and later years will be higher (potentially substantially higher) than the expected value that was used to make the decision to build the 60 MW CC. One way to hedge this risk is to build a 130 MW CC in Fairbanks in 2010, instead of the 60 MW CC. Building the larger unit will increase expected total system costs, because the incremental capital costs (which are modeled as if they were certain) are higher than the expected fuel savings. However, in the event of higher-than-expected 2010 loads or fuel prices, the larger unit produces fuel savings that exceed the incremental capital costs. As a result, if 2005 Fairbanks load is in the highest 20 percent of possible values (and several other conditions occur as well, as discussed in the following bulleted items) building the 130 MW CC significantly reduces the uncertainty about 2010 total system costs, and reduces the 90 percent confidence level expected value of 2010 and later total system costs.

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Specific findings are as follows:

- As indicated in the preceding paragraph, if the 2005 Fairbanks load is in the highest 20 percent of possible values, either a 130 MW CC or a 60 MW CC should be built in Fairbanks to begin operation in 2010. Table 4-7 displays the circumstances under which each should be selected. In contrast, in the Base Case a 60 MW CC was selected if the 2005 Fairbanks load is in the highest 20 percent of possible values.
- If the 2006 Fairbanks load is in the highest 20 percent of all values, and a new unit was not already selected to be built in 2010, a new 130 MW CC should be built in Fairbanks in 2011. In contrast, in the Base Case a 60 MW CC was selected if the 2006 Fairbanks load is in the highest 20 percent of possible values.
- In addition, if the 2006 Anchorage load is in the highest 20 percent of possible values, the Fairbanks load is in the 40 – 80 percentile, and the Henry Hub gas price is in the highest 20 percent of possible values, a 130 MW CC should be built in the Anchorage area in 2011.
- As shown in Table 4-8, if a new unit has not already been selected to be built in 2010 or 2011, the likelihood of building a new unit in 2012 is significantly greater than in the Base Case. Moreover, any unit built in Fairbanks to begin operation in 2012 would be a 130 MW CC; in the Base Case, in some circumstances a 60 MW CC would be built in Fairbanks in 2012.

**Table 4-7
Risk Aversion Case Possible 2010 Capacity Additions**

2010 Additions	2005 Values of Uncertain Variables (Percentile)			
	Load by Area			Henry Hub Gas Price
	Fairbanks	Anchorage	Kenai	
No Additions	0 - 80	0 - 100	0 - 100	0 - 100
130 MW CC in Fairbanks	80 - 100	0 - 80	0-100	20-100
	80 - 100	80-100	0-80	40-100
	80 - 100	80-100	80-100	60-100
60 MW CC in Fairbanks	80 - 100	0 - 100	0 - 100	0 - 20
	80 - 100	40 - 60	40 - 60	20 - 40
	80 - 100	40 - 60	80 - 100	20 - 40
	80 - 100	60 - 80	80 - 100	20 - 40
	80 - 100	80 - 100	0 - 100	20 - 40
	80 - 100	80 - 100	40 - 60	40 - 60

Table 4-8
Risk Aversion Case Possible 2012 Capacity Additions
No Additions Are Made in 2010 and 2011

2012 Additions	2007 Values of Uncertain Variables (Percentile)			
	Load by Area			Henry Hub
	Fairbanks	Anchorage	Kenai	Gas Price
No Additions	0 - 20	0 - 80	0 - 100	0 - 80
	20 - 40	0 - 60	0 - 100	0 - 80
	20 - 40	60 - 80	0 - 100	0 - 60
	20 - 40	60 - 80	0 - 60	60 - 80
	40 - 60	0 - 60	0 - 100	0 - 80
	40 - 60	60 - 80	20 - 100	0 - 60
	40 - 60	60 - 80	0 - 20	0 - 80
130 MW CC in Anchorage	0 - 60	0 - 80	0 - 100	80 - 100
	0 - 60	80 - 100	0 - 100	0 - 100
	20 - 40	60 - 80	60 - 100	60 - 80
	40 - 60	60 - 80	20 - 100	60 - 80
130 MW CC in Fairbanks	60 - 80	0 - 80	0 - 100	0 - 80
	60 - 80	0 - 20	0 - 100	80 - 100
	60 - 80	20 - 40	0 - 20	80 - 100
	80 - 100	0 - 20	0 - 100	80 - 100
	80 - 100	0 - 80	0 - 100	0 - 80
130 MW CCs in Anchorage and Fairbanks	60 - 80	20 - 40	20 - 100	80 - 100
	60 - 80	40 - 80	0 - 100	80 - 100
	60 - 100	80 - 100	0 - 100	0 - 100
	80 - 100	20 - 80	0 - 100	80 - 100

