DRAFT

SOUTHEAST ALASKA INTEGRATED RESOURCE PLAN

Volume 2 - Technical Report

B&V PROJECT NO. 172744

PREPARED FOR

ALASKA ENERGY AUTHORITY

Alaska Energy Authority

DECEMBER 2011

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Building a world of difference.

HDR Alaska

Acronym List

AATP	Southeast Alaska Transportation Plan
AC	Alternating Current
ACEEE	American Council for an Energy Efficient Economy
ACS	American Community Survey
AEA	Alaska Energy Authority
AEL&P	Alaska Electric Light & Power
AEO 2010	Annual Energy Outlook 2010
AHFC	Alaska Housing Finance Corporation
AN	Audible Noise
ANGDA	Alaska Natural Gas Development Authority
AP&T	Alaska Power & Telephone
APC	Alaska Pulp Company
ARRA	American Recovery and Reinvestment Act
ASD	Alaska Ship & Drydock
AVEC	Alaska Village Electric Cooperative, Inc.
AWG	Advisory Work Group
BC	British Columbia
BESS	Battery Energy Storage System
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CDP	Census-Designated Place
CI	Compression Ignition
CL	Corona Losses
CNPV	Cumulative Net Present Value
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COP	Coefficient of Performance
CORAC	Composite Refiner Acquisition Cost of Crude Oil
CSC	Source Converters
CWIP	Construction-Work-In-Progress
DC	Direct Current
DNR	Department of Natural Resources

DOL&WD	Department of Labor and Workforce Development
DOT	Department of Transportation
DOTPF	Department of Transportation and Public Facilities
DR	Demand Response
DSM/EE	Demand-Side Management/Energy Efficiency
EEI	Edison Electric Institute
EEIRR	Energy Efficiency Interest Rate Reduction Program
EIA	Energy Information Administration's
EIS	Environmental Impact Statement
EMS	Emergency Medical Service
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Electric Power Systems, Inc
FDPPA	Four Dam Pool Power Agency
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
FS	Forest Service
FSA	Farm Services Agency
GE	General Electric Co.
GIS	Geographic Information System
GSHP	Ground-Source Heat Pump
HDD	Heating Degree Day
HDR	Hdr Alaska Inc.
HERP	Home Energy Rebate Program
HEV	Hybrid Electric Vehicles
HS	High-Speed
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IFA	Inter-Island Ferry Authority
IPEC	Inside Passage Electric Cooperative
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
ISER	Institute of Social and Economic Research

JEDC	Juneau Economic Development Council
kcmil	Thousand Circular Mils
KMC-GC	Kennecott Mining Company - Greens Creek Mine
KPU	Ketchikan Public Utilities
kV	Kilovolt
kW	Kilowatt
KWETICO	Kwaan Electric Transmission Intertie Cooperative, Inc.
LUD	Land Use Designation
M&E	Measurement and Evaluation
MIC	Metlakatla Indian Community
mmbf	Million Board Feet
MMBtu	Million British Thermal Units
MP&L	Metlakatla Power & Light
MS	Medium-Speed
MSRP	Manufacturer's Suggested Retail Price
MVA	Megawatt-Ampere
MW	Megawatt
N_2	Nitrogen
NEL	Net Energy For Load
NIMBY	Not In My Back Yard
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
O_3	Ozone
OATT	Open Access Transmission Tariff
OEM	Original Equipment Manufacturers
PCE	Power Cost Equalization
PCS	Power-Conditioning System
PHEV	Plug-In Hybrid Electric Vehicle
PMPL	Petersburg Municipal Power and Light
PNW	Pacific Northwest
PSA	Power Sales Agreement
PWM	Pulse-Width Modulation

R&R	Repair and Replacement
RD	Rural Development
REAP	Renewable Energy Alaska Project
REGF	Renewable Energy Grant Fund
RI	Radio Interference
RICE	Reciprocating Internal Combustion Engine
RIM	Ratepayer Impact Measure
RIRP	Railbelt IRP
rms	Roof Mean Square
ROD	Record of Decision
ROR	Run-of-River
RPS	Renewables Portfolio Standard
RurAL CAP	Rural Alaska Community Action Program, Inc.
SCADA	Supervisory Control and Data Acquisition
SE	Southern Energy
SEAPA	Southeast Alaska Power Agency
STATCOM	Static Synchronous Compensator
STI	Swan-Tyee Intertie
TRC	Total Resource Cost
ULC	Upper Lynn Canal
UMTRI	Transportation Research Institute At The University of Michigan
USDA	US Department of Agriculture
USFS	United States Forest Service
VAC	Volts Alternating Current
VEEP	Village Energy Efficiency Program
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound
VSC	Voltage Source Converters
WEC	Wave Energy Conversion
WECC	Western Electricity Coordinating Council
WEST	Wave Energy/Sequestration Technology
WGA	Governor’s Association
WMLP	Wrangell Municipal Light & Power

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2.0 Project Overview and Approach

This section provides an overview of the Southeast Alaska Integrated Resource Plan (IRP) and Black & Veatch's approach to the completion of this study.

2.1 PROJECT OVERVIEW

In response to a directive from the Alaska Legislature, the AEA was the lead agency for the development of this IRP for the Southeast region, which includes over 30 communities. To complete this study, Black & Veatch grouped these communities into 8 subregions, as shown on Figure 2-1.

A significant portion of the analyses (e.g., load and fuel forecasts) was completed at the community level. These analyses provided the foundation for the development of specific Preferred Resource Lists for each subregion, which were then combined to result in the overall Southeast Alaska IRP.

It should be noted that Hyder is not included in the subregions shown on Figure 2-1 because it is currently served by a Canadian utility and will continue to be so served in the future.

The objective of this project is to minimize future power supply and heating costs, and maintain or improve on current levels of power supply reliability, through the development of an expansion plan for the Southeast region. The major work components for this project, as established by the AEA, included the following:

- **Task Group 1 - Data Collection, Load Forecasts, Technology Review, and Regional Action Plan - (Tasks 1 through 5)**--Accomplish public outreach and data collection, to include in-depth consultation with Southeast public utilities on their load forecasts. Participate in Technical Conference 1. From these initial tasks, develop a "Regional Action Plan" that addresses and identifies Southeast region energy issues and provides criteria for more detailed planning in Task Groups 2 and 3 and reporting in Task Group 4.
- **Task Group 2 - Region-wide Transmission Planning - (Task 6)**--Review existing Southeast Intertie Plan and other previous studies, develop new planning methodologies, and develop a plan for transmission interconnections in Southeast Alaska.
- **Task Group 3 - Integrated Resource Planning - (Tasks 7 through 9)**--Using data collection and analysis work from Task Groups 1 and 2, provide detailed integrated resource planning for interconnected networks and for insular communities where it is impractical to interconnect with an existing network.
- **Task Group 4 - Reporting - (Tasks 10 through 13)**--Assemble work from Task Groups 1 through 3 into a regional plan, present the plan, consider and incorporate review comments, and produce final report.

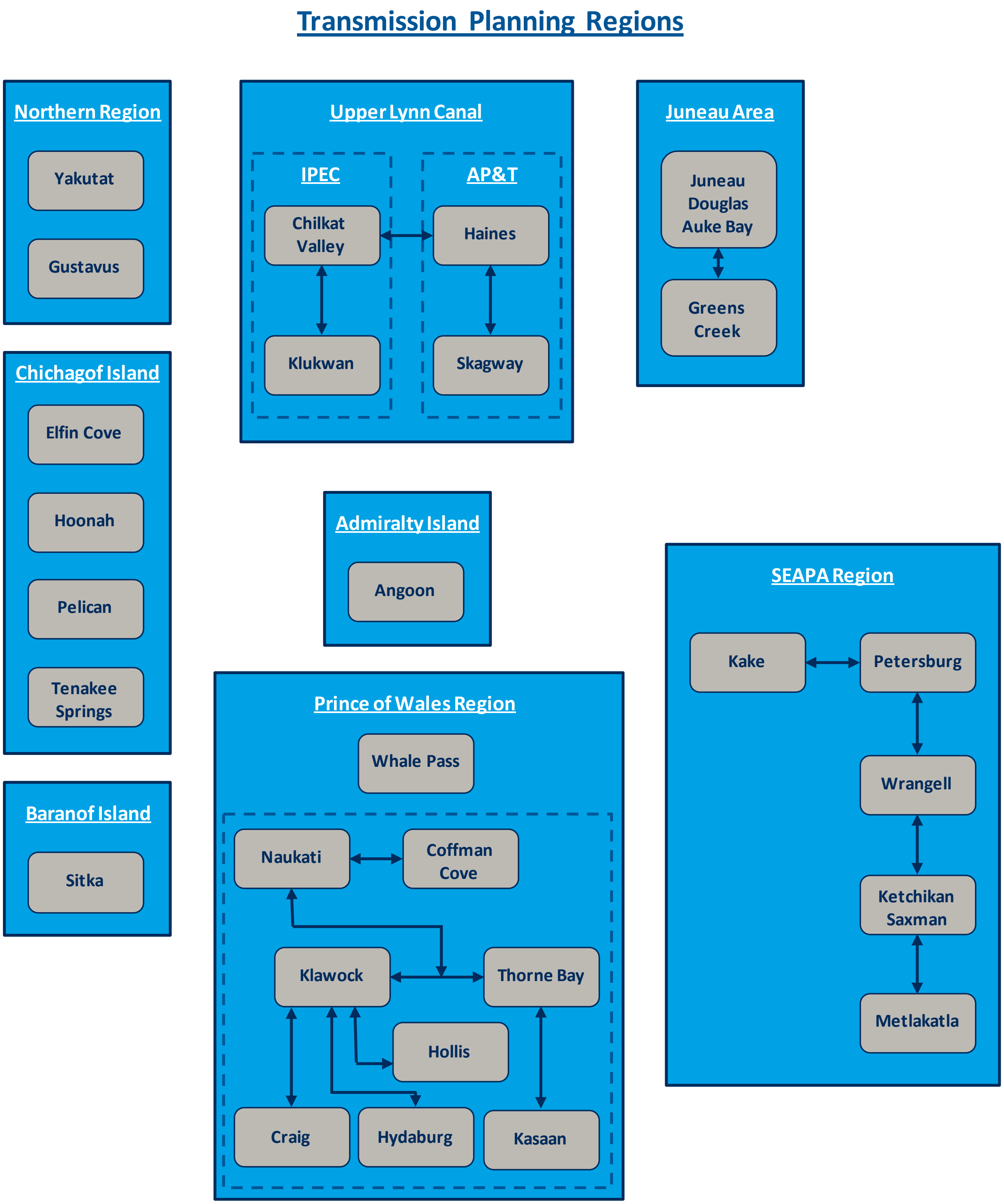

Figure 2-1 Southeast Alaska Subregions Schematic

Black & Veatch had primary responsibility for completing this Southeast Alaska IRP. Additionally, HDR Alaska, Inc., acting as a subcontractor to Black & Veatch, assisted in the analysis of the feasibility, costs, output, and risks associated with the large number of potential hydroelectric projects in Southeast Alaska.

2.2 PROJECT APPROACH

The IRP study process for the Southeast Alaska region consisted of four key stages: data collection, optimal generation expansion along with integrated demand-side management/energy efficiency (DSM/EE) and transmission expansion planning, consideration of heating requirements, and report writing and documentation. Throughout this process, data related to alternative demand-side, supply-side, and transmission resource options were compiled, reviewed, screened, and modeled, where appropriate, using Ventyx's Strategist® optimal generation expansion model. Model inputs and assumptions take into consideration possible sensitivity cases and any considerations unique to each community and their serving utilities, to derive an expansion plan for the Southeast region. To complete this study, the Black & Veatch project team completed the tasks shown on Figure 2-2.

Task Group 1 – Data Collection, Load Forecast, Technology Review and Regional Action Plan

- Task 1 – Understand the Southeast Energy Model: Past, Present, and Future
- Task 2 – Assess Existing and Future Energy Technologies
- Task 3 – Develop an Energy Conservation and Demand Side Management Program for Southeast Alaska
- Task 4 – Determine Financing the Southeast Energy Future
- Task 5 – Determine Technical Conference and Preliminary Action Plan

Task Group 2 – Region-wide Transmission Planning

- Task 6 – Develop a Regional Transmission Plan

Task Group 3 – Integrated Resource Planning

- Task 7 – Develop a Preferred Resource List for Interconnected Electrical Grids
- Task 8 – Develop Integrated Resource Planning for SEAPA
- Task 9 – Develop Planning for Isolated Communities

Task Group 4 – Reporting

- Task 10 – Provide Preliminary Capital Budgets for Region-wide IRP
- Task 11 – Assemble Task Groups 1-3 Components into a Regional Plan
- Task 12 – Present the Plan
- Task 13 – Complete the Plan

Figure 2-2 Project Approach Overview

2.3 MODELING METHODOLOGY

2.3.1 Study Period and Considerations

The evaluation time frame consists of a 50 year study period from 2012 through 2061. Evaluations were conducted in nominal dollars with the annual costs discounted to 2012 dollars for comparison purposes using the present worth discount rate discussed in Section 5.0.

For comparison purposes, existing project capital costs are not carried forward in the modeling effort since they are sunk costs (i.e., costs that have already been incurred) and, therefore, do not affect the future use of resources. Only new generation, transmission, and DSM/EE costs, as well as system fuel, operation and maintenance (O&M) and carbon dioxide (CO_2) emissions allowance costs, are considered when comparing the various expansion plan scenarios.

2.3.2 Strategist® Overview

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

The model evaluates the relative economics between all possible plans within a given set of criteria and minimizes utility costs through optimization. The model checks all feasible combinations in every year of the study period using dynamic programming. At the end of the study period, the model traces back through the matrix of feasible states to find the plans with the best financial or other operational criteria (cumulative present worth cost in this case).

2.3.3 Benchmarking of the SEAPA System

With the uniqueness of the Southeast Alaska Power Agency (SEAPA) system, it was important that Black & Veatch benchmark the model's production costing against an actual year in order to validate the model's abilities to appropriately model the characteristics of the SEAPA subregion. The benchmarking exercise was based on 2010 actual data, as that was the most recent year with complete generation and transmission costs.

The goal of the benchmarking effort was to model SEAPA's system input assumptions and validate the outputs against actual values for 2010. Outputs to be validated were generating unit capacity factors, hydroelectric generation amounts, generation wholesale power costs, and resulting costs. Wheeling rates, fuel costs, O&M costs, and other costs were input on a per-unit basis. Scheduled and forced outages were input directly to reflect actual unit availability.

Overall, the benchmarking process verified that the model adequately reflects operation in the SEAPA system for purposes of this project.

2.3.4 Hydroelectric Methodology

Strategist® treats hydroelectric generation as a load modifier (i.e., load forecasts are adjusted downward to reflect hydroelectric generation, from which other combinations of resources are selected). Hydroelectric generating units are dispatched one at a time. Each unit has a maximum and minimum capacity level at which it operates. Each unit can also be given a monthly total energy that is available. Each utility's overall load is reduced by the minimum hydroelectric generation available in each hour. The difference between the total hydroelectric energy in the month and the minimum hydroelectric energy is the energy available for peak shaving. Capacity available for peak shaving is the difference between the maximum and minimum capacities of the unit. The resulting load shape is then met by unit dispatch of other available resources.

Black & Veatch provided the model with the monthly energy limits for hydroelectric units and allowed the model to perform the load modifications. These limits were calculated from the average monthly historical generation of the units provided by the utilities. Providing monthly energy limits for each hydroelectric unit prevents the model from taking an unrealistic amount of water from the reservoirs, but still allows for variance throughout the year. The amount of baseload energy to be met will be reduced, thereby allowing some units to be shut down, or run minimally. This methodology will also lower the amount of load to be met by less-efficient thermal units and lowers production costs. Peak load reduction will also work to reduce the amount of units that need to be started to handle peak times. Modeling assumptions specific to each hydroelectric unit are presented in Section 4.0.

2.3.5 Committed Resources

As part of its deliberations, the Southeast Alaska IRP Advisory Work Group, or AWG (refer to Section 2.5 for a description of the role and membership of the AWG), passed a resolution directing Black & Veatch to consider the following generation and transmission projects as "Committed Resources" for purposes of this study:

- Blue Lake Expansion Hydro (Sitka) - 2015
- Gartina Falls Hydro (Hoonah) - 2015
- Reynolds Creek Hydro (Prince of Wales) - 2014
- Thayer Creek Hydro (Angoon) - 2016
- Whitman Lake Hydro (Ketchikan) - 2014
- Kake – Petersburg Intertie - 2015
- Ketchikan – Metlakatla Intertie - 2013

From an analytical and modeling perspective, the designation of these projects as Committed Resources means that they are treated as existing units. In other words, the analysis underlying the identification of additional resources to be included in the Preferred Resource Lists for each subregion, as well as for the Southeast region as a whole, assumes that these projects will be completed and in service consistent with their commercial operation dates (COD) shown above. The Committed Resources are also included in the Preferred Resource Lists.

2.4 STAKEHOLDER INPUT PROCESS

One of the AEA's directives to Black & Veatch was to proactively solicit input from a broad cross section of the Southeast region's stakeholders. Elements of the stakeholder involvement process are summarized on Figure 2-3.

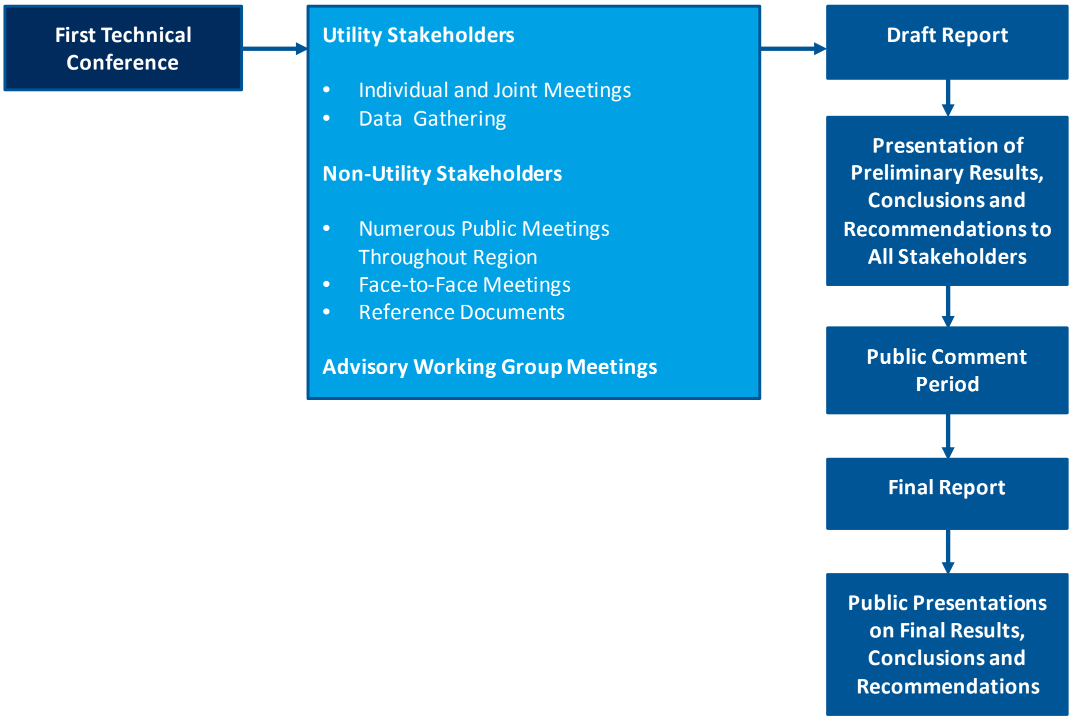

Figure 2-3 Elements of Stakeholder Involvement Process

As the initial element of this public participation process, the AEA held a 2 day Technical Conference near the beginning of the project. The purpose of this conference was to enable a number of industry participants to provide their views regarding the broad array of energy-related issues confronting the Southeast region and to provide comments specific to the completion of this study. Approximately 100 individuals, including Black & Veatch project team members, participated in this conference.

Additionally, Black & Veatch met with a number of utility and non-utility stakeholders, both in individual meetings and in various public meeting forums, to provide them with the opportunity to present their input directly to the Black & Veatch project team members. Black & Veatch and the AEA also held seven meetings with the Advisory Work Group that was assembled for this project.

2.5 ROLE OF ADVISORY WORK GROUP AND MEMBERSHIP

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

- Rick Harris, Sealaska Corporation, Chairman
- Chris Brewton, City of Sitka Electric
- Paul Bryant, Metlakatla Power & Light
- Dave Carlson, Southeast Alaska Power Agency
- Bill Corbus, Alaska Electric Light and Power
- Tom Crafford, Alaska Department of Natural Resources
- Russell Dick, Huna Totem
- Bob Grimm, Alaska Power and Telephone Company
- Steve Henson/Clay Hammer, Wrangell Light & Power
- Henrich Kadake, City of Kake
- Mike Kline/Tim McConnell, Ketchikan Public Utilities
- Dan Lesh/Angel Drobnica, SEACC
- Richard Levitt, Gustavus Electric
- Jeremy Maxand, City and Borough of Wrangell
- Tim McLeod, Alaska Electric Light and Power
- Jodi Mitchell, Inside Passage Electric Cooperative
- Joe Nelson, Petersburg Municipal Power & Light
- Scott Newlun, Yakutat Power
- Merrill Sanford, Assembly Member, Juneau
- Paul Southland, ACE Coalition
- Barbara Stanley/Larry Dunham, USDA Forest Service
- Robert Venables, Southeast Conference

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

- Project objectives, scope, and approach.
- General and project-specific input assumptions.
- Potential projects to be treated as Committed Resources.
- Preliminary results, conclusions, and recommendations.
- Draft report.

3.0 Situational Assessment

This section summarizes the various energy-related drivers and issues facing Southeast Alaska, including those listed in Table 3-1. Each of these issues is discussed in more detail in Section16.0.

Table 3-1 External Drivers and Regional Issues Facing Southeast Alaska

EXTERNAL DRIVERS	REGIONAL ISSUES
• Federal and State energy policy legislation • Fossil fuel prices and availability • Land use regulations	• Uniqueness of Southeast Alaska • Subregional Differences o Cost of electricity o Conversion to electric space heating o Rapidly declining excess hydroelectricity o Declining population in communities o Declining economies in communities • High cost of space heating • Difficulty in developing new hydroelectricity and transmission interconnection projects • Low levels of weatherization and energy efficiency • Availability and cost of capital • Risk management issues

3.1 EXTERNAL DRIVERS

3.1.1 Energy Policy Legislation

ISSUE	DESCRIPTION
Carbon and Other Environmental Restrictions	Federal regulations have been increasingly reducing the allowed emissions of fossil fuel combustion, resulting in increased cost for industry and utilities. While Alaska is not included under some of the latest Environmental Protection Agency (EPA) regulations, many do affect Alaska. Much of Southeast Alaska is heavily dependent on diesel generation, which is directly affected by the compression ignition (CI) reciprocating internal combustion engine (RICE) regulations, adding capital and operating costs for Southeast Alaska utilities (note: even utilities that do not rely on diesel are mandated to install redundant diesel generation, which is then subjected to regulations whether used or not). Carbon regulation continues to provide significant uncertainty. Currently, there is less emphasis regarding cap and trade legislation, but there is greater uncertainty over EPA regulation. This uncertainty extends not only to fossil fuels, but to biomass combustion as well.

ISSUE	DESCRIPTION
State Energy Policy Legislation	Two recently enacted bills have important implications for Southeast Alaska. **SB 220** – Enacted in 2010, this bill included a number of provisions, including: 1) establishing a State energy efficiency revolving loan fund, 2) establishing an emerging energy technology fund, 3) establishing a Southeast energy fund to assist in the funding of energy projects in the Southeast region, 4) establishing a goal of developing a standardized methodology to collect and store energy consumption and expense data, 5) retrofitting 25 percent of public facilities to reduce energy consumptions, and 6) promoting energy conservation, energy efficiency, and alternative energy through training and public education. **HB 306** – Declares a State Energy Policy that includes: 1) instituting a comprehensive and coordinated approach to supporting energy efficiency and conservation through new energy efficiency codes for new and renovated residential, commercial, and public buildings; decreasing public building energy consumption; and instituting a program to educate State residents on the benefits of energy efficiency and conservation; 2) encouraging economic development though promotion of renewable and alternative energy resources; promoting the development of nonrenewable and alternative energy resources; working to identify and assist with the development of the most cost-effective, long-term sources of energy for each community; creating and maintaining a State fiscal regime and permitting and regulatory processes that encourage private sector development of the State's energy resources; and promoting the efficient use of energy for transportation; and 3) supporting energy research, education, and workforce development.
The State's Role in Developing Energy Infrastructure	Historical State infrastructure-related investments have provided significant benefits to the residential and commercial customers in Southeast Alaska. Going forward, one question that needs to be answered is what the proper role of the State should be relative to the further development of the region's generation and transmission infrastructure.

3.1.2 Fossil Fuel Prices and Availability

ISSUE	DESCRIPTION
Fossil Fuel Prices and Availability	The future availability and variability of prices of fossil fuels represent a fundamental challenge to the region in developing a sustainable and affordable energy future. This issue is critically important for those communities that are partially or completely dependent on diesel fuel for heating and the generation of electricity. This issue is addressed in detail in Section 5.0.

3.1.3 Land Use Regulations

ISSUE	DESCRIPTION
Land Use Regulations	Many issues will impact the ability to achieve long-term employment growth objectives in the Southeast Alaska region, but it is apparent that two key issues will heavily influence the overall results of stabilization efforts as well as the success of stabilization efforts in specific communities and industries. The first is the ability to balance the competing interests surrounding land use of federal lands in the Tongass National Forest. The second key issue is the ability to provide affordable and stable electricity to businesses and residents in the Southeast communities. Perhaps the largest consideration related to use of federal lands is the Forest Service 2001 Roadless Area Conservation Rule (the Roadless Rule) that limits road construction on designated areas of public land, called "inventoried roadless areas." The rule was passed in 1991 to help prevent erosion, pollution, and species loss in National Forest areas. It has been the subject of several court actions since 2001, and the ultimate outcome is unknown at this time.

3.2 REGIONAL ISSUES

3.2.1 Uniqueness of Southeast Alaska

ISSUE	DESCRIPTION
Size and Geographic Expanse	Southeast Alaska is characterized as a series of coastal islands and peninsulas, rich in thick timber preserves. This region has steep and rocky terrain in a Pacific maritime climate. Water energy resources abound in high altitude lakes and in streams flowing through steep water passages moving rain water run-off to the ocean. With the relatively small populations of the region, peak electrical loads of all utilities serving the region is projected to be approximately 204 MW in 2011. When compared to the peak loads of other utilities throughout the United States, a combined "Southeast Alaska utility" would still be relatively small. Southeast Alaska has unique geographic diversity which calls for unique solutions. Furthermore, most communities (outside of Juneau, Ketchikan, and Sitka) are disconnected "islands" with sparse populations, due to the lack of transmission and road connections.
Limited Interconnections and Redundancies	The region's electric transmission grid is limited in the number of communities connected and is very different from the integrated, interconnected, and redundant grid that is in place throughout the lower 48 states. This characterization reflects the fact that the Southeast Alaska transmission grid is limited in length and reach, isolated with no external interconnections to other areas, and has limited total transfer capabilities and redundancies.
Inflexible Utility Business Structure	A joint action agency, SEAPA, operates as a non-jurisdictional generation and transmission entity serving southern Southeast Alaska. SEAPA, by contract, is obligated and required to provide its services only to the three communities of Petersburg, Wrangell, and Ketchikan. This system has no open access rules which would allow for interconnections with other utility systems. Under the terms of power sales agreements, the SEAPA system is not economically dispatched. Construction of new State-funded capital projects may require these structures to be changed, so that the benefits from State funds could be equitably distributed.

3.2.2 High Cost of Space Heating

ISSUE	DESCRIPTION
High Cost of Space Heating	Space heating in Southeast Alaska is provided primarily by fuel oil. While only 34 percent of homes in the entire State are heated by fuel oil and 23 percent of homes in the Railbelt used fuel oil, 70 percent of homes in Southeast Alaska used fuel oil in the 2005 through 2009 period. Electric heating was a distant second in the Southeast, at 16 percent, but this was higher than the 10 percent figure for the State as a whole, since the Railbelt region currently has access to natural gas supplies. Only 4 percent of the homes in the Southeast used natural gas or propane for heating, while 50 percent of homes at the State level and 63 percent of Railbelt homes used natural gas or propane for heating. Wood is also used for space heating in the region. Combined, 86 percent of homes in Southeast Alaska use either fuel oil or electricity for heating. The cost of fuel oil is very volatile and depends on many factors. A study by the Institute of Social and Economic Research (University of Alaska, Anchorage), ISER, studied the price of delivered fuel oil to 10 Alaska communities, including Yakutat and Angoon in Southeast Alaska, and found that prices in some areas were more than 100 percent higher than in other areas.

3.2.3 Conversion to Electric Space Heating

ISSUE	DESCRIPTION
Conversion to Electric Space Heating	The region has recently seen a large increase in the number of conversions to electric space heating. These conversions provide cost savings, often very significant savings, to the individual businesses, government facilities, and consumers who make the conversion. However, from a regional perspective, these conversions are adding stress to the system as they lead to previously unplanned growth in electric loads, reducing the amount of additional generation available from existing hydroelectric generation facilities. Additionally, these conversions represent a significant energy policy for the region to address as alternatives (e.g., wood pellet biomass generation) may be a more appropriate regional solution, especially in the near- or mid-term as more hydro is built.

3.2.4 Declining Population in Communities

ISSUE	DESCRIPTION
Declining Population in Communities	While Alaska's population increased by approximately 53,000, or 8.4 percent, from 2001 through 2008, six of the nine census areas and boroughs in Southeast Alaska decreased in population. In total, the region experienced a decrease in resident population from 71,949 to 70,456. This is a loss of 2.1 percent. The downward population trend for Southeast Alaska began in 1998 due primarily to forest industry declines. According to the Alaska Department of Labor and Workforce Development, this downward trend is expected to continue and represents a serious threat to long-term social and economic stability.

3.2.5 Declining Economies in Communities

ISSUE	DESCRIPTION
Declining Economies in Communities	Southeast Alaska is a sparsely populated, geographically dispersed region that includes many small island communities dependent on industries linked to the area's natural resources. Employment is largely connected with the industries of fishing, tourism, timber, and mining. Juneau, as the State capital, also has a large number of government workers and differs from the remainder of Southeast Alaska in terms of population density, transportation access, and dependency on resource-related industry. Consequently, while most communities in the Southeast have been suffering population loss and economic challenges over the past decade, Juneau has remained relatively stable. The total number of workers in 2010 grew by 0.4 percent compared to the average 2009 workers in the region (36,050). This slight growth was encouraging given the 2.2 percent loss in the 2008 to 2009 period and given the sluggish national economy. However, regional jobs were lost in the trade, transportation, manufacturing, information, construction, and leisure and hospitality sectors. The Alaska Department of Labor and Workforce Development projects that the 2011 average employment level in the Southeast region will decrease by 1.1 percent. This projection is based on the expectation that "structural demographic changes and hesitant tourists will continue to erode employment in the trade, transportation, leisure, and accommodation sectors.

3.2.6 Rapidly Declining Excess Hydroelectric Power

ISSUE	DESCRIPTION
Rapidly Declining Excess Hydroelectric Power	In communities where hydroelectric power is available, rapid conversion from heating oil to electricity for space heating has been common in recent years due to the lower cost of hydroelectric electricity for home heating and other uses. While a benefit to users who convert to electricity, this has had the effect of reducing the availability of excess hydroelectric generation and increasing the reliance on diesel generation for communities having limited hydroelectric capacity. As a result, the average cost of electricity generation has gone up in many communities that have hydroelectric power. The most cost-effective way to address the declining excess hydroelectric power depends on the specific circumstances of the municipality. Some municipalities will be able to utilize new hydroelectric facilities cost-effectively so that the reliance on diesel generation decreases. Other communities that may not be candidates for new hydroelectric facilities may benefit from converting to alternative sources for home heating. These alternative sources of heating could include wood pellet systems or propane if a State-wide investment is made in further developing propane systems.

3.2.7 Difficulty in Developing New Hydro and Transmission Interconnection Projects

ISSUE	DESCRIPTION
Difficulty in Developing New Hydroelectric and Transmission Interconnection Projects	Cost-effective power supply alternatives identified through planning efforts must also be achievable if they are to become a reality, which requires obtaining all permits and approvals required to allow the construction and operation of the resource. In any state and region, the hurdles associated with gaining approvals for new transmission facilities, or a new hydroelectric project, are significant. These approvals include local, state, and federal approvals and can require environmental studies that can take years to perform and gain approval. Given the unique geographical characteristics and land classification of much of Southeast Alaska, the difficulty in gaining approval to develop hydroelectric and transmission projects is considerably more difficult and involved than in other locations due to the majority of land being in the Tongass National Forest and due to the uncertainty surrounding the Roadless Rule.

3.2.8 High Cost of Electricity

ISSUE	DESCRIPTION
Relative Costs – Alaska Versus Other States	The cost of electricity in Alaska is significantly higher, on average, than in the rest of the United States. In the power sector, the average price for electricity in the United States was 9.82 cents/kWh in 2009, compared to an average of 15.09 cents/kWh in Alaska. Only five other states had a higher cost of electricity than Alaska in 2009.
Relative Costs – Among Southeast Alaska Communities	Section 4.0 lists available power cost data for the municipalities in the study. The average of these rates was 16.97 cents in 2010, but the range was from a low of 9.2 cents/kWh (where hydroelectric power was available) to 31.51 cents/kWh after the power cost equalization (PCE) adjustment. Prior to the PCE adjustment, the cost of electricity for some municipalities exceeded 60 cents/kWh in 2010.
Economies of Scale	The Southeast Alaska region, due to its smaller size, has not been able to take full advantage of economies of scale and scope. With respect to scale economies, there are several reasons that the region has been limited by scale constraints. First, as previously noted, the combined peak load of the region is small. Second, the region's transmission grid is very limited (i.e., the number of communities connected to a transmission grid is limited), and it lacks redundancies and interconnections with other regions. As a result, the region is severely and adversely impacted by its ability to develop and take advantage of large low-cost generation sources.

3.2.9 Low Levels of Weatherization and Energy Efficiency

ISSUE	DESCRIPTION
Low Levels of Weatherization and Energy Efficiency	Southeast Alaska utilities have limited direct experience with the planning, development and delivery of energy efficiency programs, and the general belief is that there are additional opportunities to reduce energy consumption through weatherization and energy efficiency measures. There has been discussion as to whether such measures and programs should be implemented by the individual utilities or whether a regional approach would be more effective. Given some of the specialized training involved in administering the measures, it seems clear that either approach, or a combined effort, would benefit by utilizing State experts, programs, and resources that are available. The State of Alaska administers multiple weatherization and energy efficiency programs primarily through two agencies. These agencies are the Alaska Housing Finance Corporation (AHFC) and the Alaska Energy Authority (AEA). A third organization, RurAL CAP, also provides some energy efficiency services to small communities. The State has generously funded energy efficiency programs, especially since 2008; however, the widespread benefits of these programs in the southeast have been minimal. The funding for some of the larger programs is being consumed, and the availability of on-going State funding at comparable levels in the long-term is uncertain.

3.2.10 Availability and Cost of Capital

ISSUE	DESCRIPTION
Historical Dependence on State Funding	Southeast Alaska utilities and communities have been dependent on State funding for various portions of the regional generation and transmission infrastructure, as well as for certain local infrastructure investments. Developing power projects or alternatives to electric power in the Southeast region will require significant capital investment. The magnitude of this investment is such that development of key projects will not likely occur unless financial assistance from the State continues. One reason that State involvement will be required is that local utilities and municipalities have limited ability to raise the required capital. The ability for a utility to raise capital is limited by the requirement of lenders that for financing to occur, certain coverage ratios on debt must be maintained by a borrowing utility, and the utility must be able to invest retained earnings or equity funds into the project. A second reason for State funding assistance relates to the inability of local power customers to absorb the rate impact of a new, capital-intensive project. That is, even if the required equity funds were available for investment by the region's utilities, the construction of new hydroelectric power and transmission would result in a large rate increase under traditional financing approaches.

3.2.11 Risk Management Issues

ISSUE	DESCRIPTION
Need to Maintain Flexibility	The region, for numerous reasons, lacks a diversified combination of electric generation resources. Just as investors rely on a portfolio of assets, it is important for utilities and communities to develop a more diversified portfolio of assets to ensure safe, reliable, and cost-effective service to customers. It also demonstrates the importance of maintaining flexibility. Of course, the challenge facing the region is how to accomplish this given its small size.
Aging Infrastructure	The fact that some of the generation and transmission infrastructure in the Southeast Alaska region is aging adds to the challenges facing utility managers. Much of the low-cost hydroelectric generation is dependent on aging single contingency submarine cables. That represents the “half empty” view of the situation. The “half full” view leads one to a more positive perspective that the region has an unprecedented opportunity to diversify its resource mix.
Ability to Spread Regional Risks	The level of uncertainty facing the Southeast Alaska region continues to grow, as do the risks attendant on utility operations. One important approach to risk management is to spread the risk to a greater base of investors and consumers so that the impact of those risks on individuals is reduced. Simply stated, the ability of the region to absorb the risks facing it is greater on a regional basis than it is on an individual utility basis.

4.0 Description of Existing System and Committed Resources

This section provides basic information on each community included in this study. It also provides information on the development of the region's existing transmission system and generation resources. This is followed by a discussion of Committed Resources, which are the transmission and hydro projects designated by the Advisory Work Group as projects where the decision to develop them has already been made. Finally, this section provides additional information on each utility system in the region.

4.1 COMMUNITIES AND LOADS INCLUDED INTEGRATED RESOURCE PLAN

The Southeast region of Alaska is composed of several load centers, few of which connect to each other and allow sharing of resources and participation in economies of scale. Electricity is presently being generated by hydro plants and diesel generating units. With the increasing cost of fuels, the cost of diesel generation in Southeast Alaska is not conducive to economic development. The communities that are included in this study are shown on Figure 4-1 and discussed below.

The electric rates presented in the following sections are taken from the Statistical Report of the Power Cost Equalization (PCE) Program Fiscal Year 2010, July 1, 2009 – June 30, 2010. The rates are shown as Rate 1/Rate 2. Where Rate 1 is the residential rate based on 500 kWh in cents per kWh for Fiscal 2010, and Rate 2 is the rate including the PCE on June 30, 2010. These rates do not fully include the impact of the recent increases in the price of fuel oil. Commercial and other non-residential consumers do not receive PCE. In some cases, these non-residential rates are set at the same rates as pre-PCE residential rates.

