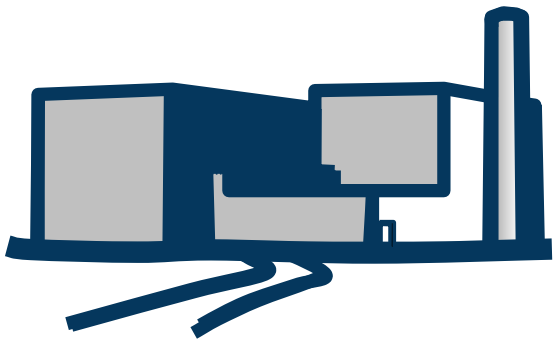
Chugach Electric Association, Inc.
Anchorage, Alaska

2006 Generation Plan

CHUGACH
POWERING ALASKA'S FUTURE

May 2007



CHUGACH ELECTRIC ASSOCIATION
2006 GENERATION PLAN

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EXECUTIVE SUMMARY

In June 2004, Chugach Electric Association, Inc. ("Chugach") hired R.W. Beck to prepare an Integrated Resource Plan (IRP). That plan considered nine scenarios, each a combination of decisions by Homer Electric Association (HEA) and Matanuska Electric Association (MEA) to remain wholesale customers of Chugach. In the scenario in which both HEA and MEA become independent of Chugach, the IRP indicated that it is optimal for Chugach to build an approximately 130-MW natural gas-fired combined cycle combustion turbine (CC) power plant that would begin operation in 2011. The IRP did not make specific recommendations about the actual type and size of the unit. Since Chugach's IRP was completed, Chugach has continued to study different generation options to provide its customers with low-cost, reliable power in the future. This report summarizes the activities completed during the study, and the results of these activities.

Background and Objectives

After considering various generation options, including coal, wind and hydro, the Chugach 2004 IRP recommended that Chugach install a 130 MW gas-fired generator by 2011. With higher natural gas prices, aging generation equipment, and the availability of significantly more efficient new generation, Chugach's decision to install new generation is driven almost entirely by fuel savings and reliability than by capacity shortfall issues.

- The bulk of Chugach's current generation mix is gas-fired power plants. Over the last five years, natural gas prices have increased from about $1.56/MMBtu in 2000 to about $4.80/MMBtu in 2006, which is almost a 200% increase. Additionally, Chugach's existing natural gas supply will be exhausted in the 2010-2011 timeframe. Although Chugach has provisions for future gas supply in existing contracts, the future price of that natural gas is uncertain. Chugach is currently in the process of negotiating new contracts with the gas producers.
- All of Chugach's thermal generation units are 25-40 years old. Chugach is faced with making major investment decisions in order to extend unit lives. Specifically, Chugach's most efficient generator requires approximately $50 million in repairs and significant outage time in order to perform those repairs.
- New generation is significantly more efficient than any of Chugach's existing thermal generation, which results in significant fuel savings. The fuel savings are enough to cover the capital costs of adding the new generation.
- Although load is not a primary driver in Chugach's decision to install new generation, with expected load growth and no generating resource additions or retirements by 2013, Chugach's planning reserve margin may drop below the 30 percent threshold it is obligated to maintain per the Intertie Operating Agreement. However, by 2014 when HEA is no longer on Chugach's system and then again in

2015 when MEA follows, Chugach will have more than enough capacity to meet its planning reserve margin.

As a result, Chugach undertook this 2006 Generation Plan study to re-examine the results of the 2004 IRP, to analyze other generation alternatives that became available after the 2004 IRP and to further document its findings prior to committing to the major investment of adding new generation. This plan differs from Chugach's 2004 IRP, because Chugach focused its analysis on the near-term addition of gas-fired generation and the retirement of Beluga Unit 8. What Chugach learned from analyzing the results of the 2004 IRP is that although Chugach has many generating units that are over 25-40 years old, the only generation retirement that has a significant impact on Chugach's future generation costs is the retirement of Beluga Unit 8. The overall goals of this plan remained the same as the IRP 1) ensure least cost electric supply service to Chugach's retail customers, and 2) maintain current levels of power supply reliability.

Approach

To complete Chugach's 2006 Generation Plan, Chugach performed the following activities:

- Reviewed and updated Chugach's load and fuel price forecasts and characteristics of existing generating units.
- Hired Black and Veatch to provide detailed characteristics of potential new generating units and engineering, procurement and construction (EPC) and owners costs for the potential new generation.
- Developed nine alternative resource plans to compare. The alternative plans considered in the study are listed in Table ES-1.
- Reviewed and updated Chugach's maintenance plans for its existing generation.
- Used Chugach's economic dispatch model (Strategist®)[1] to dispatch the generation under all of the different resources plans.
- Used a Microsoft Excel-based model to combine the generation dispatch data under all of the different resource plans with the annual power supply costs for each of the identified resource plans (including capital costs of the new generation and maintenance costs of existing generation) to calculate the 30-year net present value (NPV) of costs.
- Developed alternative forecasts of Chugach loads and fuel prices, and combined various load and fuel price forecasts into scenarios for consideration in sensitivity the risk assessment cases. In particular, in addition to the Base Case, Chugach analyzed High Gas Price scenarios, Low Gas Price scenarios, High Load

[1] Chugach employs an integrated resource planning model, Strategist®, developed and supported by New Energy Associates, a Siemens Company, to produce projected generation. Strategist® combines load forecasts, generation options and characteristics and forecasted fuel prices to provide projected generation by unit based on economic dispatch.

scenarios, Low Load scenarios, High Capital Costs for New Generation and Low Capital Costs for New Generation and a 50-year life on coal-fired Generation.

- Used the top three plans to further analyze the impact of the Beluga Unit 8 retirement. In particular, examined whether or not rebuilding Beluga 8 instead of retiring it is the least cost option.
- Ran an additional scenario after the initial generation analysis was complete which included both the retail load and wholesale load of MEA and HEA even after their contracts expire and then analyzed the impact of wholesale load on the least cost plan.

Table ES-1
Alternative Plan Definitions

Plan Name		Additions	Retirements
Plan 1	**Status Quo - No New Generation**	No new additions Purchase capacity from ML&P	Bernice Lake 2, 3, 4 by 2015
Plan 2	**Flexibility Plan 3x1 LM6000 180 MW**	LM6000 SC by 2009 LM6000 SC by 2010 LM6000 3x1 CC by 2012	IGT 3 by 2010 IGT 2 by 2011 IGT 1 by 2012 Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 3	**Current FMP Plan 130 MW**	106FA CC 1x1 by 2011	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 4	**5-yr Deferral (Coal) 180 MW**	50 MW LM6000 by 2009 130 MW (net 118) Coal by 2015	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 5	**10-yr Deferral (Coal) 230MW**	100 MW LMS100 by 2009 130 MW (net 118) Coal by 2020	Bernice Lake 2, 3, 4 by 2015 Beluga 8 by 2020
Plan 6	**Chugach Owns Half of 260 MW- ~130MW**	206FA CC 2x1 by 2011 - Chugach owns half the output	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 7	**Build 3 LM6000 (SC) 150 MW**	LM6000 SC by 2009 LM6000 SC by 2010 LM6000 SC by 2012	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 8	**Chugach Owns Entire 260 MW**	206FA CC 2x1 by 2011	Beluga 8 by 2011 Bernice Lake 2, 3, 4 by 2015
Plan 9	**Base-Load Coal Plant 130 MW (net 118)**	130 MW (net 118) Coal by 2015	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015