- Regarding the long run, Table 4-9 shows the additions that should be selected if expected loads and fuel prices happens to occur in every year. Compared to the Base Case (Table 4-4), the 130 MW CC in Anchorage in 2014 is one year earlier in the Risk Aversion case, and the two CCs built in Fairbanks (in 2015 and 2029) are both 130 MW in the Risk Aversion case instead of 60 MW in the Base Case.
- Tables 4-10 and 4-11 show the additions that should be selected if low (4-10) and high (4-11) values of loads and fuel prices happen to occur in every year. Table 4-10 is identical to the analogous table for the Base Case (Table 4-5), indicating that incorporating risk aversion does not affect capacity decisions under low load and fuel prices. Compared to the analogous Base Case table (Table 4-6), Table 4-11 shows that under high load and fuel price conditions incorporating risk aversion will lead to construction of units somewhat sooner than in the Base Case, and to selection of somewhat larger units.

**Table 4-9
Risk Aversion Case Capacity Additions
If Expected Loads and Natural Gas Prices Occur**

Year	Fairbanks				Anchorage				Railbelt Total Cumulative Additions (MW)
	# Units			Cumulative Additions (MW)	# Units			Cumulative Additions (MW)	
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		
2008	1			85				0	85
2009				85				0	85
2010				85				0	85
2011				85				0	85
2012				85				0	85
2013				85				0	85
2014				85			1	130	215
2015			1	215				130	345
2016				215				130	345
2017				215				130	345
2018				215				130	345
2019				215				130	345
2020				215			1	260	475
2021				215			1	390	605
2022				215				390	605
2023				215				390	605
2024				215			1	520	735
2025				215				520	735
2026				215				520	735
2027				215				520	735
2028				215				520	735
2029			1	345				520	865
2030				345				520	865

- In the Base Case, the present value of total expected 2008 – 2033 system costs is \$5.04 billion. The standard deviation of this present value is \$760 million, indicating that there is a 90 percent probability that the present value of costs will be less than \$6.007 billion (\$5.04 billion plus 1.28 times \$760 million)³¹. In the Risk Aversion Case, the expected present value of total expected 2008 – 2033 system costs is \$5.07 billion, the standard deviation is \$730 million, and there is a 90 percent probability that the present value of costs will be less than \$6.005 billion.

³¹ Conversely, there is a 10 percent probability that the present value of costs will exceed \$6.01 billion.

**Table 4-10
Risk Aversion Case Capacity Additions
If Low (10th Percentile) Loads and Natural Gas Prices Occur**

Year	Fairbanks				Anchorage				Railbelt Total Cumulative Additions (MW)
	# Units			Cumulative Additions (MW)	# Units			Cumulative Additions (MW)	
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		
2008	1			85				0	85
2009				85				0	85
2010				85				0	85
2011				85				0	85
2012				85				0	85
2013				85				0	85
2014				85				0	85
2015				85				0	85
2016				85				0	85
2017				85				0	85
2018				85				0	85
2019				85				0	85
2020				85				130	215
2021				85				260	345
2022				85				260	345
2023				85				260	345
2024				85				390	475
2025				85				390	475
2026				85				390	475
2027				85				390	475
2028				85				390	475
2029				85				390	475
2030				85		1		450	535

Analysis of Unique Investment Opportunities and Sensitivity Cases

The results of the analysis of the five “unique investment opportunities” are presented the following section:

- Pseudo-Healy Clean Coal Project
- Southern Intertie Project
- Fire Island Wind Project
- Nikiski Repowering Project
- Emma Creek Coal Project

**Table 4-11
Risk Aversion Case Capacity Additions
If High (90th Percentile) Loads and Natural Gas Prices Occur**

Year	Fairbanks			Cumulative Additions (MW)	Anchorage			Cumulative Additions (MW)	Railbelt Total Cumulative Additions (MW)
	# Units				# Units				
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		
2008	1			85			0	85	
2009				85			0	85	
2010			1	215			0	215	
2011				215			0	215	
2012				215			130	345	
2013				215			1	475	
2014				215				475	
2015				215			1	605	
2016				215				605	
2017				215				605	
2018				215				605	
2019				215				605	
2020				215			1	735	
2021				215				735	
2022				215				735	
2023				215				735	
2024			1	345			1	995	
2025				345				995	
2026				345				995	
2027				345				995	
2028				345				995	
2029				345				995	
2030				345		1	710	1055	

- In addition, two sensitivity cases, involving the possibilities of 1) building generic coal units in the Fairbanks and/or Anchorage areas and 2) natural gas becoming available in the Fairbanks area, are also reported in the following sections.