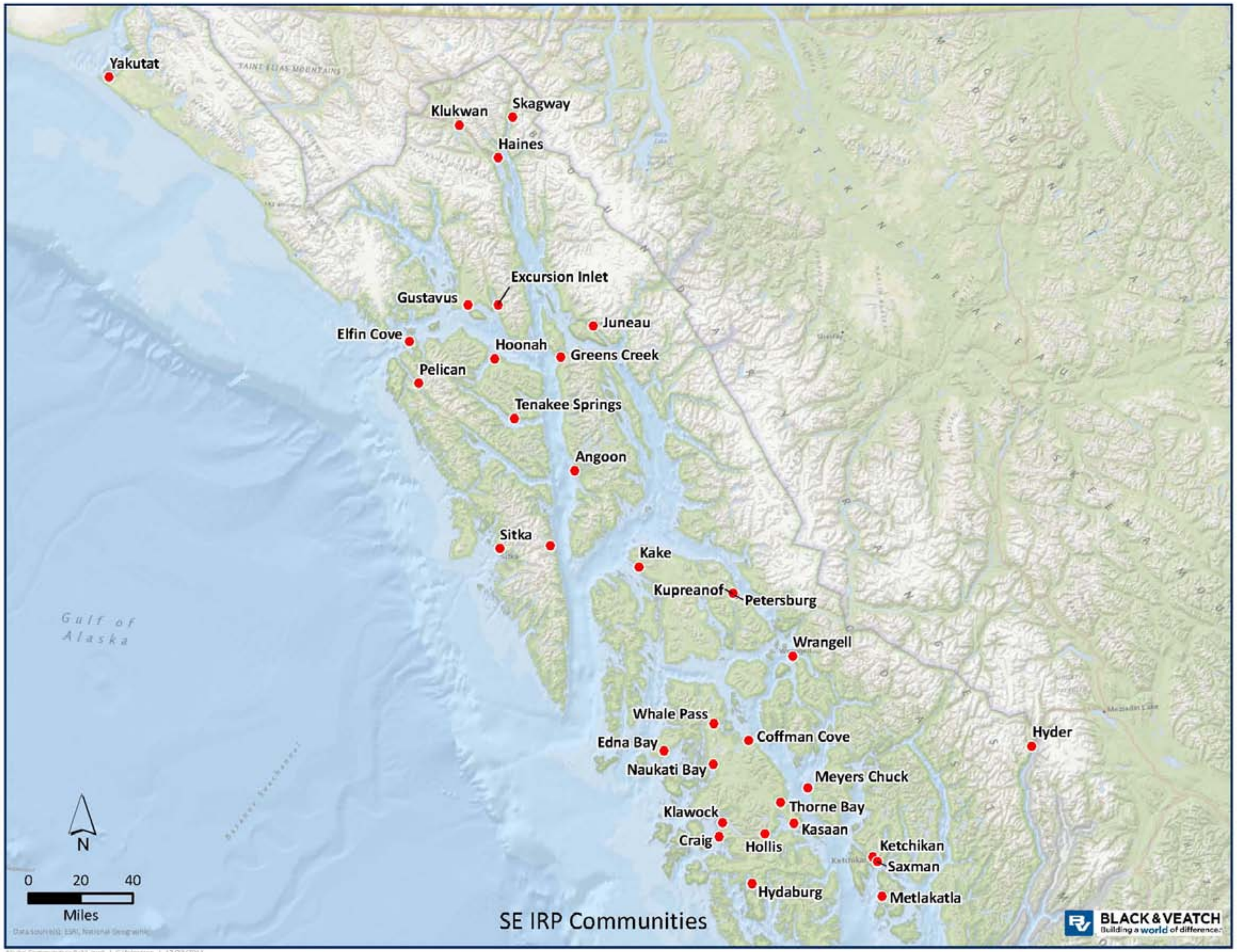

Figure 4-1 Southeast Alaska Communities

4.1.1 Angoon

Angoon is the largest permanent settlement on Admiralty Island and is located on the southwest coast at Kootznoowoo Inlet. Angoon is 55 miles southwest of Juneau and 41 miles northeast of Sitka. The only other community on the island is Cube Cove, to the north. The city has a total area of approximately 38.6 square miles of which 22.5 square miles is land and 16.1 square miles is water. Angoon is a Tlingit village with a commercial fishing and subsistence lifestyle. Commercial fishing is a major source of income for the residents of Angoon. Fluctuating salmon prices significantly affect the income in this area. The Chatham School District is the primary employer in the area. Additionally, logging on Prince of Wales Island provides occasional jobs.

Based on the 2010 census, the population is 459 with 167 occupied households. Approximately 34 percent of the population was reported to be below the age of 18. Angoon School is in the Chatham School District K-12. Access to the city is by float plane or by boat. Scheduled and charter float plane services are available from the state-owned seaplane base located on Kootznoowoo Inlet. There is also a deep draft dock, a small boat harbor with 45 berths, and the state ferry terminal. The Angoon ferry terminal is scheduled for modifications to enable docking of other ferries. The Alaska Department of Transportation (DOT) is in the preliminary phase of planning to build the Angoon Airport.

Electric service is provided by Inside Passage Electric Cooperative from diesel generation. Fiscal year 2010 residential electric rates were 56.08 cents per kWh before effects of the PCE Program, and the effective rate after PCE was 19.78 cents per kWh[1]. Water is provided from the Tillinghast Lake reservoir and treated at the Tillinghast Lake Water Treatment Plant. Sewage is processed at a secondary treatment plant that flows to an ocean outfall. The city collects refuse and hauls it to the landfill located approximately 2 miles from Angoon.

4.1.2 Coffman Cove

Coffman Cove is one of the major log transfer sites on Prince of Wales Island. Logs are tied together and towed to transshipment points for export. The majority of employment for the area is provided through logging support services and the local school. Oyster farming also occurs in Coffman Cove. According to the census of 2010, there are 176 people with 89 occupied households. Howard Valentine School is in the Southeast Island Schools District offering K-12 classes. Medical service is supplied by Seaview Medical Center located in Craig. Coffman Cove is accessible by float/sea plane or small water craft. The Inter-Island Ferry Authority (IFA) provides service to the Island. A state-owned float/seaplane base, boat launch, and dock are available. The state highway connects Coffman Cove to most other communities on the island.

Electric power is provided by Alaska Power & Telephone (AP&T) using diesel engines. Fiscal year 2010 residential electric rates were 49.53 cents per kWh before PCE and 18.57 cents per kWh after PCE. AP&T extended the Prince of Wales Intertie to connect Coffman Cove to the grid in 2011. Coffman Cove uses a surface water source with water treatment system and storage tank to supply the piped water system. Coffman Cove has a piped sewage treatment system. Refuse collection operations are provided by Road-Run-R Sanitation. The city burns refuse and the ash is hauled to Thorne Bay along with bales of non-combustibles.

[1] http://www.akenergyauthority.org/PDF%20files/FY10PCEreport.pdf - Based on monthly usage of 500 kWh

4.1.3 Craig

Craig is a first-class city in the Prince of Wales-Hyder Census Area on the west coast of Prince of Wales Island in the Unorganized Borough in Alaska. As of the census of 2010, there are 1,201 people with 470 occupied households. The economy in Craig is based primarily on fishing, logging support, and saw mill operations. Other key industries include a fish buying station and a cold storage plant located in the city. Craig is accessible by float plane and IFA ferry service via Hollis. A city-owned seaplane base and a US Coast Guard heliport are located in Craig. The IFA ferry terminal is located in Hollis, 30 miles away by state/city highway. Two small boat harbors, at North Cove and South Cove, a small transient float and dock in the downtown area, and a boat launch ramp at North Cove also provide access to the city.

There are five schools within the Craig City School District; one elementary school, grades P-5; one middle school grades 6-8; one high school, grades 9-12; a correspondence school, grades K-12; and one alternative high school.

Electric power is supplied by Alaska Power Company, a subsidiary of AP&T, primarily through hydroelectric power. Fiscal year 2010 residential electric rates were 21.28 cents per kWh before PCE and 14.48 cents per kWh after PCE. The Craig Wood Waste Boiler heats the city pool, pool building, and community schools. Water is supplied by a dam on North Fork Lake and is then treated, stored in a tank, and piped to homes. Sewage is collected by a piped gravity system, and receives primary treatment before discharge into Bucareli Bay. The city collects refuse and takes it to the Klawock transshipment facility for shipment to the lower 48 states.

4.1.4 Edna Bay

Edna Bay is a Census-designated place (CDP) on Kosciusko Island in the Prince of Wales-Hyder Census Area. The population is 42, according to the 2010 census. Edna Bay is a fishing community, originally named by the US Coast & Geodetic Survey in 1904. Edna Bay is one of only two populated towns on Kosciusko Island, the other being Cape Pole, and has both year-round and seasonal residents. Year-round residents are either retired, or work primarily in the fishing and logging industries. Some permanent residents also work seasonally off-island in various industries. Due to the very remote location of Edna Bay and the subsequent difficulty and expense of traveling between Edna Bay and larger Southeast Alaska communities, subsistence hunting, fishing, and gathering comprise a large portion of the livelihood activities for residents. As of 2008, Edna Bay is home to an engineering and software development company, made possible by the broadband-internet service brought to the community by the state of Alaska and AP&T, which also provides telephone service and operates a generator for the phone system and school. Edna Bay School is in the Southeast Island School District and has grades K-12.

Residents in Edna Bay are responsible for providing their own power sources. All residents use individual untreated water sources, such as springs or rain catchment. Transportation and cargo are provided by float plane or boat from Craig, Ketchikan, or Petersburg. Edna Bay is not connected to the state/city highway on the Island. A dock and harbor with breakwater are available for transportation services.

4.1.5 Elfin Cove

According to the 2010 census, Elfin Cove has a population of 20 persons in 13 occupied households. The area is historically a fish-buying and supply center for the commercial fishing fleet. More recently sport fishing and tourism have emerged as key economic components. Most residents participate in commercial fishing, sport fishing, tourism lodging, or charter services, making the economy largely seasonal. Summer lodges and local retail businesses provide seasonal employment. Economic growth is limited by the availability of cost effective energy and transportation to this remote community.

The primary means of transportation is by skiff. There are no roads but a boardwalk runs through the community. Elfin Cove is accessible by seaplane and small boat and has a state-owned seaplane base. A state-operated small boat harbor exists with moorage for 25 vessels. Due to declining enrollment, the school was closed prior to the 1998-99 school year, and currently there are no school-age children. No health care facilities are located in this community.

Electric power is provided by the Elfin Cove Utility Commission using diesel. Fiscal year 2010 residential electric rates were 52.3 cents per kWh before participation in PCE and 19.84 cents per kWh with PCE. A hydroelectric project has been engineered and the community is seeking funding. Homes are served from a community installed spring water system. Wastewater is managed individually by beach outfall or by septic tank with beach outfall. Due to the geography of the area, a landfill does not exist and is not feasible. To address this, community has started talks with a local barge company and the Southeast Conference.

4.1.6 Excursion Inlet

Excursion Inlet is located within the Haines Borough and was originally an Alaska Native village that was used as a prisoner-of-war camp and a strategic base for the Aleutian Campaign during World War II. Excursion Inlet has had a fishing cannery since 1891 and the current plant, constructed in 1918, still functions to this day. One of the largest fish canneries in the world today, it primarily processes pink and chum salmon, as well as salmon roe, salmon caviar, halibut, and sablefish. The plant, acquired in 2003 by Ocean Beauty Seafoods, is located near the mouth of the inlet, about 40 miles west of Juneau. The peak seasons run from late June to mid-September.

As of the census of 2010, there are 12 people residing in the CDP. The CDP has a total area of 56.9 square miles, of which, 56.8 square miles consists of land and 0.2 square miles is water. There are 6 occupied households located in the community.

4.1.7 Greens Creek

Greens Creek is a lead, zinc, silver, and gold mine located in Southeast Alaska on the northern end of Admiralty Island National Monument, approximately 16 miles South of Juneau. It is situated on federal land administered by the US Forest Service (USFS). Greens Creek's permitting activities are coordinated by the DNR. The mine is operated by the Hecla Greens Creek Mining Company and is a significant part of the economy in Southeast Alaska; it is the fifth largest silver producing mine in the world.

The mine is an underground operation, with surface disposal of tailings onto two 29-acre sites. The mine and mill site lie on 18 patented claims with mineral rights to 12 square miles of surrounding land owned by the federal government. The mine produces ores of silver and gold, and concentrates of zinc and lead, from a structurally and mineralogical complex volcanic massive sulfide ore deposit. Geologists discovered mineralized outcrops in 1975 and exploration drilling began in 1978. Full-scale development was initiated in 1987 and production of metal concentrate began in 1989. Production was halted, due to low metal prices, for a few years in the mid-1990s, but has since restarted. Concentrates are trucked nine miles from the mine/mill complex to a port site on Hawk Inlet; where there they are shipped worldwide for smelting and refining.

In 2007, Greens Creek produced 8.6 million ounces of silver, 68,000 ounces of gold, 63,000 tons of zinc, and 21,000 tons of lead. Proven and probable reserves at Greens Creek (as of 2006) are 33 million ounces of silver, 257,000 ounces of gold, and 237,000 tons of zinc contained in 2.3 million tons of ore grading approximately 14 opt silver, 0.11 opt gold, 10 percent zinc, and 4 percent lead. These numbers reflect the mill recovery rates of approximately 70 percent for all metals. New mine reserves have kept pace with production and the mine is expected to operate well into the next decade. Greens Creek Mine began purchasing surplus hydroelectric energy from AEL&P in 2005. Greens Creek is connected to the AEL&P system with an interruptible power sales agreement that allows it to displace diesel when surplus hydro energy is available. These incremental sales have been valuable in the financing support for hydroelectric development in the AEL&P system.

4.1.8 Gustavus

Gustavus lies on the north shore of Icy Passage at the mouth of the Salmon River, 48 miles west of Juneau. Gustavus is surrounded by Glacier Bay National Park and Preserve on three sides and the waters of Icy Passage on the south. The city boundary encompasses 29.2 square miles of land and 10.0 square miles of water.

Gustavus is a town of 442 residents, and based on data compiled by the Alaska Department of Labor and Workforce Development (DOL&WD), the population has increased in recent years from 429 in 2000. Population growth in Gustavus is likely related to the US National Park at Glacier Bay. According to the 2010 census, Gustavus has a per capita income of $21,089, which is 93 percent of the statewide average, while the median household income is $34,766.

The park service is the largest employer in the community, with an average of 74 annual employees. Glacier Bay Lodge, other area lodges, bed and breakfasts, and charter and tour companies provide additional local employment, which peaks seasonally. Historically, fishing has been an important part of the economy however, participation and local earnings from fisheries have dropped substantially in recent years due in part to the Glacier Bay commercial fishing closures and restrictions. This trend is expected to continue, which will impact the local fishing economy. The park service provides some year-round stability to the economy along with the Gustavus Public School and seasonal construction projects in recent years.

Gustavus has become a popular community for a number of seasonal residents, largely from Juneau. The nearby Glacier Bay Park is a major recreation and tourist attraction in Southeast. Many of the residents who have relocated here chose Gustavus for the lifestyle, the nearness to natural resources, the beauty of the area, and for the subsistence activities available. Gustavus is accessible by small aircraft and boat/small ferry, and Alaska Airlines provides seasonal service. A seaplane base is located 10 miles outside of town. Gustavus does have a road connection to Bartlet Cove in Glacier Bay National Park where freight and transit docks were upgraded in 2009-2010.

Gustavus is located in the Chatham Schools District, and the Public School is grades K-12. Gustavus has one health care facility, the Community Clinic, and is served by the Gustavus Volunteer Fire Department.

Electric power is provided by Gustavus Electric Company, a private electric company. Energy is sourced primarily from hydroelectric resources supplemented by diesel as needed. Fiscal year 2010 residential electric rates were 39.15 cents per kWh before participation in PCE and 25.49 cents per kWh after PCE. Planning is under way to connect the National Park Service facilities at Glacier Bay Park that are currently on diesel-generated power to the hydroelectric grid. Water is either collected from private wells or from a community well. The public school purchases water from the US Park Service. Individual septic systems are used for sewer service. Concerns have been raised about water safety, due to shallow wells and individual septic systems. The city owns and operates a landfill, but offers no refuse collection program.

4.1.9 Haines

The Haines Borough is a "Home-rule" borough located 90 miles north of Juneau. As of the 2010 census, the population of the area is 2,508. Haines was formerly a first-class city within a third-class borough, but in October 2002 voters approved a measure consolidating the city of Haines and Haines Borough into a home rule borough. The Haines Borough contains the CDP communities of Covenant Life, Excursion Inlet, Haines, Lutak, Mosquito Lake, and Mud Bay. The borough's local government and school district, fisheries, tourism, retail trade, business and transportation services are the main employment sources. Haines is a major transshipment point because of its ice-free, deep water port and dock, and year-round road access to Canada and Interior Alaska.

Haines is accessible via state-operated marine highway, small plane, seaplane, boat, and is also connected to the Alaska Highway via the Haines Highway. The Haines terminal for the Alaska Marine Highway System provides direct connection for travelers from the Southeast and the lower-48 states to the Yukon and Interior of Alaska and is one of the busiest ports for the ferry system. There is a deep water dock for year-round road access to Canada and Interior Alaska, and a 4,600 foot runway.

Haines is located within the Haines Borough School District and there are four schools. Three are located in Haines grades K-12 and a home school program. Mosquito Lake has Mosquito Lake Elementary School K-5. Other services include the SEARHC Haines Health Center and the Haines and Klehini Valley Volunteer Fire Departments

Electric power is supplied by the Alaska Power and Telephone with primarily hydroelectric (from Skagway) and supplemented with diesel. Fiscal year 2010 residential rates were 21.89 cents per kWh before participation in PCE and 14.65 cents per kWh after PCE. The residents of the Chilkat Valley area of the borough (beyond 10 mile Haines Highway) are supplied by the Inside Passage Electric Cooperative (IPEC), while Excursion Inlet is supplied by individual diesel generators. Lily Lake and Piedad Springs water is treated, stored, and then distributed throughout Haines. Sewage in the area receives primary treatment before being discharged through two ocean outfalls, with the exception of a few homes that have wells and septic tanks. Residents in the rest of the borough use a combination of water wells, drawing water, or having water delivered individual septic systems used for sewage disposal. Community Waste Solutions provides a privately operated landfill and refuse collection facility to which access is granted to all communities. However, refuse is collected only in the Haines townsite.

4.1.10 Hollis

Hollis is a nonnative residential community on Prince of Wales Island whose residents are largely employed in Craig and Klawock. Hollis is the location of the IFA landing for Prince of Wales Island. Hollis has a population of 112 people with 44 occupied households residing in the CDP, based on the 2010 census. Residents use rain catchment or surface water for their water needs. State-owned seaplane base, harbor, dock and boat ramps are available on nearby Clark Bay. Hollis School is located in the Southeast Island School District. Between 2000 and 2010, enrollment dropped from 29 to 14. Hollis is served by the AP&T island-grid electrical system. Fiscal year 2010 residential electric rates were 21.28 cents per kWh before participation in PCE and 14.48 cents per kWh after PCE.

4.1.11 Hoonah

Hoonah is a Tlingit community on Chichagof Island. It is 30 miles west of Juneau, across Icy Straits and Chatham Straits. According to the 2010 census, the population is 760, though summer population can swell to more than 1,300, depending on fishing, boating, hiking, and hunting conditions. Hoonah means “village by the cliff” or “place protected from the North Wind” in the Tlingit language. Hoonah is the largest Tlingit village in Alaska. Commercial fishing and logging support the population, though most residents maintain a subsistence lifestyle. Tourism is playing a more significant role in Hoonah’s economy with the development of the private cruise ship destination at Huna Totem’s Icy Strait Point.

Hoonah is a first class city and provides all municipal services including police, utilities, and road maintenance, and is accessible by small plane, seaplane, and the state-operated AMHS. The State owns and operates a 2,997 foot asphalt runway, seaplane base, ferry terminal, and harbor/dock area. The city also maintains a city park near the harbor built in 2010 and a youth center.

The police department has a five-bed jail and employs four paid police officers, along with several volunteer reserve officers. The Hoonah volunteer Emergency Medical Service (EMS) was recognized by the state of Alaska in 2009 for excellence and the Hoonah Volunteer Fire Department was accredited by the Alaska Fire Commission in 2010. The Alaska State Troopers have an office post in Hoonah. The Hoonah City School District operates Hoonah Elementary, grades K-6, and Hoonah Junior/Senior High, grades 7-12. The Hoonah Medical Clinic is operated by Hoonah Indian Association.

The Inside Passage Electric Cooperative supplies electric power at an average rate of 56.08 cents per kWh for fiscal year 2010 before residential participation in PCE and 19.78 cents per kWh after PCE. Water is derived from Gartina Creek and is treated and piped to most homes and facilities. Piped sewage is processed in a sewage treatment plant. The city owns and operates refuse collection and landfill operations.

4.1.12 Hydaburg

Hydaburg is a town in the Prince of Wales-Hyder census area on Prince of Wales Island. Hydaburg is the largest Haida village in Alaska where residents maintain a subsistence and commercial fishing lifestyle. A totem park, developed in the 1930s, is located in the village. The population is 376, according to the 2010 census, with 128 occupied households. Access to Hydaburg is available via float/seaplane and small water craft. A state-owned seaplane base and emergency heliport base are also located in Hydaburg, and the city owns a dock and small boat harbor. The state/city highway connects the community to most of the other communities on the island. Within the Hydaburg City School District there is one school, Hydaburg School, which consists of grades K-12. Health services are provided by the Hydaburg Clinic, which is operated by SEARHC. Emergency services are provided by Hydaburg EMS.

AP&T supplies hydroelectric power with diesel engines as a backup. As of fiscal year 2010, the electric residential customer rate was 21.28 cents per kWh before participation in PCE and 14.48 cents per kWh after PCE. The Hydaburg River provides water which is treated and piped throughout the city to its residents. Piped gravity sewage is treated at a secondary treatment plant, with an 800 foot outfall to Sukkwaw Strait. The city provides refuse collection and operates a landfill.

4.1.13 Hyder

Hyder is a CDP in Prince of Wales-Hyder census area located on the mainland at the head of the Portland Canal, 75 miles from Ketchikan. As determined by the 2010 census, the population is 87 people with 48 occupied households. As the easternmost town in Alaska, Hyder has achieved fame as a point in Alaska which is accessible to automobile and motorbike travelers from Canada who want to say that they have been to Alaska.

Hyder is accessible via highway from Stewart, British Columbia, which is 2 miles away by road and connects with the British Columbia highway system. The AMHS ferry that used to connect Hyder to Ketchikan stopped running in the 1990s, leaving the only public transportation between Hyder and the rest of Alaska the Taquan Air floatplane that arrives twice a week with US mail. Hyder residents use Canadian time, Canadian currency, observe Canadian holidays, send their children to Canadian schools, and rely on the Canadian police. Hyder is served by Tongass Power & Light Company from British Columbia.

4.1.14 Juneau

Juneau is the largest city in Southeast Alaska and the third largest in the state. It is the state capital and relies heavily on government employment. Juneau is a transportation hub and a regional service center for the region. As of the census of 2010, there are 31,275 people with 12,187 occupied households. Tourism is a significant contributor to the private sector economy during the summer months, providing about $130 million in annual income and nearly 2,000 jobs. More than 690,000 visitors arrive by cruise ship, and another 100,000 independent travelers visit Juneau each year.

Juneau is accessible by commercial jet service and the state-owned AMHS, as well as small air and water craft. Marine facilities include a seaplane landing area at Juneau Harbor, two deep draft docks, five small boat harbors, and a state ferry terminal. The municipal-owned airport includes a paved 8,460 150 foot runway and a seaplane landing area.

Within the Juneau School District, there are 14 schools: six elementary with two offering preschool classes, two middle schools, three high schools, a home school program, a correspondence program, and grades 9-12 offered through the Johnson Youth Center. The University of Alaska Southeast also has a campus in Juneau.

The Bartlett Regional Hospital, the SEARHC Medical/Dental Clinic, and the Juneau Public Health Center are health care facilities located in Juneau, along with numerous private medical practices. The hospital is a qualified Acute Care facility and Medevac Service.

Juneau is served by the AEL&P Company, a private electric utility through hydro and diesel resources. As of March 2011, residential electric rates are 12 cents per kWh. The municipal water supply is obtained from the Last Chance Basin well field on Gold Creek and the Salmon Creek Reservoir, and is treated and piped to more than 90 percent of Juneau households. Juneau's water demand is 5.0 million gallons per day. The borough's piped sewage system serves almost 80 percent of residents, and receives secondary treatment while sludge is incinerated. North Douglas Island residents use individual septic tanks, and funds have been allocated to begin planning a sewer main extension to this area. Refuse collection, the landfill, and incinerator are owned by Waste Management Co., a private firm. Juneau has a sludge site, a hazardous waste collection facility, and several recycling programs provided by local organizations.

4.1.15 Kake

According to the 2010 census, there are 557 people with 213 occupied households. The town has a total area of 14.2 square miles, of which 8.2 square miles is land and 6.0 square miles is water. Kake is accessible via air with small craft and by sea on the AMHS. The city has a state-owned 4,000 by 100 foot lighted paved runway west of town and two seaplane bases. Facilities also include a small boat harbor, boat launch, deep water dock and state-owned/operated ferry terminal. Kake Elementary and High School, grades K-12, are part of the Kake City School District.

Electric service for the area is provided by the Inside Passage Electric Cooperative with diesel. As of fiscal year 2010, electric rates were 56.08 cents per kWh for fiscal year 2010 before participation in PCE and 19.78 cents per kWh after PCE. The city also operates city water system and a piped sewer system and primary treatment plant. The city also provides refuse collection, recycling, and hazardous waste disposal.

4.1.16 Kasaan

Kasaan is a city in the Prince of Wales-Hyder census area located on Prince of Wales Island. The population is 49, according to the 2010 census, with 23 occupied households. Kasaan was traditionally a Haida village, but the population has become mixed, with Haida, Tlingit, Eskimos, and non-Natives. Kasaan is accessible by float plane, seaplane and small water craft. Small wheeled aircraft service is available in Klawock ,and there is IFA ferry service in Hollis. The city is also home to a state-owned seaplane base, city dock, and a small boat harbor, and is connected to the island road system. Kasaan School is in the Southeast Island School District and consists of grades K-12. Kasaan is home to the Kasaan Clinic, which provides medical services operated by SEARHC.

Alaska Power and Telephone supplies electric power with hydro resources, with diesel used as backup. As of fiscal year 2010, residential electric rates were 21.28 cents per kWh for fiscal year 2010 before participation in PCE and 14.48 cents per kWh after PCE. Water is derived from a water infiltration gallery at Linkum Creek, and is treated and piped to all homes in the core area. Homes use individual septic tanks. The city also collects refuse weekly and ships it to the Thorne Bay landfill.

4.1.17 Ketchikan

Ketchikan has a population density of 2,349 per square mile and is the most densely populated city in Alaska. As of the 2010 census, there are 8,050 people with 3,259 occupied households. Ketchikan is a diverse community where most Native residents are Tlingit. The largest collection of totem poles in the world is found here at the Totem Bight State Historical Park, Saxman Native Village, and the Totem Heritage Center Museum.

Ketchikan is accessible by commercial jet service, the state-owned Alaska Marine Highway System, and small air and water craft. The state-owned Ketchikan International Airport has a paved and lighted 7,500 by 150 foot runway. Ketchikan has four seaplane/float plane landing facilities, a deep draft dock, five small boat harbors, a state-owned and operated ferry terminal, and a large dry dock for ship repair.

Within the Ketchikan Gateway School District, there are 10 schools. The district consists of five elementary schools, with three offering preschool classes, one middle school with grades 7 and 8, and one senior high school offering grades 7-12. There is also a correspondence school and a school with grades 5-12 offered through the Ketchikan Regional Youth Facility. In addition to the variety of school offerings, the University of Alaska Southeast has a campus located in Ketchikan. Ketchikan General Hospital and Ketchikan Indian Community Tribal Health Clinic (operated by Ketchikan Indian Corporation) are also located in Ketchikan to provide residents with health care services.

Ketchikan Public Utilities (KPU) buys, generates and resells all of the electricity consumed in the City of Ketchikan/Ketchikan Gateway Borough area. KPU owns Ketchikan Lakes Hydro and Beaver Falls Hydro (including the Silvis Plant), and operates Swan Lake Hydro, which is owned by the Southeast Alaska Power Agency. KPU also owns and operates a four-unit diesel plant. As of March 2010, the residential electric rate is 9.58 cents per kWh. Water is derived from a dam on Ketchikan Lake, and is chlorinated, stored, and piped to homes within the city's boundaries. The borough operates a water treatment facility at Mountain Point, south of the city while a few homes use rain catchment systems. The city owns a central sewage collection system with primary treatment and a borough sewage treatment plant is located at Mountain Point. The Deer Mountain landfill has an incinerator, bale fill system, recycling and resource reuse, and household hazardous waste collection events.

4.1.18 Klawock

Klawock is a city in the Prince of Wales-Hyder Census Area on the west coast of Prince of Wales Island, on the Klawock Inlet and across from Klawock Island. The population is 755, according to the 2010 census, with 297 occupied households. Klawock is located about 56 miles from Ketchikan, 7 miles from Craig, and 24 miles from Hollis. Klawock's population is a mixture between Tlingit and non-Native ethnicities. The Island has been greatly influenced by logging operations and most residents pursue a subsistence lifestyle to provide food for their families. The community takes great pride in its Totem Park, which displays 21 restored totem poles and replicas from the old village.

Access to Klawock is available via wheeled and float plane and small water craft. Access to the IFA ferry terminal via Hollis is 23 miles away. A 5,000 by 100 foot paved and lighted jet capable runway is also available. Klawock has a small boat harbor and boat launch ramp. A deep draft dock is located at Klawock Island, which is primarily used for loading timber. In addition, the community is connected to the state/city highway on the island.

The Klawock City School is in the Klawock City Schools District and consists of grades K-12. The Alicia Roberts Medical Center, which is owned and operated by SEARHC, provides health care services to the residents of Klawock, while emergency service is supplied by the Klawock Volunteer Fire/EMS.

Alaska Power and Telephone provides electric power from hydro resources with diesel as back-up. As of fiscal year 2010, residential electric rates were 21.28 cents per kWh for fiscal year 2010 before participation in PCE and 14.48 cents per kWh after PCE. Water is derived from a dam on the Half Mile Creek and is then treated, stored, and distributed throughout Klawock. Most homes have piped sewage collection, which receives secondary treatment. More than 90 percent of the homes in Klawock are equipped with connection to the sewage collection system. The city provides refuse collection which is hauled to the Klawock transshipment facility for shipment to the lower 48 states.

4.1.19 Klukwan

Klukwan is a traditional Tlingit village, known for its Chilkat blankets and dance robes woven from mountain goat hair and cedar bark. Fishing, logging, and subsistence activities support the 95 residents of this village. Access to the area is available by road from nearby Haines. The community is dependent on the transportation infrastructure of Haines for goods, services, and travel. The Klukwan School consists of grades K-12 and is located in the Chatham School District. Student enrollment dropped from 23 to 18 between 2008 and 2009. The Klukwan Clinic in Klukwan provides medical services for the residents and is operated by SEARHC.

IPEC provides electric service with diesel to the residents of Klukwan. As of fiscal year 2010, residential electric rates were 56.08 cents per kWh for fiscal year 2010 before participation in PCE and 19.78 cents per kWh after PCE. Water is derived from a groundwater infiltration gallery and is stored in a 126,000 gallon tank operated by the village council. Approximately 90 percent of homes are connected to the piped water and sewer system. The Village Council owns and operates refuse collection and landfill services in addition to a recycling center.

4.1.20 Kupreanof

Kupreanof, a CDP in the Hoonah-Angoon Census Area, is a small, closely-knit, non-Native community near Petersburg. According to the 2010 census, the population is 27, with 15 occupied households. All of the homes are built on the waterfront and there are no roads. Residents use skiffs to travel to Petersburg for school, goods, and services. The majority of the working residents are self-employed or commute by boat to jobs in Petersburg. Subsistence and recreational uses of resources around Kupreanof provide supplemental household income. The city has no full-time staff, few services, and no public utilities.

Kupreanof is a community where residents live in a rural, scarcely populated area, pay minimal taxes, receive few urban services, and have minimal impact on their environment. Residents want to protect themselves from any changes that might infringe on their existing lifestyles.

Access to Kupreanof is available only by small boat. The city relies on the city of Petersburg for access to air service and the state-owned and operated AMHS. There are no community transportation facilities, and small water crafts are privately owned. There is not a school located in the city of Kupreanof, students are transported independently to the nearby Petersburg City Schools District. Residents rely on Petersburg Medical Center in Petersburg for medical services, which can be accessed by skiff.

There are no public utilities in Kupreanof and no central electric. Residents use individual generators to provide electric power, and pipe water from nearby creeks. Individual septic tanks or pit privies are used for sewage disposal. Household refuse is composted, recycled, burned, or buried.

4.1.21 Metlakatla

Metlakatla, a CDP on Annette Island, is a traditional Tsimshian community and the only American Indian reservation in the Alaska. The 2010 census indicates that the population is 1,405 with 493 occupied households. The Metlakatla economy is based primarily on government, fishing, and fish processing services. The community built a salmon hatchery on Tamgas Creek which releases millions of all five salmon species. The largest employer is the Metlakatla Indian Community, which operates the hatchery, the tribal court, and all local services. Annette Island Packing Co. is a cold storage facility owned by the community.

Access to Metlakatla is available by float/seaplane. The state-owned AMHS also serves this community. Annette Island Airport is owned and operated by the community, with a 7,500 foot asphalt runway (currently unused) and a 5,700 foot gravel crosswind runway. Two seaplane bases are available at Port Chester: one state-owned, and one community-owned. Port facilities include a dock with a barge ramp, two small boat harbors, and two marine ways. Waldon Point Road connects Metlakatla to the northeast portion of the Island. An Alaska Marine Highway ferry terminal is located at Metlakatla and a new terminal is planned for the end of Waldon Point Road for a closer ferry crossing to Ketchikan.

Within the Annette Island School District, there are three school: an elementary school, grades K-6; a middle school, grades 7-8; and a high school, grades 9-12. Annette Island Family Medical Clinic has been upgraded to a 33,000-square-foot facility. This clinic is operated by the Metlakatla Indian Community. Emergency service is provided by the Metlakatla Volunteer Fire/EMS/Ambulance.

Metlakatla Power & Light generates electricity at two nearby hydro sites, Purple Lake and Chester Lake. They also operate the Centennial Diesel Plant. The community currently has an excess of hydropower and, as of March 2011, the residential electric rate for Metlakatla is 9.2 cents per kWh. The community is served by two water sources, Chester Lake and Yellow Hill Lake. Chester Lake provides water to a 200,000 gallon water tank in the main part of the community and a piped gravity sewage system provides primary treatment in an aerated lagoon with effluent discharge through an ocean outfall. Approximately 485 homes as well as the local school are served by the system, but some areas of the community use individual septic tanks. The community's water system and landfill do not require state permits, because the reserve is not within state jurisdiction. The community offers refuse collection and landfill operations.

4.1.22 Meyers Chuck

Meyers Chuck is a neighborhood in the city and borough of Wrangell. The population was 21 as of the 2000 census with 9 households. On June 1, 2008 Meyers Chuck was annexed into the newly created city and borough of Wrangell, most of whose territory came from the former Wrangell-Petersburg Census Area. Meyers Chuck is located along Clarence Strait on the northwest tip of the Cleveland Peninsula. Meyers Chuck is located in the Prince of Wales-Outer Ketchikan Recording District. The area encompasses 0.6 square miles of land and 0.2 square miles of water.

4.1.23 Naukati Bay

Naukati Bay is a CDP in the Prince of Wales-Hyder Census Area located on the northwest portion of Prince of Wales Island. Also known as Naukati or Naukati West, the community lies approximately 30 miles north of the city of Craig and 20 miles southwest of Coffman Cove on Prince of Wales Island. Naukati Bay Subdivision East and West are located on the east side of the Tuxekan Passage in Naukati Bay. The community of Naukati Bay has developed over the past 30 years from its original logging camp status to an independent community. The population is 113 with 49 occupied households, according to 2010 census.

Naukati is accessed primarily by float plane or via the North Island Road. A small boat dock has been built and is now operated by Naukati West Inc. Wheeled plane service is also available at Klawock and the IFA ferry service is available at Hollis. A community owned sea/float plane base is also located at Naukati. Primary local access is via unpaved gravel logging roads and the community is connected to the island road system. Naukati School is in the Southeast Island Schools District, and has grades K-12.

Naukati residents are primarily logging families and homesteaders. Two community nonprofit associations have been organized for planning and local issue purposes. Small sawmills and related logging and lumber services are the sole income sources for the residents of Naukati, and most employment in Naukati is seasonal in nature. Naukati serves as a log transfer site for several smaller camps on the Island. In 2002, Naukati Bay needed funds to assist in the community financial needs and obtained a grant from the state of Alaska. With financial help from the United States Forest Service, Naukati built an "Oyster Nursery." The Oyster Nursery raises oyster spat (seed) from as small as 3 millimeters to a marketable 18 to 25 millimeters and sells the larger healthy oysters to the grow-out farms in the area and throughout Alaska. Naukati Bay's Oyster Nursery has been the only successful nursery in Alaska and provides the oyster farmers with a premium product that gives the farmers a one-year head start to bring their product to market. The Naukati Oyster Nursery provides the community with more than $20,000 a year in revenue to be used for everything from supporting youth to repairing roads.

AP&T supplies electric power from diesel and, as of fiscal year 2010, residential electric rates were 49.28 cents per kWh for fiscal year 2010 before participation in PCE and 18.54 cents per kWh after PCE. Grant funds have been awarded to connect Naukati to the Prince of Wales electrical grid with construction expected in 2012. Water is derived from rain catchment and several small streams. The nine logging camp homes are connected to a piped water and sewer system with full plumbing. The 27 homesteaders collect rainwater and use outhouses for their sewer. Feasibility studies are currently being conducted for individual water systems and sewers. The community burns its refuse and ships the ash to Thorne Bay's landfill.

4.1.24 Pelican

Pelican is a city in the northwestern part of Chichagof Island in the Hoonah-Angoon Census Area. The city is located on the east side of Lisianski Inlet, a body of water that opens into Lisianski Strait and Cross Sound. According to the 2010 census, the population of the city is 88 with 41 occupied households. Pelican is a small remote fishing community with a year-round population and a seasonal influx of commercial fishermen. The community characteristics also include seasonal residents with homes and/or tourism and recreational businesses. Pelican is accessible by seaplane and via the state-operated AMHS. The city owns a seaplane base, a boat harbor with permanent and transient moorage, and a state ferry dock and terminal.

Pelican school operates with grades K-12 and is located in the Pelican City School District. The Pelican Health Center is city owned, but is operated by SEARHC. Emergency services are provided by the Pelican Volunteer Fire and EMS.

The Pelican Utility Company, a privately owned and operated utility, supplies electric power from hydro and diesel resources. Electric rates were 41.67 cents per kWh for fiscal year 2010 before participation in PCE and 17.97 cents per kWh after PCE. The city of Pelican operates the piped water system. Water is supplied from a dam and reservoir on Pelican Creek, and is treated at the newly constructed water treatment plant facility. A new water distribution system was constructed during the summer of 2010 that connects homes along the boardwalk to the piped water system. Expansion of the water distribution system to the remaining areas of Pelican is scheduled for construction in 2011. Approximately 75 percent of the homes are piped into a city sewage system, with four 10,000 gallon septic tanks and an ocean outfall system. The city's Village Safe Water project will assist the city with design and construction of a sludge removal system for sludge disposal at the Pelican Landfill. The city owns and operates a garbage collection system, a recycling facility, and a burn box at the landfill.

4.1.25 Petersburg

Petersburg is a city in Petersburg Census Area located on the north end of Mitkof Island and, according to the 2010 Census Bureau estimates, is home to approximately 2,369 full time residents with 1,053 occupied households. The community maintains a mixture of Tlingit and Scandinavian history. It is known as "Little Norway" for its history and annual Little Norway Festival during May.

Access to Petersburg is available by air with regular jet and float/small plane service and by sea via the state-operated AMHS. The state-owned James A. Johnson Airport, a 6,000 foot airstrip, and Lloyd R. Roundtree Seaplane Base are located within the city. Harbor facilities include three docks, two petroleum wharves, two barge terminals, three boat harbors with moorage for 700 boats, a boat launch, and boat haul-out.

Within the Petersburg City School District there are three schools: one elementary school grades K-5, one middle school grades 6-8, and one high school grades 9-12. Medical service is provided by the Petersburg Medical Center and the Petersburg Public Health Center.

Petersburg Municipal Power & Light buys the vast majority of its electrical requirements from the Tyee Lake Hydro Plant owned by the SEAPA. Additionally, the city owns a hydro facility at Blind Slough (Crystal Lake) and a small diesel plant. As of March 2011, the rate for residential electric service is 11.8 cents per kWh. Water is supplied by Cabin Creek dam, a 50-million gallon water reservoir, then is treated, stored in a 600,000 gallon tank and distributed via pipes to about 80 percent of the households. A few homes use individual wells or water delivery services. Nearly all homes are equipped with plumbing fixtures and piped sewage receives primary treatment. Petersburg operates a city-owned/operated landfill and refuse collection facility. Refuse is shipped and baled to Washington state.

4.1.26 Saxman

Saxman is a city on Revillagigedo Island located within the Ketchikan Gateway Borough. According to the 2010 census, the population is 411 with 120 occupied households. The city of Ketchikan lies just northwest of Saxman. The community relies on Ketchikan for its boat moorage, air travel, and state ferry services. Saxman and Ketchikan are connected by the South Tongass Highway. A dock and commercial barge off-loading facilities are available at the Saxman Seaport. There is not a school in Saxman. Students are enrolled in the Ketchikan Gateway School. Saxman's residents utilize the Ketchikan General Hospital and other facilities located in Ketchikan.