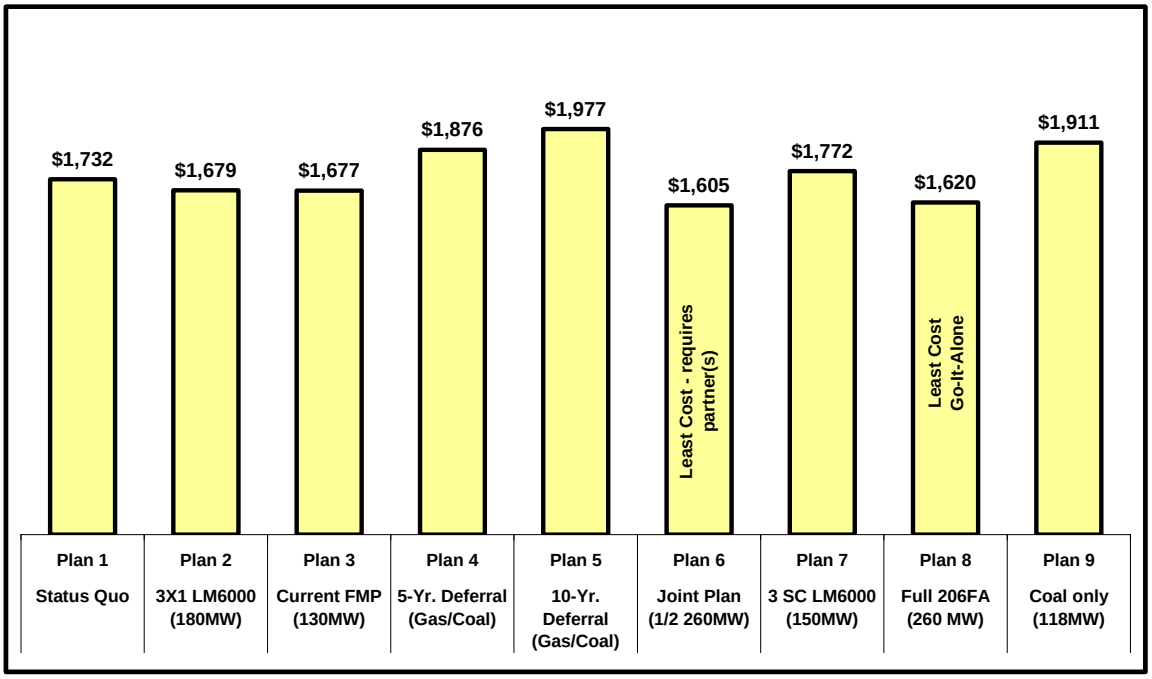
All additions and retirements are at the beginning of the mentioned year

Results

The Base Case results are summarized in Figure ES-1.

- The resource plan with the lowest net present value (NPV) of 2009 – 2040 power supply costs is Plan 6, which involves joint (e.g., 50 percent) development of a 260 MW Combined Cycle gas-fired generator with another utility to begin operation in 2011 and retirement of the Beluga Unit 8 and Bernice Lake 2, 3, and 4 units in 2015.
- In the event that Chugach is not able to find partners to join in the development of a 260 MW unit, the least cost power supply plan is Plan 8 where Chugach would build the entire 260MW unit by itself and retire Beluga Unit 8 in 2011 instead of 2015.
- If Chugach is not willing to take on the large capital investment of a 260 MW unit, Chugach should pursue Plans 2 or 3 and install between 130-180 MWs of combined-cycle gas-fired generation by 2011 and retire Beluga 8 and Bernice Lake 2, 3, and 4 units by 2015.
- Plan 1, the Status Quo plan in which Chugach does not build any new generation but maintains it's existing fleet, is ranked fifth out of the nine plans. The other four plans all have lower power supply costs than Plan 1 (Status Quo) because the lower overall fuel costs more than offset the higher capital cost increases.

Figure ES-1
NPVs of Power Supply Costs for Alternative Plans
For Base Case Scenarios (Million $)



Similar results occurred in the sensitivity scenarios that Chugach used to test the risks associated with building new generation:

- If the capital costs for the new generation are 20% higher or 10% lower, the least cost plan continues to be Plan 6 which involves joint (e.g., 50 percent) development of a 260 MW Combined Cycle gas-fired generator with another utility to begin operation in 2011 and retirement of the Beluga 8 unit in 2014 and Bernice Lake 2, 3, and 4 units in 2015.
- If Chugach experiences higher gas priced than used in its base cases, it is more economic for Chugach to own the entire 260 MW unit by itself, if Chugach is willing to take on the large capital investment of a 260 MW unit.
- In the higher natural gas price scenarios, the results show that if Chugach is unable to find partners in the 260 MW unit (Plan 6) and Chugach is unwilling to build the 260 MW unit alone (Plan 8), Chugach would be better off building approximately 180 MW unit as opposed to the 130 MW unit as indicated in the base cases.
- The only time that Plan 1, the Status Quo Plan where Chugach does not build any new generation, is the least cost plan occurs in the lowest natural gas price sensitivity scenario when natural gas prices are forecasted to be $3.00/MMBTU. In that case the results show that the Status Quo case is approximately equal to Plan 6 where Chugach and another utility build a 260 MW unit and Chugach only owns half the output, i.e. 130 MW.
- Furthermore, sensitivities about the Beluga Unit 8 retirement show that it would be the least cost option in the top three plans to retire Beluga 8 by 2015 than to repair it.

Based on these results, Chugach should continue to seek one or more partners for a new 260 MW gas-fired, combined-cycle generator, so that Chugach has access to at least 50 percent of the plant output beginning in 2011. In the event that such partners cannot be found, Chugach should develop the 260 MW unit on its own, so that Chugach has access to 100 percent of the output of the plant beginning in 2011. If Chugach is unwilling to take the large such a capital-intensive project like the full 260 MW unit, Chugach should pursue development of a 130-180MW gas-fired new generation to begin operation in 2011.

Section 1
INTRODUCTION

The Chugach Electric Association ("Chugach") 2004 Integrated Resource Plan (IRP) prepared by R.W. Beck recommended that Chugach install a 130 MW gas-fired generator by 2011. Before undertaking such a large capital project, Chugach studied several different generation alternatives to determine the least cost option for its customers. This report summarizes the activities completed during the study, and the results of these activities.

Background

R. W. Beck prepared Chugach's 2004 Integrated Resource Plan (IRP). That plan considered nine primary scenarios, each a combination of decisions by Homer Electric Association (HEA) and Matanuska Electric Association (MEA) to 1) remain a full requirements customer of Chugach, 2) become a partial requirements customer of Chugach, or 3) become independent of Chugach when their current full requirements contracts with Chugach expire at the end of 2013 (HEA) and 2014 (MEA). In the scenario in which both HEA and MEA become independent, the IRP indicates it is optimal for Chugach to build a new 130-MW natural gas-fired combined cycle combustion turbine (CC) power plant that would begin operation in 2011. Overall, the addition of new more efficient gas-fired generation is cost effective because the significant fuel savings more than offset the capital costs.

After completion of Chugach's IRP, Chugach continued to analyze different generation additions and retirements focusing on the scenario in which both HEA and MEA become independent of Chugach when their current contracts with Chugach expire. Further, Chugach concentrated on the near term addition of new generation and did not address later additions or retirements.

Objectives

The objectives of this study are as follows:

- Prepare a Generation Plan that shows that the least cost generation alternatives for Chugach based on expected loads and fuel prices which results in lower power supply costs during the a 30-year period compared to other resource plans that Chugach could adopt.
- Conduct a risk assessment of the Generation Plan, to compare the 30-year power supply costs for the resource plan identified as optimal to those for other potential plans under alternative assumptions about Chugach loads and fuel prices.
- Show potential economies of scale if MEA, HEA and Chugach work together.