Pseudo-Healy Clean Coal Project

As discussed in Section 2, the HCCP as it currently exists was not analyzed. Instead, HCCP was modeled as if it had the same operating characteristics (i.e., heat rate, unit variable O&M, maintenance rate, and forced outage rate) as a generic 50 MW coal unit, assumed to be “built” in the Healy transmission area in 2008. As a result, this case is referred to as the “Pseudo-Healy Clean Coal Project” or “Pseudo-HCCP” case, not the “Healy Clean Coal Project” or “HCCP” case.

It was outside the scope of the RES to estimate the capital costs required to transform the HCCP as it currently exists into a unit with the same performance characteristics as the 50 MW generic unit that was modeled. Estimation of the ongoing annual fixed O&M expenses that would be required to continue to achieve these performance characteristics was also beyond the scope of this study. The capital costs required to transform the existing HCCP facilities into this generic unit, as well as the ongoing annual fixed O&M expenses, were therefore assumed to be zero.

Given these assumptions, the estimated present value (as of January 2008) of expected 2008 – 2033 total system costs is \$4.82 billion. This represents a gross savings of \$220 million compared to the Base Case.

This \$220 million estimate can be viewed in several different ways:

- If the present value of the sum of 1) the actual capital costs required to transform the existing facility into one with the characteristics of a generic 50 MW coal unit and 2) the actual fixed O&M expenses is less than \$220 million, customers of the six Railbelt utilities would be better off (i.e., pay lower electricity bills) during the 2008 – 2033 period if the HCCP transformation was made than if the facility remained unused. However, if the present value of these capital and fixed O&M costs is higher than \$220 million, customers of the six Railbelt utilities would be better off during the 2008 – 2033 period if the existing facility remained unused.
- The present value of the expected 2008 – 2033 fixed O&M expenses for a generic 50 MW coal unit is \$70 million³². If this amount could be achieved, capital costs could be as high as \$150 million and the project would still produce net savings to Railbelt customers, i.e., if the existing facility could be transformed into the one analyzed in this study for \$150 million or less, Railbelt customers would be better off if the transformation was made than allowing the facility remained unused.

There are two reasons for these savings:

- Table 4-12, which displays the capacity additions if the transformed HCCP is brought back into operation and expected loads and fuel prices happen to occur in all years, indicates that the unit essentially replaces the first 60 MW CC that would otherwise need to be built in the Fairbanks area. The present value of the capital costs of the replaced 60 MW CC are approximately \$50 million.
- The fuel costs associated with generating 50 MWh per hour year-round are substantially lower burning coal than burning Naptha, the fuel that new 60 MW CCs in Fairbanks are projected to burn. The present value of these fuel cost savings are approximately \$170 million.

Southern Intertie Project

Construction of the Southern Intertie would increase the transfer capability between the Anchorage and Kenai areas by 50 MW (in each direction), and reduce transmission losses. The estimated capital costs of the project are \$119 million in real 2003 dollars, \$134 million in real 2008 dollars. The estimated fixed O&M costs for the Intertie are \$400 thousand per year, in real 2003 dollars. The present value (in real 2008 dollars) of the 2008 – 2033 fixed O&M expenses is \$7 million (calculated in the

³² The \$70 million was calculated in the following manner. Table 3-3 indicates that the estimated annual fixed O&M expenses for a 50 MW coal-fired unit are \$80 / kW-year in real 2003 dollars, or \$4.0 million per year (50,000 kW x \$80 / kW-year). With 2.5 percent inflation per year, the nominal fixed O&M expenses for such a unit are expected to be \$4.5 million in 2008, \$4.6 million in 2009, etc., increasing to \$8.4 million in 2033. The present value as of January 2008 of this stream of 2008 – 2033 costs, using a 7.0 percent discount rate, is \$70 million.

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same manner as described above for the pseudo-HCCP unit), so the present value of the capital and fixed O&M costs for the 2008 – 2033 period is \$141 million.

**Table 4-12
Pseudo-Healy Clean Coal Project Case Capacity Additions
If Expected Load and Natural Gas Prices Occur**

Year	Fairbanks			Cumulative Additions (MW)	Anchorage			Cumulative Additions (MW)	Railbelt Total Cumulative Additions (MW)
	# Units				# Units				
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		
2008	1			85			0	85	
2009				85			0	85	
2010				85			0	85	
2011				85			0	85	
2012				85			0	85	
2013				85			0	85	
2014				85			0	85	
2015				85			0	85	
2016				85			130	215	
2017				85			130	215	
2018				85			130	215	
2019				85			130	215	
2020				85			260	345	
2021				85			390	475	
2022				85			390	475	
2023				85			390	475	
2024				85			520	605	
2025				85			520	605	
2026				85			520	605	
2027		1		145			520	665	
2028				145			520	665	
2029				145			520	665	
2030				145			520	665	