Electric power is supplied by the Ketchikan Public Utilities using hydropower and diesel. Water is derived from a dammed reservoir and is treated and stored in a 128,000 gallon storage tank. The city of Saxman operates a piped water and sewer system and all homes are equipped with plumbing. A few homes use individual septic tanks. Refuse is collected by a private company and disposed of at the nearby Ketchikan landfill.

4.1.27 Sitka

The city and borough of Sitka is a unified city-borough located on Baranof Island and the southern half of Chichagof Island in the Alexander Archipelago of the Pacific Ocean. With a population of 8,881 per the 2010 census, Sitka is the fourth-largest city by population in Alaska. Urban Sitka is situated on the west side of Baranof Island. Tlingit culture, Russian influences, and arts and artifacts remain a part of the local color. Sitka has year-round access to outdoor recreation in the Gulf of Alaska and Tongass National Forest.

Access to Sitka is available via commercial jet service, small air craft, and the state-owned Alaska Marine Highway System. Regular ferry service is provided weekly by mainline vessels north- and southbound and dayboat service is provided seasonally with the fast ferry, M/V Fairweather which serves Sitka with a 6-hour run to Juneau. Daily jet service is provided, and several scheduled air taxis, air charters, and helicopter services are available. The US Coast Guard Air Station Sitka provides search and rescue services throughout the state. The state-owned Rocky Gutierrez Airport on Japonski Island has a 6,500 by 150 foot paved and lighted runway, an instrument landing system, and a 24-hour FAA Flight Service Station. The city and borough operates five small boat harbors with 1,350 stalls. A seaplane base is located on Sitka Sound and Baranof Warm Spring Bay. There is a breakwater at Thompson Harbor, but no deep-draft dock. A boat launch, haul-out, boat repairs and other services are available. The Alaska Marine Highway ferry terminal is located 7 miles north of town.

The community has recently completed upgrades to the high school auditorium and is served by the Sitka Borough School District. There are two elementary schools: one offering preschool and first grade and the other grades 2-5; one middle school grades 6-8; three high schools grades 9-12; and a correspondence course that offers K-12 classes. In addition, the University of Alaska Southeast has a campus located at Sitka. The city's health care services are provided by the Mt. Edgecombe/SEARHC and Sitka Community Hospitals. Emergency services are provided by the Sitka Fire Department/Ambulance/Rescue.

The Sitka Electric Department provides electric power from hydro and with partial diesel backup. As of March 2011, the residential electric rate is 14.2 cents per kWh. Water is drawn from a reservoir on Blue Lake and Indian River, treated, stored, and piped to nearly all homes in Sitka. The maximum capacity is 8.6 million gallons per day, with 197 million gallons of storage capacity. 95 percent of homes are connected to the piped sewage system, which receives primary treatment. Refuse is collected by a private firm, under contract to the city, and is incinerated. The ash is then disposed of at the permitted, lined landfill. The community participates in annual hazardous waste disposal events.

4.1.28 Skagway

Skagway, incorporated on June 28, 1900, was the first first-class city in the territory of Alaska. During the early 1900s, Skagway was known as the “Gateway to the Klondike.” On June 5, 2007, voters approved dissolution of the city of Skagway and incorporation of the first first-class borough in the state of Alaska. The state of Alaska certified this election and the Municipality of Skagway Borough was incorporated on June 20, 2007. Skagway is located in the Upper Lynn Canal and is considered the northern-most point in Southeast Alaska, 80 air miles from Juneau and 110 road miles from Whitehorse. Skagway’s population is 920 with 410 occupied households, according to the 2010 census.

Access to Skagway is available by small aircraft, road, state-owned AMHS, and private seasonal rail tours to Lake Bennett, and Carcross, Canada. The Klondike Highway and Alaska Highway provide a connection through British Columbia and the Yukon Territory, to the lower 48 US states, or north to Interior Alaska. The state owns the 3,550 by 75 foot paved runway and a seaplane base at the boat harbor. A breakwater, ferry terminal, cruise ship dock, small boat harbor, boat launch, and boat haul-out are also available. The White Pass and Yukon Route Company operates two deep draft docks for cargo loading and storage and provides private rail connection to Canada, primarily for tourism operations.

Skagway City School is located in the Skagway City Schools District and consists of grades K-12. Bartlett Memorial Regional Hospital operates the Dahl Memorial Clinic. Emergency services are provided by the Skagway Volunteer Fire Department/EMS.

Alaska Power and Telephone provides electric power to Skagway from a mix of predominately hydro and diesel. As of fiscal year 2010, residential electric rates were 21.89 cents per kWh for fiscal year 2010 before participation in PCE and 14.65 cents per kWh after PCE. Water is obtained from three wells near 15th and Alaska Streets, stored, and piped throughout Skagway. Piped sewage receives primary treatment with an ocean outfall system. The demands of the system nearly double each summer, with the influx of tourism business operators. The landfill is closed, but the city operates an incinerator, baler, and ash fill facility. The community participates in recycling and annual hazardous waste disposal events.

4.1.29 Tenakee Springs

Tenakee Springs is predominantly a retirement community and summer retreat for Juneau and Sitka residents. The census of 2010 indicates there are 131 people in 72 occupied households. Most residents practice a subsistence lifestyle and actively exchange resources with their neighbors. The 108 degree sulfur hot springs is the social focus of the community. Bathing times are posted for men and women.

Tenakee Springs is accessible by seaplane and the state-operated AMHS for passenger service only (the state-owned and operated ferry dock has no vehicle landing facilities). With only 3 miles of road constructed, local transportation is primarily by bicycle or ATV. The city owns a seaplane base, heliport, and small boat harbor. Tenakee Springs has a K-12 school that is part of the Chatham School District. Emergency services are provided by the Tenakee Springs Volunteer Fire/EMS departments.

Electric power is provided by the city of Tenakee Springs from diesel. The city owns the electrical system and there is local interest in developing hydroelectric power facilities at Indian River. Residential electric rates were 64.00 cents per kWh for fiscal year 2010 before participation in PCE and 31.51 cents per kWh after PCE There is no community water or sewer system, residents haul water from local streams or use individual wells. Homes in the community are not fully plumbed and privies are used.

4.1.30 Thorne Bay

Thorne Bay originally began as a large logging camp for the Ketchikan Pulp Company in 1960 and is located on Prince of Wales Island. According to the 2010 census, there are 471 people with 214 occupied households. Employment is primarily in small sawmills and with the US Forest Service, with some commercial fishing, tourism, and local government employment. Thorne Bay is one of the log transfer sites on the island. To supplement incomes, residents will often fish and trap. Deer, salmon, halibut, shrimp, and crab are popular food sources.

Thorne Bay is accessible via float/sea plane and small water craft. Access to the state/city highway provides service to the IFA ferry terminal in Hollis and most of the other communities on the island. A breakwater, dock, small boat harbor and grid, boat launch, and state-owned seaplane base are also available. The state highway provides access to most other Prince of Wales communities.

The Thorne Bay School is one of eight schools operated by the Southeast Island Schools District and consists of grades K-12. Health services are provided by the Thorne Bay Health Center which is operated by SEARHC. Emergency services are provided by the Thorne Bay Volunteer Rescue Squad/EMS.

Alaska Power and Telephone supplies power through its island electrical grid system from hydro resources with diesel fuels serving as backup. Residential electric rates were 21.28 cents per kWh for fiscal year 2010 before participation in PCE and 14.48 cents per kWh after PCE. Water Lake, north of Thorne Bay, supplies water to Thorne Bay residents. It is treated and stored in a tank before piped distribution. The gravity sewage system includes secondary treatment before discharge into the bay. Residents on the south side of the community use rain catchment and streams or springs. The city provides refuse collection services, a regional baler, a recycling facility and a landfill, and participates in annual hazardous waste disposal events.

4.1.31 Whale Pass

Whale Pass is a CDP located on north Prince of Wales Island. The census of 2010 indicates that there are 31 people with 20 occupied households residing in Whale Pass. The area has been the site of logging camps since 1964. In the early 1980s, the last camp moved out, and the area was permanently settled as the result of a state land disposal sale. The logging road was completed in 1981, and private phones were installed in 1992. Many Whale Pass residents are homesteaders and enjoy a subsistence lifestyle. Due to declining enrollment, the school was closed for the 1998-1999 school year and students are home-schooled. Logging operations and related services provide the only steady employment. Subsistence activities and public assistance payments supplement income. The community does have access to the island road system. The IFA ferry is accessible from Hollis. Float planes and boats are common means of transportation for Whale Pass residents. The Whale Pass Homeowner's Association operates the state-owned seaplane base, dock, boat slips, and launch ramp.

Most homes draw untreated water from a creek and have individual water tanks. Residential electric rates from AP&T were 52.17 cents per kWh for fiscal year 2010 before participation in PCE and 22.65 cents per kWh after PCE. Privies and septic tanks are used for sewage disposal though almost all houses have complete plumbing. One-third of the homes are used seasonally. The community's landfill is no longer in operation.

4.1.32 Wrangell

Wrangell, one of the oldest non-native communities in Alaska, is located on the northern tip of Wrangell Island. It is 155 miles south of the Alaskan capital of Juneau. It is across the narrow Zimovia Strait from the mouth of the Stikine River on the Alaska mainland. The 2010 census indicates there are 2,369 people with 1,053 occupied households. The city has a total area of 70.8 square miles, 45.3 of which is land and 25.6 of which is water. Wrangell's economy is based on commercial fishing, tourism, and timber services from the Tongass National Forest. Although Wrangell has a deep-water port, it mostly serves small cruise ships. The nearby Stikine River attracts independent travelers for sport fishing.

Wrangell is accessible via commercial jet service, small aircraft, and state-owned AMHS. The state-owned 6,000 by 150 foot paved, lighted runway enables jet service. A seaplane base is adjacent to the runway. The marine facilities include a breakwater, deep draft dock, the state ferry terminal, two boat harbors with 498 slips, and a boat launch.

Wrangell Municipal Light & Power (WMLP) buys the vast majority of its electrical requirements from the Lake Tyee Hydro Plant owned by SEAPA. WMLP also owns a diesel plant which is used for backup. As of March 2011, the residential electric rate is 12.6 cents per kilowatt hour. Two surface reservoirs south of town supply 64 million gallons of water, which is filtered, treated, and piped to most households. Sewage receives secondary treatment at the Shoemaker Bay plant. The city provides garbage collection service, a recycling facility, an incinerator and annual hazardous waste disposal events.

4.1.33 Yakutat

Yakutat was first settled as a fort in 1795 to facilitate trade and was incorporated as a unified city-borough on September 22, 1992. According to the 2010 census, the population is 662 with 275 occupied households. The name is derived from the Tlingit word, Yaakwdáat, meaning "the place where canoes rest." Besides the original city of Yakutat, the only other significant population center in the borough is the community of Icy Bay in the west-central part. Yakutat City is the largest city in the United States by area, and the eighth largest city in the world by area. Fishing is currently the largest economic activity in Yakutat.

Electricity is provided by Yakutat Power from diesel generation. Electric rates were 46.67 cents per kWh for fiscal year 2010 before residential participation in PCE and 17.96 cents per kWh after PCE. Yakutat has piped water and sewage systems.

4.2 GENERAL HISTORY

Southeast Alaska is characterized by numerous islands, marine passages, mountains, and evergreen forests in a wet, relatively temperate climate. The combination of high precipitation levels and the mountainous terrain provides significant opportunity for hydroelectric generation. The mountainous island environment, however, has limited the development of roads and other infrastructure systems, including electric transmission lines, generally to relatively confined areas surrounding the region's cities, towns, and villages. Consequently, although significant hydroelectric power is available in some locations, the lack of power transmission facilities prevents its distribution to the region as a whole.

As communities began to become electrified, hydro projects were developed where their location was such that the power could be transmitted to the loads. Diesel generation was developed to supplement and backup the hydro generation, and for communities that could not economically access hydro generation. As a result, hydro facilities provide the majority of the power requirements in Juneau, Ketchikan, Sitka, Petersburg, Wrangell, Skagway, Haines, Metlakatla, Pelican, Klukwan, and the majority of Prince of Wales Island. In communities where hydro power is not available, the reliance upon diesel generation has contributed to very high electric rates. Regions with hydro generation are generally experiencing high load growth as customers switch from oil heating to electric heating. Many of these communities are beginning to run short of hydro energy at least during some parts of the years and are increasingly supplementing with diesel generation.

As hydro projects developed, they generally fell within two categories based on interconnection requirements.

1. Projects developed by local utilities to serve local demand. Those projects include projects for Skagway, Haines, Juneau, Sitka, Petersburg, Ketchikan, Metlakatla and Prince of Wales Island.

2. Projects developed by the state or the Federal Power Administration to serve shared interconnected load centers. Those projects include Snettisham/Crater Lake, Lake Tyee, and Swan Lake.

The existing utility systems considered in the Southeast IRP are shown on Figure 4-2. Hyder's utility system is not considered in the Southeast IRP since Hyder is served by Tongass Power & Light Company, a Canadian utility located in British Columbia.

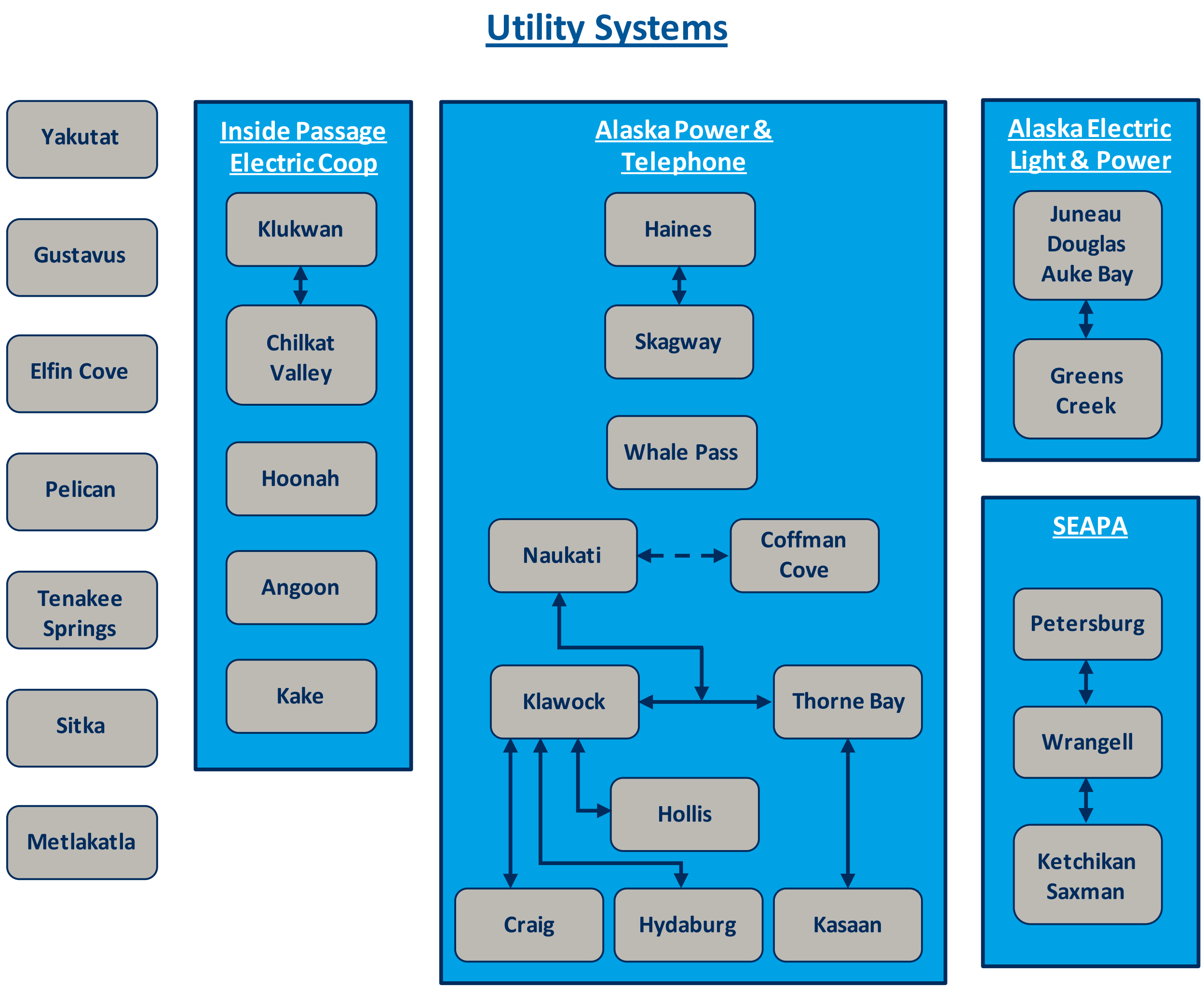

Figure 4-2 Existing Utility Systems Considered in the IRP

The existing transmission system in Southeast Alaska is limited; however, the electric systems in a few communities are currently interconnected. To date, the Southeast Alaska power system has developed to utilize hydroelectric resources on a subregional or isolated community basis. Within the subregions, some transmission lines are currently planned to be constructed in the near future to further distribute power from relatively small hydroelectric projects. For the purposes of analyzing the transmission system in Southeast Alaska, the following transmission subregions are identified and shown on Figure 4-3.

- SEAPA Region--Existing SEAPA system connects Ketchikan/Saxman, Petersburg, and Wrangell; currently isolated communities Kake and Metlakatla will be interconnected with the SEAPA system by interconnections included as Committed Resources.
- Admiralty Island--Currently isolated community of Angoon.
- Baranof Island--Currently isolated community of Sitka.
- Chichagof Island--Currently isolated communities of Hoonah, Tenakee Springs, Pelican, and Elfin Cove.
- Juneau Area--Existing AEL&P system connects Juneau, Douglas Island, Auke Bay, and Greens Creek which is served with interruptible hydro.
- Northern Region--Isolated communities of Yakutat and Gustavus.
- Prince of Wales Island--Existing AP&T system connects Coffman Cove, Craig, Hollis, Hydaburg, Kasaan, Klawock, and Thorne Bay; currently isolated but with an interconnection under construction is Naukati; currently isolated Whale Pass.
- Upper Lynn Canal Region--Existing AP&T system connects Haines and Skagway. An intertie connects the AP&T system to the existing IPEC system serves Klukwan and Chilkat Valley.

4.2.1 Existing Transmission System

Existing transmission facilities in Southeast Alaska were constructed to deliver power from hydro generation to specific load centers. While the 1997 Southeast Alaska Electrical Intertie System Plan identified a goal of a region-wide electrical transmission system, few segments have been constructed with the notable exception of the SEAPA system's Swan-Tyee Intertie (STI) and AEL&P's extension to the Greens Creek mine. Figure 4-4 presents the existing transmission systems in the Southeast Alaska.

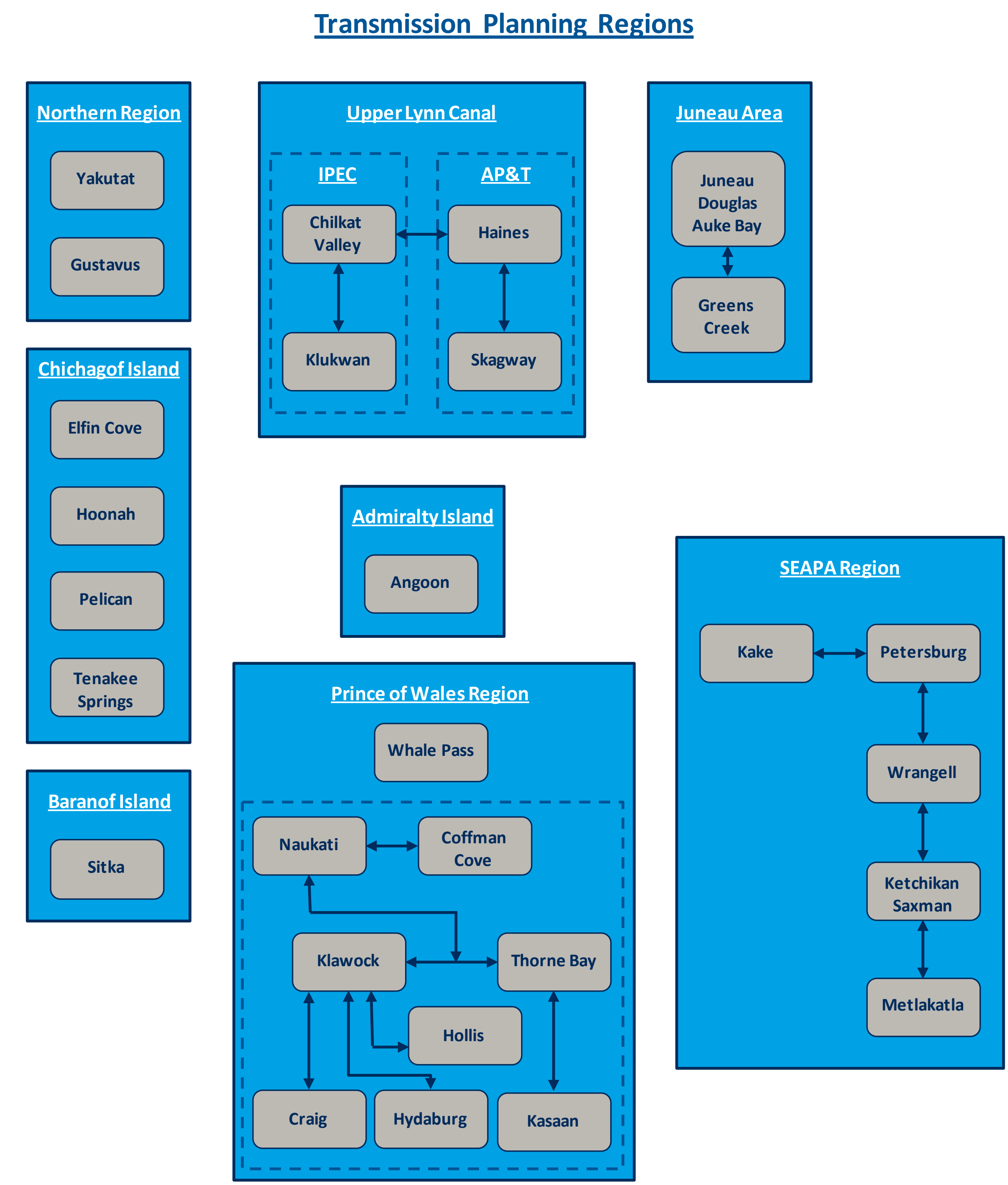

Figure 4-3 Transmission Systems Considered in the IRP

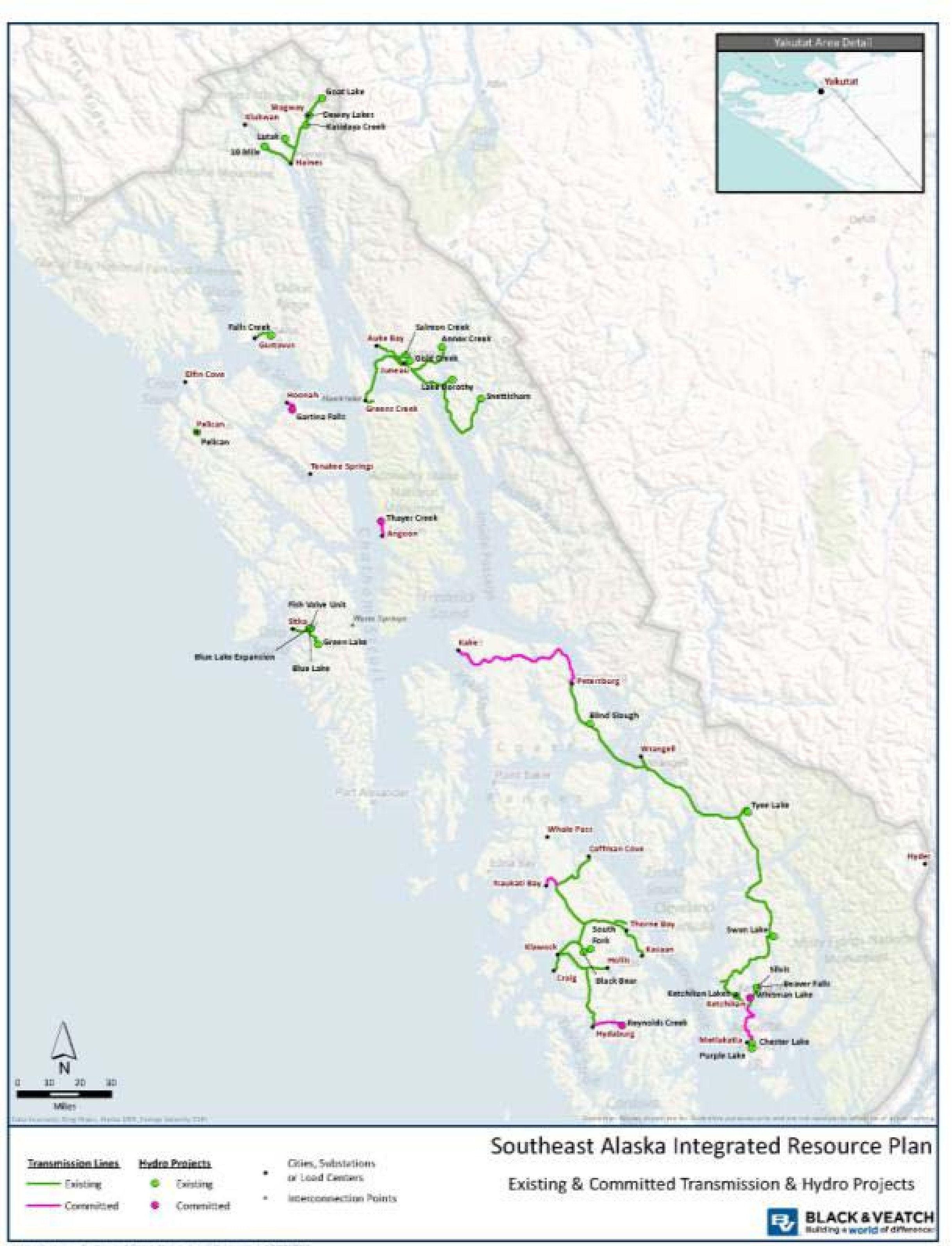

Figure 4-4 Existing and Committed Resources

4.2.1.1 SEAPA System Region

The SEAPA Region includes the SEAPA system comprised of Petersburg, Wrangell, and Ketchikan and including Saxman, which is served by KPU as well as currently isolated systems of Kake and Metlakatla. The Tyee Lake and Swan Lake projects are the largest projects in the region. The Tyee Lake Hydroelectric Project is located approximately 40 miles southeast of the city of Wrangell. The Tyee Lake Project was constructed in 1981 and provides power to both Wrangell and Petersburg. It uses a lake tap to draw water from Tyee Lake. Excess energy is dispatched to Ketchikan via the STI. The project has two 12.5 megawatt-ampere (MVA) 13.8 kilovolt (kV) generators. The switchyard has two 138/69 kV step-up transformers, each rated at 11.25 MVA. The transmission line is designed and built for 138 kV, but is operated at 69 kV. The transmission line connects Wrangell and Petersburg and consists of 68.2 miles of overhead and 12.6 miles of submarine cable. The transmission system includes substations in Wrangell and Petersburg.

Swan Lake is located on Revillagigedo Island about 22 miles northeast of Ketchikan. This project includes a pipeline, powerhouse, and tunnel with a total rated capacity of 22 megawatt (MW). A 30.5 mile 115 kV line runs from Swan Lake to the SW Bailey substation in Ketchikan. The STI is a 57-mile 138 kV transmission line which currently operates at 69 kV connecting the project to the Tyee-Wrangell transmission line. It is located in remote mountainous areas accessible only by helicopter. The STI uses 397 thousand circular mils (kcmil) AACSR/AW 30/7 (LarkSP) conductor at the lower elevations, and 37 No. 8 Alumoweld conductor at the higher elevations and for the extremely long spans.

The Tyee and Swan projects were originally developed as part of the Four Dam Pool Project. The STI was developed to provide excess hydro from Tyee to Ketchikan and was largely state-grant financed.

Kake, located on Kupreanof Island, is a currently isolated system served by IPEC with diesel generation, but has been actively pursuing the Kake-Petersburg intertie.

Metlakatla is a currently isolated island system south of Ketchikan. The Chester and Purple Lake hydro projects provide the majority of Metlakatla Power & Light's electric loads with diesel providing supplemental and backup power. Metlakatla has been pursuing an interconnection with Ketchikan.

4.2.1.2 Admiralty Island

The currently isolated system of Angoon is located on the western side of Admiralty Island. Angoon is served with diesel generation by IPEC. Angoon has been pursuing the development of the Thayer Creek Hydro Project.

4.2.1.3 Baranof Island

Sitka is located on Baranof Island and is not interconnected with other electric systems due to the to utilize long sections of expensive submarine cable in order to connect to other systems. Over the years, Sitka has developed two relatively major hydroelectric facilities that have continued to supply nearly all local power requirements. In the early 1980s, the Green Lake hydroelectric project was completed and a considerable amount of energy from the project was sold to the Alaska Pulp Company (APC). The APC energy sale was a critical factor in allowing Sitka to bring the project on line with minimal negative impact on electric rates. Often, the high capital cost and lower initial utilization of new hydroelectric facilities can cause the need for rate increases when the projects are initially included in a utility's revenue requirements.

4.2.1.4 Chichagof Island

Chichagof Island contains the currently isolated systems of Hoonah, Tenakee Springs, Pelican, and Elfin Cove. Hoonah is served by diesel generation by IPEC. Pelican is served by the 0.7 MW Pelican hydro project and diesel generation. The Pelican Project is connected at 2.4 kV into the city's distribution system owned by the Pelican Utility Company. Tenakee Springs and Elfin Cove are currently served by diesel generation, but both are investigating local hydro generation.

4.2.1.5 Juneau Area

AEL&P serves the Juneau area, Douglas, Auke Bay, and the Kennecott Mining Company - Greens Creek Mine (KMC-GC). The KMC-GC mine, located on Admiralty Island uses electric power for mining operations and also for electric loads at the Hawk Inlet and Young Bay dock facilities. The mine is interconnected with AEL&P and purchases power from AEL&P on an interruptible basis with surplus hydro. The mine load averages approximately 6 MW throughout the day and the peak load is about 7.5 MW. The loads at the Hawk Inlet powerhouse average about 370 kW but can increase to 500 kW when loading a ship. KMC-GC does not expect significant changes in its electric power requirements in the future. The expected remaining operating life of the mining facilities is estimated by KMC-GC to be approximately 10 years, subject to exploration success, metal prices and other factors. AEL&P also serves cruise ships with interruptible surplus hydro. Table 4-1 presents the existing transmission interconnections for the Juneau area.

Table 4-1 Existing Transmission Interconnections - Juneau Area

INTERCONNECTION	OWNER	VOLTAGE (KV)	DISTANCE (MILES)	CONDUCTOR
North Douglas – Young Bay	KWETICO	69	9.3	240 mm^2 Subcable
Young Bay – Greens Creek Mine	KWETICO	69	12.8	336 ACSR
Snettisham – Taku Inlet	SOA	138	33	795 ACSR
Taku Inlet	SOA	138	3	630 mm^2 Subcable
Taku Inlet - Juneau	SOA	138	8	1590 ACSR
Lake Dorothy – Taku Inlet/Juneau	AEL&P/SOA	138	3.2/(14.2)	556.6 ACSR/(Snettisham Conductor)
Annex Creek - Juneau	AEL&P	23	12.5	2/0 CU
Gold Creek - Juneau	AEL&P	69	0	652.4 AAAC
Salmon Creek - Juneau	AEL&P	69	0	652.4 AAAC

4.2.1.6 Northern Region

The Northern Region is comprised of the Yakutat and Gustavus communities, which are isolated from the rest of Southeast Alaska. Yakutat, due to its remote location, is pursuing research and development of emerging technologies such as wave and biomass. Gustavus is served by the privately owned Gustavus Electric Company. Power is supplied by 0.8 MW Falls Creek Hydro Project and diesel generation. Falls Creek is connected to Gustavus Electric Company distribution system. Residents of Excursion Inlet supply their own power through distributed diesel generator.

4.2.1.7 Prince of Wales Island

Prince of Wales Island lies to the west of Ketchikan in Southeast Alaska and is the third largest island in the United States, with an area of more than 2,200 square miles. The towns of Craig and Klawock, the largest population areas on the island, were electrically intertied in 1987. In 1995 the Black Bear Hydro Project was completed with connection to Craig, Klawock, and the Viking Sawmill. In 1999, the hydropowered electrical transmission system was extended to Thorne Bay. In 2001, the line was extended to the village of Kasaan. In 2004, the transmission system was extended to Hollis, the ferry port for the island. In 2005, the South Fork Hydro project was completed adding capacity to the island grid. Also in 2005 the transmission line was extended to connect with the Hydaburg power system. Transmission line construction is presently underway to connect Coffman Cove in 2011 and Naukati in 2012.

While the Black Bear Lake Hydro and South Fork Hydro projects meet the majority of the electrical demand, there are times during the year that the hydro capacity is insufficient and must be supplemented with diesel generation. The hydropowered grid capacity varies with the time of year. Black Bear Lake Hydro has water storage, enabling it to operate at capacity through most of the low water inflow periods. South Fork is a run-of-river project and output fluctuates over the year, depending on runoff available. Preliminary construction has started on the 5.0 MW Reynolds Creek Hydro Project located 10 miles east of Hydaburg and jointly owned by Haida Corporation and AP&T.

4.2.1.8 Upper Lynn Canal

The Upper Lynn Canal (ULC) regional electrical supply serves the populated areas around Skagway, Dyea, Haines by AP&T and the IPEC service areas of Klukwan and Chilkat Valley up the Haines Highway to the US/Canadian border. Prior to 1998, these areas were not electrically intertied. Skagway's power was supplied by diesel generators supplemented by Dewey Lakes Hydro. Haines' power was supplied by diesel generators eventually supplemented by the small Lutak Hydro. Klukwan's power was supplied entirely with diesel generators. The Haines Highway area (Chilkat Valley) was supplied by diesel generators at Mosquito Lake.

In 1997 the Goat Lake Hydro Project was completed as the first part of the ULC Regional Supply Plan. In 1998, a submarine cable was laid connecting the Skagway and Haines electrical systems. In 1999, Southern Energy (SE) built the 10 Mile Hydro project to supply IPEC's customers at Klukwan and Chilkat Valley (Haines Highway). The Dyea Valley diesel-powered system was intertied with Skagway in 2005. In 2007, the Haines system was extended to 10 Mile and connected with the Haines Highway system. In 2008, the Kasidaya Hydro Project was completed and connected into the ULC system via submarine cable. This completed the ULC Regional Supply Plan, providing a hydropowered grid from IPEC's service area at the Haines Highway Canadian border through Haines to the Klondike Highway Canadian border station north of Skagway.

4.2.2 Generating Resources

Existing generating resources in the region are either hydro or diesel with a small battery energy storage system (BESS) facility in Metlakatla. The following sections discuss the existing resources.

4.2.2.1 Existing Hydro Facilities

Figure 4-4 and Table 4-2 present the existing hydro resources in the Southeast.

Table 4-2 Existing Hydro Resources

PROJECT NAME	DATE	CAPACITY (MW)	ANNUAL ENERGY (MWH)	CATEGORY	FERC #	LOCATION	OWNER
Falls Creek	2009	0.80	2,160	Run-of-river	11659	Gustavus	Gustavus Electric
Lutak		0.25	780	Run-of-river	-	Haines	AP&T
10 Mile	1999	0.55	1,050	Run-of-river	-	Haines	IPEC
Annex Creek	1915	3.60	26,000	Storage	2307	Juneau	AEL&P
Snettisham	1973	78.20	325,000	Storage	-	Juneau	State of Alaska
Salmon Creek	1914	5.1	29,500	Storage	2307	Juneau	AEL&P
Lake Dorothy	2009	14.30	74,500	Storage	12379	Juneau	AEL&P
Gold Creek	1893	1.60	4,500	Run-of-river	-	Juneau	AEL&P
Swan Lake	1983	22.00	75,700	Storage	2911	Ketchikan	SEAPA
Ketchikan Lakes	1938,-52	4.20	22,200	Run-of-river	420	Ketchikan	KPU
Beaver Falls	1947-54	5.40	42,200	Storage	1922	Ketchikan	KPU
Silvis Lake	1968	2.10	12,400	Storage	1922	Ketchikan	KPU
Chester Lake	1984	1.00	7,170	Storage	-	Metlakatla	MPL
Purple Lake	1956	3.60	14,639	Storage	-	Metlakatla	MPL
Pelican	1985	0.70	449	Run-of-river	10198	Pelican	City of Pelican
Blind Slough	1924-54	2.00	11,000	Run-of-river	201	Petersburg	City of Petersburg
Black Bear Lake	1997	4.50	22,300	Storage	10440	Prince of Wales	AP&T
South Fork	2005	2.00	6,000	Run-of-river	-	Prince of Wales	AP&T
Pulp Mill Feed Unit	1993	0.87	Decom	Run-of-river	2230	Sitka	City of Sitka
Green Lake	1979	18.60	60,000	Storage	2818	Sitka	City of Sitka
Fish Valve Unit	1993	0.67	5,870	Run-of-river	2230	Sitka	City of Sitka
Blue Lake	1961	6.00	62,500	Storage	2230	Sitka	City of Sitka
Goat Lake	1997	4.00	20,600	Storage	11077	Skagway	AP&T
Kasidaya Creek	2008	3.00	10,200	Run-of-river	11588	Skagway	AP&T
Dewey Lakes		0.94	3,400	Run-of-river	1051	Skagway	AP&T
Tyee Lake	1984	24.00	120,000	Storage	3015	Wrangell	SEAPA

4.2.2.2 Existing Diesel Facilities

Every utility system has diesel generation that supplies loads or serves as backup generation to hydro. Table 4-3 presents the diesel and combustion turbine units in the Southeast.