Report Overview

The remainder of this report is organized as follows:

- The approach that was utilized in the study, including the methodology, data, and assumptions, are summarized in Section 2.
- The results of the study are summarized in Section 3.

Section 2
APPROACH

To accomplish the objectives for the study, Chugach performed the following activities:

- Reviewed and updated the load and fuel price forecasts, characteristics of existing generating units, and characteristics of potential new generating units.
- Developed alternative resource plans to compare to the one identified as optimal in the 2004 IRP.
- Developed alternative forecasts of Chugach loads and fuel prices, and combined various load and fuel price forecasts into scenarios for consideration in the risk assessment. Also, considered plans that included the load for HEA and MEA after existing wholesale power contracts expire.
- Used Chugach's economic dispatch model (Strategist®)[2] to dispatch the generation under all of the different resources plans.
- Used a Microsoft Excel-based model to combine the generation dispatch data under all of the different resource plans with the annual power supply costs for each of the identified resource plans (including capital costs of the new generation and maintenance costs of existing generation) to calculate the 30-year net present value (NPV) of costs and levelized $/MWh cost of power.

Data and Assumptions

The key data elements and assumptions utilized in the study are as follows:

- Load forecasts – base, low, and high
- Natural gas price forecasts – base, low, and high
- Coal prices – base
- Characteristics of existing Chugach generation resources
- Maintenance costs of Chugach's existing generation resources
- Characteristics of potential new Chugach generation resources

The following paragraphs describe the data elements and assumptions that were utilized in the study, and how they were developed.

[2] Chugach employs an integrated resource planning model, Strategist®, developed and supported by New Energy Associates, a Siemens Company, to produce projected generation. Strategist® combines load forecasts, generation options and characteristics and forecasted fuel prices to provide projected generation by unit based on economic dispatch.

Load Forecasts

Chugach used its 2007 Load Forecast as the basis for the energy and peak demand. The energy requirements include Chugach retail and its wholesale customers Seward through the entire study period, HEA through 2013 and MEA through 2014. Based on this forecast, Chugach system sales are forecasted to increase at an annual average rate of 1.4% through 2013 and at an annual average of 0.9% after 2013. The forecast growth rates are similar to historical growth rates. The base energy requirements forecast is summarized in Figure 2-1.

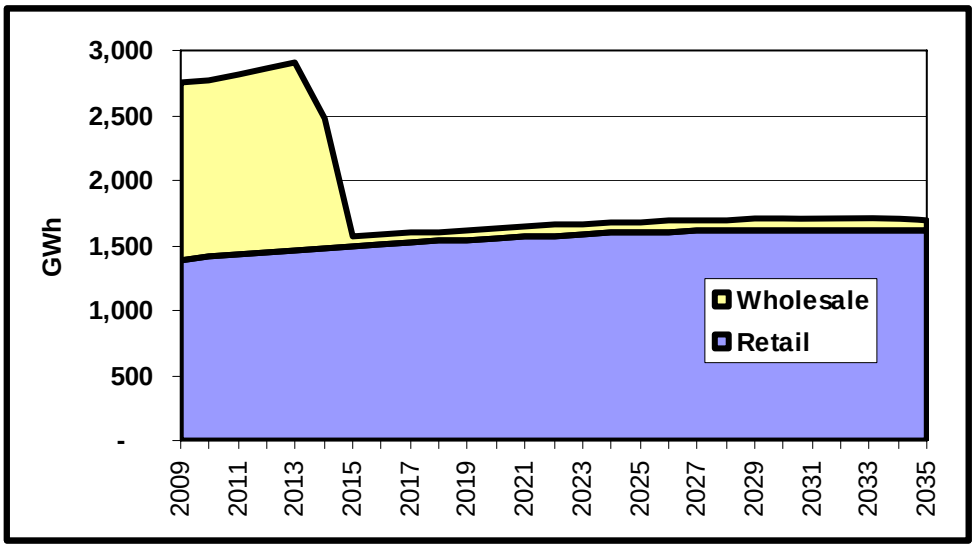


Figure 2-1
Base Case Energy Requirements Forecast, by Source (GWh)

Like the energy requirements, the peak demand represents Chugach retail and the wholesale customers Seward through the entire study period, HEA through 2013 and MEA through 2014. The peak demand represents Chugach's estimate of the highest demand by company that will be coincident with Chugach's system peak in the corresponding year. Chugach compares this peak demand with its available generation resources to determine if Chugach has enough generation to not only meet its peak demand but also to have a 30% reserve margin based on the requirements set forth in the Intertie Operating Agreement. However, for planning purposes, Chugach does not include Seward's peak demand as part of its planning reserves.

The peak demand forecast plus the 30% planning reserve compared with Chugach's existing generation resources are summarized in Figure 2-1. As Figure 2-1 illustrates, Chugach will meet it peak demand plus its 30% reserve margin in all years except an insignificant amount in 2013. Also, after HEA and MEA are no longer on Chugach's system, Chugach will have enough of generation to meet its reserves. However, it is

important to note, that in the past, extreme weather events have increased demand between 20-30 MWs. The long-term forecast does not include these events. Subsequently, if an extreme weather event were to occur, it would represent 20-30 MWs of peak demand above that presented in this long-term forecast.

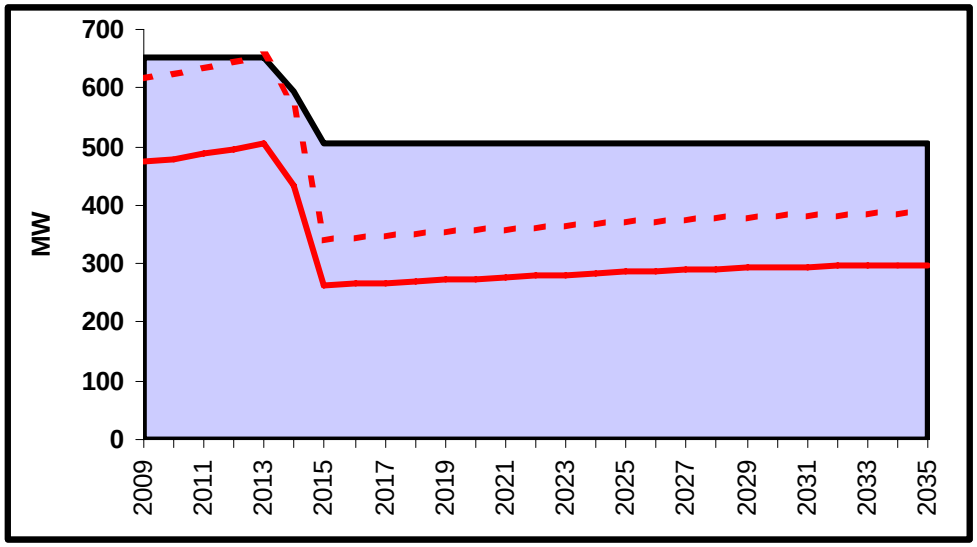


Figure 2-2 - Base Case Peak Demand Forecast and Generation Resources, (MW)

Chugach has also developed low and high load forecasts. Generally, the low load forecast reflects a lower growth rate than the Base Case forecast and the high load forecast reflects higher growth than the Base Case forecast. These forecast were used to run sensitivities on the generation plans. The base, low, and high forecasts are summarized in Figures 2-3 (energy requirements) and 2-4 (peak loads).