The Southern Intertie was modeled assuming zero capital and fixed O&M costs. Given this assumption, the estimated present value of 2008 – 2033 system costs is \$5.01 billion. This represents a gross savings of \$28 million compared to the Base Case. Given the \$141 million of estimated (but not modeled) capital and fixed O&M costs, the net savings are estimated to be negative \$113 million (real 2008 dollars), i.e., the customers of the Railbelt would be worse off by approximately \$113 million during the 2008 – 2033 period if the Southern Intertie is constructed.

The reasons for the relatively small savings estimate of \$28 million are as follows:

- Although from a reliability standpoint completion of the Intertie is equivalent to construction of a new 50 MW generating unit in the Anchorage area, completion of the Intertie has little effect on the need to build new generating capacity in the Anchorage area. As shown in Table 4-13, if expected loads and natural gas prices occur in all years, new 130 MW combined cycle units should be constructed in 2016, 2020, 2021, and 2024. In the Base Case (Table 4-4), similar units are built in 2015, 2020, 2021, and 2024, so the only effect (at least with expected loads and natural gas prices) on capacity is to delay the date of construction of the first unit

by one year (from 2015 to 2016). The value of this one-year delay is almost \$17 million at the time it occurs (interest savings of almost \$12 million in 2015, equal to the 7 percent discount rate times \$166 million capital cost; plus \$5 million of fixed O&M savings) and has a present value in 2008 of \$11 million.

- The annual fuel cost savings attributable to the project are minor. As modeled, construction of the project will not change the dispatch of the Bradley Lake or Cooper Lake hydroelectric generating units. The respective dispatch limits of 90 MW and 20 MW (and the annual generation limit) constrain exports of hydroelectric output from the Kenai area to the Anchorage area, not the transmission limit. The only fuel cost savings attributable to the project are therefore associated with dispatching one or more of the three Bernice Lake generating units to serve load in the Anchorage area during high-load hours instead of having to use the three generating units at the International station or Beluga units 1 and 2³³.

Fire Island Wind Project

The Fire Island Wind Project was modeled as a 50 MW project, with an annual capacity factor of 32 percent, which varies across the months of the year. Assuming zero capital and fixed O&M costs, the estimated present value of 2008 – 2033 system costs is \$4.94 billion, which represents a gross savings of \$104 million compared to the Base Case. Capital costs were assumed to be \$83 million (real 2003 \$), and annual fixed O&M costs were assumed to be \$0.4 million. The present value of the capital and fixed O&M costs were therefore \$101 million (real 2008 dollars)³⁴. Subtracting these costs from the gross savings estimate of \$104 million yields a net savings attributable to construction of the project of \$3 million (real 2008 \$). Thus, customers of the Railbelt would be better off by approximately \$3 million during the 2008 – 2033 period if the project is constructed³⁵.

³³ It is important to note that the Southern Intertie was analyzed in isolation from other unique investment opportunities and upgrade projects that the Railbelt utilities are considering. In particular, the Southern Intertie might be cost-effective if the Nikiski Repowering Project is executed. Similarly, the utilities are considering improvements to Bradley Lake that would increase its dispatchable capacity to 117 MW. If these improvements are made, the Intertie project might be cost-effective.

³⁴ The \$83 million capital cost in real 2003 dollars inflates (at 2.5 percent per year) to \$94 million in 2008 dollars. The annual fixed O&M costs of \$400 thousand in real 2003 dollars inflates to nominal values of \$450 thousand in 2008, \$460 thousand in 2009, etc., up to \$840 thousand in 2033. Using a 7.0 percent discount rate, the present value at January 2008 of this stream of fixed O&M costs is \$7 million. The \$94 million of capital costs and \$7 million of fixed O&M costs (both in real 2008 dollars) sum to \$101 million.

³⁵ As stated above, the RES model probably overstates the production cost savings generated by the Fire Island Wind Project. However, the magnitude of any such overstatement is not known.