Table 4-3 Diesel and Combustion Turbine Units in the Southeast

UTILITY SYSTEM	PLANT NAME - UNIT	COD	OUTPUT	HEAT RATE BTU/KWH	FIXED O&M $/KW-YR	VARIABLE O&M $/MWH
Alaska Electric Light & Power	Auke Bay 4	1983	2.2	10,500	6.36	28.75
	Auke Bay 13	1993	2.0	13,651	5.86	28.80
	Auke Bay 14(1)	1994	21.0	15,167	1.57	28.75
	Gold Creek IC3	1961	1.1	10,500	7.26	532.00
	Gold Creek IC4	1963	3.2	10,500	2.89	532.20
	Gold Creek IC1	1952	1.2	10,500	7.83	532.33
	Gold Creek IC2	1954	1.2	10,500	4.41	532.25
	Gold Creek IC5	1961	1.1	10,500	8.24	532.20
	Lemon Creek 5(1)	1980	16.0	15,167	1.58	31.29
	Lemon Creek 6(1)	1983	16.0	15,167	1.50	31.29
	Lemon Creek 1	1969	2.2	10,500	7.46	31.29
	Lemon Creek 2	1969	2.2	10,500	7.46	31.29
	Lemon Creek 3	1974	2.2	10,500	7.46	31.29
	Lemon Creek 7	1983	2.2	10,500	3.49	31.28
	Lemon Creek IC10	1984	2.2	10,500	3.49	31.28
	Lemon Creek IC11	1984	2.2	10,500	3.49	31.28
	Lemon Creek IC12	1984	2.2	10,500	3.49	31.28
	Lemon Creek IC8	1985	2.2	10,500	3.49	31.28
	Lemon Creek IC9	1985	2.2	10,500	3.49	31.28

UTILITY SYSTEM	PLANT NAME - UNIT	COD	OUTPUT	HEAT RATE BTU/KWH	FIXED O&M $/KW-YR	VARIABLE O&M $/MWH
Alaska Power & Telephone	Coffman Cove 1A	1997	0.32			
	Coffman Cove 2	1992	0.1			
	Coffman Cove 3	1992	0.235			
	Craig 1	1984	0.6	10,402	24.64	3.32
	Craig 3A	1991	1.6			
	Craig 5	1983	1.1			
	Craig 6	1989	1.1			
	False Island	2003	1.3	10,585	18.81	2.33
	Haines 10	1991	1.2	35,073	24.92	3.59
	Haines 5	1968	0.6			
	Haines 7A	1995	2.8			
	Haines IC8A	1996	1.6			
	Hollis 1A	1993	0.1	10,110		105.00
	Hollis-1C	1998	0.18			43.00
	Hollis-2	1990	0.09			
	Hollis-2B	1998	0.165			
	Hydaburg 1A	1990	0.4			
	Hydaburg 3	1983	0.3			
	Hydaburg 5	1985	0.3			
	Hydaburg 4	1980	0.9	12,787		
	Kasaan		0.246	10,425		238.00
	Naukati 1	1997	0.32	11,152		43.00
	Skagway 6A	1986	0.8	11,900	16.78	2.09
	Skagway 7A	1996	1.1			
	Skagway 8A	1991	0.5			
	Viking Lumber	2003	1.0	15,958	10.28	0.94
	Whale Pass 1	1995	0.07	11,206		306.00
	Whale Pass 2	1995	0.1			
	Whale Pass 3	2000	0.125			

UTILITY SYSTEM	PLANT NAME - UNIT	COD	OUTPUT	HEAT RATE BTU/KWH	FIXED O&M $/KW-YR	VARIABLE O&M $/MWH
City of Sitka Electric	Jarvis Street 1	1969	2.0	12,073	17.25	1.89
	Jarvis Street 2	1979	2.8	12,073		
	Jarvis Street 3	1979	2.8	12,073		
	Jarvis Street 4	2002	4.5	9,809		
City of Thorne Bay	Thorne Bay Plant 2	1993	0.6	20,119	8.03	0.77
	Thorne Bay Plant 4	1996	0.4			
Elfin Cove	No. 1	2007	0.101			
	No. 2	2007	0.0067			
	No. 3	2007	0.179			
Gustavus Electric Company	Diesel Plant		0.842	7,298		364.00
Inside Passage Electric Cooperative	Angoon Diesel 1	1975	0.4	10,950	30.05	4.25
	Angoon Diesel 1A	2009	0.5			
	Angoon Diesel 2A	1998	0.5			
	Angoon Diesel 3	1990	0.5			
	Hoonah Diesel 1	1977	0.6	10,016	83.67	6.19
	Hoonah Diesel 2A	1997	1.0			
	Hoonah Diesel 3	1991	0.8			
	Kake Diesel 1	1984	0.6	11,452	64.69	6.59
	Kake Diesel 2	1993	1.1			
	Kake Diesel 3A	1993	0.8			
	Chilkat Valley 2A	1991	0.5		30.05	4.25
	Chilkat Valley-1	1993	0.6		30.05	4.25
Ketchikan Public Utilities	North Point Higgins Sub 1-2	N/A	3.2			
	SW Bailey 1	1969	3.5	10,292	24.90	2.65
	SW Bailey 2	1970	3.5			
	SW Bailey 3	1976	5.5			
	SW Bailey 4	1998	10.5			
Metlakatla Power & Light	Centennial Power Plant-IC6	1987	3.3	16,958	29.37	3.94

UTILITY SYSTEM	PLANT NAME - UNIT	COD	OUTPUT	HEAT RATE BTU/KWH	FIXED O&M $/KW-YR	VARIABLE O&M $/MWH
Pelican Utility District	Pelican IC6	2008	0.4			
	Pelican IC7	2008	0.4	13,268	13.59	1.45
	Pelican IC8	2008	0.2			
Petersburg Municipal Power & Light	Petersburg IC1	1972	2.1			
	Petersburg IC2	1972	0.3			
	Petersburg IC3	1965	1.2			
	Petersburg IC4	1979	0.6	10,229	10.28	1.09
	Petersburg IC5	1979	0.8			
	Petersburg IC6	1993	2.5			
	Petersburg IC7	2001	2.5			
Wrangell Municipal Light & Power	Wrangell 11	2000	2.0			
	Wrangell 12	2000	2.0	10,734	10.28	1.12
	Wrangell 13	2002	2.0			
	Wrangell 9	1987	2.5	12,804	10.28	1.12
Yakutat Power	Yakutat Power Plant 2B	1999	0.8			
	Yakutat Power Plant 3A	1999	0.6	10,540	59.82	4.24
	Yakutat Power Plant 4A	1993	1.1			
	Yakutat Power Plant 6	2007	1.2			
Tenakee Springs	Tenakee 1	1992	0.125			
	Tenakee 2	1993	0.125			

(1)Combustion Turbines.

4.2.2.3 Existing Battery Energy Storage System

Metlakatla Power & Light (MP&L) installed a BESS to stabilize the community's utility grid by providing instantaneous power into the grid when demand was high from local industry, and to absorb excess power from the grid to allow its hydroelectric-generating units to operate under steady-state conditions. The traditional method for this operation was to baseload the hydro resource and use diesel generation to absorb the power fluctuations.

Before 1986, the Annette Hemlock Mill, the largest electricity customer on the Annette Island, used about one-third of the utility's total generation capacity. Although the mill's load fluctuated appreciably, MP&L could absorb the fluctuation without much problem. When the mill bought a chipper, the hydro-dominated system struggled to address load swings, which were estimated at about 500 kW. Despite adequate generation capacity to cover the increase load, hydro response time of approximately 10 seconds was too slow to follow load swings that occurred in about one-twentieth of a second.

In an attempt to solve the problem the utility purchased a 3.3 MW diesel system, bringing MP&L's generating capacity to just over 8 MW, which was twice the average base load. This, however, did not solve the problem. General Electric Co. (GE) and GNB Industrial Battery designed a BESS for MP&L in 1995. The BESS is capable of completely automatic, unattended operation, including charge, discharge, standby, ready, synchronization, disconnect, and black-start. The BESS consists of a power-conditioning system (PCS), AGC, batteries, racking and cables, and a building to house the system. The BESS connects to the MP&L's system at the 12.47 kV diesel substation.

The PCS is based on gateturn-off thyristors supplied by GE, and allows bidirectional power flow between the ac system and the battery in less than a quarter-cycle. The BESS can support a continuous load of 800 kVA and handle pulse loads up to 1200 kVA which was enough to support the 15 minute demand of the chipper at the mill. A 900 kVA filter bank removes the harmonics and compensates the voltage of the electrical signal. The AGC insures optimum integration of the BESS response and the operation of the hydro facility.

4.2.3 Committed Resources

Committed Resources are the transmission and hydro projects designated so by the Advisory Work Group as projects where the decision to develop them has already been made. These projects are identified in the resolution of the Advisory Work Group presented in Appendix D. In addition, the Advisory Work Group subsequently added the Gartina Falls Hydroelectric Project to the list of Committed Resources. The following sections provide a description of each of the Committed Resources along with their current status, budget, and schedule.

4.2.3.1 Transmission Projects

There are two Committed Transmission Projects, the Kake-Petersburg Intertie and the Ketchikan-Metlakatla Intertie. They were designated SEI-2 and SEI-3, respectively, in the 2003 Southeast Alaska Intertie Study conducted by D. Hittle & Associates, and the designations are maintained in this report. The following sections discuss the two projects.

4.2.3.1.1 Kake-Petersburg Transmission Line (SEI-2)

The Kake to Petersburg intertie will interconnect the community of Kake on Kupreanof Island to the SEAPA system.

The SEI-2 transmission line has been studied in reasonable detail in the past, including the 2005 Kake-Petersburg Intertie Study by D. Hittle & Associates, the 2009 Kake-Petersburg Intertie Study Update Draft Report by D. Hittle & Associates, and the 2010 Kake-Petersburg Intertie Study Update Final Draft Report by D. Hittle & Associates. There have been several routes considered with variations to each. The three main routes considered are described in the 2009 D. Hittle study as follows.

- *Northern Alternative* – (60.2 miles total length, one marine crossing) Generally located at the north end of Kupreanof Island. For the most part, this route follows the most likely route of a permanent road between Kake and Petersburg, as defined in the Southeast Alaska Transportation Plan (SATP) dated August 2004. There are two options related to this alternative. One involves a 3.1 mile submarine cable crossing just north of the mouth of Wrangell Narrows. The other option involves a proposed directional bore and installation of a pipe to house power cables under Wrangell Narrows near Petersburg.
- *Center-North Alternative* – (57.5 miles total length, one 0.6 mile long marine crossing) Connects to the existing Tyee transmission line south of Petersburg, crosses Wrangell Narrows, proceeds west across and then north on the Lindenberg Peninsula through the Petersburg Creek-Duncan Salt Chuck Wilderness where it intersects with the route of the Northern Alternative. Also referred to as the Wilderness Route.
- *Center-South Alternative* – (51.8 miles total length, two marine crossings totaling 1.6 miles) Originates at the same location near Petersburg as the Center-North route but continues northwest toward Kake across Duncan Canal, avoiding the Wilderness area.

Each route has pros and cons and a final route selection has not been made. Route selection is beyond the scope of this study. The 2010 D. Hittle report eliminates discussion of the Center-North Alternative. The 2010 D. Hittle update describes the two remaining routes as follows.

- *Northern Alternative* – (56.6 miles total length, one marine crossing) Generally located at the north end of Kupreanof Island. For the most part, this route follows the most likely route of a permanent road between Kake and Petersburg as defined in the Southeast Alaska Transportation Plan (AATP) dated August 2004. There are two options related to this alternative, Option 1 involves a 3.1 mile submarine cable crossing just north of the mouth of Wrangell Narrow. Option 2 involves a proposed horizontal directional bore and installation of a pipe to house power cables under Wrangell Narrows near Petersburg.
- *Center-South Alternative* – (46.6 miles total length, two marine crossings totaling 1.6 miles) Connects to the existing Tyee transmission line south of Petersburg, crosses Wrangell Narrows, proceeds west across the Lindenberg Peninsula, crosses Duncan Canal and continues northwest toward Kake.

Figure 4-5 presents the Northern Alternative and the Center South Alternative. For purposes of estimating costs, the Northern Alternative with Option 1 is used because it was the highest cost alternative presented in the 2010 D. Hittle update and, as such, provides the maximum amount of funding that will be required. Black & Veatch reviewed and revised the cost estimate based on the D. Hittle conceptual design and estimate from the 2010 D. Hittle report. The revised cost estimate is presented in Table 4-4, and is based on a 2015 commercial operation date with a two year permitting and licensing schedule and a two-year construction schedule. Escalation from the revised 2011 costs to the midpoint of construction and interest during construction from the midpoint of construction to the commercial operation date are included based on the economic parameters in Section 6.0. If the remainder of the project is grant funded prior to expenditures for construction, the interest during construction in Table 4-4 would not be necessary. The cost estimate for the Northern Alternate assumes that the road between Kake and Petersburg will be constructed.

Figure 4-5 Proposed Petersburg to Kake Interconnection (Northern and Center-South Routes)

Table 4-4 Estimated Cost of Project Development and Construction

	ESTIMATED COSTS
Overhead Line	
Material and Freight	
Poles	$1,474,322
Conductor	$1,058,487
Insulators	$764,021
Guys and Hardware	$500,394
Fiber Optic Cable (ADSS 24 Strand)	$390,964
Subtotal - Materials	$4,188,187
Labor	$10,296,375
Incidental and Other Direct Costs	
Camp Cost/ Food / Lodging	$1,405,679
Rockdrills and Blasting Materials	$310,383
Equipment and Tools	$699,358
Fuel and Maintenance	$699,358
Barge and Landing Craft	$177,078
Air Transportation	$88,539
Helicopter Use	$483,482
Mobilization and Demobilization	$530,238
Bond and Insurance	$159,171
Subtotal - Incidental and Other Direct Costs	$4,553,286
Subtotal - Overhead Line	$19,037,848
Clearing and Road Construction	
Clearing with Timber Credit	$1,512,125
Road Construction - Forested Areas	-
Road Construction - Muskeg Areas	-
Subtotal	$1,512,125
Submarine Cable - Wrangell Narrows S1-S2	
Cable - 3-500 kcmil copper bundled, 69-kV, 24 fiber strands	-
Fiber-Optic Cable System	-

	ESTIMATED COSTS
Installation	-
Cathodic Protection	-
Mob/Demob	-
Transition Structures	-
Subtotal	$13,517,033
Petersburg Tap Switchyard	
Civil Site Prep and Foundations	$71,627
Ground Grid and Fencing	$35,813
Bus Works	$32,829
Control Cable and Conduit	$21,886
SCADA and Control Interface	$17,907
Sectionalizing Switch (2)	$76,601
Disconnect Switches	$35,813
Breaker and CT	$98,487
Relaying, PT	$37,803
Revenue Metering	$46,756
Installation Labor	$89,534
Station Service and Battery	$89,534
Shunt Reactor and Disc SW	-
Subtotal	$654,591
Kake Substation	
Civil Site Prep and Foundations	$135,295
Ground Grid and Fencing	$44,767
Bus Works	$33,824
Control Cable and Conduit	$32,829
SCADA and Control Interface	$39,793
Fuses/Switches	$39,793
Transformer -69/12.5-kV, 2.5 MVA, Relaying, LA, etc.	$270,591
Voltage Regulators/Bypass Switches	$33,824

	ESTIMATED COSTS
Recloser/Disconnect Switch	$33,824
Relaying PT	$35,813
Installation Labor	$90,529
Station Service and Battery	$67,648
Subtotal	$858,529
Total Direct Costs	$35,580,125
Indirect Costs	
Construction Management (4 percent of Direct Costs)	$2,234,200
Owners Administration (4 percent of Direct Costs)	$2,234,200
Subtotal - Indirect Costs	$4,468,400
Contingency at 15 percent	$6,007,000
Interest During Construction (5.5 percent)	$2,533,000
Total Project Cost	$48,287,000

The 2010 D. Hittle update states that $2.6 million in costs in 2009 dollars are not included in the cost estimate in Table 4-4 for conducting the NEPA process to permit the interconnection and for final design, geotechnical surveys, alignment surveys, and structure staking. The 2010 D. Hittle update also indicates that Option 2 results in a savings of $5.9 million in 2009 dollars. If the Alaska DOT road is not constructed prior to the interconnection, the 2010 D. Hittle update estimates that Option 1 would cost $6.1 million more and Option 2 would cost $5.4 million more, both in 2009 dollars. The Alaska DOT estimated that there would be a combined $7.3 million savings in development costs by co-locating the intertie and the road.

The intertie is proposed to be constructed at 69 kV with single wood pole construction where feasible on the overhead portions. The line's capability at 69 kV will be more than adequate to carry Kake's loads for the foreseeable future. If the line is ultimately extended to Sitka and power from Takatz or other proposed projects is transferred on it, there may be transfer limitations. The 2010 D. Hittle update estimates that building the line at 138 kV would increase the cost $2.7 million and $3.7 million for Options 1 and 2, respectively, for the Northern Alternative and $3.0 million for the Center-South Alternative, with all costs being in 2009 dollars. Permitting issues for the intertie will vary with the route selection, and it is beyond the scope of this study to conduct a detailed permitting analysis. The permitting process will need to deal with the USFS Land Use Designations (LUDs) within the Tongass Natural Forest under the Tongass Land and Resource Management Plan requiring an Environmental Impact Statement (EIS). The Alaska Department of Transportation and Public Facilities (DOTPF) has an easement for constructing the Kake-Petersburg road which could be used for the Northern Alternative. The construction of the Kake-Petersburg Intertie will require federal, state, and local permits.

The Kwaan Electric Transmission Intertie Cooperative, Inc. (KWETICO) has received AEA Grant No. 2195414 for $2,990,000. This grant is for a number of items associated with the interconnection, including

- Completion of the participants' agreement, identifying an owner for the intertie, and determining a preferred route acceptable to stakeholders and the AEA.
- Accomplish all necessary tasks to facilitate the federal NEPA process for the project and design and permitting.
- Work with SEAPA to identify a preferred route that can be supported by SEAPA, IPEC, local governments in Kake and Petersburg, Petersburg Municipal Power and Light, and others.
- Work with the USFS for the second Federal Register notice planned by the USFS.
- Work with SEAPA and others to develop an approach for ownership of the transmission line, and the means to reasonably recover the costs of ownership operations and maintenance, that is satisfactory to AEA, local governments of Kake and Petersburg, and the rate payers of Kake and SEAPA.
- Facilitate the naming of the project advocate in the planned second Federal Register notice planned by the USFS.

Grant No. 2195414 indicates that $1,060,895 of the grant funds is unallocated, but that KWETICO expects to need those additional funds to complete additional environmental assessment and/or engineering work to get the project fully permitted. In KWETICO's application for Grant No. 2195414, KWETICO indicated that it had received or had access to $2.5 million in previous grants. The capital cost estimate in Table 4-4 does not include the tasks or costs associated with these grants. Thus the funding necessary to complete the project is that shown as the capital cost in

Table 4-4, subject to the potential adjustments discussed above. Grant No. 2195414 extends through 2013. The 2010 D. Hittle update indicates a two- to three-year construction schedule. Black & Veatch has assumed the permitting and development work will be completed in two years and construction will be completed in two years, resulting in a 2015 commercial operation date.

4.2.3.1.2 Ketchikan-Metlakatla Transmission Line (SEI-3)

MP&L currently has some surplus hydroelectric generation capacity that could be sold to Ketchikan or other utilities located in the Tyee-Swan region or Kake if SEI-2 is completed, and has an additional hydro project that could be developed. The Ketchikan--Metlakatla Intertie project is 17 miles in length and includes overhead and submarine components. The line will originate at KPU's Mountain Point substation and cross Revillagigedo Channel with a submarine cable to Walden Point on Annette Island, a cable crossing distance of about 3 miles. A 14-mile overhead line on Annette Island will extend from the cable landing point to an MP&L substation to complete the intertie. Control system upgrades to allow interconnected operation of the two systems will also be conducted. The proposed route is shown on Figure 4-6.

A previous study sized the line for a delivery of 8 MW from MP&L resources to KPU. The line was specified at 34.5-kV, which is adequate for the anticipated power loads as well as capable of accommodating higher power loads. KPU's transmission system at the Mountain Point substation is also at 34.5-kV. Overhead conductors for the line were specified to be 4/0 Penguin/AW and the submarine cable was specified to be a three conductor, bundled cable at 35-kV, 1/0 AWG.

Final design of the Ketchikan-Metlakatla Intertie is underway. Construction began in 2010 and approximately three miles of the overhead line is complete. The control system upgrades were completed in July 2011. As stated in its Round 5 Renewable Energy Fund Grant Application, the Metlakatla Indian Community (MIC) owns and will operate the intertie. MIC has applied for a Round 5 Renewable Energy Fund Grant of $8,225,200 for the project. MIC has received grants of $500,000 from, the Denali Commission, $2,000,000 from Alaska Energy Authority, and $2,000,000 from the state of Alaska, for total obtained grants of $4,500,000. Electric Power Systems, Inc (EPS) has been retained to provide engineering and design services for the overhead line, to provide specifications for the submarine cable, and design of the submarine cable termination facilities. Poles and hardware for the overhead line have been ordered.

MIC has authority over all aspects related to land ownership and site approval for the overhead portion of the line located on Annette Island. The following permits are expected to be required for the submarine cable:

- Army Corps of Engineers Permit
- State Fire Marshall
- US Coast Guard Notification
- NOAA Notification
- Alaska DOT
- Ketchikan Gateway Borough Planning

MIC expects the permitting process to take 6 months after completion of field research and studies and to be completed by January 2013.

Figure 4-6 Proposed Ketchikan to Metlakatla Interconnection (SEI-3)

MIC's schedule for the project as stated in its Round 5 Grant Application is presented in Table 4-5.

Table 4-5 Project Schedule

Complete Design	November 2011
Select Project Manager	November 2011
Select Consultant for Permitting Services	November 2011
Complete Field Research and Studies	June 2012
Complete Permitting	January 2013
Initiate Power Sales Negotiations	October 2011
Complete Power Sales Negotiations	May 2012
Request Bids for Materials and Construction	February 2012
Begin Overhead Line Construction	June 2010
Install Submarine Cable	March 2013
Complete Construction	May 2013

MIC's estimated total cost for the project, as stated in its Round 5 Grant Application, is presented in Table 4-6. The estimate was prepared in January 2010 by EPS. While the Round 5 Grant Application does not specify, it is presumed that the estimate is in 2010 dollars. The Round 5 Grant Application is for $8,225,200, which together with the $4,500,000 of grants already obtained, would cover the entire cost of the project. Since construction is not scheduled to be completed until May 2013, there is some concern that potential escalation could increase the cost such that the Round 5 requested grant would not be adequate to cover the entire project cost. MIC estimates that annual O&M and R&R expenses will be $60,000 and $50,000, respectively.

Table 4-6 Estimated Cost of Project Development and Construction

WALDEN POINT ROAD TRANSMISSION LINE	
Overhead Line	3,713,000
Chester Lake Underground Line	504,000
Overhead Double-Circuit Rebuild	415,000
Subtotal	**4,632,000**
SUBSTATION IMPROVEMENTS	
Mountain Point	112,000
Centennial Plant	321,000
Subtotal	**433,000**
SUBMARINE CABLE	
Materials	1,267,200
Installation	2,870,000
Subtotal	**4,137,200**
METLAKATLA CONTROL SYSTEM UPGRADES	
Hydroelectric Plant Controls	556,000
SCADA Controls	146,000
Substation Modifications for Interconnection	200,000
Subtotal	**902,000**
TOTAL PROJECT COST	
Materials and Installation	10,104,200
Indirect Costs	
Engineering, Field Surveys, Staking	500,000
Permitting	200,000
Owner’s Administration	200,000
Subtotal - Indirect Costs	**900,000**
Contingency - Nonsubmarine Cable (10 percent)	687,000
Contingency - Submarine Cable (25 percent)	1,034,000
Total Project Cost	**12,725,200**

4.2.3.2 Hydro Projects

There are five committed hydro projects.

- Blue Lake Expansion Hydro (Sitka)
- Gartina Falls Hydro (Hoonah)
- Reynolds Creek Hydro (Prince of Wales)
- Thayer Creek Hydro (Angoon)
- Whitman Lake Hydro (Ketchikan)

The following sections discuss the projects.

4.2.3.2.1 Blue Lake Expansion Hydro

The existing Blue Lake Hydroelectric Plant has two 3.0 MW generating units, a 0.7 MW Fish Valve Unit, and a 0.9 MW Pulp Mill Feed Unit owned and operated by the city of Sitka. The Blue Lake Expansion Project will include:

- Increasing the height of the Blue Lake Dam by 83 feet, to increase the maximum gross head of the plant from 329 feet to 413 feet.
- Modification of the waterways from the dam to the powerhouse, including the addition of a surge chamber.
- Decommissioning of the existing 6 MW powerhouse and construction of a new powerhouse with three 5.3 MW (nominal capacity) generating units.
- Modification to the existing switchyard.
- Relocation of the existing Sitka electric system control center to the new Blue Lake powerhouse.
- Replacement of the Fish Valve Unit with a new unit designed for higher operating head.
- Decommissioning of the Pulp Mill Feed Unit.

The Expansion Project will provide 8 MW of additional capacity and an additional annual average of 34,500 MWh, as shown in Table 4-7.

Table 4-7 Blue Lake Expansion Project Average Generation

MONTH	GENERATION(1) (MWH)
January	3,780
February	3,326
March	3,571
April	3,038
May	3,038
June	2,760
July	2,500
August	2,300
September	2,700
October	1,550
November	2,400
December	3,000
Annual	34,500

(1)Incremental generation compared to the existing Blue Lake Hydro Project.

The Blue Lake Expansion Project will require an amendment to the FERC license. The Application for Capacity-Related Amendment Blue Lake Hydroelectric Project (FERC No. 2230) Expansion was filed in November 2010. The Final Draft Environmental Assessment was also filed in November 2010. The requisite studies have been conducted and the resulting draft plans have been filed. The FERC License Amendment is expected to be received in December 2011, a month later than scheduled.

The project was originally scheduled for completion in October 2014. Sitka has recently postponed the advertising for bids for the construction contract due to a delay in the anticipated date of receiving the FERC License Amendment and concerns that the construction contractor may be delayed in starting, such that the first season construction work required for the new intake structure could not be completed. The procurement process for equipment is continuing. The current schedule is to issue the General Construction contract documents for bid in early May 2012, followed by a Notice to Proceed in September or October 2012 with the contractor mobilizing in late 2012 and beginning major construction efforts in the lake and powerhouse areas in January 2013, with project completion in October 2015.

Table 4-8 presents the estimated capital cost. The estimated capital cost was developed prior to the recent year delay in completion. To account for that delay, one additional year of escalation is applied based on the 3 percent escalation rate in Section 6.

Table 4-8 Blue Lake Expansion Cost Estimate

DESCRIPTION	COST ($1000)
Preparatory Work	8,320
Arch Dam Raise	8,900
Intake Tunnel and Gate Shaft Excavation	3,730
Surge Chamber Excavation	4,060
Intake Civil Works and Equipment	1,530
Tunnel Refurbishment	1,950
New Penstock	3,750
Powerhouse Civil and Access Road	7,646
Powerhouse Mechanical Equipment	8,938
Powerhouse Electrical Equipment	8,500
Switchyard Upgrade	1,732
Subtotal	**59,060**
Escalation During Construction	780
Direct Construction Cost	**59,840**
Contingency (25 percent)	14,960
Engineering and Owner Admin. (12.5 percent)	9,350
Total Construction Cost (Jan. 2010 bid)	**84,150**
Interest During Construction	4,170
Total Investment Cost (Jan. 2010 bid)	**88,320**
Escalation	5,380
Total Investment Cost (Jan. 2012 bid)	**93,700**
Escalation for 1 Year Delay (3 percent)	2,800
Total	**96,500**

The total estimated capital cost is $96.5 million for October 2015 commercial operation. Sitka has received or been approved for a total of $49 million in state funding. In 2010, Sitka conducted a bond issue with $20 million of net proceeds for the project. Table 4-9 presents the existing funding and remaining requirements.

Table 4-9 Blue Lake Expansion Funding Requirements

FUNDING SOURCE	AMOUNT ($ MILLION)
Capital Cost	96.5
Approved State Funding	49.0
Bond Proceeds	20.0
Remaining Requirements	27.5

The remaining capital requirements for the Blue Lake Expansion Project are $27.5 million.

4.2.3.2.2 Gartina Falls Hydro

The Gartina Falls Hydroelectric Project is located on the northeast side of Chichagof Island approximately 5 air miles southeast of Hoonah. Gartina Creek is a low-gradient stream that originates in the mountains to the south of Hoonah Harbor. The project will consist of a small diversion dam and intake just above Gartina Falls, a steel penstock, a powerhouse located at the base of Gartina Falls, access roads, and a 4.5 mile 12.5 kV transmission line. The estimated capacity is 455 kW. Gartina Falls will be a run-of-river project supplying power to Hoonah. Table 4-10 presents the estimated annual average generation. The project has a dependable capacity of 110 kW. The project will be operated automatically and controlled remotely from the diesel power plant in Hoonah.

The project will be owned and operated by IPEC. The project is being licensed under FERC's Traditional Licensing Process. IPEC was issued a Preliminary Permit on September 12, 2011. IPEC will request early scoping following the submittal of the Pre-Application Document. Table 4-11 presents IPEC's licensing schedule. The project is projected to be in commercial operation in 2015.

The estimated project cost is $5.79 million in 2011 dollars and is presented in Table 4-12. Three years of escalation based on the escalation rate in Section 6, will add another $537,000 to the capital cost. IPEC has received previous grants totaling $850,000, leaving estimated remaining costs of $5.48 million to reach commercial operation. Annual O&M costs and insurance costs are estimated to be $55,000 and $60,000, respectively.

Table 4-10 Gartina Falls Project Average Generation

MONTH	GENERATION (MWH)
January	117.5
February	105.4
March	112.3
April	177.3
May	247.5
June	167.8
July	85.1
August	82.1
September	160.2
October	231.0
November	172.5
December	148.4
Annual	1,807

Table 4-11 Gartina Falls Licensing Schedule

ACTIVITY	RESPONSIBLE PARTIES	TIME FRAME
Distribution of Consultation Information Packet and Request for Information	IPEC	August 5, 2011
Project Site Visit	Stakeholders, Agencies, IPEC, FERC	August 11, 2011
Request for Support of TLP	IPEC, Agencies	September 27, 2011
File NOI, PAD and Request to Use the TLP with FERC	IPEC	Early October
Public Comment Period on Use of TLP	Stakeholders, Agencies	30 days following submittal of PAD/NOI(1)
FERC Determination on Request to Use TLP	FERC	No later than 30 days following close of public comment period
Joint Public/Agency Meeting	Stakeholders, Agencies, IPEC	~November 15(2) or the week of December 5-9
Comments on PAD Due	Stakeholders, Agencies, FERC	~January 15, 2012 (60 days following Joint Meeting)
Potential Early Scoping by FERC	FERC	TBD
Consultation Meetings to Develop License Application and Protection, Mitigation, and Enhancement Measures	Stakeholders, Agencies, IPEC	December 2011 - February 2012, as needed
Request for Waiver of Draft License Application and Submittal of License Application	IPEC	~February 15, 2012
Comment on License Application	Stakeholders, Agencies, FERC	Comments due no later than 90 days following submittal of license application

(1)IPEC will request that FERC shorten the 30-day comment period for public and agency comment on use of the TLP to allow for a mid-November Joint Meeting. IPEC is soliciting support for use of the TLP from resource agencies and other interested parties prior to filing the PAD, and will submit responses to this request with its PAD/NOI filing in early October.

(2)If FERC approves use of TLP and IPEC's proposed schedule, a Joint Meeting will be held on approximately November 15. A Joint Meeting will be in early December if FERC does not approve the proposed schedule, or if agency representatives' schedules do not allow for a November meeting date.

Table 4-12 Gartina Falls Capital Cost ($2011)

PROJECT COSTS	
Direct Construction Costs	3,600,000
Contingency	900,000
Engineering	360,000
Licensing	370,000
Owners General Administration	180,000
Construction Management	180,000
Interest During Construction	200,000
Total	**5,790,000**

4.2.3.2.3 Reynolds Creek Hydro

The Reynolds Creek hydroelectric project is located 10 miles east of Hydaburg on Prince of Wales Island. The project is a joint venture between Haida Energy Inc. and AP&T. The project consists of the following

- Dam: 20 foot long dam, 6 foot high, concrete diversion dam with an uncontrolled spillway.
- Penstock: 42 inch diameter, 3,200 foot long steel penstock.
- Powerhouse: pre-engineered insulated metal powerhouse on a concrete slab with one 5 MW generating unit.
- Switchyard/Substation: 6 MVA switchyard/substation located next to the powerhouse.
- Transmission Line: Overhead 34.5 KV 12 mile long transmission line to AP&T's system.

The Reynolds Creek Hydro project will provide 5 MW of capacity and approximately 19,000 MWh of annual average energy as shown in Table 4-13.

The project is under construction, with current work including the following:

- Civil access.
- Transmission line.
- Award of geotech contract.
- Ordering turbine/generator.
- Final design.

The projected commercial operation date is 2014.

The project cost estimate is presented in Table 4-14.

Table 4-13 Reynolds Creek Project Average Generation

MONTH	GENERATION (MWH)
January	1,598
February	1,594
March	912
April	1,298
May	2,246
June	2,312
July	980
August	1,093
September	1,394
October	2,533
November	1,935
December	1,381
Annual	19,276

Table 4-14 Reynolds Creek Project Cost Estimate

PROJECT COST ESTIMATE	
HDR EOR Project Estimate	$22,750,000
Task Order No. 5 HDR	$100,000
Project Management Agreement (Comp. Reg.)	$100,000
HDR 2010 Outstanding Liabilities Task Order No. 4	$607,548
SEC Grant Admin. (Rev. 1 3-14-11)	$5,628
ADDITIONS TO CONSTRUCTION ESTIMATE	
HDR 2011 Outstanding Liabilities Task Order No. 4	$29,873
AP&T 2010 Outstanding Liabilities	$88,450
PM Team Recommended Civil Budget Increase	$500,000
Total Required to Complete Project	**$24,181,499**
Haida Energy Inc. Previous Expenditures	$4,000,000
AP&T Previous Expenditures	$400,0000
Total Project Cost	**$28,581,499**

Project funding commitments and shortfalls are presented in Table 4-15.

Table 4-15 Reynolds Creek Hydro Project Funding Commitments and Shortfalls

Funding Commitments	
AEA Grant (SEC No. 2195323)	$2,000,000
AEA Grant (HC No. 2195440) Unsigned	$2,000,000
DOE Grant (DE-EE0002502.000) (Rev. 1, 3-14-2011)	$1,120,000
APC Transmission Line Grant (Unsigned)	$2,000,000
Total Funding Commitments (6-14-2011)	$7,120,000
Project Construction Funding Short Fall	$17,061,499
AEA Loan (Resolution No. 2010-01)	$9,000,000
AP&T Transmission Line AEA Renewable Energy Fund Grant Round 5 Application	$1,200,000
Additional Funds Required	$6,861,499

The $9,000,000 AEA Loan was authorized as part of an $11,000,000 authorization in Senate Bill 42 for the project during the 27th Legislative Session in 2011.

The Reynolds Creek Hydro project has value engineering options and possible Alaska Department of Fish & Game repermitting conditions that could reduce the project costs $1,000,000. Note that several of the funding commitments have not been signed and the Round 5 Renewable Energy Fund Grant has not been awarded.

4.2.3.2.4 Thayer Creek Hydro

The Thayer Creek Hydro project will be located 6 miles north of the city of Angoon within Admiralty Island National Monument and Kootznoowoo Wilderness. The project will be a run-of-river project including the lower 8,500 feet of Thayer Creek. The project would consist of the following facilities as described in the July 2010 Forest Service Issue paper.

- 10 foot high diversion dam on Thayer Creek.
- 10 to 20 acre impoundment above the diversion dam.
- 1.2 mile 42 inch diameter pipeline from the intake structure to the powerhouse.
- 510 foot long, 36 inch diameter penstock.
- 30 foot 68 foot by 25 foot powerhouse with two generating units.
- 2.1 mile access road from the powerhouse to the diversion dam.
- 1.4 mile road from near the powerhouse to the diversion dam/intake structure.
- 2.2 mile 12.5 kV transmission line segment.
- 0.5 mile submarine cable from the northern shore of Kootznoowoo Inlet to Angoon.
- Two switchyards where the submarine cable enters and exits Kootznoowoo Inlet.

The project is estimated to provide 1 MW of capacity and approximately 8,400 MWh of average annual energy. A feasibility study was conducted by HDR in March 2000. The project could be designed for greater output, but is limited by loads for Angoon. Table 4-16 presents the estimated average monthly energy.

Table 4-16 Thayer Creek Hydro Project Average Generation

MONTH	GENERATION (MWH)
January	658
February	621
March	652
April	699
May	743
June	720
July	743
August	736
September	713
October	743
November	709
December	709
Annual	8,446

The project will be owned by Kootznoowoo, Inc. The power will be sold to IPEC for the city of Angoon. The Alaska National Interest Lands Conservation Act, Section 506(a)3(B) granted Kootznoowoo, Inc., the right to develop the project, subject to such conditions as the secretary of agriculture shall prescribe for protection of water, fishery, wildlife, recreational, and scenic values of Admiralty Island. In January 2001, FERC issued an order finding that FERC lacked jurisdiction to issue a license for the project. Even though the project is not required to be licensed by FERC, Forest Service guidelines for implementing the project in wilderness still apply. The Forest Service would authorize the project through issuance of a special use authorization.

In 2003 Kootznoowoo, Inc., requested the Forest Service begin the NEPA work for the project and issue the authorization. An EIS was developed and on May 8, 2009, the forest supervisor signed the Record of Decision (ROD) selecting Alternative 3 from the Final Environmental Impact Statement (FEIS).

The ROD requires many general and specific terms and conditions, including the following:

- All transmission lines will be buried. Exceptions due to difficulties related to terrain may be authorized on a site-specific basis.
- A minimum instream flow of 40 cubic feet per second be maintained at all times in the Thayer Creek bypass reach.
- All water not needed for power generation be returned to Thayer Creek at the diversion dam and sent through the bypass reach.
- The tailrace discharge will be returned above or immediately below the lowest anadromous fish barrier on Thayer Creek.
- The road from the marine facilities to the powerhouse be routed to minimize effects to karst, streams, and steep slopes along Thayer Creek.
- The term for the special use authorization will be 30 years.

The appeal period for the ROD ended July 7, 2009 without an appeal. Before construction can begin, Kootznoowoo, Inc. must obtain all necessary federal and state permits including the Forest Service's special use authorization. This requires submittal of design plans, site plans, and specifications necessary to assure consistency and compliance with the ROD.

The estimated cost for the Thayer Creek Hydro project is presented in Table 4-17.

Table 4-17 Thayer Creek Hydro Capital Cost Estimate

Reconnaissance, Feasibility, Environmental	$2,200,000
Preconstruction, Engineering, Permitting, Design and Construction	$2,221,000
Construction Costs Generating Facility	$4,732,402
Construction Cost Transmission Facility	$4,784,000
Contingency	$1,263,706
Total	$15,201,108

Kootznoowoo, Inc., has two applications for the AEA's Renewable Energy Fund Round 5 Grant. One application is for $3.5 million for the generation facilities and the other application is for $3.5 million for the transmission facilities. The Round 5 applications indicate a total of $2,156,402 in project match from other funds. The remaining funding needed is $13 million without the Round 5 applications and $6 million if both applications are fully granted.

The project's schedule as presented in the Round 5 applications is presented in Table 4-18.

Table 4-18 Thayer Creek Hydro Schedule

Confirmation that all design and feasibility requirements are complete	September 2012
Completion of Bid Documents	October 2012
Bidding, Feedback and Bid Awards	January 2013
Road Construction – Generation Facility	Spring/Summer 2013
Road Construction – Transmission Line	Spring/Summer 2013
Power House Construction	Spring/Summer 2013
Transmission Line Construction	Spring/Summer 2013
Integration and Testing	Fall 2013
Decommissioning Old Systems or System Integration	Winter 2013
Final Acceptance, Commissioning and Startup	Spring 2014
Operations Reporting	Spring 2014

Based on past slippage in the schedule, Black & Veatch has assumed a more conservative January 1, 2016 commercial operation date.

4.2.3.2.5 Whitman Lake Hydro

The Whitman Lake Hydroelectric project will be located about 4 miles from the city of Ketchikan. The project will provide 4.6 MW of capacity in two units from the existing dam. Unit 1 will generate power with water that would otherwise be spilled. Unit 2 will generate power from water delivered to a fish hatchery located adjacent to the project. The project will operate in cooperation with the Whitman Lake Hatchery which is owned and operated by the Southern Southeast Regional Aquaculture Association. The Whitman Lake Hydro project is expected to provide approximately 16,000 MWh of average annual energy, as presented in Table 4-19.

Ketchikan Public Utilities owns and will operate the project. KPU received a FERC license for the project on March 17, 2009, and has also been granted a two-year extension to begin construction. The extension requires that construction begin by March 16, 2013, and be completed by March 15, 2016. The construction schedule has been sliding since the issuance of the FERC permit. The last commercial operation date that Black & Veatch had access to was 2014, which is the commercial operation date that Black & Veatch has assumed in the economic evaluations. Figure 4-7 presents a detailed construction schedule provided by KPU. The schedule has a project startup date of July 23, 2013, based on an equipment award date of October 14, 2011. Given that construction is less extensive due to the existing dam, the 2014 commercial operation appears feasible.