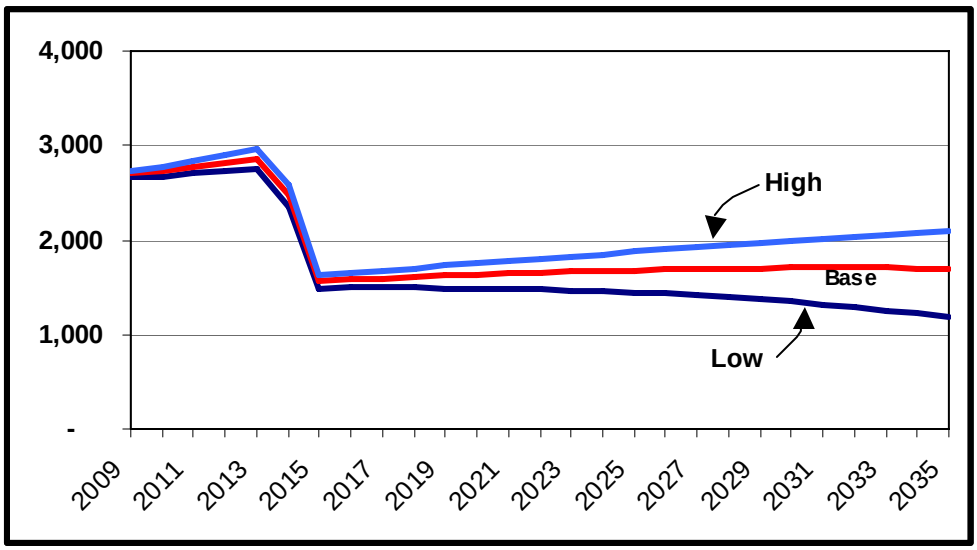


Figure 2-3 Energy Requirements (GWh)

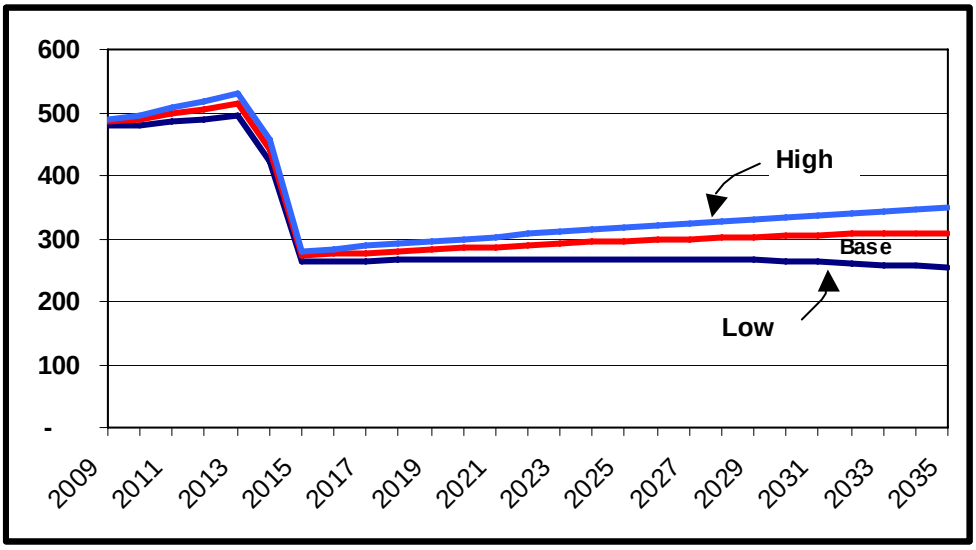


Figure 2-4
Peak Demand Scenarios (MW)

Fuel Price Forecasts

Chugach has developed base case forecasts of the price of natural gas delivered to particular locations, and the price of coal delivered to a specific location. Chugach developed the natural gas price forecast from 2007-2012 using existing natural gas price contract provisions. The estimated Marathon contract fuel price forecast is based on indices of NYMEX futures for Light Sweet Crude oil, CPI Heating Oil and the PPI Natural Gas. It is assumed the Conoco/Phillips price is 88% of the Marathon price and the Chevron price is 1.10% of the Marathon price. The Marathon price is used for the Bernice, Nikiski and IGT sites while the natural gas price used at Beluga represents 40% Marathon price, 20% Chevron and 40% Conoco/Phillips prices. Also, the IGT site assumes an additional transportation charge of $0.35/MCF.

Since Chugach's existing natural gas supply contracts will be exhausted in the 2010-2011 timeframe, and although Chugach has provisions for future gas supply in existing contracts, the price of that natural gas is uncertain. Therefore, after 2012, Chugach used one natural gas price, which is based on escalating the forecasted 2012 natural gas price at the assumed rate of inflation of 2.5% per year. Chugach has compared this forecast with other publicly available forecasts and believes that not only is this forecast reasonable but it is also probably very conservative. Figure 2-5 shows the historical natural gas price and the base case natural gas price forecast in 2006 and nominal dollars. As the figure shows, the base case natural gas price is approximately $4.50 in today's dollars.

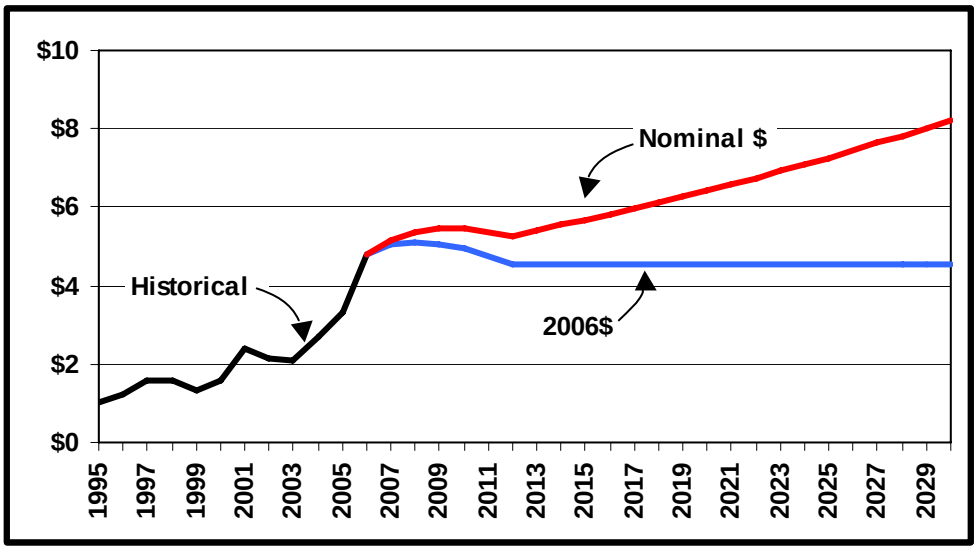


Figure 2-5
Historical and Base Case Natural Gas Price Forecast ($ / MMBtu)

The coal price that Chugach used is based on input from the Chuitna coal field developer and represents the approximate cost of the coal at the remote Chuitna mine site, which is 10 miles from Beluga. Chugach estimates the coal price is $1.25/MMBtu in today's dollars.

Chugach also developed low and high natural gas price forecasts. To stress the base case results Chugach ran scenarios at $3.00 and $4.00/MMBtu for the low natural gas price scenarios and from $5.00 to $9.00/MMBtu for the high natural gas prices scenarios.

Characteristics of Existing Units

The characteristics of existing generating resources are shown in Table 2-1. This data is based on historical information and has been used in previous resource planning studies such as Chugach's 2004 IRP and the Railbelt Energy Study (RES).