**Table 4-13
Southern Intertie Project Case Capacity Additions
If Expected Loads and Natural Gas Prices Occur**

Year	Fairbanks				Anchorage				Railbelt Total Cumulative Additions (MW)
	# Units			Cumulative Additions (MW)	# Units			Cumulative Additions (MW)	
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		
2008	1			85				0	85
2009				85				0	85
2010				85				0	85
2011				85				0	85
2012				85				0	85
2013				85				0	85
2014				85				0	85
2015		1		145				0	145
2016				145			1	130	275
2017				145				130	275
2018				145				130	275
2019				145				130	275
2020				145			1	260	405
2021				145			1	390	535
2022				145				390	535
2023				145				390	535
2024				145			1	520	665
2025				145				520	665
2026				145				520	665
2027				145				520	665
2028				145				520	665
2029		1		205				520	725
2030				205				520	725

Analysis of the hourly wind data that Chugach provided (discussed above) suggests that construction of the project would not improve the reliability of the Railbelt system, due to the random variations in project output. As a result, the project was modeled as having no capacity value, i.e., its construction does not affect the need to build capacity for reliability purposes. Therefore, all of the gross savings are attributable to fuel cost savings, i.e., construction of the project produces electric energy at a very low variable cost (\$2.70 per MWh variable O&M in real 2003 \$) and reduces the need to generate electric energy by burning natural gas or other fuels. Furthermore, construction of the project has an insignificant effect on the pattern of capacity additions in both the short- and long-term. For this reason, a table similar to Table 4-4 is not provided for this case.

Nikiski Repowering Project

The Nikiski Repowering Project was modeled as a 25 MW steam turbine added to the existing 42 MW gas turbine and steam generator at the Nikiski plant. The steam turbine would begin operation in 2008. Assuming zero capital and fixed O&M costs, the estimated present value of 2008 – 2033 system costs is \$4.95 billion, which represents a gross savings of \$94 million compared to the Base Case. Capital costs were assumed to be \$20 million (real 2003 \$), and annual fixed O&M costs were

assumed to be \$0.4 million. The present value at January 2008 of the capital and fixed O&M costs is therefore \$29 million (real 2008 dollars). Subtracting these costs from the gross savings estimate of \$94 million yields a net savings attributable to construction of the project of \$65 million (real 2008 \$). Thus, customers of the Railbelt would be better off by approximately \$65 million during the 2008 – 2033 period if the project is constructed.

Analysis of the project indicated that its construction would not affect reliability and the need for new generating capacity for reliability purposes in either the Anchorage or Fairbanks areas, because of its location and size. Therefore, all of the gross savings are attributable to fuel cost savings. The steam turbine generates electric energy without burning any fuel (over and above what the gas turbine is already burning), so the variable cost of the energy is very low (\$4.60 / MWh variable O&M in real 2003 \$) and reduces the need to generate electric energy by burning natural gas or other fuels. Furthermore, construction of the project has an insignificant effect on the pattern of capacity additions in both the short- and long-term. For this reason, a table similar to Table 4-4 is not provided for this case.

Emma Creek Project

The Emma Creek Project was modeled as two 100 MW coal-fired units in the Healy transmission area, which begin operation in 2012. Assuming zero capital and fixed O&M costs, the estimated present value of 2008 – 2033 total system costs is \$4.56 billion, which represents a gross savings of \$477 million compared to the Base Case. Capital costs were assumed to be \$420 million (real 2003 \$) and annual fixed O&M costs were assumed to be \$8 million³⁶. The present value as of January 2008 of the capital and fixed O&M costs is \$504 million. Subtracting these costs from the gross savings estimate yields a net savings attributable to construction of the project of negative \$27 million (real 2008 \$), i.e., the customers of the Railbelt would be worse off by approximately \$27 million during the 2008 – 2033 period if the project is constructed.

The primary reason that the project is not cost-effective is a combination of its size and location, which has two effects:

- As indicated above, from a reliability standpoint the project is equivalent to constructing a new 60 MW unit in the Fairbanks area and a new 20 MW unit in the Anchorage area. Table 4-14 shows that construction of the project makes construction of the 60 MW CC in the Fairbanks area in 2015 unnecessary (in contrast to the Base Case, as indicated in Table 4-4) if all uncertain variables take on their expected values, and also delays the date that the first CC is built in the Anchorage area from 2015 in the Base Case to 2017. Displacing the 60 MW CC produces capital cost savings of \$53 million and fixed O&M savings of \$31 million (both present value in 2008), while delaying the construction of the 130 MW CC in Anchorage by two years saves \$13 million (present value in 2008) in

³⁶ Note that the estimated capital costs do not include costs to connect the project to the existing transmission grid, or the costs of any upgrades to the transmission grid that might be required to safely absorb the output of the facility.

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capital costs and \$6 million in fixed O&M costs. However, if construction of the 130 MW CC in Anchorage could have been avoided altogether (instead of merely delayed), \$104 million in construction costs and \$40 million in fixed O&M costs (present value in 2008; instead of, not in addition to, the \$13 million and \$6 million) would have been saved. The \$125 million of additional cost savings (\$104 million plus \$40 million, less \$13 million plus \$6 million) added to the negative \$27 million of estimated savings would have been enough to make the project cost-effective.