Table 4-19 Whitman Lake Project Average Generation

MONTH	GENERATION (MWH)		
	UNIT 1	UNIT 2	TOTAL
January	290	485	775
February	359	459	818
March	182	443	625
April	389	392	781
May	1,405	510	1,915
June	1,700	516	2,216
July	1,180	519	1,699
August	786	500	1,286
September	932	489	1,421
October	1,635	531	2,167
November	719	513	1,233
December	479	518	997
Total	**10,057**	**5,874**	**15,932**

The estimate capital cost provided by KPU for the Whitman Lake Hydro project is presented in Table 4-20 in 2010 dollars along with a summary of existing grants and KPU Cash Reserves for the project. Black & Veatch has added three years of escalation as presented in Section 6 to the remaining funds required. Table 4-20 indicates that an additional $13.4 million will be required. KPU also listed the following financing costs:

- Reserve Fund $1,200,000
- Financing and Legal $400,000
- Working Capital $100,000
- Total $1,700,000

KPU provided the following annual costs in 2010 dollars:

- O&M Cost $250,000
- Administrative and General $100,000
- Insurance $20,000
- Interim Replacements $20,000
- Total $390,000

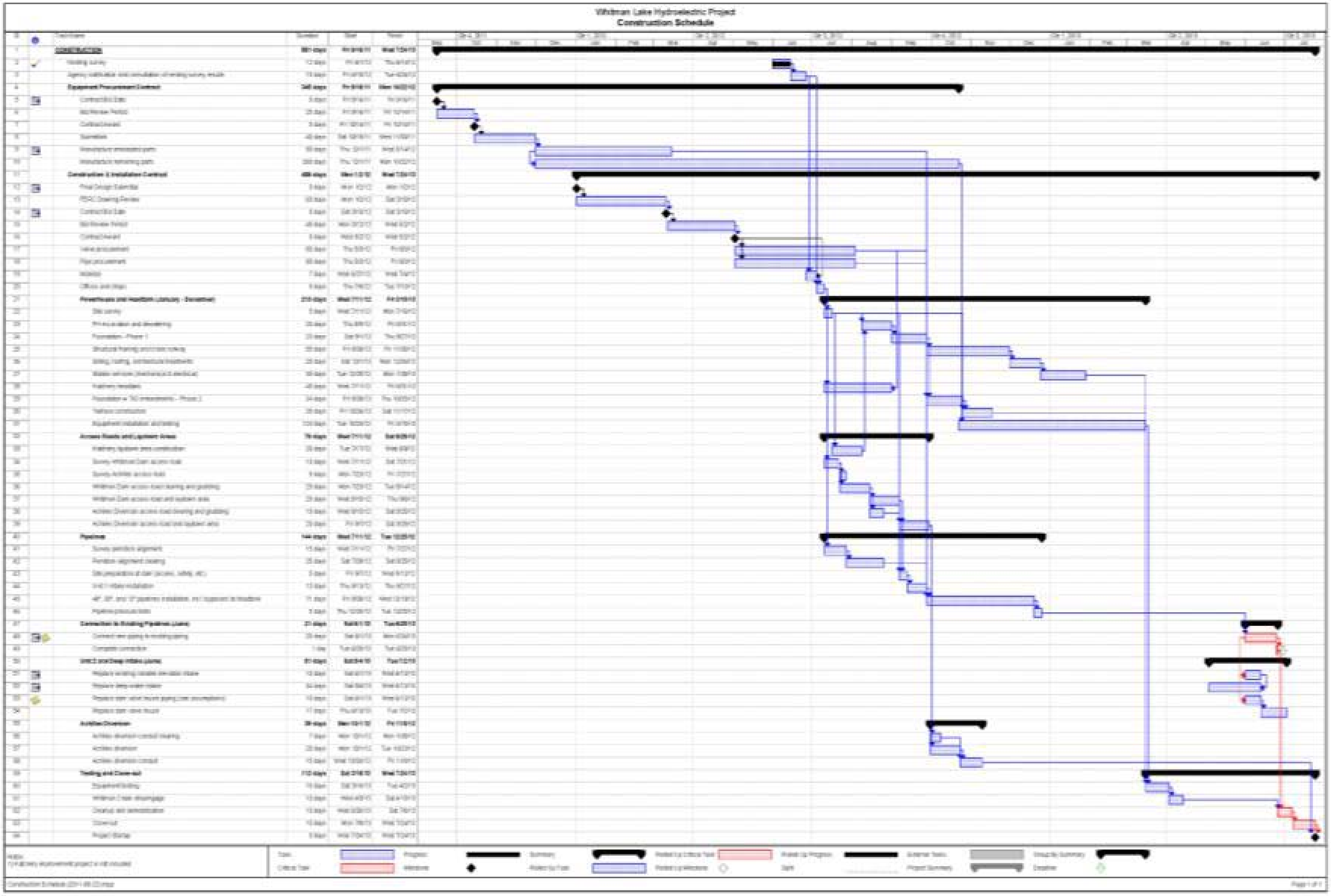

Figure 4-7 Whitman Lake Hydro Project Construction Schedule

Table 4-20 Whitman Lake Hydroelectric Project Cost Estimate

ITEM	ESTIMATED COST (2010$)
Land and Land Rights	370,000
Structures and Improvements	3,510,000
Reservoirs, Dams, and Waterways	6,230,000
Turbines and Generators	4,960,000
Accessory Electrical Equipment	360,000
Miscellaneous Power Plant Equipment	110,000
Switchyards	1,130,000
Overhead Conductors and Devices	100,000
Poles and Fixtures	--
Direct Construction Cost	**16,770,000**
Contingencies	2,520,000
Engineering and Owner Administration	3,240,000
Hatchery Mitigation	1,290,000
Hatchery Mitigation Engineering	230,000
Indirect Construction Cost	**7,280,000**
Total Engineering and Construction Cost	**24,050,000**
AEA Round I Grant	(1,300,000)
AEA Round IV Grant	(700,000)
2011 State Legislative Grant	(1,000,000)
2012 State Legislative Grant	(8,025,000)
KPU Cash Reserves	(1,400,000)
Engineering and Construction Cost to be Financed	**11,625,000**
Interest During Construction	640,000
Total Investment Cost	**12,265,000**
Three Years Escalation	1,137,000
Total Additional Requirements	**13,402,000**

4.3 UTILITY SYSTEMS

4.3.1 Southeast Alaska Power Agency

The Southeast Alaska Power Agency (SEAPA) began as the Four Dam Pool. The Four Dam Pool Project began in the early 1980s when the state of Alaska constructed or acquired four hydroelectric facilities. The Alaska Legislature provided that the four projects would be treated as one project that would be operated and managed jointly and further required that they would share risks and charge equal wholesale power rates to each of the five member utilities. These projects (Terror Lake, Solomon Gulch, Swan Lake and Tyee Lake) were initiated by the Alaska State Legislature in 1981 as part of the Energy Program for Alaska in response to the increasing and uncertain costs of diesel generation. These facilities and related transmission lines were placed into service between 1981 and 1985. A long-term power sale agreement was signed in 1985 between the state of Alaska and the member utilities receiving power from these state-owned hydro facilities. The member utilities were Kodiak Electric Association, Copper Valley Electric Association, and the cities of Ketchikan, Wrangell, and Petersburg.

In 1995, the member utilities began discussions with the state of Alaska to purchase the projects. This effort culminated successfully on January 31, 2002. As a result of this sale, The Four Dam Pool Power Agency (FDPPA) was created. The proceeds from the sale of the projects were used to establish the Power Cost Equalization Endowment which is used to partially offset the very high electricity rates in many of the smaller communities in the state.

In 2006, the member utilities of the FDPPA began discussions to diversify the agency, whereby one or more projects could be sold back to the member utilities. This effort was also successful, and on February 24, 2009, the FDPPA sold or transferred the Terror Lake project to Kodiak Electric Association and the Solomon Gulch project to Copper Valley Electric Association.

The Agency became the SEAPA to better reflect the geographic location of the remaining projects (Swan Lake and Tyee Lake). In addition, SEAPA completed construction of the STI, which interconnected the Swan Lake and Tyee Lake projects. As a result, all of the remaining member utilities (Ketchikan, Wrangell, and Petersburg) are interconnected and the hydroelectric projects can be more efficiently operated and existing surplus power from the Tyee Lake project can be used to displace diesel generation in Ketchikan.

4.3.1.1 Ketchikan Public Utilities (KPU)

KPU was created in 1932 when the city of Ketchikan purchased the Citizen’s Light and Power Company, which first started delivering power to Ketchikan in 1903. KPU is owned by the citizens of Ketchikan and makes every effort to be responsive to the needs and desires of the community.

KPU owns and operates Ketchikan Lakes Hydro Project, and Beaver Falls Hydro Project (which includes Silvis Lakes). KPU operates the Swan Lake Hydro Project, which is owned by SEAPA. Ketchikan also receives surplus energy (when available and as needed) via SEAPA’s STI transmission line, which now connects the community to Wrangell and Petersburg’s electrical grids.

Ketchikan’s total hydro capacity is approximately 34 MW, including both KPU and SEAPA-owned projects. KPU maintains four peaking/standby diesel generators at Bailey Powerhouse totaling 24 MW, and two other diesel generators at the North Point Higgins Substation totaling 3.2 MW. The diesel generators provide power to the community in times of low reservoir levels, hydro maintenance periods, and for emergency use during outages.

KPU's infrastructure includes seven distribution substations, 30 miles of 34.5 kV sub-transmission lines, and nearly 100 miles of 12.47 kV distribution lines, and nearly 7,700 electric meters.

Saxman located immediately south of Ketchikan is served by KPU.

4.3.1.2 Petersburg Municipal Power & Light (PMP&L)

PMP&L is a municipally owned electric utility providing electric service to approximately 2,000 customers on Mitkof Island. The utility's primary source of electrical energy is the Tyee Hydroelectric Power Project. The Tyee project is part of SEAPA and can produce 20 MW of hydropower. Tyee presently has adequate capacity to serve the Petersburg area. PMP&L also owns, operates, and maintains the 2 MW Blind Slough Hydro project. The utility also has a standby 10 MW diesel generation plant sufficient to meet the electrical demand in the event of an outage at Tyee.

The SEAPA transmission line comes ashore about 1/2 mile from the new South Mitkof Island Ferry terminal. The transmission line runs from there to a substation at Scow Bay. The PMP&L-owned electrical distribution system for the entire island begins at Scow Bay. The newer portion of the distribution system is energized at 14.4/24.9 kV, with the older portion of the system energized at 2.4 kV. The majority of the downtown area was rebuilt using underground construction. PMP&L has approximately 300 miles of overhead and five miles of underground distribution.

4.3.1.3 Wrangell Municipal Light & Power (WMLP)

Wrangell is located on Wrangell Island in the heart of the Tongass National Forest, approximately 75 miles northwest of Ketchikan and 30 miles southeast of Petersburg. WMLP is a municipally owned utility providing electric service to approximately 1,800 customers in the Wrangell area. WMLP obtains the majority of its power through SEAPA from the Tyee Hydro Project. WMLP also operates a four-unit diesel plant with 8.5 MW of total capacity that provides backup to hydroelectric power. Wrangell's distribution system consists of 21.3 miles of overhead distribution and 1 mile of underground distribution at 7.2 kV.

4.3.2 Alaska Power and Telephone (AP&T)

AP&T is a diversified investor-owned utility serving several communities in Southeast Alaska through its wholly owned energy subsidiaries, Alaska Power Company, BBL Hydro, Inc., and Goat Lake Hydro, Inc., AP&T's service territory in southeast Alaska is divided into three areas, Prince of Wales Island, Lynn Canal, and Whale Pass.

AP&T owns and operates hydroelectric and diesel generating facilities. AP&T's conventional hydroelectric facilities include Dewey Lake, Goat Lake, Kasidaya Creek, Lutak, Black Bear, and South Fork. AP&T operates diesel units to supplement its hydroelectric generation.

4.3.2.1 Prince of Wales Island

AP&T serves the following communities on Prince of Wales:

- Coffman Cove
- Craig
- Hollis
- Hydaburg
- Kasaan
- Klawock
- Naukati
- Thorne Bay

All of the communities are interconnected and receive hydropower from Black Bear Lake and South Fork except for Coffman Cove and Naukati, which are solely supplied by diesel. Transmission lines to interconnect Coffman Cove are under construction and a transmission line to interconnect Naukati is planned for 2012. The Prince of Wales transmission system is 34.5 kV.

4.3.2.2 Haines-Skagway

AP&T serves the Haines-Skagway area with hydro power from Goat Lake, Dewey Lakes, Kasidaya, and Lutak projects.

4.3.2.3 Whale Pass

Whale Pass is served by AP&T from local diesel generation. Whale Pass is not interconnected to other systems.

4.3.3 Alaska Electric Light & Power (AEL&P)

AEL&P is an investor-owned electric utility serving the cities of Juneau, Douglas, and Auke Bay. In addition to serving retail customers, AEL&P has Power Sales Agreements with Princess Cruise Lines and the Greens Creek Mine. These are interruptible contracts and both of these customers own and maintain their own diesel generation for periods when AEL&P cannot serve them with hydroelectric power.

AEL&P owns and operates hydroelectric and fossil fuel fired generating units. The hydroelectric resources include Gold Creek, Salmon Creek, Annex Creek, Snettisham, and Lake Dorothy. The Snettisham hydroelectric project was built and is owned by the federal government, and AEL&P operates the project. The Snettisham project has two stages, the Long Lake Stage and the Crater Lake Stage.

AEL&P operates a number of fossil fuel fired generators. The Gold Creek fossil plant consists of five slow speed diesel engines that are used as backup when Snettisham is off-line for an extended period. The Lemon Creek fossil plant consists of nine Electro Motive Division diesel engines and two gas turbines that are also used as backup when Snettisham is on outage. The Auke Bay fossil plant has a Solar Centaur Gas Turbine that runs on either diesel or natural gas. This plant is also used for backup of the Snettisham hydroelectric project.

4.3.4 Inside Passage Electric Cooperative (IPEC)

IPEC is a nonprofit, independent electric utility owned by the members it serves. IPEC operates in five service areas, four of which are not interconnected to each other. These areas are Angoon, Kake, Hoonah, and Klukwan/Chilkat Valley. IPEC operates diesel generating units in all four areas and purchases hydroelectric power in the Klukwan/Chilkat Valley area. IPEC recently purchased the 10 Mile Hydro project from Southern Energy.

4.3.4.1 Angoon

The diesel plant in Angoon consists of three Caterpillar generators operating on diesel fuel. Power is provided to customers over a three-phase overhead distribution system. IPEC is supportive of the Thayer Creek hydro project which will have enough capacity to serve all of Angoon's electrical needs.

4.3.4.2 Hoonah

The diesel plant in Hoonah also consists of three diesel generators operating on diesel fuel. IPEC is exploring feasibility of other resources to displace a portion of diesel-generated power.

4.3.4.3 Kake

The diesel plant in Kake also consists of three diesel generators operating on diesel fuel. IPEC is working through the EIS process for an electrical intertie to Petersburg. The EIS should be complete by 1Q 2012. Construction will be contingent on financing.

4.3.4.4 Klukwan/Chilkat Valley

IPEC owns a diesel plant to serve Klukwan and the Chilkat Valley. This diesel plant is used for backup for the IPEC hydroelectric purchases used to meet the local electric demand. IPEC purchases hydroelectric power from Southern Energy and AP&T.

4.3.4.5 Metlakatla Power & Light (MPL)

MPL owns and operates the Purple Lake and Chester Lake hydroelectric plants. Purple Lake has three 1956-era Francis type turbine-generators. Chester Lake has a single Pelton type turbine-generator. MPL also owns and operates the Centennial Power Plant. The Centennial Power Plant consists of a single Caterpillar 3612 diesel fired engine-generator and a BESS. The diesel fired generator is rated 3.3 MW and the BESS is rated 1 MW. The diesel generator is used as backup and the BESS provides quick response.

One step-up transformer at each hydroelectric plant increases the voltage to a 12,470Y/7200 configuration. Two distribution circuits leave the Purple Lake plant, one serving the town and one serving the airport area. A single distribution circuit leaves the Chester Lake plant serving the town. The distribution system is mainly overhead lines, with some underground and pad mount equipment being used for some new facilities and residential development.

4.3.5 City of Sitka Electric (Sitka)

Sitka owns Blue Lake, Green Lake, Pulp Mill Feed Unit, and Fish Valve Unit hydroelectric plants. Sitka generates nearly all of its electric requirements from these hydroelectric plants. Sitka also owns and operates a diesel plant at Jarvis Street. The diesel plant consists of a single Caterpillar diesel fired engine-generator (4.8 MW) and three Fairbanks Morse generators (7.5 MW total). The diesel generation is used as backup. The Fairbanks Morse units are 30 years old and cannot operate at full capacity. A total of 11.4 MW can be produced using all four diesel units. Sitka is in the final permitting process to expand the Blue Lake Project to 15.9 MW.

4.3.6 Yakutat Power

Yakutat generates all of its electric requirements from diesel engines at the Yakutat Power Plant. The diesel plant consists of four Caterpillar diesel fired engine-generators. The Yakutat distribution system consists of three feeders that supply the community and one that supplies station service for the power plant. The feeders operate at different voltage levels. Yakutat is in the process of upgrading the distribution system to a single voltage level to improve efficiency and allow for one feeder to provide backup for another feeder.

4.3.7 Gustavus Electric

Gustavus Electric was formed in 1983 to provide electric service in the Gustavus and Glacier Bay forelands. Gustavus Electric operates the Falls Creek Project, a run-of-river hydroelectric unit. An underground transmission cable runs the five miles from the Falls Creek powerhouse to the existing diesel plant. The diesel units provide power when there is not enough water flow through Falls Creek to provide the required energy.

4.3.8 Tongass Power & Light Company

Hyder is served by Tongass Power & Light Company, which purchases its power from BC Hydro.

4.3.9 Chichagof Island Communities

The Chichagof Island Communities of Elfin Cove, Pelican, and Tenakee Springs have individual utility systems that are not interconnected.

4.3.9.1 Elfin Cove

Electricity for Elfin Cove is provided by the Elfin Cove Utility Commission with diesel generation.

4.3.9.2 Pelican

Electricity for Pelican is provided by the privately owned and operated Pelican Utility Company from two hydro and five diesel units.

4.3.9.3 Tenakee Springs

Electricity for Tenakee Springs is provided by the city-owned utility with diesel generation.

5.0 Fuel Price Projections

Fuel price projections were developed by the Institute of Social and Economic Research (ISER) at the University of Alaska Anchorage and provided to Black & Veatch by Alaska Energy Authority (AEA). ISER developed a spreadsheet model based on projections from the Energy Information Administration's (EIA) Annual Energy Outlook 2010 (AEO 2010) to create fuel price forecasts for natural gas and diesel for the communities that participate in the Power Cost Equalization (PCE) program, and home heating oil purchased in Anchorage, Fairbanks, Juneau, Kenai, Ketchikan, Palmer, and Wasilla. Black & Veatch adjusted the forecasts to reflect nominal dollars and extrapolated the forecasts by using the average real escalation rate of the last 10 years provided and the general inflation rate to create nominal forecasts from 2012 through 2061. Black & Veatch then used the forecasts to develop forecasts for each of the communities included in the Southeast Alaska IRP in Section 4.1. Assumptions, methodologies, and resulting forecasts are discussed in this section.

5.1 NATURAL GAS

ISER developed natural gas prices for Southcentral Alaska based on specific contracts for the region and the Henry Hub natural gas price forecast provided in the AEO 2010. Since Southeast Alaska does not have access to natural gas, Black & Veatch used the ISER Henry Hub forecast to develop a 50 year forecast for Henry Hub. The ISER Henry Hub forecast was provided through 2030. Black & Veatch converted the forecast to nominal dollars using the general inflation rate of 3.0 percent. Beyond 2030, Black & Veatch extrapolated the 2030 price using the average real escalation rate for the last 10 years of projections, plus the general inflation rate of 3.0 percent. Table 5-1 presents the Henry Hub natural gas price forecast used in this study.

5.2 COMMUNITY DIESEL

ISER developed low, medium, and high diesel price projections for the various PCE communities across the State. Prices were developed using the AEO's imported crude oil price from the low, medium, and high price cases, the Composite Refiner Acquisition Cost of crude oil (CORAC), and the historical cost of fuel for each PCE member community as available. Under direction from the AEA, prices also include a carbon dioxide (CO_2) adder based on low and high projections published in a 2007 study by MIT[1]. Table 5-2 presents the CO_2 prices used by ISER. The MIT study projects the carbon emissions allowance cost to become effective in 2015. ISER assumed the CO_2 costs became effective in 2010 and ramped up the prices to equal that of the MIT study in 2015. ISER then performed regression analysis to project final prices on a $/gallon basis. Black & Veatch converted the price forecasts to nominal dollars using the general inflation rate of 3.0 percent and extrapolated beyond 2030 price using the average real escalation rate for the last 10 years of ISER projections, plus the general inflation rate of 3.0 percent to create a forecast in nominal dollars from 2012 through 2061. Tables 5-3, 5-4, and 5-5 present the diesel price projections for low, medium, and high cases used in this study on a $/gallon basis. The forecast was then converted from a $/gallon basis to $/MMBtu (million British thermal units) for use in modeling using a fuel heat content of 138,690 Btu per gallon for No. 2 fuel oil[2]. The $/MMBtu prices are presented in Appendix A. Several communities in this study did not have specific diesel forecasts developed by ISER because they were not covered under PCE. Those communities are Edna Bay, Excursion Inlet,

[1] Massachusetts Institute of Technology. 2007. *The Future of Coal: Options for a Carbon-Constrained World*. (March). Available at: http://web.mit.edu/coal/

[2] www.eia.doe.gov/neic/experts/heatcalc.xls

Hyder, Juneau, Ketchikan, Metlakatla, Pelican, Petersburg, Sitka, and Wrangell. For these communities, a forecast from the ISER projections was chosen as a proxy for each of the communities without ISER forecasts. Whale Pass's forecast was chosen to represent the Edna Bay forecast. Gustavus's forecast was chosen to represent the Excursion Inlet forecast. Hollis's forecast was chosen to represent the Hyder forecast. Eighty five (85) percent of Craig's forecast was chosen to represent the Ketchikan forecast. Elfin Cove's forecast was chosen to represent the Pelican forecast. Haines's forecast was chosen to represent the Sitka forecast. The forecast for Juneau is based on the relationship between the Ketchikan and Juneau heating oil costs discussed in Section 5.3. The forecasts for Metlakatla, Petersburg, and Wrangell were developed by increasing the Ketchikan forecast by 10 percent.

Table 5-1 Natural Gas Price Forecast

YEAR	HENRY HUB (NOMINAL $/MMBTU)
2012	6.36
2013	6.50
2014	6.65
2015	7.06
2016	7.39
2017	7.62
2018	7.91
2019	8.24
2020	8.66
2021	9.06
2022	9.59
2023	9.92
2024	10.15
2025	10.58
2026	11.14
2027	11.70
2028	12.45
2029	13.24
2030	14.12
2031	14.83
2032	15.58
2033	16.36
2034	17.19
2035	18.06
2036	18.97
2037	19.93
2038	20.94
2039	22.00
2040	23.11
2041	24.28
2042	25.50

YEAR	HENRY HUB (NOMINAL $/MMBTU)
2043	26.79
2044	28.14
2045	29.57
2046	31.06
2047	32.63
2048	34.28
2049	36.01
2050	37.83
2051	39.74
2052	41.75
2053	43.86
2054	46.07
2055	48.40
2056	50.85
2057	53.42
2058	56.11
2059	58.95
2060	61.93
2061	65.06

Table 5-2 CO_2 Emission Allowance Prices used by ISER (nominal $/metric ton)

YEAR	LOW	MEDIUM	HIGH
2010	9.21	14.76	25.77
2011	9.96	15.96	27.87
2012	10.77	17.26	30.14
2013	11.65	18.67	32.59
2014	12.60	20.19	35.25
2015	13.62	21.84	38.12
2016	14.73	23.62	41.23
2017	15.93	25.54	44.59
2018	17.23	27.63	48.22
2019	18.64	29.88	52.15
2020	20.16	32.31	56.40
2021	21.80	34.95	61.00
2022	23.58	37.79	65.97
2023	25.50	40.87	71.35
2024	27.57	44.21	77.16
2025	29.82	47.81	83.45
2026	32.25	51.71	90.25
2027	34.88	55.92	97.61
2028	37.72	60.48	105.56
2029	40.80	65.41	114.17
2030	44.12	70.74	123.47

Table 5-3 Low Case Diesel Price Projections ($/gal)

Year	Angoon	Chilkat Valley	Coffman Cove	Craig	Edna Bay	Elfin Cove	Excursion Inlet	Gustavus	Haines	Hollis	Hoonah	Hydaburg	Hyder	Juneau	Kake	Ketchikan	Klawock	Klukwan	Metlakatla	Naukati	Pelican	Petersburg	Sitka	Skagway	Tenakee Springs	Thorne Bay/Kasaan	Whale Pass	Wrangell	Yakutat
2012	2.56	2.60	2.74	2.47	2.65	3.30	3.08	3.08	2.54	2.47	2.68	2.51	2.47	2.41	2.56	2.10	2.47	2.56	2.31	2.60	3.30	2.31	2.54	2.48	3.17	2.56	2.65	2.31	2.79
2013	2.61	2.66	2.80	2.52	2.71	3.38	3.15	3.15	2.59	2.52	2.74	2.56	2.52	2.46	2.61	2.14	2.52	2.61	2.36	2.65	3.38	2.36	2.59	2.53	3.25	2.62	2.71	2.36	2.85
2014	2.68	2.73	2.87	2.59	2.78	3.46	3.23	3.23	2.66	2.59	2.81	2.63	2.59	2.52	2.68	2.20	2.59	2.68	2.42	2.72	3.46	2.42	2.66	2.59	3.33	2.68	2.78	2.42	2.92
2015	2.75	2.80	2.94	2.65	2.85	3.56	3.32	3.32	2.73	2.65	2.88	2.69	2.65	2.58	2.75	2.25	2.65	2.75	2.48	2.78	3.56	2.48	2.73	2.66	3.42	2.75	2.85	2.48	3.00
2016	2.82	2.87	3.02	2.72	2.92	3.65	3.41	3.41	2.80	2.72	2.96	2.76	2.72	2.65	2.82	2.31	2.72	2.82	2.54	2.86	3.65	2.54	2.80	2.72	3.51	2.82	2.92	2.54	3.08
2017	2.89	2.94	3.10	2.79	3.00	3.75	3.50	3.50	2.87	2.79	3.04	2.84	2.79	2.72	2.89	2.37	2.79	2.89	2.61	2.93	3.75	2.61	2.87	2.80	3.60	2.90	3.00	2.61	3.16
2018	2.97	3.02	3.19	2.87	3.08	3.86	3.60	3.60	2.95	2.87	3.12	2.91	2.87	2.79	2.97	2.44	2.87	2.97	2.68	3.01	3.86	2.68	2.95	2.87	3.70	2.98	3.08	2.68	3.25
2019	3.05	3.11	3.27	2.94	3.17	3.96	3.70	3.70	3.03	2.94	3.20	2.99	2.94	2.87	3.05	2.50	2.94	3.05	2.75	3.10	3.96	2.75	3.03	2.95	3.81	3.06	3.17	2.75	3.34
2020	3.14	3.19	3.37	3.03	3.25	4.08	3.80	3.80	3.11	3.03	3.29	3.08	3.03	2.95	3.14	2.57	3.03	3.14	2.83	3.18	4.08	2.83	3.11	3.03	3.92	3.14	3.25	2.83	3.43
2021	3.23	3.28	3.46	3.11	3.35	4.19	3.91	3.91	3.20	3.11	3.39	3.16	3.11	3.03	3.23	2.65	3.11	3.23	2.91	3.27	4.19	2.91	3.20	3.12	4.03	3.23	3.35	2.91	3.53
2022	3.32	3.38	3.56	3.20	3.44	4.32	4.03	4.03	3.30	3.20	3.49	3.26	3.20	3.12	3.32	2.72	3.20	3.32	2.99	3.37	4.32	2.99	3.30	3.21	4.15	3.33	3.44	2.99	3.63
2023	3.42	3.48	3.67	3.30	3.54	4.44	4.14	4.14	3.39	3.30	3.59	3.35	3.30	3.21	3.42	2.80	3.30	3.42	3.08	3.47	4.44	3.08	3.39	3.30	4.27	3.42	3.54	3.08	3.74
2024	3.52	3.58	3.78	3.40	3.65	4.58	4.27	4.27	3.49	3.40	3.70	3.45	3.40	3.30	3.52	2.89	3.40	3.52	3.18	3.57	4.58	3.18	3.49	3.40	4.40	3.53	3.65	3.18	3.85
2025	3.63	3.69	3.89	3.50	3.76	4.72	4.40	4.40	3.60	3.50	3.81	3.56	3.50	3.41	3.63	2.97	3.50	3.63	3.27	3.68	4.72	3.27	3.60	3.51	4.53	3.63	3.76	3.27	3.97
2026	3.74	3.81	4.01	3.61	3.88	4.86	4.53	4.53	3.71	3.61	3.93	3.67	3.61	3.51	3.74	3.07	3.61	3.74	3.37	3.79	4.86	3.37	3.71	3.61	4.67	3.75	3.88	3.37	4.09
2027	3.86	3.93	4.14	3.72	4.00	5.01	4.68	4.68	3.83	3.72	4.05	3.78	3.72	3.62	3.86	3.16	3.72	3.86	3.48	3.91	5.01	3.48	3.83	3.73	4.82	3.87	4.00	3.48	4.22
2028	3.98	4.05	4.27	3.84	4.13	5.17	4.82	4.82	3.95	3.84	4.18	3.91	3.84	3.74	3.98	3.27	3.84	3.98	3.59	4.04	5.17	3.59	3.95	3.85	4.97	3.99	4.13	3.59	4.35
2029	4.11	4.19	4.41	3.97	4.26	5.34	4.98	4.98	4.08	3.97	4.32	4.03	3.97	3.86	4.11	3.37	3.97	4.11	3.71	4.17	5.34	3.71	4.08	3.97	5.13	4.12	4.26	3.71	4.49
2030	4.25	4.33	4.56	4.10	4.41	5.51	5.14	5.14	4.22	4.10	4.46	4.17	4.10	3.99	4.25	3.49	4.10	4.25	3.83	4.31	5.51	3.83	4.22	4.11	5.30	4.26	4.41	3.83	4.64
2031	4.51	4.59	4.84	4.36	4.68	5.85	5.46	5.46	4.48	4.36	4.74	4.43	4.36	4.24	4.51	3.70	4.36	4.51	4.07	4.58	5.85	4.07	4.48	4.36	5.62	4.52	4.68	4.07	4.93
2032	4.79	4.88	5.14	4.63	4.97	6.21	5.80	5.80	4.76	4.63	5.03	4.70	4.63	4.50	4.79	3.93	4.63	4.79	4.33	4.86	6.21	4.33	4.76	4.63	5.97	4.80	4.97	4.33	5.23
2033	5.09	5.18	5.46	4.91	5.28	6.60	6.16	6.16	5.05	4.91	5.34	4.99	4.91	4.78	5.09	4.18	4.91	5.09	4.59	5.16	6.60	4.59	5.05	4.92	6.34	5.10	5.28	4.59	5.56
2034	5.41	5.50	5.79	5.22	5.60	7.00	6.54	6.54	5.37	5.22	5.67	5.30	5.22	5.08	5.41	4.44	5.22	5.41	4.88	5.48	7.00	4.88	5.37	5.23	6.73	5.42	5.60	4.88	5.90
2035	5.74	5.84	6.15	5.54	5.95	7.44	6.94	6.94	5.70	5.54	6.02	5.63	5.54	5.39	5.74	4.71	5.54	5.74	5.18	5.82	7.44	5.18	5.70	5.55	7.15	5.75	5.95	5.18	6.27
2036	6.10	6.21	6.53	5.89	6.32	7.90	7.37	7.37	6.05	5.89	6.40	5.98	5.89	5.73	6.10	5.00	5.89	6.10	5.50	6.18	7.90	5.50	6.05	5.89	7.59	6.11	6.32	5.50	6.66
2037	6.48	6.59	6.94	6.25	6.71	8.38	7.83	7.83	6.43	6.25	6.79	6.35	6.25	6.08	6.48	5.31	6.25	6.48	5.84	6.57	8.38	5.84	6.43	6.26	8.06	6.49	6.71	5.84	7.07
2038	6.88	7.00	7.37	6.64	7.13	8.90	8.31	8.31	6.83	6.64	7.22	6.75	6.64	6.46	6.88	5.64	6.64	6.88	6.21	6.97	8.90	6.21	6.83	6.65	8.55	6.89	7.13	6.21	7.51
2039	7.31	7.43	7.82	7.05	7.57	9.45	8.82	8.82	7.25	7.05	7.66	7.16	7.05	6.86	7.30	5.99	7.05	7.30	6.59	7.41	9.45	6.59	7.25	7.06	9.08	7.32	7.57	6.59	7.97
2040	7.76	7.89	8.31	7.49	8.04	10.04	9.37	9.37	7.70	7.49	8.14	7.61	7.49	7.29	7.76	6.37	7.49	7.76	7.00	7.86	10.04	7.00	7.70	7.50	9.64	7.77	8.04	7.00	8.46
2041	8.24	8.38	8.82	7.95	8.54	10.65	9.95	9.95	8.18	7.95	8.64	8.08	7.95	7.74	8.24	6.76	7.95	8.24	7.44	8.35	10.65	7.44	8.18	7.96	10.24	8.25	8.54	7.44	8.99
2042	8.75	8.90	9.37	8.45	9.07	11.31	10.56	10.56	8.69	8.45	9.18	8.58	8.45	8.22	8.75	7.18	8.45	8.75	7.90	8.87	11.31	7.90	8.69	8.46	10.87	8.76	9.07	7.90	9.54
2043	9.29	9.45	9.95	8.97	9.63	12.01	11.22	11.22	9.22	8.97	9.75	9.12	8.97	8.73	9.29	7.63	8.97	9.29	8.39	9.42	12.01	8.39	9.22	8.98	11.55	9.31	9.63	8.39	10.14
2044	9.87	10.04	10.57	9.53	10.22	12.75	11.91	11.91	9.80	9.53	10.35	9.68	9.53	9.27	9.87	8.10	9.53	9.87	8.91	10.00	12.75	8.91	9.80	9.54	12.26	9.88	10.22	8.91	10.76
2045	10.48	10.66	11.22	10.12	10.86	13.54	12.65	12.65	10.40	10.12	10.99	10.28	10.12	9.85	10.48	8.60	10.12	10.48	9.46	10.62	13.54	9.46	10.40	10.13	13.02	10.50	10.86	9.46	11.43
2046	11.13	11.32	11.92	10.75	11.53	14.38	13.43	13.43	11.05	10.75	11.67	10.92	10.75	10.46	11.13	9.13	10.75	11.13	10.05	11.28	14.38	10.05	11.05	10.76	13.82	11.15	11.53	10.05	12.14
2047	11.82	12.03	12.65	11.41	12.25	15.27	14.26	14.26	11.74	11.41	12.39	11.60	11.41	11.11	11.82	9.70	11.41	11.82	10.67	11.98	15.27	10.67	11.74	11.43	14.67	11.84	12.25	10.67	12.89
2048	12.56	12.77	13.44	12.12	13.00	16.21	15.14	15.14	12.46	12.12	13.16	12.32	12.12	11.80	12.55	10.30	12.12	12.55	11.33	12.72	16.21	11.33	12.46	12.14	15.58	12.57	13.00	11.33	13.69
2049	13.33	13.56	14.27	12.87	13.81	17.21	16.08	16.08	13.24	12.87	13.98	13.08	12.87	12.53	13.33	10.94	12.87	13.33	12.04	13.51	17.21	12.04	13.24	12.89	16.54	13.35	13.81	12.04	14.53
2050	14.16	14.40	15.15	13.67	14.67	18.27	17.07	17.07	14.06	13.67	14.84	13.89	13.67	13.31	14.16	11.62	13.67	14.16	12.78	14.35	18.27	12.78	14.06	13.69	17.57	14.18	14.67	12.78	15.43
2051	15.04	15.30	16.09	14.52	15.58	19.40	18.12	18.12	14.93	14.52	15.76	14.75	14.52	14.13	15.04	12.34	14.52	15.04	13.58	15.24	19.40	13.58	14.93	14.54	18.65	15.06	15.58	13.58	16.39
2052	15.97	16.24	17.09	15.42	16.54	20.60	19.24	19.24	15.85	15.42	16.74	15.67	15.42	15.01	15.97	13.11	15.42	15.97	14.42	16.19	20.60	14.42	15.85	15.44	19.80	16.00	16.54	14.42	17.40
2053	16.96	17.25	18.15	16.38	17.57	21.87	20.43	20.43	16.84	16.38	17.78	16.64	16.38	15.94	16.96	13.92	16.38	16.96	15.31	17.19	21.87	15.31	16.84	16.40	21.03	16.99	17.57	15.31	18.48
2054	18.01	18.32	19.27	17.40	18.65	23.22	21.70	21.70	17.88	17.40	18.88	17.67	17.40	16.93	18.01	14.79	17.40	18.01	16.26	18.26	23.22	16.26	17.88	17.42	22.33	18.04	18.65	16.26	19.63
2055	19.13	19.46	20.47	18.47	19.81	24.65	23.04	23.04	18.99	18.47	20.05	18.77	18.47	17.98	19.13	15.70	18.47	19.13	17.27	19.39	24.65	17.27	18.99	18.50	23.71	19.16	19.81	17.27	20.84
2056	20.32	20.66	21.73	19.62	21.04	26.18	24.46	24.46	20.17	19.62	21.29	19.93	19.62	19.10	20.31	16.68	19.62	20.31	18.35	20.59	26.18	18.35	20.17	19.65	25.17	20.35	21.04	18.35	22.13
2057	21.58	21.94	23.08	20.84	22.34	27.79	25.98	25.98	21.42	20.84	22.61	21.17	20.84	20.28	21.57	17.71	20.84	21.57	19.48	21.87	27.79	19.48	21.42	20.87	26.73	21.61	22.34	19.48	23.50
2058	22.92	23.30	24.51	22.13	23.73	29.51	27.58	27.58	22.75	22.13	24.01	22.48	22.13	21.54	22.91	18.81	22.13	22.91	20.69	23.22	29.51	20.69	22.75	22.16	28.38	22.95	23.73	20.69	24.96
2059	24.34	24.75	26.03	23.50	25.20	31.33	29.29	29.29	24.16	23.50	25.50	23.88	23.50	22.88	24.33	19.98	23.50	24.33	21.98	24.66	31.33	21.98	24.16	23.54	30.13	24.37	25.20	21.98	26.50
2060	25.85	26.28	27.64	24.96	26.76	33.27	31.10	31.10	25.66	24.96	27.08	25.36	24.96	24.30	25.84	21.22	24.96	25.84	23.34	26.19	33.27	23.34	25.66	25.00	31.99	25.88	26.76	23.34	28.14
2061	27.45	27.91	29.35	26.51	28.42	35.32	33.02	33.02	27.25	26.51	28.76	26.93	26.51	25.80	27.44	22.54	26.51	27.44	24.79	27.81	35.32	24.79	27.25	26.55	33.97	27.49	28.42	24.79	29.89

Table 5-4 Medium Case Diesel Price Projections ($/gal)