Maintenance of Existing Units

Because Chugach's existing fleet of generation resources is old, assumptions about major maintenance of the units are critical inputs. Each plan has different assumptions about the existing unit maintenance requirements and outage time depending on run hours associated with the units. It is also important to note, that Chugach amortizes its major maintenance costs over time. These specific assumptions for each plan are included in the 2006 Generation Plan Appendix that accompanies this report.

In particular, however, assumptions about maintenance-related capital expenditures and the length of outages for Beluga Unit 8 have an even more important effect on the

results. If Chugach does not build new generation, Chugach anticipates that Beluga Unit 8 will need approximately $50 million for major maintenance and life extension between 2008 and 2013 in order for Beluga Unit 8 to continue to be a reliable base-load generating unit. The required maintenance will include new controls in 2008, a new de-aerator in 2011 and both boilers will need to be rebuilt in 2012 and 2013 respectively. These maintenance activities will require significant outage time over and above the historical annual average outage time. Specifically, Chugach believes it will need an additional two weeks to rebuild the de-aerator, and an additional four weeks each year in 2012 and 2013 to rebuild Boiler 1 and 2. Without the addition of new generation, other less efficient thermal units will have to provide generation, further adding to the cost of Beluga Unit 8 rebuild.

Table 2-1
Characteristics of Existing Generating Units

	Average Heat Rate at Maximum	Average Heat Rate at Minimum	Fixed O&M Costs	Variable O&M Costs	Maximum Capacity	Minimum Capacity
	Btu/KWh	Btu/KWh	$/KW	$/MWh	MW	MW
Beluga Unit 1	16,500	35,573	$11.29	$2.13	19.6	3.0
Beluga Unit 2	16,600	38,927	$11.29	$2.13	19.6	3.0
Beluga Unit 3	12,295	74,151	$11.29	$2.13	64.8	3.0
Beluga Unit 5	12,446	77,507	$11.29	$2.13	68.7	3.0
Beluga Unit 6/8	9,620	11,490	$31.24	$2.13	108.5	48.0
Beluga Unit 7/8	9,884	11,490	$31.24	$2.13	108.5	48.0
Beluga Unit 6	11,906	73,500	$11.29	$2.13	82.0	3.0
Beluga Unit 7	11,906	73,500	$11.29	$2.13	82.0	3.0
International 1	16,348	36,592	$12.40	$24.13	14.1	3.0
International 2	17,435	36,671	$12.40	$24.13	14.1	3.0
International 3	15,127	38,902	$12.40	$24.13	18.5	3.0
Bernice Lake 2	14,655	36,625	$10.26	$2.30	19.0	3.0
Bernice Lake 3	13,460	42,798	$10.26	$2.30	26.0	3.0
Bernice Lake 4	14,146	24,123	$10.26	$2.30	22.5	3.0
Nikiski	12,500	12,500	-	$6.01	42.0	6.0

Characteristics of Potential New Units

Chugach's 2006 Generation Plan considers plans comprised of new natural gas-fired generation as well as new coal-fired generation based on the results of the 2004 IRP. These units were chosen based on Chugach's near-term generation needs and the fact that these potential new units are capable of being built in that timeframe. Specific unit types considered in the GP include:

- An LM6000 simple cycle (SC) combustion turbine (CT).
- A Combined Cycle (CC) with three LM6000 CTs combined with one heat recovery steam generator (HRSG) and one steam turbine, (ST).
- A CC with one 6FA CT, one HRSG, and one ST (labeled "106FA").
- A LMS100 CT.
- Half interest in a CC with two 6FA CTs, one HRSG, and one ST (labeled "206FA").
- A 130-MW (net 118) coal plant.

The majority of the characteristics of the potential new units and the capital costs associated with the new units were based on Conceptual Engineering and Economic Assessment reports prepared by Black and Veatch during the 2005-2007 timeframe. Once the 2004 IRP was complete, Chugach hired Black and Veatch to provide more detailed information about potential generating units. Specifically, the Black and Veatch reports include a technology assessment, conceptual design, permitting and environmental assessments, and project cost, schedule and economic analysis. The reports also include characteristics of the new units. These characteristics are summarized in Table 2-2 and include the heat rates, the fixed and variable O&M costs, capacity and capital costs on a $/KW basis. Unlike Chugach's existing units, the maintenance costs associated with the potential new units are included in the variable O&M costs on a $/MWh.

Table 2-2
Characteristics of Potential New Units

	Average Heat Rate at Maximum	Average Heat Rate at Minimum	Fixed O&M Costs	Variable O&M Costs	Maximum Capacity	Minimum Capacity	Capital Costs
	Btu/KWh	Btu/KWh	$/KW	$/MWh	MW	MW	$/kW
LM6000 SCCT	9,349	11,220	$12.60	$6.00	49.4	25.0	$1,485
LM6000 CC	7,230	8,680	$12.64	$4.00	176.0	90.0	$1,575
106FA CC	7,299	8,759	$12.64	$4.00	126.0	62.0	$1,864
LMS100 SCCT	8,260	9,900	$12.60	$6.00	100.0	50.0	$1,688
Coal	10,138	10,138	$200.00	$2.75	118.3	100.0	$4,090
Half 206FA CC	7,117	8,540	$10.00	$4.50	130.0	120.0	$1,146
206FA CC	7,117	8,540	$10.00	$4.50	252.0	124.0	$2,292

Long-term Generation Strategy

In addition to the natural gas- and coal-fired units considered in Table 2-2, Chugach continues to investigate and monitor other types of generation that will meet its long-term generation goal to economically displace its gas-fired generation with renewable generation resources and very low-emission thermal generation. Specifically, Chugach is monitoring or investigating hydro, geothermal, tidal and very low emission

thermal generation as long-term base load resources. Chugach is also monitoring non-base load resources such as wind power.

Chugach's hydro generation investigations include a review of the 1980's Susitna River Hydro (1600 MW) and Chakachamna Hydro (355 MW) projects. The review shows these projects are too large for Chugach alone because of the high capital cost ($4,000 per kW). Nevertheless, scaled down versions of these projects and State or Federal assistance (similar to the 50% State grant for the Bradley Lake project) may make one of these projects economic to the Railbelt ratepayers . Chugach continues to monitor the possible development of these projects.

Another approach to hydropower is development of a group of small-scale hydro projects that in total may make a significant contribution to Chugach's power needs. Chugach supports development of small-scale hydro that can reduce Chugach's cost of power. Potential projects include small (less than 2 MW) run-of-river projects located in the South Fork of Eagle River and Fishhook Creek in the Hatcher Pass area.

Chugach has monitored development of geothermal generation and in particular a site near Mt. Spur. If the project is 50 MW, it would cost about $200 million for the power plant alone. The capital cost of a 40-mile transmission line from the Beluga Power Plant substation could add $40 to $80 million to the cost of the project. If would also require about a 5-year investigation, costing about $15 to $30 million, to have sufficient information to make a major capital commitment. Chugach continues to monitor the possible development of this project.

Cook Inlet tides have attracted numerous parties to test tidal generation technologies. Chugach views tidal power as another small to mid size resource that in combination with other small scale resources could make a significant contribution to Chugach's long-term renewable goals. Tidal power is not commercial at this time. Chugach continues to monitor this renewable generation.

Chugach is also monitoring the development of technologies that use low-cost, abundantly available fossil fuels to produce power and have very low emissions. Chugach is researching coal gasification as the technology that may meet these criteria. If the coal based generation industry can develop a coal gasification process that is of the appropriate size for Chugach load, Chugach could benefit from a 100 year or longer coal supply located 10 miles west of the Beluga Power Plant. Coal gasification can produce synthetic gas that can be efficiently burned in gas fired generation located at Beluga. An appropriately sized coal gasification plant is not commercial at this time. Chugach continues to monitor this technology.