Table 4-14
Emma Creek Project Case Capacity Additions
If Expected Loads and Natural Gas Prices Occur

Year	Fairbanks				Anchorage				Railbelt Total Cumulative Additions (MW)
	# Units			Cumulative Additions (MW)	# Units			Cumulative Additions (MW)	
	85 MW CT	60 MW CC	130 MW CC		85 MW CT	60 MW CC	130 MW CC		
2008	1			85				0	85
2009				85				0	85
2010				85				0	85
2011				85				0	85
2012				85				0	85
2013				85				0	85
2014				85				0	85
2015				85				0	85
2016				85				0	85
2017				85			1	130	215
2018				85				130	215
2019				85				130	215
2020				85			1	260	345
2021				85			1	390	475
2022				85				390	475
2023				85				390	475
2024				85			1	520	605
2025				85				520	605
2026				85				520	605
2027				85				520	605
2028				85				520	605
2029		1		145				520	665
2030				145				520	665

- Only 215 MW can be exported from the Healy transmission area (140 MW north to the Fairbanks area, 75 MW south to the Anchorage area). GVEA's existing 27 MW Healy coal unit is also located in the Healy transmission area. In the Base Case, the Healy unit has the lowest dispatch cost of all of the thermal plants in the Railbelt, and therefore dispatches fully in all hours that it is available. The Emma Creek plant has a lower dispatch cost than the Healy unit (\$21.30 per MWh versus \$28.70 per MWh in 2012). Because of the export constraint, in order to fully dispatch the Emma Creek plant, output at the Healy unit must be reduced by 12 MW. Therefore, the variable cost savings attributable to the last 12 MW of

Emma Creek output are approximately \$0.8 million in 2012 (nominal \$; \$7.40 / MWh unit cost difference x 8,760 hours x 12 MW).

In contrast, the existing unit in the Anchorage area with the lowest dispatch cost is the ML&P 7/6 unit, whose costs in 2012 are \$44.00 per MWh. If the Emma Creek project were located in the Anchorage area, and the last 12 MW of Emma Creek output displaced output at ML&P 7/6, it would produce \$2.4 million of variable cost savings in 2012 (nominal \$; \$22.70 per MWh unit cost difference x 8,760 hours x 12 MW)³⁷, \$1.6 million more than it does by displacing Healy.

Assuming the last 12 MW of Emma Creek output would displace output at ML&P 7/6 through 2023, and output at a new 130 MW CC thereafter, the present value in 2008 of the associated variable cost savings is \$34 million. In contrast, displacing 12 MW of output at the Healy unit produces variable cost savings with a present value in 2008 of \$8 million. The difference, \$26 million, is almost large enough that when added to offset the actual savings estimate of negative \$27 million, to make the project cost-effective.

Generic Coal Sensitivity Case

The purpose of the Generic Coal Sensitivity Case was to investigate how the optimal investment strategy would change if coal plants could be constructed in the Fairbanks and Anchorage transmission areas. Two key assumptions of the analysis are³⁸ :

- Coal could be delivered to coal plants in the two areas, beginning in 2015, at the same prices that GVEA's existing Healy 1 plant pays. These prices are provided in Section 3.
- It would be possible to find at least one site in each transmission area at which a coal plant could be permitted and cost-effectively constructed and operated.

In order to streamline the analysis, additional screening (over and above that described in Section 3) was performed. This analysis indicated that in the overwhelming majority of possible circumstances (though not all), constructing and operating a 150 MW coal-fired plant was more cost-effective than a 100 MW coal-fired plant in either the Fairbanks or Anchorage areas. As a result of this finding, the case was constructed in the following manner:

- The Investment Module was forced to construct either a single 150 MW coal-fired plant in Fairbanks to begin operation in 2015, a single 150 MW coal-fired unit in Anchorage to begin operation in 2015, or both.
- If only one of the plants was selected to begin operation in 2015, the module could select the unit in the other location to begin operation at a later date.

³⁷ Note that if the last 12 MW of Emma Creek output displaced output of a facility other than ML&P 7/6, the savings would be even greater; conversely, after ML&P 7/6 is retired in 2024, the displaced unit is likely to be a new 130 MW CC, and the annual savings would be lower.

³⁸ It was outside the scope of this study to verify either of these assumptions. Given the results of the analysis described below, R. W. Beck recommends that the Railbelt utilities begin the process of verifying the assumptions as soon as possible.

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- The module was not allowed to consider units of other sizes, different on-line dates for the first unit, or multiple coal-fired units in the same transmission area (e.g., two 150 MW coal-fired units in Anchorage).