Year	Angoon	Chilkat Valley	Coffman Cove	Craig	Edna Bay	Elfin Cove	Excursion Inlet	Gustavus	Haines	Hollis	Hoonah	Hydaburg	Hyder	Juneau	Kake	Ketchikan	Klawock	Klukwan	Metlakatla	Naukati	Pelican	Petersburg	Sitka	Skagway	Tenakee Springs	Thorne Bay/Kasaan	Whale Pass	Wrangell	Yakutat
2012	3.56	3.61	3.74	3.48	3.66	4.30	4.09	4.09	3.55	3.48	3.69	3.52	3.48	3.28	3.56	2.96	3.48	3.56	3.25	3.60	4.30	3.25	3.55	3.48	4.18	3.57	3.66	3.25	3.79
2013	3.80	3.85	3.99	3.71	3.90	4.57	4.34	4.34	3.78	3.71	3.93	3.75	3.71	3.50	3.80	3.16	3.71	3.80	3.47	3.84	4.57	3.47	3.78	3.72	4.43	3.81	3.90	3.47	4.04
2014	4.05	4.09	4.24	3.95	4.14	4.83	4.60	4.60	4.03	3.95	4.18	4.00	3.95	3.73	4.05	3.36	3.95	4.05	3.70	4.08	4.83	3.70	4.03	3.96	4.70	4.05	4.14	3.70	4.29
2015	4.30	4.35	4.49	4.20	4.40	5.11	4.87	4.87	4.28	4.20	4.43	4.24	4.20	3.96	4.30	3.57	4.20	4.30	3.93	4.33	5.11	3.93	4.28	4.21	4.97	4.30	4.40	3.93	4.55
2016	4.55	4.60	4.75	4.45	4.66	5.39	5.14	5.14	4.53	4.45	4.69	4.50	4.45	4.20	4.55	3.79	4.45	4.55	4.16	4.59	5.39	4.16	4.53	4.46	5.24	4.56	4.66	4.16	4.81
2017	4.81	4.87	5.02	4.71	4.92	5.67	5.42	5.42	4.79	4.71	4.96	4.76	4.71	4.45	4.81	4.01	4.71	4.81	4.41	4.85	5.67	4.41	4.79	4.72	5.53	4.82	4.92	4.41	5.08
2018	5.08	5.13	5.30	4.98	5.19	5.97	5.71	5.71	5.06	4.98	5.23	5.02	4.98	4.70	5.08	4.23	4.98	5.08	4.65	5.12	5.97	4.65	5.06	4.98	5.82	5.09	5.19	4.65	5.36
2019	5.36	5.41	5.58	5.25	5.47	6.27	6.00	6.00	5.33	5.25	5.51	5.30	5.25	4.95	5.35	4.46	5.25	5.35	4.91	5.40	6.27	4.91	5.33	5.25	6.11	5.36	5.47	4.91	5.64
2020	5.64	5.69	5.86	5.52	5.75	6.57	6.30	6.30	5.61	5.52	5.79	5.57	5.52	5.21	5.63	4.70	5.52	5.63	5.16	5.68	6.57	5.16	5.61	5.53	6.41	5.64	5.75	5.16	5.93
2021	5.92	5.98	6.15	5.81	6.04	6.89	6.60	6.60	5.90	5.81	6.08	5.86	5.81	5.48	5.92	4.93	5.81	5.92	5.43	5.96	6.89	5.43	5.90	5.81	6.72	5.92	6.04	5.43	6.22
2022	6.21	6.27	6.45	6.09	6.33	7.21	6.91	6.91	6.19	6.09	6.38	6.15	6.09	5.75	6.21	5.18	6.09	6.21	5.70	6.26	7.21	5.70	6.19	6.10	7.04	6.22	6.33	5.70	6.52
2023	6.51	6.57	6.75	6.39	6.63	7.53	7.23	7.23	6.48	6.39	6.68	6.44	6.39	6.03	6.51	5.43	6.39	6.51	5.97	6.55	7.53	5.97	6.48	6.39	7.36	6.51	6.63	5.97	6.82
2024	6.81	6.87	7.06	6.68	6.94	7.86	7.56	7.56	6.78	6.68	6.98	6.74	6.68	6.31	6.81	5.68	6.68	6.81	6.25	6.86	7.86	6.25	6.78	6.69	7.68	6.81	6.94	6.25	7.14
2025	7.12	7.18	7.38	6.99	7.25	8.20	7.88	7.88	7.09	6.99	7.30	7.04	6.99	6.59	7.11	5.94	6.99	7.11	6.53	7.17	8.20	6.53	7.09	6.99	8.02	7.12	7.25	6.53	7.45
2026	7.43	7.49	7.70	7.30	7.57	8.55	8.22	8.22	7.40	7.30	7.61	7.35	7.30	6.88	7.43	6.20	7.30	7.43	6.82	7.48	8.55	6.82	7.40	7.30	8.36	7.43	7.57	6.82	7.78
2027	7.75	7.81	8.03	7.61	7.89	8.90	8.56	8.56	7.72	7.61	7.94	7.67	7.61	7.18	7.75	6.47	7.61	7.75	7.11	7.80	8.90	7.11	7.72	7.61	8.70	7.75	7.89	7.11	8.10
2028	8.07	8.14	8.36	7.93	8.22	9.26	8.91	8.91	8.04	7.93	8.27	7.99	7.93	7.48	8.07	6.74	7.93	8.07	7.41	8.12	9.26	7.41	8.04	7.93	9.05	8.08	8.22	7.41	8.44
2029	8.40	8.47	8.69	8.25	8.55	9.62	9.26	9.26	8.37	8.25	8.60	8.32	8.25	7.79	8.40	7.01	8.25	8.40	7.72	8.45	9.62	7.72	8.37	8.26	9.41	8.40	8.55	7.72	8.78
2030	8.73	8.80	9.03	8.58	8.89	9.99	9.62	9.62	8.70	8.58	8.94	8.65	8.58	8.10	8.73	7.29	8.58	8.73	8.02	8.79	9.99	8.02	8.70	8.59	9.77	8.74	8.89	8.02	9.12
2031	9.39	9.47	9.71	9.23	9.55	10.72	10.33	10.33	9.35	9.23	9.61	9.30	9.23	8.71	9.39	7.85	9.23	9.39	8.63	9.45	10.72	8.63	9.35	9.24	10.50	9.40	9.55	8.63	9.80
2032	10.10	10.18	10.44	9.93	10.27	11.51	11.10	11.10	10.06	9.93	10.33	10.00	9.93	9.37	10.10	8.44	9.93	10.10	9.28	10.16	11.51	9.28	10.06	9.94	11.27	10.10	10.27	9.28	10.54
2033	10.86	10.95	11.22	10.68	11.04	12.36	11.92	11.92	10.82	10.68	11.11	10.76	10.68	10.08	10.86	9.08	10.68	10.86	9.99	10.93	12.36	9.99	10.82	10.69	12.10	10.87	11.04	9.99	11.32
2034	11.68	11.77	12.06	11.49	11.87	13.27	12.80	12.80	11.64	11.49	11.94	11.57	11.49	10.84	11.68	9.77	11.49	11.68	10.74	11.75	13.27	10.74	11.64	11.50	12.99	11.69	11.87	10.74	12.17
2035	12.56	12.66	12.97	12.36	12.77	14.24	13.75	13.75	12.52	12.36	12.84	12.45	12.36	11.66	12.56	10.50	12.36	12.56	11.56	12.64	14.24	11.56	12.52	12.37	13.95	12.57	12.77	11.56	13.08
2036	13.51	13.61	13.94	13.29	13.72	15.29	14.77	14.77	13.46	13.29	13.80	13.39	13.29	12.54	13.50	11.30	13.29	13.50	12.43	13.59	15.29	12.43	13.46	13.30	14.98	13.51	13.72	12.43	14.06
2037	14.52	14.64	14.98	14.30	14.76	16.41	15.86	15.86	14.48	14.30	14.84	14.40	14.30	13.49	14.52	12.16	14.30	14.52	13.37	14.61	16.41	13.37	14.48	14.31	16.09	14.53	14.76	13.37	15.11
2038	15.62	15.74	16.10	15.38	15.87	17.62	17.03	17.03	15.57	15.38	15.95	15.49	15.38	14.52	15.62	13.08	15.38	15.62	14.38	15.71	17.62	14.38	15.57	15.39	17.27	15.63	15.87	14.38	16.24
2039	16.80	16.92	17.31	16.55	17.06	18.91	18.29	18.29	16.74	16.55	17.15	16.66	16.55	15.61	16.80	14.07	16.55	16.80	15.47	16.90	18.91	15.47	16.74	16.56	18.55	16.81	17.06	15.47	17.45
2040	18.06	18.20	18.60	17.80	18.34	20.30	19.65	19.65	18.01	17.80	18.44	17.92	17.80	16.80	18.06	15.13	17.80	18.06	16.64	18.17	20.30	16.64	18.01	17.81	19.92	18.08	18.34	16.64	18.76
2041	19.43	19.57	20.00	19.15	19.72	21.79	21.10	21.10	19.37	19.15	19.82	19.27	19.15	18.07	19.43	16.28	19.15	19.43	17.90	19.54	21.79	17.90	19.37	19.16	21.39	19.44	19.72	17.90	20.16
2042	20.89	21.04	21.50	20.60	21.20	23.40	22.66	22.66	20.83	20.60	21.31	20.73	20.60	19.44	20.89	17.51	20.60	20.89	19.26	21.01	23.40	19.26	20.83	20.61	22.96	20.91	21.20	19.26	21.67
2043	22.47	22.62	23.11	22.16	22.79	25.11	24.34	24.34	22.40	22.16	22.91	22.30	22.16	20.91	22.47	18.83	22.16	22.47	20.72	22.59	25.11	20.72	22.40	22.17	24.66	22.48	22.79	20.72	23.29
2044	24.16	24.33	24.84	23.83	24.51	26.96	26.14	26.14	24.09	23.83	24.63	23.98	23.83	22.49	24.16	20.26	23.83	24.16	22.28	24.29	26.96	22.28	24.09	23.85	26.48	24.18	24.51	22.28	25.03
2045	25.99	26.16	26.70	25.64	26.35	28.94	28.07	28.07	25.91	25.64	26.47	25.79	25.64	24.19	25.98	21.79	25.64	25.98	23.97	26.12	28.94	23.97	25.91	25.65	28.43	26.00	26.35	23.97	26.90
2046	27.95	28.13	28.70	27.58	28.33	31.07	30.15	30.15	27.87	27.58	28.46	27.74	27.58	26.02	27.94	23.44	27.58	27.94	25.79	28.09	31.07	25.79	27.87	27.59	30.53	27.96	28.33	25.79	28.91
2047	30.05	30.25	30.85	29.67	30.46	33.35	32.38	32.38	29.97	29.67	30.60	29.84	29.67	27.99	30.05	25.22	29.67	30.05	27.74	30.21	33.35	27.74	29.97	29.68	32.78	30.07	30.46	27.74	31.07
2048	32.32	32.52	33.16	31.91	32.75	35.80	34.78	34.78	32.23	31.91	32.90	32.09	31.91	30.11	32.32	27.12	31.91	32.32	29.84	32.48	35.80	29.84	32.23	31.93	35.20	32.34	32.75	29.84	33.39
2049	34.76	34.97	35.64	34.33	35.21	38.43	37.35	37.35	34.67	34.33	35.36	34.52	34.33	32.39	34.76	29.18	34.33	34.76	32.10	34.93	38.43	32.10	34.67	34.34	37.80	34.78	35.21	32.10	35.89
2050	37.38	37.61	38.31	36.93	37.85	41.26	40.11	40.11	37.28	36.93	38.02	37.13	36.93	34.84	37.38	31.39	36.93	37.38	34.53	37.56	41.26	34.53	37.28	36.94	40.59	37.40	37.85	34.53	38.57
2051	40.20	40.44	41.18	39.72	40.70	44.29	43.08	43.08	40.10	39.72	40.87	39.93	39.72	37.48	40.20	33.76	39.72	40.20	37.14	40.39	44.29	37.14	40.10	39.74	43.58	40.22	40.70	37.14	41.46
2052	43.23	43.48	44.26	42.73	43.76	47.54	46.27	46.27	43.12	42.73	43.94	42.95	42.73	40.32	43.23	36.32	42.73	43.23	39.95	43.43	47.54	39.95	43.12	42.75	46.80	43.25	43.76	39.95	44.56
2053	46.49	46.76	47.58	45.96	47.05	51.04	49.70	49.70	46.38	45.96	47.24	46.20	45.96	43.37	46.49	39.07	45.96	46.49	42.97	46.70	51.04	42.97	46.38	45.98	50.25	46.52	47.05	42.97	47.89
2054	50.00	50.28	51.14	49.44	50.58	54.79	53.37	53.37	49.88	49.44	50.79	49.69	49.44	46.65	50.00	42.02	49.44	50.00	46.23	50.22	54.79	46.23	49.88	49.46	53.96	50.02	50.58	46.23	51.47
2055	53.77	54.06	54.98	53.18	54.38	58.81	57.32	57.32	53.65	53.18	54.60	53.45	53.18	50.19	53.77	45.21	53.18	53.77	49.73	54.00	58.81	49.73	53.65	53.21	57.94	53.80	54.38	49.73	55.32
2056	57.83	58.14	59.09	57.21	58.47	63.13	61.56	61.56	57.70	57.21	58.70	57.49	57.21	53.98	57.82	48.63	57.21	57.82	53.49	58.07	63.13	53.49	57.70	57.23	62.21	57.85	58.47	53.49	59.45
2057	62.19	62.51	63.52	61.54	62.86	67.77	66.12	66.12	62.05	61.54	63.10	61.83	61.54	58.07	62.18	52.31	61.54	62.18	57.54	62.44	67.77	57.54	62.05	61.57	66.80	62.22	62.86	57.54	63.90
2058	66.88	67.22	68.28	66.20	67.59	72.75	71.01	71.01	66.73	66.20	67.84	66.50	66.20	62.47	66.87	56.27	66.20	66.87	61.90	67.15	72.75	61.90	66.73	66.23	71.73	66.91	67.59	61.90	68.67
2059	71.92	72.28	73.39	71.21	72.67	78.10	76.27	76.27	71.77	71.21	72.93	71.53	71.21	67.20	71.92	60.53	71.21	71.92	66.58	72.20	78.10	66.58	71.77	71.24	77.02	71.95	72.67	66.58	73.81
2060	77.35	77.72	78.89	76.60	78.13	83.84	81.91	81.91	77.19	76.60	78.41	76.94	76.60	72.28	77.34	65.11	76.60	77.34	71.62	77.64	83.84	71.62	77.19	76.63	82.70	77.38	78.13	71.62	79.33
2061	83.18	83.58	84.80	82.40	84.00	90.00	87.97	87.97	83.02	82.40	84.29	82.75	82.40	77.75	83.18	70.04	82.40	83.18	77.04	83.49	90.00	77.04	83.02	82.43	88.81	83.22	84.00	77.04	85.26

Table 5-5 High Case Diesel Price Projections ($/gal)

Year	Angoon	Chilkat Valley	Coffman Cove	Craig	Edna Bay	Elfin Cove	Excursion Inlet	Gustavus	Haines	Hollis	Hoonah	Hydaburg	Hyder	Juneau	Kake	Ketchikan	Klawock	Klukwan	Metlakatla	Naukati	Pelican	Petersburg	Sitka	Skagway	Tenakee Springs	Thorne Bay/Kasaan	Whale Pass	Wrangell	Yakutat
2012	5.09	5.13	5.27	5.00	5.18	5.83	5.61	5.61	5.07	5.00	5.21	5.04	5.00	4.61	5.09	4.25	5.00	5.09	4.68	5.12	5.83	4.68	5.07	5.01	5.70	5.09	5.18	4.68	5.32
2013	5.59	5.63	5.77	5.50	5.68	6.35	6.13	6.13	5.57	5.50	5.71	5.54	5.50	5.07	5.59	4.67	5.50	5.59	5.14	5.62	6.35	5.14	5.57	5.50	6.22	5.59	5.68	5.14	5.82
2014	5.98	6.02	6.17	5.88	6.07	6.76	6.53	6.53	5.96	5.88	6.11	5.92	5.88	5.42	5.98	5.00	5.88	5.98	5.50	6.01	6.76	5.50	5.96	5.89	6.63	5.98	6.07	5.50	6.22
2015	6.37	6.42	6.57	6.28	6.47	7.18	6.95	6.95	6.35	6.28	6.51	6.32	6.28	5.78	6.37	5.34	6.28	6.37	5.87	6.41	7.18	5.87	6.35	6.28	7.04	6.38	6.47	5.87	6.62
2016	6.78	6.83	6.98	6.68	6.88	7.61	7.37	7.37	6.76	6.68	6.92	6.73	6.68	6.16	6.78	5.68	6.68	6.78	6.25	6.82	7.61	6.25	6.76	6.69	7.47	6.78	6.88	6.25	7.04
2017	7.20	7.25	7.41	7.10	7.30	8.06	7.81	7.81	7.18	7.10	7.34	7.14	7.10	6.54	7.20	6.03	7.10	7.20	6.63	7.24	8.06	6.63	7.18	7.10	7.91	7.20	7.30	6.63	7.46
2018	7.62	7.68	7.84	7.52	7.73	8.51	8.25	8.25	7.60	7.52	7.77	7.57	7.52	6.93	7.62	6.39	7.52	7.62	7.03	7.67	8.51	7.03	7.60	7.52	8.36	7.63	7.73	7.03	7.90
2019	8.06	8.11	8.28	7.95	8.17	8.97	8.70	8.70	8.04	7.95	8.21	8.00	7.95	7.33	8.06	6.76	7.95	8.06	7.44	8.10	8.97	7.44	8.04	7.96	8.82	8.07	8.17	7.44	8.34
2020	8.51	8.56	8.73	8.40	8.62	9.44	9.17	9.17	8.48	8.40	8.66	8.45	8.40	7.73	8.51	7.14	8.40	8.51	7.85	8.55	9.44	7.85	8.48	8.40	9.28	8.51	8.62	7.85	8.80
2021	8.96	9.02	9.20	8.85	9.08	9.93	9.65	9.65	8.94	8.85	9.12	8.90	8.85	8.15	8.96	7.52	8.85	8.96	8.27	9.01	9.93	8.27	8.94	8.85	9.76	8.97	9.08	8.27	9.26
2022	9.43	9.49	9.67	9.31	9.55	10.42	10.13	10.13	9.40	9.31	9.59	9.36	9.31	8.58	9.43	7.91	9.31	9.43	8.70	9.47	10.42	8.70	9.40	9.31	10.25	9.43	9.55	8.70	9.74
2023	9.90	9.96	10.15	9.78	10.03	10.93	10.63	10.63	9.88	9.78	10.07	9.84	9.78	9.01	9.90	8.31	9.78	9.90	9.14	9.95	10.93	9.14	9.88	9.79	10.75	9.91	10.03	9.14	10.22
2024	10.39	10.45	10.64	10.26	10.52	11.44	11.13	11.13	10.36	10.26	10.56	10.32	10.26	9.45	10.39	8.72	10.26	10.39	9.59	10.44	11.44	9.59	10.36	10.27	11.26	10.39	10.52	9.59	10.71
2025	10.88	10.94	11.14	10.75	11.01	11.97	11.65	11.65	10.85	10.75	11.06	10.81	10.75	9.91	10.88	9.14	10.75	10.88	10.05	10.93	11.97	10.05	10.85	10.76	11.78	10.89	11.01	10.05	11.22
2026	11.38	11.45	11.65	11.25	11.52	12.50	12.18	12.18	11.35	11.25	11.57	11.31	11.25	10.36	11.38	9.56	11.25	11.38	10.52	11.43	12.50	10.52	11.35	11.26	12.31	11.39	11.52	10.52	11.73
2027	11.90	11.96	12.17	11.76	12.04	13.05	12.71	12.71	11.87	11.76	12.09	11.82	11.76	10.83	11.89	9.99	11.76	11.89	10.99	11.95	13.05	10.99	11.87	11.76	12.85	11.90	12.04	10.99	12.25
2028	12.42	12.49	12.70	12.27	12.56	13.60	13.26	13.26	12.39	12.27	12.61	12.34	12.27	11.31	12.41	10.43	12.27	12.41	11.48	12.47	13.60	11.48	12.39	12.28	13.40	12.42	12.56	11.48	12.78
2029	12.95	13.02	13.24	12.80	13.10	14.17	13.81	13.81	12.91	12.80	13.15	12.87	12.80	11.79	12.94	10.88	12.80	12.94	11.97	13.00	14.17	11.97	12.91	12.81	13.96	12.95	13.10	11.97	13.32
2030	13.48	13.56	13.79	13.33	13.64	14.74	14.38	14.38	13.45	13.33	13.69	13.40	13.33	12.29	13.48	11.33	13.33	13.48	12.47	13.54	14.74	12.47	13.45	13.34	14.53	13.49	13.64	12.47	13.87
2031	14.53	14.61	14.86	14.37	14.70	15.87	15.48	15.48	14.50	14.37	14.76	14.45	14.37	13.24	14.53	12.22	14.37	14.53	13.44	14.60	15.87	13.44	14.50	14.38	15.64	14.54	14.70	13.44	14.95
2032	15.66	15.75	16.01	15.50	15.84	17.08	16.67	16.67	15.63	15.50	15.90	15.57	15.50	14.28	15.66	13.17	15.50	15.66	14.49	15.73	17.08	14.49	15.63	15.50	16.84	15.67	15.84	14.49	16.10
2033	16.88	16.97	17.25	16.71	17.07	18.38	17.94	17.94	16.85	16.71	17.13	16.79	16.71	15.39	16.88	14.20	16.71	16.88	15.62	16.95	18.38	15.62	16.85	16.71	18.12	16.89	17.07	15.62	17.35
2034	18.20	18.29	18.58	18.01	18.39	19.78	19.32	19.32	18.16	18.01	18.46	18.09	18.01	16.59	18.20	15.31	18.01	18.20	16.84	18.27	19.78	16.84	18.16	18.02	19.51	18.21	18.39	16.84	18.69
2035	19.61	19.71	20.02	19.41	19.82	21.29	20.80	20.80	19.57	19.41	19.89	19.50	19.41	17.89	19.61	16.50	19.41	19.61	18.15	19.69	21.29	18.15	19.57	19.42	21.00	19.62	19.82	18.15	20.13
2036	21.14	21.24	21.57	20.93	21.36	22.92	22.40	22.40	21.10	20.93	21.43	21.02	20.93	19.28	21.14	17.79	20.93	21.14	19.57	21.22	22.92	19.57	21.10	20.94	22.61	21.15	21.36	19.57	21.69
2037	22.79	22.90	23.24	22.56	23.02	24.66	24.11	24.11	22.74	22.56	23.10	22.66	22.56	20.79	22.78	19.18	22.56	22.78	21.10	22.87	24.66	21.10	22.74	22.57	24.34	22.79	23.02	21.10	23.37
2038	24.56	24.68	25.04	24.32	24.80	26.55	25.96	25.96	24.51	24.32	24.89	24.43	24.32	22.41	24.56	20.67	24.32	24.56	22.74	24.65	26.55	22.74	24.51	24.33	26.20	24.57	24.80	22.74	25.17
2039	26.47	26.59	26.98	26.22	26.73	28.57	27.95	27.95	26.42	26.22	26.82	26.33	26.22	24.16	26.47	22.29	26.22	26.47	24.52	26.57	28.57	24.52	26.42	26.23	28.21	26.48	26.73	24.52	27.12
2040	28.53	28.66	29.06	28.27	28.80	30.75	30.10	30.10	28.47	28.27	28.90	28.38	28.27	26.04	28.53	24.03	28.27	28.53	26.43	28.63	30.75	26.43	28.47	28.28	30.37	28.54	28.80	26.43	29.22
2041	30.75	30.89	31.31	30.47	31.04	33.09	32.41	32.41	30.69	30.47	31.14	30.60	30.47	28.07	30.75	25.90	30.47	30.75	28.49	30.86	33.09	28.49	30.69	30.48	32.69	30.76	31.04	28.49	31.47
2042	33.14	33.29	33.74	32.85	33.45	35.62	34.89	34.89	33.08	32.85	33.55	32.98	32.85	30.27	33.14	27.92	32.85	33.14	30.71	33.26	35.62	30.71	33.08	32.86	35.19	33.15	33.45	30.71	33.91
2043	35.72	35.88	36.35	35.41	36.04	38.33	37.57	37.57	35.66	35.41	36.15	35.55	35.41	32.63	35.72	30.10	35.41	35.72	33.11	35.84	38.33	33.11	35.66	35.43	37.88	35.73	36.04	33.11	36.53
2044	38.50	38.66	39.17	38.18	38.84	41.26	40.45	40.45	38.43	38.18	38.96	38.32	38.18	35.17	38.50	32.45	38.18	38.50	35.69	38.63	41.26	35.69	38.43	38.19	40.78	38.52	38.84	35.69	39.35
2045	41.50	41.67	42.20	41.15	41.85	44.40	43.55	43.55	41.42	41.15	41.98	41.31	41.15	37.92	41.50	34.98	41.15	41.50	38.48	41.63	44.40	38.48	41.42	41.17	43.90	41.51	41.85	38.48	42.39
2046	44.73	44.91	45.46	44.37	45.10	47.79	46.89	46.89	44.65	44.37	45.23	44.53	44.37	40.88	44.72	37.71	44.37	44.72	41.48	44.87	47.79	41.48	44.65	44.38	47.26	44.74	45.10	41.48	45.67
2047	48.21	48.40	48.98	47.83	48.60	51.44	50.49	50.49	48.13	47.83	48.74	48.00	47.83	44.06	48.21	40.65	47.83	48.21	44.72	48.36	51.44	44.72	48.13	47.84	50.88	48.22	48.60	44.72	49.20
2048	51.96	52.16	52.78	51.56	52.37	55.36	54.36	54.36	51.87	51.56	52.52	51.74	51.56	47.50	51.96	43.83	51.56	51.96	48.21	52.12	55.36	48.21	51.87	51.58	54.77	51.98	52.37	48.21	53.01
2049	56.00	56.21	56.86	55.58	56.44	59.58	58.53	58.53	55.91	55.58	56.59	55.77	55.58	51.21	56.00	47.24	55.58	56.00	51.97	56.17	59.58	51.97	55.91	55.60	58.96	56.02	56.44	51.97	57.10
2050	60.36	60.58	61.26	59.92	60.82	64.12	63.02	63.02	60.27	59.92	60.98	60.12	59.92	55.21	60.36	50.93	59.92	60.36	56.02	60.53	64.12	56.02	60.27	59.94	63.47	60.38	60.82	56.02	61.52
2051	65.06	65.29	66.01	64.59	65.54	69.01	67.85	67.85	64.96	64.59	65.71	64.80	64.59	59.51	65.06	54.91	64.59	65.06	60.40	65.24	69.01	60.40	64.96	64.61	68.33	65.08	65.54	60.40	66.27
2052	70.12	70.36	71.12	69.63	70.63	74.28	73.05	73.05	70.02	69.63	70.81	69.85	69.63	64.16	70.12	59.19	69.63	70.12	65.11	70.31	74.28	65.11	70.02	69.65	73.56	70.14	70.63	65.11	71.40
2053	75.58	75.83	76.62	75.07	76.11	79.94	78.65	78.65	75.47	75.07	76.30	75.30	75.07	69.16	75.57	63.81	75.07	75.57	70.19	75.78	79.94	70.19	75.47	75.09	79.19	75.60	76.11	70.19	76.92
2054	81.46	81.73	82.55	80.93	82.02	86.04	84.69	84.69	81.35	80.93	82.21	81.16	80.93	74.56	81.46	68.79	80.93	81.46	75.67	81.67	86.04	75.67	81.35	80.95	85.24	81.48	82.02	75.67	82.86
2055	87.80	88.08	88.95	87.24	88.38	92.60	91.18	91.18	87.68	87.24	88.59	87.49	87.24	80.38	87.80	74.15	87.24	87.80	81.57	88.02	92.60	81.57	87.68	87.26	91.77	87.82	88.38	81.57	89.27
2056	94.63	94.92	95.83	94.05	95.24	99.66	98.17	98.17	94.51	94.05	95.46	94.31	94.05	86.65	94.63	79.94	94.05	94.63	87.93	94.86	99.66	87.93	94.51	94.07	98.79	94.66	95.24	87.93	96.17
2057	102.00	102.30	103.25	101.39	102.63	107.26	105.70	105.70	101.87	101.39	102.86	101.66	101.39	93.41	101.99	86.18	101.39	101.99	94.80	102.24	107.26	94.80	101.87	101.41	106.35	102.02	102.63	94.80	103.61
2058	109.93	110.25	111.24	109.30	110.60	115.45	113.81	113.81	109.80	109.30	110.83	109.58	109.30	100.70	109.93	92.90	109.30	109.93	102.19	110.18	115.45	102.19	109.80	109.32	114.48	109.96	110.60	102.19	111.61
2059	118.49	118.82	119.86	117.82	119.18	124.25	122.54	122.54	118.35	117.82	119.43	118.12	117.82	108.55	118.48	100.15	117.82	118.48	110.17	118.75	124.25	110.17	118.35	117.85	123.24	118.52	119.18	110.17	120.24
2060	127.71	128.06	129.13	127.02	128.43	133.73	131.93	131.93	127.56	127.02	128.69	127.33	127.02	117.02	127.71	107.96	127.02	127.71	118.76	127.98	133.73	118.76	127.56	127.05	132.67	127.74	128.43	118.76	129.54
2061	137.65	138.01	139.13	136.93	138.40	143.92	142.05	142.05	137.49	136.93	138.67	137.25	136.93	126.16	137.64	116.39	136.93	137.64	128.03	137.93	143.92	128.03	137.49	136.96	142.82	137.68	138.40	128.03	139.55

5.3 HEATING OIL

ISER developed heating oil price projections using historical heating oil prices, imported crude oil prices from the AEO, and the CORAC. Prices also include a CO_2 adder based on low and high projections published in a 2007 study by MIT[3]. Table 5-2 presented the CO_2 prices as used by ISER. The MIT study projects a carbon emissions allowance cost to become effective in 2015. ISER assumed the CO_2 costs became effecting in 2010, and ramped up the prices to equal that of the MIT study in 2015. ISER performed regression analysis using the average historical price for No. 1 and No. 2 heating oil and developed prices for Anchorage, Fairbanks, Juneau, Kenai, Ketchikan, Palmer and Wasilla. This study uses the projections for Juneau and Ketchikan to develop low, medium, and high heating oil prices in the region. Black & Veatch developed heating oil prices for the other communities by multiplying the Ketchikan heating oil price by the ratio of the community's diesel price to the Ketchikan diesel price. Black & Veatch converted the price forecasts to nominal dollars using the general inflation rate of 3.0 percent and extrapolated beyond 2030 price using the average real escalation rate for the last 10 years of ISER projections plus the general inflation rate of 3.0 percent to create a forecast in nominal dollars from 2012 through 2061. Tables 5-6 through 5-8 present the resulting low, medium, and high price forecasts for the communities on a nominal $/gallon basis. Heating oil prices have also been converted to a $/MMBtu basis using a heat content of 136,820, which represents the average heat content of No. 1 and No. 2 heating oils. These prices are presented in Appendix A.

[3] *Ibid.*

Table 5-6 Low Case Heating Oil Price Projections ($/gal)

Year	Angoon	Chilkat Valley	Coffman Cove	Craig	Edna Bay	Elfin Cove	Excursion Inlet	Gustavus	Haines	Hollis	Hoonah	Hydaburg	Hyder	Juneau	Kake
2012	3.28	3.34	3.51	3.17	3.40	4.23	3.96	3.96	3.26	3.17	3.44	3.22	3.17	3.09	3.28
2013	3.35	3.41	3.59	3.23	3.47	4.33	4.04	4.04	3.33	3.23	3.51	3.29	3.23	3.16	3.35
2014	3.44	3.50	3.68	3.32	3.56	4.45	4.15	4.15	3.41	3.32	3.61	3.37	3.32	3.24	3.44
2015	3.53	3.59	3.78	3.41	3.66	4.57	4.27	4.27	3.51	3.41	3.70	3.46	3.41	3.33	3.53
2016	3.63	3.69	3.89	3.50	3.76	4.70	4.38	4.38	3.60	3.50	3.80	3.56	3.50	3.41	3.63
2017	3.72	3.79	3.99	3.59	3.86	4.83	4.50	4.50	3.69	3.59	3.91	3.65	3.59	3.51	3.72
2018	3.82	3.89	4.10	3.69	3.96	4.96	4.63	4.63	3.79	3.69	4.01	3.75	3.69	3.61	3.82
2019	3.92	3.99	4.21	3.78	4.07	5.09	4.75	4.75	3.89	3.78	4.12	3.85	3.78	3.71	3.92
2020	4.03	4.10	4.32	3.88	4.17	5.23	4.88	4.88	4.00	3.88	4.23	3.95	3.88	3.82	4.03
2021	4.15	4.22	4.45	4.00	4.30	5.39	5.03	5.03	4.12	4.00	4.35	4.07	4.00	3.92	4.15
2022	4.26	4.33	4.57	4.11	4.41	5.53	5.16	5.16	4.23	4.11	4.47	4.17	4.11	4.03	4.26
2023	4.39	4.46	4.70	4.23	4.55	5.70	5.32	5.32	4.35	4.23	4.60	4.30	4.23	4.16	4.38
2024	4.52	4.60	4.84	4.36	4.68	5.87	5.48	5.48	4.48	4.36	4.74	4.43	4.36	4.28	4.52
2025	4.65	4.73	4.99	4.49	4.82	6.05	5.64	5.64	4.62	4.49	4.88	4.56	4.49	4.41	4.65
2026	4.79	4.88	5.14	4.62	4.97	6.23	5.81	5.81	4.76	4.62	5.03	4.70	4.62	4.54	4.79
2027	4.94	5.02	5.29	4.76	5.12	6.41	5.98	5.98	4.90	4.76	5.18	4.84	4.76	4.69	4.93
2028	5.10	5.19	5.47	4.92	5.29	6.62	6.18	6.18	5.06	4.92	5.35	5.00	4.92	4.83	5.10
2029	5.25	5.35	5.63	5.07	5.45	6.82	6.36	6.36	5.21	5.07	5.51	5.15	5.07	5.00	5.25
2030	5.43	5.52	5.82	5.24	5.63	7.04	6.57	6.57	5.39	5.24	5.70	5.32	5.24	5.17	5.43
2031	5.76	5.86	6.17	5.56	5.97	7.47	6.97	6.97	5.72	5.56	6.05	5.65	5.56	5.49	5.76
2032	6.11	6.22	6.55	5.90	6.34	7.92	7.39	7.39	6.07	5.90	6.42	6.00	5.90	5.83	6.11
2033	6.49	6.60	6.95	6.26	6.73	8.41	7.85	7.85	6.44	6.26	6.81	6.36	6.26	6.19	6.49
2034	6.89	7.01	7.38	6.65	7.14	8.92	8.33	8.33	6.84	6.65	7.22	6.75	6.65	6.57	6.89
2035	7.31	7.44	7.83	7.05	7.57	9.46	8.83	8.83	7.25	7.05	7.67	7.17	7.05	6.98	7.31
2036	7.76	7.89	8.31	7.48	8.04	10.04	9.37	9.37	7.70	7.48	8.14	7.61	7.48	7.42	7.75
2037	8.23	8.37	8.82	7.94	8.53	10.65	9.95	9.95	8.17	7.94	8.63	8.07	7.94	7.88	8.23
2038	8.74	8.89	9.36	8.43	9.05	11.30	10.55	10.55	8.67	8.43	9.16	8.57	8.43	8.37	8.73
2039	9.27	9.43	9.93	8.95	9.61	11.99	11.20	11.20	9.20	8.95	9.72	9.09	8.95	8.89	9.27
2040	9.84	10.01	10.54	9.50	10.19	12.73	11.88	11.88	9.77	9.50	10.32	9.65	9.50	9.44	9.84
2041	10.44	10.62	11.18	10.08	10.82	13.50	12.61	12.61	10.36	10.08	10.95	10.24	10.08	10.03	10.44
2042	11.08	11.27	11.87	10.70	11.48	14.33	13.38	13.38	11.00	10.70	11.62	10.87	10.70	10.65	11.08
2043	11.76	11.96	12.59	11.35	12.18	15.20	14.19	14.19	11.67	11.35	12.33	11.53	11.35	11.31	11.76
2044	12.48	12.70	13.36	12.05	12.93	16.13	15.06	15.06	12.39	12.05	13.09	12.24	12.05	12.01	12.48
2045	13.25	13.47	14.18	12.79	13.72	17.11	15.98	15.98	13.15	12.79	13.89	12.99	12.79	12.76	13.24
2046	14.06	14.30	15.05	13.57	14.56	18.16	16.96	16.96	13.95	13.57	14.74	13.79	13.57	13.55	14.05
2047	14.92	15.18	15.97	14.40	15.45	19.26	17.99	17.99	14.81	14.40	15.64	14.63	14.40	14.40	14.92
2048	15.83	16.10	16.95	15.29	16.40	20.44	19.09	19.09	15.72	15.29	16.60	15.53	15.29	15.29	15.83
2049	16.80	17.09	17.98	16.22	17.40	21.69	20.26	20.26	16.68	16.22	17.61	16.48	16.22	16.24	16.80
2050	17.83	18.14	19.08	17.22	18.47	23.01	21.49	21.49	17.70	17.22	18.69	17.49	17.22	17.25	17.83
2051	18.93	19.25	20.25	18.27	19.60	24.41	22.81	22.81	18.79	18.27	19.84	18.56	18.27	18.32	18.92
2052	20.08	20.43	21.49	19.39	20.80	25.90	24.20	24.20	19.94	19.39	21.05	19.70	19.39	19.46	20.08
2053	21.31	21.68	22.81	20.58	22.07	27.48	25.68	25.68	21.16	20.58	22.34	20.91	20.58	20.67	21.31
2054	22.62	23.01	24.20	21.84	23.43	29.16	27.25	27.25	22.46	21.84	23.71	22.19	21.84	21.95	22.62
2055	24.01	24.42	25.68	23.18	24.86	30.94	28.91	28.91	23.83	23.18	25.16	23.55	23.18	23.32	24.00
2056	25.48	25.91	27.25	24.60	26.38	32.83	30.68	30.68	25.29	24.60	26.70	24.99	24.60	24.77	25.47
2057	27.04	27.50	28.92	26.11	28.00	34.83	32.55	32.55	26.84	26.11	28.33	26.53	26.11	26.31	27.03
2058	28.70	29.18	30.69	27.71	29.71	36.95	34.54	34.54	28.49	27.71	30.07	28.15	27.71	27.94	28.69
2059	30.45	30.97	32.57	29.41	31.53	39.21	36.65	36.65	30.23	29.41	31.91	29.88	29.41	29.68	30.45
2060	32.32	32.87	34.56	31.22	33.46	41.60	38.88	38.88	32.08	31.22	33.86	31.71	31.22	31.52	32.31
2061	34.30	34.88	36.68	33.13	35.51	44.14	41.26	41.26	34.05	33.13	35.93	33.65	33.13	33.48	34.29