The primary wind power project under consideration by developers is the Fire Island Wind Project. At this time the project needs approximately $54 million for infrastructure and a commitment from a developer. Chugach continues to monitor the development of the project.

Plans Studied

Chugach identified nine plans to study in detail to determine its least cost options in the near-term. The key features of these plans are summarized in Table 2-4.

The first plan Chugach considered is the "Status Quo" plan where Chugach re-builds Beluga 8 and does not add any new generation. Although the 2004 IRP shows that that plan is not optimal, Chugach wanted to have this plan for comparison purposes to be able to calculation the actual savings that Chugach would achieve from building new generation.

Plan 2, which involves staged development of a 3x1 LM6000 CC to begin full operation in 2012 (approximately 180MWs of new generation), is included because, based on Chugach's load duration curve, it appears that 180 MW would be a better fit for Chugach's retail system than the 130 MW size that the IRP showed as the most optimal option. The 2004 IRP only had a 130 MW option or a 260 MW option and nothing in between. The 2006 Generation Plan allows Chugach to analyze an option for a generator that is greater than 130 MW but less than 260.

Plan 3 is the same as the 2004 IRP where Chugach installs 130MWs of combined cycle generation.

Plans 4, 5 and 9 are variation of adding in a 130 MW coal plant. These scenarios are included because a coal mine may be developed near the Beluga Power Plant by 2011. The price of mine-mouth coal and the proximity to Chugach's existing infrastructure made these generation plans attractive. The main difference between the plans is the timing of the addition of the coal plant and variations of adding in some near-term natural gas units.

Plan 6, where Chugach jointly builds a 260MW natural gas fired combined-cycle generator with another utility and only owns half of the output, i.e. 130 MW, shows the magnitude of the economies of scale of building a larger units instead of a smaller unit.

Plan 7 is included to determine if the least cost option for Chugach would be to install simple-cycle gas units instead of more labor intensive combined-cycle gas units.

And finally, Plan 8 was studied to see if the least cost option would be for Chugach alone to install the entire 260MW combined-cycle unit.

Table 2-4
Alternative Plan Definitions

Plan Name		Additions	Retirements
Plan 1	**Status Quo - No New Generation**	No new additions Purchase capacity from ML&P	Bernice Lake 2, 3, 4 by 2015
Plan 2	**Flexibility Plan 3x1 LM6000 180 MW**	LM6000 SC by 2009 LM6000 SC by 2010 LM6000 3x1 CC by 2012	IGT 3 by 2010 IGT 2 by 2011 IGT 1 by 2012 Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 3	**Current FMP Plan 130 MW**	106FA CC 1x1 by 2011	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 4	**5-yr Deferral (Coal) 180 MW**	50 MW LM6000 by 2009 130 MW (net 118) Coal by 2015	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 5	**10-yr Deferral (Coal) 230MW**	100 MW LMS100 by 2009 130 MW (net 118) Coal by 2020	Bernice Lake 2, 3, 4 by 2015 Beluga 8 by 2020
Plan 6	**Chugach Owns Half of 260 MW- ~130MW**	206FA CC 2x1 by 2011 - Chugach owns half the output	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 7	**Build 3 LM6000 (SC) 150 MW**	LM6000 SC by 2009 LM6000 SC by 2010 LM6000 SC by 2012	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015
Plan 8	**Chugach Owns Entire 260 MW**	206FA CC 2x1 by 2011	Beluga 8 by 2011 Bernice Lake 2, 3, 4 by 2015
Plan 9	**Base-Load Coal Plant 130 MW (net 118)**	130 MW (net 118) Coal by 2015	Beluga 8 by 2015 Bernice Lake 2, 3, 4 by 2015

All additions and retirements are at the beginning of the mentioned year

Risk Assessment Scenarios

The uncertainty of gas prices, loads and others factors contributes to generation planning risk. The following risk assessment scenarios quantify the potential impact of the uncertainties:

- High gas price scenarios.

- Low gas price scenarios.
- High load scenarios.
- Low load scenarios.
- High capital costs of new generation.
- Low capital costs of new generation.
- 50-year life on coal generation.
- Beluga 8 retirement scenarios on top three plans.
- MEA and HEA load included.

Chugach System Model Description

In order to perform this analysis, Chugach used its economic dispatch production cost model (Strategist®)[3] to dispatch the generation under all of the different resource plans. Chugach then used a Microsoft Excel-based model to combine the generation dispatch data under all of the different resource plans with the annual power supply costs for each of the identified resource plans (including capital costs of the new generation and maintenance costs of existing generation) to calculate the 30-year net present value (NPV) of costs using a seven percent discount rate.

- The inputs that are required for the production cost model include forecasts of annual energy requirements, annual peak demand, historical hourly loads, forecasts of fuel prices, forecasts of annual generation at each of Chugach's hydroelectric facilities, constraints on usage at each hydroelectric usage, spinning reserve requirements and the operating characteristics of the existing and potential new thermal generating units to be considered in the plan.
- For each year, the model then:
  - Schedules planned maintenance and forced outages of the units (the latter randomly).
  - Commits and dispatches the available thermal and hydro resources based on a typical week to try to minimize the production costs in each year.
  - Produces the fuel cost by unit for each year.

Following execution of this production cost model for each combination of plan and scenario, Chugach combined the fuel cost projection with the O&M costs and the estimates of amortized capital costs (for both new construction and maintenance of existing units) to yield estimates of annual power supply costs for each plan / scenario. Finally, Chugach calculated the net present value (NPV) of 2009 – 2040 power supply

[3] Chugach employs an integrated resource planning model, Strategist®, developed and supported by New Energy Associates, a Siemens Company, to produce projected generation. Strategist® combines load forecasts, generation options and characteristics and forecasted fuel prices to provide projected generation by unit based on economic dispatch.

costs for each plan / scenario, using a seven percent discount rate. All of the model inputs and all of the output for each of the base plans are included in the 2006 Generation Plan Appendix that is attached to this report.

Section 3
RESULTS

This section summarizes the results of the analysis. Results for 1) the Base Case and 2) the Risk Assessment are provided, followed by 3) Conclusions and Recommendations.

Base Case Results – NPV Analysis

The results for the Base Cases are summarized in Table 3 – 1, which displays the NPV of 2009 – 2040 power supply costs for each plan by cost category (capital costs, fuel, capacity purchase, and fixed and variable O&M).

- The table shows that the plan with the lowest NPV of 2009 – 2040 power supply costs and the lowest levelized $/MWh cost is Plan 6, which involves joint (e.g., 50 percent) ownership of a 260MW CC completed in 2011 and retirement of the Beluga 8 and Bernice Lake 2, 3, and 4 units in 2015.
- If Chugach is unable to find another utility to jointly own the 260 MW generator, then the lowest cost option is Plan 8, which involves development (100 percent) of a 260 MW CC completed in 2011, retirement of the Beluga 8 unit in 2011, and retirement of the Bernice Lake 2, 3, and 4 units in 2015.
- Both Plan 2 and Plans 3 have the next lowest cost. Plan 2 involves staged development of a 3x1 LM6000 CC to begin full operation in 2012, staged retirement of the IGT units to be completed by 2012, and retirement of the Beluga 8 and Bernice Lake 2, 3, and 4 units in 2015. Plan 3 is the development of a 130 MW to begin operation in 2011, and retirement of the Beluga 8 and Bernice Lake 2, 3, and 4 units in 2015.
- Plan 1, the Status Quo case where Chugach does not build any new generation is ranked fifth among all the choices mostly because of the higher fuel costs and the higher maintenance costs for aging units and rebuild costs of Beluga Unit 8.
- Plan 7, where Chugach builds three gas-fired simple cycle units instead of combined-cycle units ranks sixth because the simple cycle units are not as efficient as the combined-cycle generation.
- Plans 4, 5 and 9, which involve variations of adding in a 130 MW (118 net) coal plant are the highest cost plans because of the high capital and fixed O&M costs for a coal-fired plant compared to a gas-fired plant. The low fuel costs were not low enough to offset the high capital costs of the coal plant (≈$4,000/KW) and the higher operating costs.