The results of this case should therefore be interpreted as an indication of the savings resulting from development of coal-fired plants in either or both the Fairbanks or Anchorage areas, not the final word on this issue. The results of the analysis are as follows:

- The most important result is that the present value of total expected 2008 – 2033 system costs is \$4.62 billion. This estimate includes the fixed O&M costs and amortization of the capital costs of the constructed coal plant(s). This represents a savings of \$420 million compared to the Base Case.
- Moreover, construction of the coal plant(s) significantly reduces the level of risk of future power supply costs. The standard deviation of the present value of 2008 – 2033 total system costs is \$475 million, compared to \$760 million in the Base Case. For the Generic Coal Sensitivity Case, there is a 10 percent chance that the present value of 2008 – 2033 total system costs will exceed \$5.23 billion, compared to \$6.01 billion in the Base Case – a difference of \$780 million. The reason for this is 1) coal prices are less volatile than natural gas and fuel oil prices and 2) constructing the coal plants(s) diversifies the resource portfolio.
- In nearly all circumstances, the optimal strategy is to construct coal-fired units in both Fairbanks and Anchorage to begin operation in 2015. In a small number of circumstances involving low load growth in both areas, the optimal strategy is to wait for up to five years to build the Fairbanks unit. In only a small number of circumstances (i.e., low loads in all three areas, combined with low natural gas prices) does the second (i.e., Fairbanks) not eventually get constructed.
- Construction of the coal plant(s) modifies short-term investment strategy in an interesting way. As discussed above, in the Base Case, if the Fairbanks load is high (i.e., in the highest 20 percent of possible values) in 2005 (or 2006), a 60 MW CC should be built there in 2010 (or 2011). In the Generic Coal Sensitivity Case, under these circumstances, an 85 MW CT (in addition to the one that begins operation in 2008) would be built instead of the 60 MW CC.

The possible capacity additions in 2012 (assuming no additions were already made in 2010 or 2011) are far less complicated than in the Base Case (as shown in Table 4-3). In particular:

- A 130 MW CC should be built in Anchorage only if the 2007 Anchorage load is in the highest 20 percent of possible values.
- An 85 MW CT should be built in Fairbanks only if the 2007 Fairbanks load is in the highest 40 percent of possible values.

In contrast, Table 4-3, the analogous table for the Base Case, shows a more limited set of circumstances in which no capacity would be added in 2012; and the possibility of either a 60 MW CC or a 130 MW CC being built in Fairbanks.

The interpretation of these results is as follows. Given the high likelihood that coal plants will begin operation in both areas in 2015, it is not cost-effective to invest in any more capacity than is absolutely necessary to satisfy reserve margins prior to then. Moreover, it is not cost-effective to invest in energy-efficient CC capacity in Fairbanks prior to 2015, instead of CT capacity, because this capacity will not run very much after 2015 anyway.

- Regarding the long-term investment strategy, tables similar to Tables 4-4 through 4-6 are provided in Appendix C.6. Construction of the coal plant(s) affects the long-term investment strategy in predictable ways. In particular, if expected loads and prices happen to occur in every year, capacity additions are nearly the same as in the Base Case (as shown in Table 4-4):
 - The Anchorage coal plant built in 2015 replaces the 130 MW CC that would have been built there in the same year. All other capacity additions in Anchorage are the same as in the Base Case.
 - In Fairbanks, the coal plant built in 2015 replaces the 60 MW CCs that would have been built there in 2015 and 2029.
 - The most interesting difference between the long-term investment strategies in the Generic Coal Sensitivity Case and the Base Case is that at the same time the coal plant is built in Fairbanks, an 85 MW CT is also built there. This CT is not required to satisfy the 22 percent reserve margin. Its apparent purpose is to provide spinning reserves for the coal unit. This finding requires further analysis, and suggests that the results of the additional screening analysis, namely, that a 150 MW coal unit was more cost-effective in Fairbanks than a 100 MW unit, may need to be revisited.

Natural Gas to Fairbanks Sensitivity Case

The purpose of the Natural Gas to Fairbanks Sensitivity Case was to investigate how the optimal investment strategy would change if natural gas was made available to power plants in the Fairbanks area, beginning in 2015, at the same prices as natural gas is sold to power plants in the Anchorage and Kenai areas³⁹. These prices are provided in Section 3. This sensitivity case was constructed so that all units built in Fairbanks after 2014 would burn only gas, and that units built prior to then (as well as existing units) that burn fuel oil would be converted to natural gas in 2015⁴⁰. The results of the sensitivity case are as follows:

³⁹ The likelihood of natural gas becoming available in Fairbanks, by 2015 or any other particular date, is highly uncertain. Instead of attempting to estimate this probability, and incorporate the resulting estimate directly into the Base Case, R. W. Beck and the participating utilities determined that it would be more appropriate to construct a separate sensitivity case in which gas was assumed to become available in Fairbanks in 2015.