Year	Ketchikan	Klawock	Klukwan	Metlakatla	Naukati	Pelican	Petersburg	Sitka	Skagway	Tenakee Springs	Thorne Bay/Kasaan	Whale Pass	Wrangell	Yakutat
2012	2.70	3.17	3.28	2.97	3.33	4.23	2.97	3.26	3.18	4.07	3.29	3.40	2.97	3.58
2013	2.75	3.23	3.35	3.02	3.40	4.33	3.02	3.33	3.24	4.16	3.36	3.47	3.02	3.65
2014	2.82	3.32	3.44	3.10	3.49	4.45	3.10	3.41	3.33	4.28	3.45	3.56	3.10	3.75
2015	2.90	3.41	3.53	3.19	3.58	4.57	3.19	3.51	3.41	4.39	3.54	3.66	3.19	3.85
2016	2.97	3.50	3.63	3.27	3.68	4.70	3.27	3.60	3.50	4.51	3.63	3.76	3.27	3.96
2017	3.05	3.59	3.72	3.36	3.77	4.83	3.36	3.69	3.60	4.64	3.73	3.86	3.36	4.06
2018	3.13	3.69	3.82	3.45	3.87	4.96	3.45	3.79	3.69	4.76	3.83	3.96	3.45	4.17
2019	3.22	3.78	3.92	3.54	3.98	5.09	3.54	3.89	3.79	4.89	3.93	4.07	3.54	4.29
2020	3.30	3.88	4.03	3.63	4.08	5.23	3.63	4.00	3.89	5.02	4.03	4.17	3.63	4.40
2021	3.40	4.00	4.15	3.74	4.21	5.39	3.74	4.12	4.01	5.18	4.15	4.30	3.74	4.53
2022	3.49	4.11	4.26	3.84	4.32	5.53	3.84	4.23	4.11	5.31	4.26	4.41	3.84	4.65
2023	3.59	4.23	4.38	3.95	4.45	5.70	3.95	4.35	4.24	5.47	4.39	4.55	3.95	4.79
2024	3.70	4.36	4.52	4.07	4.58	5.87	4.07	4.48	4.36	5.64	4.52	4.68	4.07	4.94
2025	3.81	4.49	4.65	4.20	4.72	6.05	4.20	4.62	4.49	5.81	4.66	4.82	4.20	5.08
2026	3.93	4.62	4.79	4.32	4.86	6.23	4.32	4.76	4.63	5.98	4.80	4.97	4.32	5.24
2027	4.05	4.76	4.93	4.45	5.00	6.41	4.45	4.90	4.77	6.16	4.94	5.12	4.45	5.39
2028	4.18	4.92	5.10	4.60	5.17	6.62	4.60	5.06	4.93	6.36	5.11	5.29	4.60	5.57
2029	4.31	5.07	5.25	4.74	5.33	6.82	4.74	5.21	5.08	6.55	5.26	5.45	4.74	5.74
2030	4.45	5.24	5.43	4.90	5.50	7.04	4.90	5.39	5.25	6.76	5.44	5.63	4.90	5.93
2031	4.73	5.56	5.76	5.20	5.84	7.47	5.20	5.72	5.57	7.18	5.77	5.97	5.20	6.29
2032	5.01	5.90	6.11	5.52	6.20	7.92	5.52	6.07	5.91	7.61	6.12	6.34	5.52	6.68
2033	5.32	6.26	6.49	5.85	6.58	8.41	5.85	6.44	6.27	8.08	6.50	6.73	5.85	7.08
2034	5.65	6.65	6.89	6.21	6.98	8.92	6.21	6.84	6.65	8.57	6.90	7.14	6.21	7.52
2035	5.99	7.05	7.31	6.59	7.41	9.46	6.59	7.25	7.06	9.09	7.32	7.57	6.59	7.98
2036	6.36	7.48	7.75	7.00	7.86	10.04	7.00	7.70	7.50	9.65	7.77	8.04	7.00	8.46
2037	6.75	7.94	8.23	7.43	8.34	10.65	7.43	8.17	7.96	10.24	8.24	8.53	7.43	8.98
2038	7.17	8.43	8.73	7.88	8.86	11.30	7.88	8.67	8.44	10.86	8.75	9.05	7.88	9.53
2039	7.61	8.95	9.27	8.37	9.40	11.99	8.37	9.20	8.96	11.53	9.29	9.61	8.37	10.11
2040	8.07	9.50	9.84	8.88	9.97	12.73	8.88	9.77	9.51	12.23	9.85	10.19	8.88	10.73
2041	8.57	10.08	10.44	9.42	10.58	13.50	9.42	10.36	10.09	12.98	10.46	10.82	9.42	11.39
2042	9.09	10.70	11.08	10.00	11.23	14.33	10.00	11.00	10.71	13.77	11.10	11.48	10.00	12.09
2043	9.65	11.35	11.76	10.61	11.92	15.20	10.61	11.67	11.37	14.61	11.78	12.18	10.61	12.83
2044	10.24	12.05	12.48	11.26	12.65	16.13	11.26	12.39	12.07	15.50	12.50	12.93	11.26	13.61
2045	10.87	12.79	13.24	11.96	13.43	17.11	11.96	13.15	12.81	16.45	13.27	13.72	11.96	14.44
2046	11.54	13.57	14.05	12.69	14.25	18.16	12.69	13.95	13.59	17.45	14.08	14.56	12.69	15.33
2047	12.24	14.40	14.92	13.47	15.12	19.26	13.47	14.81	14.42	18.52	14.94	15.45	13.47	16.26
2048	12.99	15.29	15.83	14.29	16.05	20.44	14.29	15.72	15.31	19.65	15.86	16.40	14.29	17.26
2049	13.79	16.22	16.80	15.17	17.03	21.69	15.17	16.68	16.25	20.85	16.83	17.40	15.17	18.32
2050	14.63	17.22	17.83	16.10	18.07	23.01	16.10	17.70	17.24	22.12	17.86	18.47	16.10	19.44
2051	15.53	18.27	18.92	17.09	19.18	24.41	17.09	18.79	18.30	23.47	18.95	19.60	17.09	20.62
2052	16.48	19.39	20.08	18.13	20.35	25.90	18.13	19.94	19.42	24.90	20.11	20.80	18.13	21.89
2053	17.49	20.58	21.31	19.24	21.60	27.48	19.24	21.16	20.61	26.42	21.35	22.07	19.24	23.23
2054	18.57	21.84	22.62	20.42	22.92	29.16	20.42	22.46	21.88	28.04	22.65	23.43	20.42	24.65
2055	19.71	23.18	24.00	21.68	24.33	30.94	21.68	23.83	23.22	29.75	24.04	24.86	21.68	26.15
2056	20.91	24.60	25.47	23.01	25.82	32.83	23.01	25.29	24.64	31.57	25.51	26.38	23.01	27.75
2057	22.20	26.11	27.03	24.42	27.40	34.83	24.42	26.84	26.15	33.49	27.08	28.00	24.42	29.45
2058	23.56	27.71	28.69	25.91	29.08	36.95	25.91	28.49	27.75	35.54	28.74	29.71	25.91	31.25
2059	25.00	29.41	30.45	27.50	30.86	39.21	27.50	30.23	29.45	37.71	30.50	31.53	27.50	33.16
2060	26.53	31.22	32.31	29.19	32.75	41.60	29.19	32.08	31.26	40.01	32.37	33.46	29.19	35.19
2061	28.16	33.13	34.29	30.98	34.75	44.14	30.98	34.05	33.18	42.45	34.35	35.51	30.98	37.35

Table 5-7 Medium Case Heating Oil Price Projections ($/gal)

Year	Angoon	Chilkat Valley	Coffman Cove	Craig	Edna Bay	Elfin Cove	Excursion Inlet	Gustavus	Haines	Hollis	Hoonah	Hydaburg	Hyder	Juneau	Kake	Ketchikan	Klawock	Klukwan	Metlakatla	Naukati	Pelican	Petersburg	Sitka	Skagway	Tenakee Springs	Thorne Bay/Kasaan	Whale Pass	Wrangell	Yakutat
2012	4.44	4.49	4.66	4.33	4.55	5.36	5.09	5.09	4.41	4.33	4.59	4.38	4.33	4.08	4.44	3.68	4.33	4.44	4.05	4.48	5.36	4.05	4.41	4.33	5.20	4.44	4.55	4.05	4.72
2013	4.71	4.77	4.94	4.60	4.83	5.66	5.38	5.38	4.69	4.60	4.87	4.65	4.60	4.34	4.71	3.91	4.60	4.71	4.30	4.76	5.66	4.30	4.69	4.60	5.50	4.72	4.83	4.30	5.01
2014	5.01	5.07	5.25	4.90	5.13	5.98	5.70	5.70	4.99	4.90	5.17	4.95	4.90	4.59	5.01	4.16	4.90	5.01	4.58	5.06	5.98	4.58	4.99	4.90	5.82	5.02	5.13	4.58	5.31
2015	5.30	5.36	5.54	5.18	5.42	6.30	6.01	6.01	5.28	5.18	5.47	5.24	5.18	4.86	5.30	4.40	5.18	5.30	4.85	5.35	6.30	4.85	5.28	5.19	6.13	5.31	5.42	4.85	5.61
2016	5.60	5.66	5.85	5.48	5.73	6.63	6.33	6.33	5.58	5.48	5.77	5.54	5.48	5.13	5.60	4.66	5.48	5.60	5.12	5.65	6.63	5.12	5.58	5.49	6.45	5.61	5.73	5.12	5.92
2017	5.92	5.98	6.17	5.79	6.05	6.97	6.66	6.66	5.89	5.79	6.09	5.85	5.79	5.41	5.92	4.92	5.79	5.92	5.42	5.97	6.97	5.42	5.89	5.80	6.79	5.92	6.05	5.42	6.24
2018	6.23	6.30	6.50	6.11	6.37	7.32	7.00	7.00	6.21	6.11	6.42	6.16	6.11	5.69	6.23	5.19	6.11	6.23	5.71	6.28	7.32	5.71	6.21	6.11	7.13	6.24	6.37	5.71	6.57
2019	6.57	6.63	6.84	6.43	6.70	7.68	7.35	7.35	6.54	6.43	6.75	6.49	6.43	5.99	6.56	5.47	6.43	6.56	6.01	6.62	7.68	6.01	6.54	6.44	7.49	6.57	6.70	6.01	6.91
2020	6.90	6.96	7.17	6.76	7.04	8.04	7.71	7.71	6.87	6.76	7.09	6.82	6.76	6.28	6.90	5.75	6.76	6.90	6.32	6.95	8.04	6.32	6.87	6.77	7.85	6.90	7.04	6.32	7.25
2021	7.23	7.30	7.51	7.09	7.37	8.41	8.06	8.06	7.20	7.09	7.42	7.15	7.09	6.59	7.23	6.02	7.09	7.23	6.63	7.28	8.41	6.63	7.20	7.09	8.20	7.23	7.37	6.63	7.59
2022	7.57	7.64	7.87	7.43	7.72	8.79	8.43	8.43	7.54	7.43	7.77	7.49	7.43	6.89	7.57	6.31	7.43	7.57	6.95	7.63	8.79	6.95	7.54	7.43	8.58	7.58	7.72	6.95	7.95
2023	7.93	8.01	8.23	7.78	8.09	9.18	8.82	8.82	7.90	7.78	8.14	7.85	7.78	7.21	7.93	6.62	7.78	7.93	7.28	7.99	9.18	7.28	7.90	7.79	8.97	7.94	8.09	7.28	8.32
2024	8.28	8.35	8.59	8.12	8.43	9.56	9.18	9.18	8.24	8.12	8.49	8.19	8.12	7.53	8.27	6.90	8.12	8.27	7.59	8.33	9.56	7.59	8.24	8.13	9.34	8.28	8.43	7.59	8.67
2025	8.65	8.73	8.97	8.49	8.81	9.97	9.58	9.58	8.61	8.49	8.87	8.56	8.49	7.85	8.65	7.22	8.49	8.65	7.94	8.71	9.97	7.94	8.61	8.50	9.74	8.65	8.81	7.94	9.06
2026	9.02	9.10	9.35	8.86	9.19	10.38	9.98	9.98	8.99	8.86	9.25	8.93	8.86	8.18	9.02	7.53	8.86	9.02	8.28	9.08	10.38	8.28	8.99	8.86	10.15	9.03	9.19	8.28	9.44
2027	9.39	9.47	9.73	9.22	9.56	10.79	10.38	10.38	9.35	9.22	9.62	9.30	9.22	8.53	9.39	7.84	9.22	9.39	8.62	9.45	10.79	8.62	9.35	9.23	10.55	9.40	9.56	8.62	9.82
2028	9.77	9.86	10.12	9.60	9.95	11.21	10.79	10.79	9.74	9.60	10.01	9.68	9.60	8.87	9.77	8.16	9.60	9.77	8.98	9.84	11.21	8.98	9.74	9.61	10.96	9.78	9.95	8.98	10.22
2029	10.15	10.24	10.51	9.98	10.34	11.63	11.20	11.20	10.12	9.98	10.40	10.06	9.98	9.22	10.15	8.48	9.98	10.15	9.33	10.22	11.63	9.33	10.12	9.98	11.38	10.16	10.34	9.33	10.61
2030	10.55	10.64	10.92	10.37	10.74	12.07	11.63	11.63	10.51	10.37	10.80	10.45	10.37	9.59	10.55	8.81	10.37	10.55	9.69	10.62	12.07	9.69	10.51	10.37	11.81	10.56	10.74	9.69	11.02
2031	11.33	11.43	11.72	11.14	11.53	12.94	12.47	12.47	11.29	11.14	11.60	11.22	11.14	10.30	11.33	9.47	11.14	11.33	10.41	11.41	12.94	10.41	11.29	11.15	12.67	11.34	11.53	10.41	11.83
2032	12.17	12.27	12.58	11.97	12.38	13.88	13.38	13.38	12.13	11.97	12.45	12.06	11.97	11.06	12.17	10.17	11.97	12.17	11.19	12.25	13.88	11.19	12.13	11.98	13.59	12.18	12.38	11.19	12.70
2033	13.07	13.18	13.51	12.86	13.30	14.88	14.35	14.35	13.03	12.86	13.37	12.96	12.86	11.88	13.07	10.93	12.86	13.07	12.02	13.16	14.88	12.02	13.03	12.87	14.57	13.08	13.30	12.02	13.63
2034	14.04	14.16	14.51	13.82	14.28	15.96	15.40	15.40	14.00	13.82	14.36	13.92	13.82	12.75	14.04	11.74	13.82	14.04	12.92	14.13	15.96	12.92	14.00	13.83	15.63	14.05	14.28	12.92	14.64
2035	15.09	15.21	15.57	14.85	15.33	17.11	16.52	16.52	15.03	14.85	15.42	14.95	14.85	13.70	15.08	12.62	14.85	15.08	13.88	15.18	17.11	13.88	15.03	14.86	16.76	15.10	15.33	13.88	15.71
2036	16.21	16.33	16.72	15.95	16.47	18.34	17.72	17.72	16.15	15.95	16.56	16.06	15.95	14.71	16.20	13.56	15.95	16.20	14.91	16.30	18.34	14.91	16.15	15.96	17.98	16.22	16.47	14.91	16.87
2037	17.41	17.54	17.95	17.14	17.69	19.67	19.01	19.01	17.35	17.14	17.78	17.26	17.14	15.79	17.41	14.57	17.14	17.41	16.03	17.51	19.67	16.03	17.35	17.15	19.28	17.42	17.69	16.03	18.11
2038	18.70	18.84	19.28	18.42	18.99	21.09	20.39	20.39	18.64	18.42	19.10	18.54	18.42	16.96	18.70	15.65	18.42	18.70	17.22	18.81	21.09	17.22	18.64	18.43	20.68	18.71	18.99	17.22	19.44
2039	20.09	20.24	20.70	19.79	20.40	22.61	21.87	21.87	20.02	19.79	20.51	19.92	19.79	18.21	20.08	16.82	19.79	20.08	18.50	20.20	22.61	18.50	20.02	19.80	22.18	20.10	20.40	18.50	20.87
2040	21.58	21.73	22.22	21.26	21.90	24.25	23.47	23.47	21.51	21.26	22.02	21.40	21.26	19.56	21.57	18.07	21.26	21.57	19.88	21.70	24.25	19.88	21.51	21.27	23.79	21.59	21.90	19.88	22.40
2041	23.18	23.34	23.86	22.84	23.52	26.00	25.17	25.17	23.11	22.84	23.65	22.99	22.84	21.00	23.17	19.42	22.84	23.17	21.36	23.31	26.00	21.36	23.11	22.86	25.51	23.19	23.52	21.36	24.05
2042	24.90	25.07	25.62	24.54	25.26	27.88	27.00	27.00	24.82	24.54	25.39	24.70	24.54	22.56	24.89	20.86	24.54	24.89	22.95	25.03	27.88	22.95	24.82	24.56	27.37	24.91	25.26	22.95	25.82
2043	26.74	26.93	27.50	26.37	27.13	29.89	28.97	28.97	26.66	26.37	27.27	26.54	26.37	24.22	26.74	22.42	26.37	26.74	24.66	26.89	29.89	24.66	26.66	26.39	29.35	26.76	27.13	24.66	27.72
2044	28.73	28.92	29.53	28.33	29.13	32.05	31.08	31.08	28.64	28.33	29.28	28.51	28.33	26.01	28.72	24.08	28.33	28.72	26.49	28.88	32.05	26.49	28.64	28.35	31.48	28.74	29.13	26.49	29.75
2045	30.86	31.06	31.70	30.44	31.29	34.37	33.34	33.34	30.77	30.44	31.44	30.63	30.44	27.93	30.86	25.88	30.44	30.86	28.47	31.02	34.37	28.47	30.77	30.46	33.76	30.88	31.29	28.47	31.94
2046	33.15	33.37	34.04	32.71	33.60	36.85	35.76	35.76	33.06	32.71	33.76	32.91	32.71	30.00	33.15	27.80	32.71	33.15	30.59	33.32	36.85	30.59	33.06	32.73	36.21	33.17	33.60	30.59	34.29
2047	35.61	35.84	36.55	35.15	36.08	39.51	38.37	38.37	35.51	35.15	36.25	35.35	35.15	32.21	35.60	29.88	35.15	35.60	32.86	35.79	39.51	32.86	35.51	35.17	38.84	35.63	36.08	32.86	36.81
2048	38.25	38.49	39.24	37.76	38.75	42.37	41.16	41.16	38.15	37.76	38.93	37.98	37.76	34.59	38.25	32.10	37.76	38.25	35.31	38.44	42.37	35.31	38.15	37.78	41.66	38.27	38.75	35.31	39.52
2049	41.09	41.34	42.13	40.58	41.62	45.43	44.15	44.15	40.98	40.58	41.80	40.80	40.58	37.15	41.08	34.49	40.58	41.08	37.94	41.29	45.43	37.94	40.98	40.60	44.68	41.11	41.62	37.94	42.42
2050	44.13	44.40	45.23	43.60	44.69	48.71	47.36	47.36	44.02	43.60	44.89	43.84	43.60	39.89	44.13	37.06	43.60	44.13	40.76	44.34	48.71	40.76	44.02	43.62	47.92	44.16	44.69	40.76	45.54
2051	47.41	47.69	48.57	46.84	48.00	52.23	50.81	50.81	47.29	46.84	48.20	47.10	46.84	42.84	47.41	39.82	46.84	47.41	43.80	47.63	52.23	43.80	47.29	46.87	51.40	47.43	48.00	43.80	48.89
2052	50.93	51.22	52.14	50.33	51.54	56.00	54.51	54.51	50.80	50.33	51.76	50.60	50.33	46.00	50.92	42.78	50.33	50.92	47.06	51.16	56.00	47.06	50.80	50.36	55.12	50.95	51.54	47.06	52.49
2053	54.70	55.02	55.98	54.08	55.35	60.05	58.47	58.47	54.57	54.08	55.58	54.36	54.08	49.40	54.70	45.97	54.08	54.70	50.56	54.95	60.05	50.56	54.57	54.10	59.12	54.73	55.35	50.56	56.34
2054	58.76	59.09	60.11	58.11	59.45	64.39	62.73	62.73	58.62	58.11	59.69	58.40	58.11	53.05	58.76	49.39	58.11	58.76	54.33	59.02	64.39	54.33	58.62	58.13	63.41	58.79	59.45	54.33	60.49
2055	63.12	63.47	64.54	62.43	63.84	69.04	67.29	67.29	62.98	62.43	64.09	62.74	62.43	56.97	63.12	53.07	62.43	63.12	58.37	63.39	69.04	58.37	62.98	62.46	68.01	63.15	63.84	58.37	64.94
2056	67.81	68.17	69.29	67.08	68.56	74.03	72.19	72.19	67.65	67.08	68.82	67.40	67.08	61.17	67.80	57.02	67.08	67.80	62.72	68.09	74.03	62.72	67.65	67.11	72.95	67.84	68.56	62.72	69.71
2057	72.84	73.21	74.39	72.08	73.63	79.37	77.44	77.44	72.67	72.08	73.91	72.42	72.08	65.69	72.83	61.26	72.08	72.83	67.39	73.13	79.37	67.39	72.67	72.11	78.24	72.87	73.63	67.39	74.83
2058	78.24	78.64	79.87	77.44	79.07	85.11	83.07	83.07	78.07	77.44	79.36	77.80	77.44	70.54	78.23	65.83	77.44	78.23	72.41	78.55	85.11	72.41	78.07	77.48	83.91	78.27	79.07	72.41	80.34
2059	84.04	84.46	85.76	83.21	84.91	91.26	89.12	89.12	83.87	83.21	85.22	83.58	83.21	75.76	84.04	70.73	83.21	84.04	77.80	84.37	91.26	77.80	83.87	83.24	90.00	84.08	84.91	77.80	86.24
2060	90.28	90.71	92.08	89.41	91.19	97.85	95.60	95.60	90.09	89.41	91.51	89.80	89.41	81.35	90.27	75.99	89.41	90.27	83.59	90.62	97.85	83.59	90.09	89.44	96.53	90.32	91.19	83.59	92.58
2061	96.98	97.43	98.86	96.06	97.93	104.92	102.56	102.56	96.78	96.06	98.27	96.47	96.06	87.36	96.97	81.65	96.06	96.97	89.82	97.33	104.92	89.82	96.78	96.10	103.53	97.02	97.93	89.82	99.39

Table 5-8 High Case Heating Oil Price Projections ($/gal)

Year	Angoon	Chilkat Valley	Coffman Cove	Craig	Edna Bay	Elfin Cove	Excursion Inlet	Gustavus	Haines	Hollis	Hoonah	Hydaburg	Hyder	Juneau	Kake
2012	6.18	6.23	6.39	6.07	6.29	7.07	6.81	6.81	6.15	6.07	6.32	6.12	6.07	5.59	6.17
2013	6.75	6.81	6.98	6.64	6.87	7.67	7.41	7.41	6.73	6.64	6.91	6.69	6.64	6.10	6.75
2014	7.21	7.27	7.44	7.10	7.33	8.16	7.89	7.89	7.19	7.10	7.37	7.15	7.10	6.51	7.21
2015	7.67	7.73	7.91	7.56	7.79	8.65	8.36	8.36	7.65	7.56	7.84	7.61	7.56	6.91	7.67
2016	8.16	8.21	8.40	8.04	8.28	9.16	8.86	8.86	8.13	8.04	8.32	8.09	8.04	7.33	8.15
2017	8.65	8.71	8.89	8.52	8.77	9.68	9.37	9.37	8.62	8.52	8.82	8.58	8.52	7.76	8.64
2018	9.15	9.21	9.40	9.02	9.28	10.21	9.90	9.90	9.12	9.02	9.32	9.08	9.02	8.21	9.14
2019	9.65	9.72	9.92	9.52	9.79	10.75	10.43	10.43	9.63	9.52	9.84	9.58	9.52	8.66	9.65
2020	10.17	10.24	10.44	10.04	10.31	11.29	10.97	10.97	10.14	10.04	10.36	10.10	10.04	9.13	10.17
2021	10.70	10.77	10.98	10.56	10.84	11.85	11.51	11.51	10.67	10.56	10.89	10.62	10.56	9.59	10.70
2022	11.25	11.32	11.53	11.11	11.39	12.43	12.09	12.09	11.22	11.11	11.45	11.17	11.11	10.08	11.25
2023	11.81	11.88	12.10	11.66	11.96	13.03	12.67	12.67	11.77	11.66	12.01	11.73	11.66	10.56	11.80
2024	12.37	12.45	12.68	12.22	12.53	13.63	13.26	13.26	12.34	12.22	12.58	12.29	12.22	11.07	12.37
2025	12.94	13.02	13.26	12.79	13.10	14.24	13.86	13.86	12.91	12.79	13.16	12.86	12.79	11.58	12.94
2026	13.53	13.60	13.85	13.37	13.69	14.86	14.47	14.47	13.49	13.37	13.75	13.44	13.37	12.10	13.52
2027	14.13	14.21	14.46	13.97	14.30	15.50	15.10	15.10	14.09	13.97	14.36	14.04	13.97	12.63	14.13
2028	14.72	14.81	15.06	14.56	14.90	16.13	15.72	15.72	14.69	14.56	14.96	14.63	14.56	13.18	14.72
2029	15.34	15.43	15.69	15.17	15.52	16.79	16.37	16.37	15.30	15.17	15.58	15.24	15.17	13.73	15.34
2030	15.96	16.05	16.32	15.79	16.15	17.45	17.02	17.02	15.93	15.79	16.21	15.86	15.79	14.29	15.96
2031	17.19	17.28	17.57	17.00	17.38	18.77	18.31	18.31	17.15	17.00	17.45	17.09	17.00	15.38	17.19
2032	18.51	18.61	18.91	18.31	18.72	20.18	19.69	19.69	18.47	18.31	18.79	18.40	18.31	16.56	18.51
2033	19.93	20.04	20.36	19.72	20.15	21.70	21.18	21.18	19.89	19.72	20.23	19.82	19.72	17.83	19.93
2034	21.46	21.57	21.92	21.24	21.69	23.33	22.79	22.79	21.42	21.24	21.77	21.34	21.24	19.19	21.46
2035	23.11	23.23	23.59	22.88	23.36	25.09	24.51	24.51	23.06	22.88	23.44	22.98	22.88	20.66	23.11
2036	24.89	25.01	25.39	24.64	25.14	26.98	26.37	26.37	24.83	24.64	25.23	24.75	24.64	22.25	24.89
2037	26.80	26.93	27.33	26.54	27.07	29.01	28.36	28.36	26.74	26.54	27.17	26.65	26.54	23.95	26.80
2038	28.86	29.00	29.42	28.58	29.15	31.19	30.51	30.51	28.80	28.58	29.25	28.71	28.58	25.79	28.86
2039	31.08	31.22	31.67	30.78	31.38	33.54	32.82	32.82	31.01	30.78	31.48	30.91	30.78	27.76	31.07
2040	33.46	33.62	34.09	33.15	33.78	36.07	35.30	35.30	33.40	33.15	33.89	33.29	33.15	29.89	33.46
2041	36.03	36.20	36.70	35.71	36.37	38.78	37.98	37.98	35.96	35.71	36.49	35.85	35.71	32.18	36.03
2042	38.80	38.97	39.50	38.46	39.16	41.70	40.85	40.85	38.73	38.46	39.28	38.61	38.46	34.64	38.80
2043	41.78	41.96	42.52	41.42	42.16	44.84	43.94	43.94	41.71	41.42	42.29	41.58	41.42	37.30	41.78
2044	44.99	45.18	45.77	44.61	45.39	48.21	47.27	47.27	44.91	44.61	45.53	44.78	44.61	40.15	44.99
2045	48.45	48.65	49.27	48.05	48.86	51.84	50.85	50.85	48.36	48.05	49.01	48.23	48.05	43.23	48.45
2046	52.17	52.38	53.03	51.75	52.61	55.75	54.70	54.70	52.08	51.75	52.76	51.94	51.75	46.54	52.17
2047	56.18	56.40	57.08	55.74	56.64	59.94	58.84	58.84	56.09	55.74	56.80	55.93	55.74	50.11	56.18
2048	60.50	60.73	61.45	60.03	60.98	64.45	63.29	63.29	60.40	60.03	61.15	60.24	60.03	53.94	60.49
2049	65.14	65.39	66.14	64.65	65.65	69.30	68.08	68.08	65.04	64.65	65.83	64.87	64.65	58.08	65.14
2050	70.15	70.40	71.20	69.63	70.68	74.52	73.23	73.23	70.04	69.63	70.87	69.86	69.63	62.53	70.14
2051	75.54	75.81	76.64	75.00	76.10	80.13	78.78	78.78	75.42	75.00	76.29	75.24	75.00	67.32	75.53
2052	81.34	81.62	82.50	80.78	81.93	86.16	84.74	84.74	81.22	80.78	82.13	81.03	80.78	72.47	81.34
2053	87.59	87.88	88.80	87.00	88.20	92.65	91.15	91.15	87.46	87.00	88.42	87.26	87.00	78.02	87.59
2054	94.32	94.63	95.59	93.70	94.96	99.62	98.05	98.05	94.19	93.70	95.19	93.98	93.70	84.00	94.31
2055	101.57	101.89	102.89	100.92	102.24	107.12	105.48	105.48	101.43	100.92	102.48	101.21	100.92	90.44	101.56
2056	109.37	109.71	110.75	108.69	110.07	115.18	113.46	113.46	109.22	108.69	110.32	108.99	108.69	97.37	109.36
2057	117.77	118.12	119.22	117.06	118.50	123.85	122.05	122.05	117.62	117.06	118.76	117.38	117.06	104.82	117.77
2058	126.82	127.19	128.33	126.08	127.58	133.18	131.29	131.29	126.66	126.08	127.86	126.41	126.08	112.85	126.81
2059	136.56	136.94	138.14	135.80	137.36	143.20	141.23	141.23	136.40	135.80	137.64	136.14	135.80	121.50	136.56
2060	147.05	147.45	148.69	146.26	147.88	153.98	151.92	151.92	146.88	146.26	148.18	146.61	146.26	130.81	147.05
2061	158.35	158.76	160.06	157.52	159.21	165.57	163.42	163.42	158.17	157.52	159.52	157.89	157.52	140.83	158.34

Year	Ketchikan	Klawock	Klukwan	Metlakatla	Naukati	Pelican	Petersburg	Sitka	Skagway	Tenakee Springs	Thorne Bay/Kasaan	Whale Pass	Wrangell	Yakutat
2012	5.16	6.07	6.17	5.67	6.22	7.07	5.67	6.15	6.07	6.92	6.18	6.29	5.67	6.45
2013	5.65	6.64	6.75	6.21	6.80	7.67	6.21	6.73	6.65	7.52	6.76	6.87	6.21	7.04
2014	6.04	7.10	7.21	6.64	7.26	8.16	6.64	7.19	7.11	8.00	7.22	7.33	6.64	7.51
2015	6.42	7.56	7.67	7.07	7.72	8.65	7.07	7.65	7.56	8.48	7.68	7.79	7.07	7.98
2016	6.83	8.04	8.15	7.51	8.20	9.16	7.51	8.13	8.04	8.99	8.16	8.28	7.51	8.47
2017	7.24	8.52	8.64	7.97	8.69	9.68	7.97	8.62	8.53	9.50	8.65	8.77	7.97	8.96
2018	7.67	9.02	9.14	8.43	9.19	10.21	8.43	9.12	9.02	10.02	9.15	9.28	8.43	9.47
2019	8.10	9.52	9.65	8.91	9.71	10.75	8.91	9.63	9.53	10.56	9.66	9.79	8.91	9.99
2020	8.53	10.04	10.17	9.39	10.22	11.29	9.39	10.14	10.04	11.10	10.18	10.31	9.39	10.52
2021	8.98	10.56	10.70	9.88	10.75	11.85	9.88	10.67	10.57	11.65	10.70	10.84	9.88	11.06
2022	9.44	11.11	11.25	10.38	11.30	12.43	10.38	11.22	11.11	12.23	11.25	11.39	10.38	11.62
2023	9.91	11.66	11.80	10.90	11.86	13.03	10.90	11.77	11.67	12.82	11.81	11.96	10.90	12.18
2024	10.39	12.22	12.37	11.43	12.43	13.63	11.43	12.34	12.23	13.41	12.38	12.53	11.43	12.76
2025	10.87	12.79	12.94	11.96	13.00	14.24	11.96	12.91	12.80	14.02	12.95	13.10	11.96	13.35
2026	11.36	13.37	13.52	12.50	13.59	14.86	12.50	13.49	13.37	14.63	13.53	13.69	12.50	13.94
2027	11.87	13.97	14.13	13.06	14.19	15.50	13.06	14.09	13.97	15.26	14.14	14.30	13.06	14.55
2028	12.37	14.56	14.72	13.61	14.79	16.13	13.61	14.69	14.56	15.89	14.73	14.90	13.61	15.16
2029	12.89	15.17	15.34	14.18	15.41	16.79	14.18	15.30	15.17	16.54	15.35	15.52	14.18	15.79
2030	13.42	15.79	15.96	14.76	16.03	17.45	14.76	15.93	15.79	17.20	15.97	16.15	14.76	16.42
2031	14.45	17.00	17.19	15.90	17.26	18.77	15.90	17.15	17.01	18.50	17.20	17.38	15.90	17.68
2032	15.56	18.31	18.51	17.12	18.59	20.18	17.12	18.47	18.32	19.89	18.52	18.72	17.12	19.03
2033	16.76	19.72	19.93	18.44	20.01	21.70	18.44	19.89	19.73	21.40	19.94	20.15	18.44	20.48
2034	18.05	21.24	21.46	19.86	21.55	23.33	19.86	21.42	21.25	23.01	21.47	21.69	19.86	22.04
2035	19.45	22.88	23.11	21.39	23.20	25.09	21.39	23.06	22.89	24.75	23.12	23.36	21.39	23.72
2036	20.94	24.64	24.89	23.04	24.98	26.98	23.04	24.83	24.65	26.62	24.90	25.14	23.04	25.53
2037	22.56	26.54	26.80	24.81	26.90	29.01	24.81	26.74	26.55	28.63	26.81	27.07	24.81	27.48
2038	24.29	28.58	28.86	26.72	28.97	31.19	26.72	28.80	28.59	30.79	28.87	29.15	26.72	29.58
2039	26.17	30.78	31.07	28.78	31.19	33.54	28.78	31.01	30.79	33.12	31.09	31.38	28.78	31.84
2040	28.18	33.15	33.46	31.00	33.58	36.07	31.00	33.40	33.17	35.62	33.48	33.78	31.00	34.27
2041	30.35	35.71	36.03	33.39	36.16	38.78	33.39	35.96	35.72	38.31	36.05	36.37	33.39	36.88
2042	32.69	38.46	38.80	35.96	38.94	41.70	35.96	38.73	38.47	41.20	38.82	39.16	35.96	39.70
2043	35.21	41.42	41.78	38.73	41.92	44.84	38.73	41.71	41.44	44.31	41.80	42.16	38.73	42.73
2044	37.92	44.61	44.99	41.71	45.14	48.21	41.71	44.91	44.63	47.66	45.01	45.39	41.71	45.99
2045	40.84	48.05	48.45	44.93	48.61	51.84	44.93	48.36	48.07	51.26	48.47	48.86	44.93	49.50
2046	43.99	51.75	52.17	48.39	52.34	55.75	48.39	52.08	51.77	55.13	52.19	52.61	48.39	53.27
2047	47.38	55.74	56.18	52.11	56.35	59.94	52.11	56.09	55.75	59.29	56.20	56.64	52.11	57.34
2048	51.03	60.03	60.49	56.13	60.68	64.45	56.13	60.40	60.05	63.77	60.52	60.98	56.13	61.72
2049	54.96	64.65	65.14	60.45	65.33	69.30	60.45	65.04	64.67	68.59	65.16	65.65	60.45	66.42
2050	59.19	69.63	70.14	65.11	70.35	74.52	65.11	70.04	69.66	73.77	70.17	70.68	65.11	71.49
2051	63.75	75.00	75.53	70.12	75.75	80.13	70.12	75.42	75.02	79.34	75.56	76.10	70.12	76.95
2052	68.66	80.78	81.34	75.53	81.56	86.16	75.53	81.22	80.80	85.33	81.36	81.93	75.53	82.82
2053	73.95	87.00	87.59	81.34	87.82	92.65	81.34	87.46	87.02	91.77	87.62	88.20	81.34	89.14
2054	79.65	93.70	94.31	87.61	94.56	99.62	87.61	94.19	93.73	98.70	94.35	94.96	87.61	95.94
2055	85.78	100.92	101.56	94.36	101.82	107.12	94.36	101.43	100.94	106.15	101.59	102.24	94.36	103.27
2056	92.39	108.69	109.36	101.63	109.63	115.18	101.63	109.22	108.72	114.17	109.40	110.07	101.63	111.15
2057	99.51	117.06	117.77	109.46	118.05	123.85	109.46	117.62	117.09	122.79	117.80	118.50	109.46	119.63
2058	107.17	126.08	126.81	117.89	127.11	133.18	117.89	126.66	126.11	132.07	126.85	127.58	117.89	128.76
2059	115.43	135.80	136.56	126.97	136.86	143.20	126.97	136.40	135.83	142.04	136.59	137.36	126.97	138.58
2060	124.32	146.26	147.05	136.75	147.37	153.98	136.75	146.88	146.29	152.77	147.09	147.88	136.75	149.16
2061	133.89	157.52	158.34	147.28	158.68	165.57	147.28	158.17	157.56	164.30	158.39	159.21	147.28	160.54

6.0 Economic Parameters

The economic parameters are those necessary for conducting the various economic analyses throughout the study. They include inflation rates, escalation rates, financing costs, present worth discount rates, interest during construction interest rates, and development of levelized fixed charge rates. Although it is unlikely that the selected economic parameters will be accurate throughout the 50-year term of the study, they are selected to be internally consistent with each other such that changes to the economic parameters in the future will be somewhat mitigated. By internally consistent, it is meant that the relationships between the various economic parameters are reasonable with respect to each other. For example, the relationship between interest rates and inflation are reasonable.

There are real differences in the cost of financing depending upon the structure and credit rating of the entity doing the financing. The Southeast Alaska Integrated Resource Plan (IRP) is agnostic with respect to project ownership. As a result, for simplicity throughout the Southeast Alaska IRP, financing is considered to be conducted with tax-exempt bonds. This approach generally minimizes financing costs.

All costs in the Southeast Alaska IRP are presented in nominal dollars unless otherwise noted.

6.1 INFLATION AND ESCALATION RATES

Escalation rates are developed for capital and O&M costs and are consistent with the general inflation rate. The same general inflation rate and escalation rates are used for all Southeast Alaska utilities. For evaluation purposes, 3 percent is used for annual general inflation and escalation rates.

6.2 FINANCING RATES

The cost of capital for long-term tax-exempt bonds is assumed to be 5.5 percent and is used in all evaluations. Cost of capital for taxable entities is expected to be approximately 2 percent higher, depending on the entity's individual credit. Return on equity would be assumed to be higher as well.

6.3 PRESENT WORTH DISCOUNT RATE

The present worth discount rate was assumed to be equal to the cost of capital of 5.5 percent.

6.4 INTEREST DURING CONSTRUCTION INTEREST RATE

The interest during construction interest rate was assumed to be equal to the cost of capital of 5.5 percent. Short-term financing costs would likely be lower than the long term, but for simplicity and consistently, 5.5 percent is used as the interest during construction rate.

6.5 FIXED CHARGE RATES

Levelized fixed charge rates are used in a number of the economic analyses including the Strategist® Optimal Generation Expansion Program. Fixed charge rates were developed for new capital additions based on the cost of capital assuming 100 percent debt. It is also assumed that there will be no property taxes or payments in lieu of property taxes. The fixed charge rates include the following components in addition to debt amortization:

- Issuance costs for debt – 1.5 percent.
- Property insurance – 0.5 percent.
- Debt service reserve funds – 1 year.
- Earnings on reserve funds – 5.5 percent.

Levelized fixed charge rates were developed for the following financing terms ranging from 5 to 30 years. The terms used for alternatives are as follows.

- Biomass – 20 years.
- Diesel – 20 years.
- Wave and Tidal – 20 years.
- Wind – 20 years.
- Geothermal – 25 years.
- Coal – 30 years.
- Municipal Solid Waste – 30 years.

In addition, the long-lived capital investments of hydro and, to a lesser extent, transmission interconnections theoretically would support a longer financing term of up to 50 years; however, 30 years is generally the longest financing term available from financial institutions. A longer financing term for projects such as hydro would need State support. The fixed charge rates for these long life alternatives are developed in the various financial models utilizing State support presented in Section 9.0.

Table 6-1 Cost of Capital and Fixed Charge Rates for the Southeast Alaska Utilities

COST OF CAPITAL (%)	LEVELIZED FIXED CHARGE RATES (%) FINANCING TERMS (YEARS)					
	5	10	15	20	25	30
5.5	31.569	15.505	11.252	9.335	8.275	7.621

7.0 Reliability Criteria

7.1 INTRODUCTION

For purposes of the IRP, Black & Veatch developed reliability criteria for use in modeling the electric systems of the communities of Southeast Alaska with Strategist. The reliability criteria indentify requirements for the amount of diesel backup capacity to be in place on an electric system to cover hydroelectric resources. Setting an appropriate backup capacity decreases the likelihood of power outages at times when some generating units are not able to provide power for the system.

7.2 CRITERIA

In this study, the criteria were based on the general practice of backing up hydro generation because of the potential to run out of water in low water years. This is coupled with significant variations in load due to weather conditions. Another set of considerations also exists around the uncertainties resulting from the rapid conversion among electric customers from heating oil to electric for their home and business heating needs. This results in increased uncertainty about the magnitude of loads during extreme weather conditions in the region. As the region obtains better data on the impact of electric heating on system loads and increases the level of interconnection, it may be possible to reduce the amount of diesel backup requirements through the consideration of firm hydro capacity. Due to the current level of uncertainties, however, it has been assumed for purposes of the evaluation, that the communities in the region will continue the general current practice of backing up hydroelectric generation with diesel throughout the study period. The amount of backup diesel capacity used in this study is based on normal weather loads.

Black & Veatch set the reliability criteria for utilities with some existing or committed hydro generation equivalent to the utility's peak demand. This means that for every MW of projected annual peak demand, there is a MW of diesel capacity available. This ensures that any decrease in hydroelectric power can be covered as necessary. The criteria also address the expected lifetime of the diesel generating units. The lifetime of diesel units is generally based on operating hours. It is assumed that communities with existing hydro generation will not operate their diesel units as often and, thus, the diesel units will last 40 years before they need to be retired. Therefore, Black & Veatch included the cost of purchasing and installing new diesel units to immediately replace retired units.

For utilities with no existing or committed hydroelectric capacity and supplied only by diesel, the reliability criteria are set to the projected annual peak plus 15 percent. With this criterion, an outage of a diesel generating unit will in general be covered by the 15 percent excess diesel capacity available to the system if required. Since the diesel units owned by communities that do not have any existing hydro generation will be run exclusively, it is assumed that the units will need to be retired after 15 years of operation. Therefore, Black & Veatch included the cost of purchasing and installing new diesel units to immediately replace retired units.

Actual sizing of diesel generator additions will need to consider the loss of the largest unit for situations where the 15 percent reserve margin may not be adequate to cover the largest unit.

8.0 Load Forecasts

8.1 GENERAL ASSUMPTIONS

This section provides the general approach used by Black & Veatch to develop load forecasts, at a community level, for the study period 2012 through 2061. In addition, forecasts were developed for 2011. Forecasts were developed for each of the systems and communities evaluated in the IRP.

Black & Veatch initially developed a contact list for the communities with help of AEA and Southeast Conference. Black & Veatch developed a data request for load forecast information which was provided to each of the identified contacts. The data request sought historical data from 2000 to 2010 for the electric utility systems. To minimize individual community data requirements, Black & Veatch also obtained historical data from the Energy Information Administration (EIA) Form 861 filings by each of these utilities. The key data items requested from the communities were as follows:

- Annual generation.
- Annual sales by customer class.
- Annual system losses.
- Number of customers by customer class.
- Retail electric rate structure.