Table 3-1
Comparison of Results – Base Case Generation Plans
2009-2040 Present Value of Costs and $/MWh Levelized Cost – 2006$

	Capital Costs for New Generation	Capital Costs for Existing Generation Maintenance	Total Capital Costs	Fuel Costs	Purchased Capacity/ Power From Another Utility	Variable O&M	Fixed O&M	Total Operating Costs	Total Costs	30-Year $/MWh Levelized Cost
					$ in Thousands					
Plan 1 - Status Quo - No New Generation	-	144,522	**144,522**	1,365,124	228	70,324	152,191	1,587,867	**1,732,389**	**$79**
Plan 2 - Flexibility Plan - add 180MW (3x1 LM6000)	247,941	33,415	**281,356**	1,184,317	-	100,262	113,438	1,398,017	**1,679,373**	**$76**
Plan 3 - Current FMP - 130MW (106FA)	202,706	33,415	**236,122**	1,226,245	-	94,645	119,990	1,440,881	**1,677,003**	**$76**
Plan 4 - 5-Year Deferral - 50MW gas (LM6000 SC) + 130MW Coal	390,993	38,554	**429,547**	983,552	-	91,867	370,807	1,446,226	**1,875,772**	**$87**
Plan 5 - 10-Year Deferral - add 100MW of gas (LMS100) + 130MW Coal	385,060	101,005	**486,064**	1,076,927	-	106,691	307,705	1,491,323	**1,977,388**	**$91**
Plan 6 - Joint Utility - add 130MW ((Chugach Owns 1/2 206FA)	128,586	33,415	**162,001**	1,227,122	-	100,402	115,822	1,443,347	**1,605,348**	**$73**
Plan 7 - Build Simple Cycle - add 150MW (3 LM6000 SC)	157,988	33,415	**191,403**	1,344,113	-	128,839	107,270	1,580,221	**1,771,625**	**$81**
Plan 8 - Entire 260MW - Add 260MW (206FA)	257,172	33,415	**290,587**	1,093,710	-	117,428	117,901	1,329,040	**1,619,627**	**$74**
Plan 9 - Coal Only - add 130MW Coal	335,121	38,554	**373,675**	1,047,181	228	73,784	415,729	1,536,921	**1,910,596**	**$89**

Base Case Results – Cost/Benefit Analysis

Chugach also performed cost/benefit economic analysis on the three least-cost plans. To perform this analysis, Chugach, using expected cash flow projects, calculated the costs associated with the new generation and subtracted the benefits Chugach would receive from the new generation. The costs include the capital costs of the new generation while the benefits include the reduction in maintenance costs, the reduction in purchased capacity costs, the reduction in fuel cost and a reduction in total O&M costs. Chugach then calculated the net present value, payback period and the benefit/cost ratio. The results of this analysis are shown in Table 3-2 below and the details are included in the Appendix 2 accompanying this report.

Table 3-2
Cost/Benefit Analysis Results - Present Value Date 2007

Economic Measure	Plan 6 Half 260 MW	Plan 8 Full 260 MW	Plan 3 130MWs
Net Present Value (30-Yr.)	$129 Million	$111 Million	$51 Million
Payback Period	8 Years	13 Years	14 Years
Benefit/Cost Ratio	1.9	1.4	1.2

Overall, the cost/benefit analysis results are consistent with the previous results. Plan 6 where Chugach owns half 260 MW unit yields the most benefit, shortest payback period and highest benefit/cost ratio. However, if Chugach is unable to find a partner to share in the costs of Plan 6, then Plan 8 and Plan 3 continue to provide more benefit than Plan 1, the Status Quo case, where Chugach does not build any new generation.

Risk Assessment Results

Table 3-2 summarizes the results of the Risk Assessment, which shows the NPV of the total costs (capital costs, fuel, capacity purchase, and fixed and variable O&M) from 2009 – 2040 power supply costs for scenario by plan. The least cost plan is highlighted in each column of the table. Overall, the results show that in the majority of the sensitivities, Plan 6, which involves joint (e.g., 50 percent) ownership of a 260MW CC to begin operation in 2011 and retirement of the Beluga 8 and Bernice Lake 2, 3, and 4 units in 2015 is the least cost option across a range of gas prices and capital costs.

- If capital costs for new generation are 20% higher, the least cost option continues to be Plan 6 (1/2 260MW CC plant). If Chugach is unable to find a partner, Plan 8, 2 or 3 where Chugach owns between 130 and 260 MW by itself would be the lowest cost options.

- If capital costs for new generation are 10% lower, Plans 6 continues to be the least cost option if Chugach can find a partner to share in the costs of a 260 MW plant.
- If load is higher than expected, the least cost option is for Chugach to build the entire 260 MW by itself (Plan 8).
- If load growth is lower than historical, Plan 6 (50% of 260MW unit) continues to be the least cost option.
- Chugach also considered using a 50-year life for a coal plant in its economic analysis of Plans 4, 5 and 9 to see if any of the coal plans ever become economic. However, the results of this sensitivity still show that the least cost option is Plan 6 (1/2 260MW CC plant).
- Plan 1, the Status Quo Plan where Chugach does not build any new generation, is the least cost option in only one sensitivity – the low natural gas price sensitivity where natural gas prices are forecasted to be $3.00/MMBtu. However, the difference between this plan and Plan 6 (half of 260 MW) is quite small. Furthermore, if natural gas prices are around $4.00/MMBtu (still a low natural gas price sensitivity) then Plan 6 and Plan 9, which include new generation, are still lower cost than Plan 1.
- Chugach also performed high natural gas price sensitivities from $5.00/MMBtu to $9.00/MMBtu to test the risk associated with building different size generators and to see if a coal-fired plant ever becomes a least cost option. In all of the high gas price sensitivities, the least cost option is for Chugach to build the entire 260MW natural gas combined-cycle unit by itself.