⁴⁰ The pre-2015 units were not allowed dual-fuel capability, choosing between natural gas and fuel oil, after 2014. They could only burn natural gas. The cost to convert the pre-2015 units to natural gas was not considered in the analysis. This cost varies considerably according to unit type, the fuel oil that had been used, and the condition of the unit. Estimation of this cost was therefore outside the scope of this study

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- An 85 MW CT is still selected to begin operation in Fairbanks in 2008. Two alternatives to this decision, building a 130 MW CC to begin operation in 2008 and converting the 85 MW CT to a 130 MW CC in 2015 were considered, but found to be more costly than the 85 MW CT.
- If the 2005 Fairbanks load is high (i.e., in the highest 20 percent of possible values), a new CC should be built in Fairbanks in 2010. In the Base Case, this unit is always a 60 MW CC. In the Natural Gas to Fairbanks Sensitivity Case, if the 2005 natural gas price is in the highest 60 percent of possible values, this unit should be a 130 MW CC, and if the 2005 natural gas price is in the lowest 40 percent of possible values the unit should still be a 60 MW CC.
- If the 2006 Fairbanks load is high, and a unit was not already selected to begin operation in 2010, a 130 MW CC should be built in Fairbanks in 2011. In the Base Case, this unit was a 60 MW CC.
- The results for 2012 are nearly identical to those for the Base Case (as presented in Table 4-3). The primary difference is that any unit built in Fairbanks in 2012 is a 130 MW CC, while in the Base Case, under some circumstances a 60 MW CC would be built in Fairbanks.

These short-term results have one common aspect: in this sensitivity case, more of the Fairbanks load is met with energy actually produced in Fairbanks than in the Base Case. The reason for this is that, at least during the 2015 – 2020 period, the natural gas that can be used in this case to generate energy is less expensive than was the fuel oil that was used in the Base Case to generate this energy. As a result, the optimal investment strategy is to build more CC capacity in Fairbanks than in the Base Case.

- The long-term investment strategy is nearly identical to the Base Case strategy as well. If expected loads and natural gas prices occur in every year, a 130 MW CC is selected to begin operation in Fairbanks in 2015. No additional capacity is built in Fairbanks after 2015. In the Base Case, as presented in Table 4-4, a 60 MW CC was built in Fairbanks in 2015, and another 60 MW CC in 2029. In both cases, 130 MW CCs are built in Anchorage in 2015, 2020, 2021, and 2024.

If low loads and natural gas prices happen to occur in every year, the capacity additions are identical to those in the Base Case, as presented in Table 4-5. Finally, if high loads and natural gas prices occur in every year, the capacity additions are nearly the same as in the Base Case, as presented in Table 4-6. The primary difference is that in this case, 130 MW CCs are built in Fairbanks in 2010 and 2024; in the Base Case, 60 MW CCs were built in Fairbanks in 2010 and 2014, and a 130 MW CC was built there in 2023.

- The most interesting result is the present value of total expected 2008 – 2033 system costs. For this case, the estimate is \$5.15 billion, compared to an estimate of \$5.04 billion in the Base Case, an increase of \$110 million (in real 2008 dollars). If expected values of fuel prices (both natural gas and fuel oil) happened to occur in every year (i.e., the prices displayed in Table 3-5), the total system costs would be lower in this case than in the Base Case, because the expected

natural gas prices are lower than the fuel oil prices throughout the 2015 – 2033 period (except for one year, and the difference is less than 2 percent). Moreover, if low values of these prices occurred in every year (i.e., the lowest 40 percent of possible values), the total system costs in this case would be lower than in the Base Case. However, because natural gas prices are more volatile than fuel oil prices, if higher than expected fuel prices occur (i.e., in the higher 40 percent of possible values), the natural gas price would exceed the prices of the fuel oil used for power generation in the Fairbanks area, and so the total system costs would be higher than in the Base Case.

This result suggests that making natural gas available for power generation in Fairbanks will only provide value if the prices that are charged for the fuel are in the lower 60 percent of the possible values considered in this study. Otherwise, the Railbelt as a whole, and the Fairbanks area specifically, would be better off (at least in terms of power supply costs) continuing to burn fuel oil to generate power. More generally, the result suggests that the region as a whole might benefit (again, at least in terms of power supply costs) from fuel diversification in the event that actual natural gas prices are in the higher 40 percent of the possible values considered in this study.