Table 3-1
Comparison of Results of Sensitivities
2009-2040 30-Year Net Present Value of Costs - $ in Thousands – 2006$

	20% Higher Capital Costs for New Generation	10% Lower Capital Costs for New Generation	Higher Load Growth	Lower Load Growth	50-Year Life for Coal Generation	Lower Natual Gas Prices		Higher Natural Gas Prices				
	Gas Prices $/MMBTU =					Gas Prices $/MMBTU =		Gas Prices $/MMBTU =				
	~$4.50	~$4.50	~$4.50	~$4.50	~$4.50	$3.00	$4.00	$5.00	$6.00	$7.00	$8.00	$9.00
Plan 1 - Status Quo - No New Generation	$1,732	$1,732	$1,918	$1,609	$1,732	**$1,264**	$1,557	$1,850	$2,143	$2,436	$2,729	$3,022
Plan 2 - Flexibility Plan - add 180MW (3x1 LM6000)	$1,729	$1,655	$1,829	$1,584	$1,679	$1,456	$1,592	$1,729	$1,865	$2,001	$2,138	$2,274
Plan 3 - Current FMP - 130MW (106FA)	$1,718	$1,657	$1,840	$1,530	$1,677	$1,401	$1,570	$1,739	$1,908	$2,077	$2,246	$2,415
Plan 4 - 5-Year Deferral - 50MW gas (LM6000 SC) + 130MW Coal	$1,954	$1,837	$2,052	$1,730	$1,853	$1,636	$1,783	$1,929	$2,076	$2,222	$2,368	$2,515
Plan 5 - 10-Year Deferral - add 100MW of gas (LMS100) + 130MW Coal	$2,054	$1,939	$2,108	$1,898	$1,955	$1,743	$1,888	$2,032	$2,177	$2,322	$2,467	$2,612
Plan 6 - Joint Utility - add 130MW ((Chugach Owns 1/2 206FA)	**$1,631**	**$1,592**	$1,768	**$1,460**	**$1,605**	$1,317	**$1,494**	$1,671	$1,848	$2,025	$2,202	$2,378
Plan 7 - Build Simple Cycle - add 150MW (3 LM6000 SC)	$1,803	$1,756	$1,939	$1,618	**$1,772**	$1,509	$1,671	$1,833	$1,995	**$2,156**	**$2,318**	**$2,480**
Plan 8 - Entire 260MW - Add 260MW (206FA)	$1,671	$1,594	**$1,754**	$1,504	$1,620	$1,453	$1,552	**$1,650**	**$1,749**	**$1,847**	**$1,946**	**$2,044**
Plan 9 - Coal Only - add 130MW Coal	$1,978	$1,877	$2,081	$1,767	$1,877	$1,583	$1,785	$1,987	$2,189	$2,391	$2,593	$2,795

*** Yellow highlights indicate least cost by sensitivity**

Chugach also performed sensitivities on whether to retire Beluga Unit 8 or not in the top three plans where Chugach adds new generation. To do this analysis, Chugach assumes that Chugach would spend the approximately $50 million to rebuild Beluga Unit 8 to make it reliable after 2015 in addition to adding in the new generation. The results are listed in Table 3-2 below:

Table 3-2
NPV Results of Beluga Unit 8 Scenarios – Select Cases - 2006$ in Millions

			Difference	
	Base Cases	Based Cases w/Beluga 8	Amount	%
(1)	(2)	(3)	(4)	(5)
Plan 1 (Status Quo*)	$1,732	$1,732	$0	0%
Plan 3 (Add 130 MW)	$1,677	$1,810	$133	8%
Plan 6 (Add 1/2 260 MW)	$1,605	$1,662	$57	4%
Plan 8 (Add 260 MW)	$1,620	$1,785	$165	10%

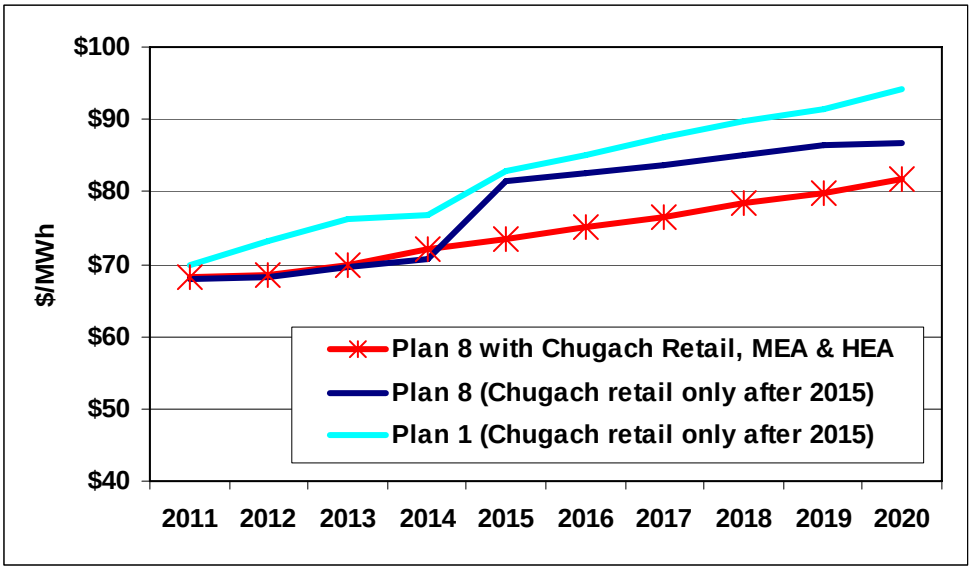
* Plan 1 includes Beluga 8 in both cases

As was shown earlier in Table 3-1 and reiterated in Column 2 of Table 3-2, the base case result for Plan 1, the Status Quo Case, where Chugach rebuilds Beluga Unit 8 and does not install any new generation is the highest cost case compared to the alternatives in which Chugach installs new gas-fired generation (Plans 3, 6 and 8). Then, Column 3 of Table 3-2 shows the NPV of each of these cases if Beluga 8 is repaired and if Chugach installs new generation. Each of these NPV are between $57 and $165 million higher than the base cases. The additional costs are partly due to the rebuild costs of Beluga Unit 8 but also because operationally, when Beluga 6/8 and 7/8 are running, they have to operate at a minimum capacity, which forces the new generation to also run at a less than maximum capacity. The overriding conclusion from this analysis is that the least cost option is for Chugach to install new generation and not rebuild Beluga Unit 8.

The final sensitivity that Chugach performed was to study Plan 8, where Chugach installs the entire 260 MW gas-fired combined-cycle generator and retires Beluga 8 in 2011 in more detail by including the load forecast for HEA and MEA in the economic dispatch model. These results are not fully comparable to the other plans on an NPV basis because the added load increases the overall costs of generation. However, the results are comparable on a $/MWh basis. The reason Chugach performed this sensitivity was to find out the impact of losing the wholesale customers on a $/MWh basis and to assess the economies-of-scale Chugach, MEA and HEA could potentially have if all utilities continue to work together. Figure 3-1 illustrates the 2011-2020

$/MWh costs for this sensitivity compared to Plans 1 and 8 where Chugach only includes its retail load.

Figure 3-1
Annual $/MWh Cost



What the chart shows is that if Chugach loses the wholesale load in 2014, the generation costs of power on a $/MWh basis goes from about $73/MWh to $81/MWh in 2015 which is about an 11% increase to the Chugach retail member. If the three loads continue to be served by the Chugach system (Plan 8), Chugach retail would not have the 11% increase. The chart also confirms that it is still less on a $/MWh basis for Chugach to install new generation compared to Plan 1, the Status Quo Plan where Chugach does not install any new generation, even after HEA and MEA are no longer on Chugach's system.

Conclusions and Recommendations

Among the nine plans considered in this study, Plan 6, in which Chugach jointly owns 260MW gas-fired combined-cycle generator with another utility and owns half the output, clearly is the preferred plan, as it has the lowest NPV of 2009 – 2040 power supply costs in both the Base Case and the majority of the Risk Assessment scenarios.

If Chugach is not able to find a partner (or partners) to own the other half of the 260MW CC incorporated in the plan, this study clearly shows that Chugach should develop the 260MW unit by itself (Plan 8). However, if Chugach is not willing or unable to take on the full capital cost of a 260 MW unit by itself, Chugach should pursue Plans 2 or 3. These two plans have lower overall costs compared to Plan 1, the Status Quo Plan, where Chugach does not add in any new generation.