Black & Veatch also collected data for each of the communities to assess the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the American Community Survey (ACS) data for 2005 to 2009. Some of the key data items collected were as follows:

- Population.
- Average household size.
- Occupied housing units.
- Vacant housing units.
- Employment status for population 16 years and older.
- Median household income.

Black & Veatch also reviewed the long-term population forecast (available through 2030) developed by the Alaska Department of Labor (ADL) and used the forecast to estimate population growth or decline in the different communities until 2030.

Based on the data obtained, Black & Veatch developed a load package spreadsheet which showed the trends of the different data items from 2000 to 2010. It should be noted that not all communities which responded had all the data requested, and so the load package developed for each of the communities varied, depending on the type of data received from the community.

After the packages were developed, Black & Veatch provided them to each community and reached out to the communities again to understand what new developments are in the pipeline for the future and their potential impact on loads. Black & Veatch also discussed each community's expectations regarding population growth, economic development, housing developments, conversion of oil-based heating systems to electric heating systems, market penetration for electric cars, and other industrial developments.

Black & Veatch then developed the load forecast based on the historical trends of the region and the expectations of the community. In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into the following three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

After the reference forecasts were developed, Black & Veatch again reached out to the communities to get their feedback. The final reference forecasts were then developed taking into account the suggestions and comments received from the communities.

For each of the communities, three forecast scenarios were developed: Reference Scenario, High Scenario, and Low Scenario.

8.1.1 Reference Scenario

The Reference Scenario represents a business-as-usual case and, in general, reflects continued operation without outside intervention. The Reference Scenario reflects current fuel prices, which are generally higher than the medium fuel price projections in Section 5.0, which is leading to the current trend in conversion to electric heat for those communities with low-cost hydroelectric generation. The Reference Scenario assumes that these higher fuel prices drop back to the medium prices in Section 5.0 by the 2012 to 2013 time frame.

The Reference Scenario forecasts for energy and peak demand are presented in Tables 8-1 and 8-2, respectively, for each of the communities.

Table 8-1 Reference Case Annual Energy (MWh)

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2011	189,796	54,750	30,205	29,089	266	28,776	418,018	1,809	4,267	2,203	375	1,218	20,511	121,751	6,418	2,245	337	883	416
2012	202,897	55,461	30,658	30,916	274	29,343	428,700	1,787	4,267	2,188	379	1,243	21,331	123,684	6,388	2,290	330	971	416
2013	205,712	56,258	30,658	31,494	282	29,920	432,233	1,765	4,267	2,173	382	1,267	21,758	124,029	6,357	2,313	324	1,020	416
2014	209,139	57,069	30,505	31,939	290	30,505	436,687	1,743	4,267	2,159	386	1,293	21,758	125,127	6,327	2,313	317	1,020	416
2015	212,635	57,894	30,353	32,599	299	31,098	441,237	1,721	4,267	2,145	389	1,318	21,758	125,692	6,296	2,313	311	1,020	416
2016	213,698	58,184	30,413	32,568	300	31,254	443,443	1,723	4,275	2,149	390	1,325	21,867	126,320	6,328	2,692	311	1,022	417
2017	214,767	58,475	30,474	32,633	302	31,410	445,660	1,725	4,284	2,153	391	1,331	21,976	126,952	6,360	2,704	312	1,024	417
2018	215,840	58,767	30,535	32,699	303	31,567	447,889	1,726	4,293	2,157	391	1,338	22,086	127,587	6,391	2,715	313	1,026	418
2019	216,920	59,061	30,596	32,764	305	31,725	450,128	1,728	4,301	2,162	392	1,345	22,197	128,224	6,423	2,727	313	1,028	419
2020	218,004	59,356	30,657	32,830	306	31,884	452,379	1,730	4,310	2,166	393	1,351	22,307	128,866	6,455	2,739	314	1,030	420
2021	219,094	59,653	30,719	32,895	308	32,043	454,641	1,731	4,318	2,170	394	1,358	22,419	129,510	6,488	2,751	315	1,032	421
2022	220,190	59,951	30,780	32,961	309	32,203	456,914	1,733	4,327	2,175	394	1,365	22,531	130,157	6,520	2,763	315	1,034	422
2023	221,291	60,251	30,842	33,027	311	32,364	459,198	1,735	4,336	2,179	395	1,372	22,644	130,808	6,553	2,775	316	1,036	422
2024	222,397	60,552	30,903	33,093	312	32,526	461,494	1,737	4,344	2,183	396	1,379	22,757	131,462	6,585	2,787	316	1,038	423
2025	223,509	60,855	30,965	33,159	314	32,689	463,802	1,738	4,353	2,188	397	1,386	22,871	132,120	6,618	2,799	317	1,040	424
2026	224,627	61,159	31,027	33,225	315	32,852	466,121	1,740	4,362	2,192	398	1,392	22,985	132,780	6,651	2,811	318	1,042	425
2027	225,750	61,465	31,089	33,292	317	33,016	468,451	1,742	4,370	2,197	398	1,399	23,100	133,444	6,685	2,823	318	1,044	426
2028	226,878	61,772	31,151	33,358	319	33,181	470,794	1,744	4,379	2,201	399	1,406	23,216	134,111	6,718	2,835	319	1,046	427
2029	228,013	62,081	31,214	33,425	320	33,347	473,148	1,745	4,388	2,205	400	1,413	23,332	134,782	6,752	2,848	320	1,049	428
2030	229,153	62,392	31,276	33,492	322	33,514	475,513	1,747	4,397	2,210	401	1,421	23,448	135,456	6,786	2,860	320	1,051	428
2031	230,299	62,703	31,338	33,559	323	33,682	477,891	1,749	4,405	2,214	402	1,428	23,566	136,133	6,819	2,873	321	1,053	429
2032	231,450	63,017	31,401	33,626	325	33,850	480,280	1,751	4,414	2,219	402	1,435	23,683	136,814	6,854	2,885	322	1,055	430
2033	232,607	63,332	31,464	33,693	327	34,019	482,682	1,752	4,423	2,223	403	1,442	23,802	137,498	6,888	2,898	322	1,057	431
2034	233,770	63,649	31,527	33,761	328	34,189	485,095	1,754	4,432	2,227	404	1,449	23,921	138,185	6,922	2,910	323	1,059	432
2035	234,939	63,967	31,590	33,828	330	34,360	487,521	1,756	4,441	2,232	405	1,456	24,040	138,876	6,957	2,923	323	1,061	433
2036	235,430	64,223	31,669	33,997	331	34,463	488,496	1,758	4,445	2,234	405	1,459	24,137	139,293	6,985	2,926	324	1,062	433
2037	235,922	64,480	31,748	34,167	331	34,567	489,473	1,759	4,450	2,236	406	1,462	24,233	139,711	7,013	2,929	324	1,063	434
2038	236,414	64,738	31,827	34,338	332	34,670	490,452	1,761	4,454	2,239	406	1,465	24,330	140,130	7,041	2,932	324	1,064	434
2039	236,908	64,997	31,907	34,510	333	34,775	491,433	1,763	4,459	2,241	406	1,468	24,427	140,550	7,069	2,935	325	1,065	434

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2040	237,403	65,257	31,987	34,683	333	34,879	492,415	1,765	4,463	2,243	407	1,471	24,525	140,972	7,097	2,938	325	1,067	435
2041	237,899	65,518	32,067	34,856	334	34,983	493,400	1,766	4,468	2,245	407	1,474	24,623	141,395	7,126	2,941	325	1,068	435
2042	238,396	65,780	32,147	35,030	335	35,088	494,387	1,768	4,472	2,248	408	1,477	24,722	141,819	7,154	2,944	326	1,069	436
2043	238,894	66,043	32,227	35,205	335	35,194	495,376	1,770	4,476	2,250	408	1,480	24,821	142,244	7,183	2,946	326	1,070	436
2044	239,394	66,307	32,308	35,381	336	35,299	496,367	1,772	4,481	2,252	409	1,483	24,920	142,671	7,211	2,949	326	1,071	437
2045	239,894	66,572	32,389	35,558	337	35,405	497,359	1,773	4,485	2,254	409	1,486	25,020	143,099	7,240	2,952	327	1,072	437
2046	240,396	66,839	32,470	35,736	337	35,511	498,354	1,775	4,490	2,257	409	1,489	25,120	143,529	7,269	2,955	327	1,073	438
2047	240,898	67,106	32,551	35,915	338	35,618	499,351	1,777	4,494	2,259	410	1,492	25,220	143,959	7,298	2,958	327	1,074	438
2048	241,402	67,374	32,632	36,094	339	35,725	500,349	1,779	4,499	2,261	410	1,495	25,321	144,391	7,327	2,961	328	1,075	438
2049	241,907	67,644	32,714	36,275	339	35,832	501,350	1,781	4,503	2,263	411	1,498	25,422	144,824	7,357	2,964	328	1,076	439
2050	242,413	67,914	32,796	36,456	340	35,939	502,353	1,782	4,508	2,266	411	1,501	25,524	145,259	7,386	2,967	328	1,077	439
2051	242,920	68,186	32,878	36,638	341	36,047	503,358	1,784	4,512	2,268	411	1,504	25,626	145,694	7,416	2,970	329	1,078	440
2052	243,428	68,459	32,960	36,822	341	36,155	504,364	1,786	4,517	2,270	412	1,507	25,729	146,131	7,445	2,973	329	1,079	440
2053	243,938	68,733	33,042	37,006	342	36,264	505,373	1,788	4,521	2,272	412	1,510	25,831	146,570	7,475	2,976	329	1,080	441
2054	244,448	69,008	33,125	37,191	343	36,373	506,384	1,790	4,526	2,275	413	1,513	25,935	147,010	7,505	2,979	330	1,082	441
2055	244,960	69,284	33,208	37,377	343	36,482	507,397	1,791	4,530	2,277	413	1,516	26,038	147,451	7,535	2,982	330	1,083	441
2056	245,473	69,561	33,291	37,564	344	36,591	508,411	1,793	4,535	2,279	413	1,519	26,143	147,893	7,565	2,985	330	1,084	442
2057	245,987	69,839	33,374	37,751	345	36,701	509,428	1,795	4,540	2,282	414	1,522	26,247	148,337	7,595	2,988	331	1,085	442
2058	246,502	70,118	33,457	37,940	345	36,811	510,447	1,797	4,544	2,284	414	1,525	26,352	148,782	7,626	2,991	331	1,086	443
2059	247,018	70,399	33,541	38,130	346	36,922	511,468	1,798	4,549	2,286	415	1,528	26,458	149,228	7,656	2,994	331	1,087	443
2060	247,535	70,680	33,625	38,321	347	37,032	512,491	1,800	4,553	2,288	415	1,531	26,563	149,676	7,687	2,997	332	1,088	444
2061	248,054	70,963	33,709	38,512	347	37,143	513,516	1,802	4,558	2,291	416	1,534	26,670	150,125	7,718	3,000	332	1,089	444

Table 8-2 Reference Case Peak Demand (MW)

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2011	30.8	10.6	7.6	5.2	0.1	5.7	80.9	0.4	0.8	0.4	0.1	0.3	4.5	23.7	1.3	0.4	0.1	0.2	0.1
2012	35.6	11.2	9.3	5.5	0.1	5.8	82.9	0.4	0.8	0.4	0.1	0.3	4.7	24.1	1.3	0.4	0.1	0.2	0.1
2013	36.1	11.3	9.3	5.6	0.1	5.9	83.6	0.3	0.8	0.4	0.1	0.3	4.8	24.1	1.3	0.4	0.1	0.2	0.1
2014	36.7	11.5	9.3	5.7	0.1	6.0	84.5	0.3	0.8	0.4	0.1	0.3	4.8	24.3	1.3	0.4	0.1	0.2	0.1
2015	37.3	11.7	9.2	5.8	0.1	6.1	85.4	0.3	0.8	0.4	0.1	0.3	4.8	24.4	1.3	0.4	0.1	0.2	0.1
2016	37.5	11.7	9.3	5.8	0.1	6.2	85.8	0.3	0.8	0.4	0.1	0.3	4.8	24.6	1.3	0.4	0.1	0.2	0.1
2017	37.7	11.8	9.3	5.8	0.1	6.2	86.2	0.3	0.8	0.4	0.1	0.3	4.8	24.7	1.3	0.4	0.1	0.2	0.1
2018	37.9	11.8	9.4	5.8	0.1	6.2	86.6	0.3	0.9	0.4	0.1	0.3	4.8	24.8	1.3	0.4	0.1	0.2	0.1
2019	38.1	11.9	9.4	5.9	0.1	6.3	87.1	0.3	0.9	0.4	0.1	0.3	4.9	24.9	1.3	0.4	0.1	0.2	0.1
2020	38.3	12.0	9.5	5.9	0.1	6.3	87.5	0.3	0.9	0.4	0.1	0.3	4.9	25.1	1.3	0.4	0.1	0.2	0.1
2021	38.5	12.0	9.5	5.9	0.1	6.3	87.9	0.3	0.9	0.4	0.1	0.3	4.9	25.2	1.3	0.4	0.1	0.2	0.1
2022	38.7	12.1	9.6	5.9	0.1	6.4	88.4	0.3	0.9	0.4	0.1	0.3	4.9	25.3	1.3	0.4	0.1	0.2	0.1
2023	38.9	12.1	9.6	5.9	0.1	6.4	88.8	0.3	0.9	0.4	0.1	0.3	5.0	25.4	1.3	0.4	0.1	0.2	0.1
2024	39.1	12.2	9.7	5.9	0.1	6.4	89.3	0.3	0.9	0.4	0.1	0.3	5.0	25.6	1.3	0.4	0.1	0.2	0.1
2025	39.3	12.3	9.7	5.9	0.1	6.5	89.7	0.3	0.9	0.4	0.1	0.3	5.0	25.7	1.3	0.4	0.1	0.2	0.1
2026	39.4	12.3	9.8	5.9	0.1	6.5	90.2	0.3	0.9	0.4	0.1	0.3	5.0	25.8	1.3	0.4	0.1	0.2	0.1
2027	39.6	12.4	9.8	6.0	0.1	6.5	90.6	0.3	0.9	0.4	0.1	0.3	5.1	26.0	1.3	0.4	0.1	0.2	0.1
2028	39.8	12.4	9.9	6.0	0.1	6.6	91.1	0.3	0.9	0.4	0.1	0.3	5.1	26.1	1.3	0.5	0.1	0.2	0.1
2029	40.0	12.5	9.9	6.0	0.1	6.6	91.5	0.3	0.9	0.4	0.1	0.3	5.1	26.2	1.4	0.5	0.1	0.2	0.1
2030	40.2	12.6	10.0	6.0	0.1	6.6	92.0	0.3	0.9	0.4	0.1	0.3	5.1	26.3	1.4	0.5	0.1	0.2	0.1
2031	40.4	12.6	10.0	6.0	0.1	6.6	92.4	0.3	0.9	0.4	0.1	0.3	5.2	26.5	1.4	0.5	0.1	0.2	0.1
2032	40.6	12.7	10.1	6.0	0.1	6.7	92.9	0.3	0.9	0.4	0.1	0.3	5.2	26.6	1.4	0.5	0.1	0.2	0.1
2033	40.9	12.8	10.1	6.0	0.1	6.7	93.4	0.3	0.9	0.4	0.1	0.3	5.2	26.7	1.4	0.5	0.1	0.2	0.1
2034	41.1	12.8	10.2	6.0	0.1	6.7	93.8	0.3	0.9	0.4	0.1	0.3	5.3	26.9	1.4	0.5	0.1	0.2	0.1
2035	41.3	12.9	10.2	6.0	0.1	6.8	94.3	0.3	0.9	0.4	0.1	0.3	5.3	27.0	1.4	0.5	0.1	0.2	0.1
2036	41.3	12.9	10.2	6.1	0.1	6.8	94.5	0.3	0.9	0.4	0.1	0.3	5.3	27.1	1.4	0.5	0.1	0.2	0.1
2037	41.4	13.0	10.3	6.1	0.1	6.8	94.7	0.3	0.9	0.4	0.1	0.3	5.3	27.2	1.4	0.5	0.1	0.2	0.1
2038	41.5	13.0	10.3	6.1	0.1	6.8	94.9	0.3	0.9	0.5	0.1	0.3	5.3	27.3	1.4	0.5	0.1	0.2	0.1
2039	41.6	13.1	10.3	6.2	0.1	6.9	95.1	0.3	0.9	0.5	0.1	0.3	5.4	27.3	1.4	0.5	0.1	0.2	0.1

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2040	41.7	13.1	10.3	6.2	0.1	6.9	95.3	0.3	0.9	0.5	0.1	0.3	5.4	27.4	1.4	0.5	0.1	0.2	0.1
2041	41.8	13.2	10.4	6.2	0.1	6.9	95.4	0.3	0.9	0.5	0.1	0.3	5.4	27.5	1.4	0.5	0.1	0.2	0.1
2042	41.9	13.2	10.4	6.3	0.1	6.9	95.6	0.3	0.9	0.5	0.1	0.3	5.4	27.6	1.4	0.5	0.1	0.2	0.1
2043	42.0	13.3	10.4	6.3	0.1	6.9	95.8	0.3	0.9	0.5	0.1	0.3	5.4	27.7	1.4	0.5	0.1	0.2	0.1
2044	42.0	13.4	10.4	6.3	0.1	7.0	96.0	0.3	0.9	0.5	0.1	0.3	5.5	27.7	1.4	0.5	0.1	0.2	0.1
2045	42.1	13.4	10.5	6.4	0.1	7.0	96.2	0.3	0.9	0.5	0.1	0.3	5.5	27.8	1.4	0.5	0.1	0.2	0.1
2046	42.2	13.5	10.5	6.4	0.1	7.0	96.4	0.3	0.9	0.5	0.1	0.3	5.5	27.9	1.5	0.5	0.1	0.2	0.1
2047	42.3	13.5	10.5	6.4	0.1	7.0	96.6	0.3	0.9	0.5	0.1	0.3	5.5	28.0	1.5	0.5	0.1	0.2	0.1
2048	42.4	13.6	10.5	6.4	0.1	7.0	96.8	0.4	0.9	0.5	0.1	0.3	5.6	28.1	1.5	0.5	0.1	0.2	0.1
2049	42.5	13.6	10.6	6.5	0.1	7.1	97.0	0.4	0.9	0.5	0.1	0.3	5.6	28.2	1.5	0.5	0.1	0.2	0.1
2050	42.6	13.7	10.6	6.5	0.1	7.1	97.2	0.4	0.9	0.5	0.1	0.3	5.6	28.2	1.5	0.5	0.1	0.2	0.1
2051	42.7	13.7	10.6	6.5	0.1	7.1	97.4	0.4	0.9	0.5	0.1	0.3	5.6	28.3	1.5	0.5	0.1	0.2	0.1
2052	42.8	13.8	10.7	6.6	0.1	7.1	97.6	0.4	0.9	0.5	0.1	0.3	5.6	28.4	1.5	0.5	0.1	0.2	0.1
2053	42.8	13.8	10.7	6.6	0.1	7.1	97.8	0.4	0.9	0.5	0.1	0.3	5.7	28.5	1.5	0.5	0.1	0.2	0.1
2054	42.9	13.9	10.7	6.6	0.1	7.2	98.0	0.4	0.9	0.5	0.1	0.3	5.7	28.6	1.5	0.5	0.1	0.2	0.1
2055	43.0	14.0	10.7	6.7	0.1	7.2	98.2	0.4	0.9	0.5	0.1	0.4	5.7	28.7	1.5	0.5	0.1	0.2	0.1
2056	43.1	14.0	10.8	6.7	0.1	7.2	98.4	0.4	0.9	0.5	0.1	0.4	5.7	28.8	1.5	0.5	0.1	0.2	0.1
2057	43.2	14.1	10.8	6.7	0.1	7.2	98.5	0.4	0.9	0.5	0.1	0.4	5.8	28.8	1.5	0.5	0.1	0.2	0.1
2058	43.3	14.1	10.8	6.8	0.1	7.3	98.7	0.4	0.9	0.5	0.1	0.4	5.8	28.9	1.5	0.5	0.1	0.2	0.1
2059	43.4	14.2	10.8	6.8	0.1	7.3	98.9	0.4	0.9	0.5	0.1	0.4	5.8	29.0	1.5	0.5	0.1	0.2	0.1
2060	43.5	14.2	10.9	6.8	0.1	7.3	99.1	0.4	0.9	0.5	0.1	0.4	5.8	29.1	1.5	0.5	0.1	0.2	0.1
2061	43.6	14.3	10.9	6.9	0.1	7.3	99.3	0.4	0.9	0.5	0.1	0.4	5.9	29.2	1.5	0.5	0.1	0.2	0.1

8.1.2 High Scenario

8.1.2.1 General Approach

This section provides the general approach used by Black & Veatch to develop High Scenario Load Forecasts for the study period 2012 through 2061. In addition, a forecast was developed for 2011. In the high load growth case scenario, two different aspects of load growth were considered:

- Load growth due to market penetration of plug-in hybrid electric vehicles (PHEVs).
- High load growth related to high economic growth and development.

8.1.2.2 Market Penetration of PHEV

Energy security and climate change issues are driving change in the transportation sector now more than ever. With the possible approval of carbon legislation and the possibility of returning higher gas prices, there is an increased need to consider new advanced technology vehicles that hold the promise of considerably improving fleet energy efficiency and reducing fleet carbon footprint, such as PHEVs.

According to a study conducted by the Transportation Research Institute at the University of Michigan (UMTRI)[1] in July 2009, fleet penetration for PHEVs is expected to vary depending on the price of gas, the level of original equipment manufacturers (OEM) subsidies provided by the government, and the provisions for sales tax exemptions for PHEVs. PHEV vehicles cost much more than the traditional gasoline-fueled cars and hybrid electric vehicles (HEV). A recent article in US News indicated that the manufacturer's suggested retail price (MSRP) of Chevy Volt, a PHEV, is $41,000. Compared to the Volt, Toyota Prius, an HEV, costs around $23,000, and a gasoline-fueled intermediate sized sedan costs less than $20,000. Since PHEVs cost a lot more than their conventional counterparts, especially in the near term, their market viability depends heavily on government subsidies and incentives.

The UMTRI study showed that when gas prices are high and when OEM subsidies and sales taxes exemptions are in place, the penetration of PHEV vehicles are expected to reach 1.2 percent of the US market by 2015, 2.2 percent by 2020, and 12.7 percent by 2040. However, when gas prices are low and with no subsidies and sales tax exemptions, market penetration of PHEVs is expected to be as low as 0.3 percent in 2015 and 1.1 percent in 2040.

According to the Annual Energy Outlook 2011 (AEO 2011) published by the EIA, the penetration of PHEVs will be very slow initially. EIA has forecast that under the reference case[2] assumptions, the total stock of PHEVs in the United States is expected to grow from approximately 200,000 vehicles[3] in 2015 to 4.56 million in 2035. AEO has also forecast that the total stock of Light Duty cars and trucks in the US will increase from 130 million cars in 2015 to 185.53 million in 2035. This indicates that the market penetration of PHEV in the United States is expected to be 0.08 percent (of light duty cars and trucks) in 2015 and 1.5 percent in 2035.

As the EIA forecasts are more recent than the UMTRI study, Black & Veatch decided to use the EIA forecasts presented in AEO 2011 as a base for forecasting the market penetration of PHEVs in Southeast Alaska.

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[1] "PHEV Marketplace Penetration: An Agent Based Simulation." Sullivan, Salmeen, and Simon. July, 2009.

[2] Refer to AEO 2011 for detailed assumptions of Reference Case.

[3] Refer to Reference Table 58 of AEO 2011.

Applying the same growth rate for PHEVs over the period from 2031 through 2035 as presented in AEO 2011, Black & Veatch has forecast that the stock of PHEVs in the United States to grow to 7.4 million in 2040 and 50.0 million by 2060. The United States stock of light duty trucks and vehicles is forecast to increase from 204.3 million to 306.9 million during this period. This shows that the penetration of PHEVs in the United States is expected to reach 2.3 percent by 2040 and 11.7 percent by 2060. Table 8-3 shows the penetration level of PHEVs in the United States at different years. Black & Veatch has assumed that the PHEV penetration in Southeast Alaska will follow a similar trend.

According to the ADL, the total population of Alaska in 2010 was approximately 698,573. ADL has forecast the population to increase to 783,942 by 2022 and to remain constant thereafter until 2030.

According to the Alaska Department of Motor Vehicles (DMV), there were 531,896 vehicle license holders in Alaska in 2010, and the total number of registered light duty cars and trucks in that year was 665,018. This indicates that there were 0.95 registered light duty vehicles per person in Alaska in 2010.

Table 8-3 Projected PHEV Penetration in the US

YEAR	MARKET PENETRATION OF PHEVS IN SOUTHEAST ALASKA (PERCENT OF LIGHT DUTY CARS AND PICKUP STOCK)
2010	0
2015	0.1
2020	0.2
2040	2.3
2060	11.7
2061	12.6

According to the ADL, the population in the southeast region of Alaska in 2010 was 70,315, and according to the Alaska DMV, the number of registered light duty vehicles in the region was 62,483 in 2010. This shows that there are 0.89 registered light duty vehicles per person in the region. This is lower than the State average of 0.95 vehicles per person. This is consistent with the economic and social trends of this region compared to the other regions of Alaska. Hence, Black & Veatch has assumed that that there would be 0.89 light duty vehicles per person in the region, and this number would remain constant throughout the study period.

The annual vehicle miles traveled (VMT) per person was approximately 7,090 miles per year in 2008. Assuming that a person travels for approximately 300 days in a year, average daily distance traveled by a person in Alaska is approximately 19 miles per day.

In the IRP study for the Railbelt Region of Alaska done by Black & Veatch in 2009, Black & Veatch had assumed the daily VMT per person to be 26 miles per day. That was more than the state average of 19 miles per day. In Southeast Alaska driving distances are much shorter compared to the Railbelt area, and so Black & Veatch assumed that the daily VMT per person in this region would be less than the state average and would be equal to 15 miles per day beginning in 2010.

According to the US Department of Energy,[4] the annual average growth rate of VMT for the entire United States was approximately 3 percent for the period 1970 to 2001. Based on this assumption, Black & Veatch forecast the growth rate of Southeast Alaska to be 2 percent per year for all years in the study period beginning in 2011. Black & Veatch is of the opinion that the growth rate of VMT in Southeast Alaska will be slower than the national long-term average growth rate, as the region has smaller areas, and the economic growth in the region is also expected to be slower than the national average growth rate. These factors would likely reduce the need for travel and distance traveled and would likely lower the VMT per person in the region.

PHEVs are designed for different categories of travel. They are designated based on the maximum distance they can travel from a one-time full battery charge. Therefore, a vehicle designated as PHEV 10 can travel 10 miles on a single charge, while a PHEV 40 can travel 40 miles on a single charge. PHEV 10, PHEV 20, PHEV 33, and PHEV 40 are expected to be the most popular categories of PHEV vehicles. The different categories of PHEVs need different levels of energy to recharge their batteries. For this forecast, Black & Veatch has assumed that, on average, all PHEV vehicles will need energy equivalent to a PHEV 33 vehicle to charge their batteries. Table 8-4 shows the average energy needs for PHEV 33 vehicles to fully recharge their batteries.

Table 8-4 Electric Consumption for a PHEV 33 to Fully Recharge Its Batteries

VEHICLE CLASS	SPECIFIC ENERGY REQUIREMENTS (KWH/MILE)
Compact Sedan	0.26
Mid-size Sedan	0.30
Mid-size SUV	0.38
Full-size SUV	0.46
Average	**0.35**

Black & Veatch developed the additional annual energy requirements from PHEVs for each of the communities for the period 2011 to 2061. Black & Veatch used the above assumptions and combined them with the population forecasts for each region to estimate the stock of PHEVs in each region and the annual energy needed to recharge them. The details of the forecasts for each area are presented separately in subsequent sections.

8.1.2.3 Additional Growth for Higher Economic Development

Black & Veatch assumed an additional 1 percent growth over the Reference Scenario Load Forecast for every year from 2011 to 2061 to account for higher demand caused by higher than expected economic growth and development. No attempt has been made to specifically identify the exact source of the higher growth, but it can come from a number of sources including those listed below, among others. The additional 1 percent growth per year represents an approximate 64 percent increase in loads over the 50 year planning period compared to the Reference Scenario.

[4] http://www1.eere.energy.gov/vehiclesandfuels/facts/2003/fcvt_fotw278.html

Potential sources of growth include the following:

- New and existing mines that are interconnected to utility systems, as well as indirect loads from the mines. This would also include loads associated with ore processing facilities. Table 8-5 presents data on proposed mines provided by Mike Satre, Executive Director Council of Alaska Producers. While these potential mine loads are significant, only the Greens Creek mine is currently being served by a Southeast utility system and it is being served under an interruptible contract. Most of these potential mine loads are isolated from the existing transmission system. Most of the plans to serve potential mine loads through hydroelectric generation are based on developing hydroelectric projects specifically for the mining projects with the hydroelectric projects not being interconnected to the rest of the utility transmission system as discussed in Section 10.0. Only two of the mines listed in Table 8-5 are currently producing. While some of the planned projects may come into operation as projected in Table 8-5, history has shown that, in general, the development of mines in Southeast Alaska is a very slow and uncertain process; the Greens Creek mine took from 1973 to 1996 to develop into a producing mine, although it did have a relatively short period of production earlier than 1996. It took Coeur from 1995 to 2010 to develop the Kensington Mine into a producing property. It is beyond the scope of this IRP to specifically evaluate the potential development of mines, but the High Scenario Load Forecast projects a 30 MW increase for the Southeast over the Reference Scenario Load Forecast by 2025.
- Increased forestry activity including possible pellet mill construction and the indirect loads associated with the increased forestry activity.
- Increased conversion to electric heat by the residential, commercial, and industrial sectors. Section 15.0 presents estimates of the maximum potential increases in load for the region if all existing oil space heating is converted to electric.
- Providing electricity to cruise ships docked in the Southeast. One estimate of this load provided by Thom Fisher indicated that it could be 35,529 MWh per year by 2018 for Ketchikan, Petersburg, and Wrangell. The additional load would represent an approximate 3.6 percent increase in annual loads for the Southeast over the projected 2011 loads. This growth would be covered by the High Scenario Load Forecast for the SEAPA subregion. Black & Veatch conducted an independent analysis of the potential load from cruise ships docked in Skagway and estimated the total potential load to be 45,000 MWh. This additional load would represent an approximate 4.6 percent increase in annual loads for the Southeast over projected 2011 loads. This growth would not be covered by the high load forecast, even through the end of the study period for the Upper Lynn Canal subregion, and would require specific actions to meet it beyond those necessary for the High Scenario Load Forecast.
- Increased fish processing and associated fishing industry.
- Other potential unidentified commercial and industrial loads coming into the Southeast and their associated indirect loads.

Table 8-5 Potential Mine Development

	LOCATION	COMMODITY	STATUS	DATE OF FIRST PRODUCTION	POWER REQUIRED	DIESEL GENERATION	ELECTRIC INTERTIE	STATED MINE LIFE	POTENTIAL FOR EXPANSION?	POSSIBLE ADDITIONAL MINE LIFE?	COMMENTS
Coeur Alaska Kensington Gold Mine	Berners Bay	Commodity	Producing	2010	~10 MW	Yes	No	10 years	Yes	>10 years	If line was extended to mine, current local grid would not have the capacity to support it.
Hecla Greens Creek Mine	Northern Admiralty Island	Silver, Zinc, Lead, Gold	Producing	1988	~8 MW	Yes	Yes	10 years	Yes	>10 years	Greens Creek is a surplus customer to AELP and cannot rely on line power. Expansion to the Southeast grid should plan for 100 percent feed to Greens Creek.
Heatherdale Resources Niblack Project	Prince of Wales Island	Copper, Zinc, Silver, Gold	Advanced Exploration	2015-2020?	~10 MW	Probably	No	unknown	?	?	Size, scale, and length of operation would be similar to Greens Creek.
UCore Bokan Mountain Project	Prince of Wales Island	Rare Earth Elements, Uranium	Advanced Exploration	2015-2020?	~10-20 MW	Probably	No	unknown	?	?	Energy demand will depend on location and type of processing facilities.
Constantine Metals Palmer Project	Haines	Zinc, Lead, Silver, Gold	Advanced Exploration	>2020?	~10 MW	Probably	No	unknown	?	?	Size, scale, and length of operation would be similar to Greens Creek.
AJ Mine	Juneau	Gold	Idle	2020?	10-20 MW	If local grid can't supply power	Yes	unknown	?	?	City and borough of Juneau is just beginning discussions on whether to look at the feasibility of re-opening this mine. If opened it would probably be ~10 year mine life and require power above and beyond the Juneau grid's ability to produce.
Herbert Glacier - Grande Portage Resources	Juneau	Gold	Exploration	??	??	If local grid can't supply power	Possible	?	?	?	Still grass-roots exploration. Kensington scale?
Woewodski Island, Olympic Resources	South of Petersburg	Gold, Silver, Lead, Zinc, Copper	Exploration	??	??	Yes	?	?	?	?	Still grass-roots exploration. Greens Creek scale?
Mount Andrew, Full Metal Minerals	Prince of Wales Island	Copper, Gold	Exploration	??	??	Yes	?	?	?	?	Still grass-roots exploration. Scale?
Duke Island, Quaterra Resources	South of Ketchikan	Copper, Nickel, PGE	Exploration	??	??	Yes	?	?	?	?	Still grass-roots exploration. Scale?

The High Scenario Load Forecasts for energy and peak demand are presented in Tables 8-6 and 8-7, respectively, for each of the communities.

8.1.3 Low Scenario

Black & Veatch developed the Low Scenario Load Forecast based on implementing the significant DSM/EE program described in Section 13.0. The limited data available relative to DSM/EE in the Southeast, results in there being significant uncertainty in the Low Scenario Load Forecast. As discussed in Section 13.0, the DSM/EE program was developed based on measures passing all the simplified DSM/EE tests. As discussed in Section 13.0, relaxing the Rate Impact Test would result in significantly more reductions for utilities that have high nonfuel costs. As discussed in Section 14.0, the Low Scenario Load Forecast does not include any increased load reductions for weatherization beyond those included in the Reference Scenario Load Forecast. Inclusion of significant additional amounts of weatherization would future reduce loads for communities where there is a significant amount of electric space heating. Lack of acceptance by customers, on the other hand, will significantly increase the Low Scenario Load Forecast.

The Low Scenario Load Forecasts for energy and peak demand are presented in Tables 8-8 and 8-9, respectively, for each of the communities.

8.1.4 Summary

Graphs of the High, Reference, and Low Load Forecasts for energy for each of the subregions are presented on Figures 8-1 through 8-8.

Table 8-6 High Case Annual Energy (MWh)

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2011	189,801	54,752	34,504	29,382	266	28,776	418,031	1,809	4,267	2,203	375	1,218	20,512	121,754	6,418	2,247	337	883	416
2012	204,809	56,015	42,573	31,527	277	29,633	432,919	1,805	4,310	2,211	383	1,255	21,538	124,912	6,453	2,315	334	980	420
2013	209,708	57,386	43,145	32,437	288	30,512	440,841	1,802	4,354	2,219	390	1,293	22,186	126,517	6,487	2,361	330	1,039	424
2014	215,310	58,793	43,466	33,225	299	31,414	449,823	1,798	4,398	2,227	397	1,332	22,409	128,910	6,521	2,385	327	1,049	429
2015	221,074	60,236	43,749	34,248	311	32,351	459,040	1,793	4,443	2,235	405	1,372	22,634	130,790	6,556	2,410	324	1,060	433
2016	224,399	61,144	44,410	34,662	315	32,839	465,951	1,813	4,497	2,262	410	1,393	22,975	132,759	6,655	2,829	328	1,073	439
2017	227,781	62,069	45,084	35,085	320	33,325	472,986	1,834	4,551	2,290	415	1,415	23,321	134,763	6,756	2,870	332	1,086	444
2018	231,209	63,006	45,766	35,511	325	33,812	480,114	1,854	4,607	2,318	420	1,436	23,673	136,793	6,858	2,911	336	1,099	450
2019	234,693	63,959	46,460	35,944	330	34,301	487,362	1,875	4,663	2,347	425	1,458	24,030	138,858	6,961	2,953	340	1,112	455
2020	238,234	64,929	47,167	36,384	335	34,872	494,734	1,897	4,720	2,377	430	1,481	24,393	140,957	7,067	2,996	344	1,126	461
2021	241,823	65,911	47,882	36,826	341	35,399	502,201	1,918	4,778	2,406	436	1,504	24,760	143,084	7,174	3,039	348	1,139	467
2022	245,478	66,913	48,614	37,279	346	35,937	509,816	1,940	4,836	2,436	441	1,527	25,135	145,252	7,283	3,083	352	1,153	473
2023	249,192	67,933	49,359	37,739	351	36,484	517,559	1,962	4,896	2,468	447	1,551	25,516	147,456	7,394	3,129	356	1,167	479
2024	252,971	68,972	50,119	38,208	357	37,042	525,447	1,985	4,957	2,500	452	1,576	25,904	149,701	7,507	3,174	361	1,182	485
2025	256,813	70,030	50,894	38,685	363	37,609	533,474	2,009	5,020	2,532	458	1,601	26,298	151,985	7,622	3,221	365	1,197	492
2026	260,721	71,109	51,684	39,171	369	38,187	541,651	2,033	5,083	2,566	464	1,627	26,700	154,311	7,740	3,269	370	1,211	498
2027	264,692	72,205	52,489	39,664	375	38,774	549,965	2,057	5,148	2,601	470	1,654	27,108	156,676	7,859	3,318	374	1,227	505
2028	268,731	73,322	53,309	40,165	381	39,371	558,432	2,082	5,214	2,636	477	1,681	27,523	159,084	7,981	3,367	379	1,242	512
2029	272,834	74,457	54,143	40,673	388	39,977	567,041	2,107	5,280	2,672	483	1,709	27,945	161,531	8,105	3,418	384	1,258	520
2030	276,999	75,610	54,990	41,188	394	40,592	575,785	2,133	5,348	2,708	489	1,737	28,373	164,017	8,230	3,469	388	1,274	527
2031	281,232	76,782	55,853	41,710	401	41,221	584,684	2,159	5,417	2,746	496	1,766	28,808	166,545	8,358	3,521	393	1,290	535
2032	285,526	77,970	56,726	42,237	407	41,860	593,708	2,185	5,487	2,784	502	1,796	29,250	169,109	8,488	3,574	398	1,306	542
2033	289,880	79,175	57,611	42,768	414	42,508	602,861	2,212	5,557	2,821	509	1,825	29,698	171,710	8,619	3,627	403	1,323	550
2034	294,302	80,399	58,510	43,306	421	43,166	612,167	2,239	5,628	2,860	516	1,855	30,153	174,353	8,752	3,682	408	1,339	558
2035	298,790	81,640	59,422	43,850	428	43,835	621,613	2,266	5,701	2,899	523	1,886	30,614	177,036	8,888	3,737	413	1,356	566
2036	302,498	82,828	60,210	44,538	435	44,431	629,413	2,295	5,769	2,937	529	1,912	31,055	179,424	9,017	3,781	418	1,372	574
2037	306,259	84,037	61,012	45,238	441	45,038	637,343	2,324	5,839	2,976	536	1,939	31,503	181,852	9,149	3,826	423	1,389	582
2038	310,077	85,268	61,829	45,951	447	45,657	645,409	2,353	5,910	3,016	543	1,967	31,958	184,322	9,284	3,872	428	1,405	591
2039	313,951	86,522	62,661	46,679	454	46,287	653,616	2,383	5,983	3,057	550	1,995	32,422	186,835	9,420	3,919	433	1,422	600

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2040	317,885	87,798	63,509	47,420	461	46,928	661,971	2,415	6,058	3,100	557	2,025	32,893	189,393	9,560	3,967	438	1,440	609
2041	321,880	89,099	64,374	48,176	468	47,583	670,481	2,447	6,134	3,144	564	2,055	33,373	191,997	9,702	4,015	443	1,458	618
2042	325,938	90,425	65,256	48,947	476	48,250	679,153	2,479	6,212	3,189	572	2,086	33,861	194,651	9,847	4,065	448	1,476	628
2043	330,061	91,776	66,157	49,735	484	48,932	687,996	2,513	6,292	3,236	580	2,118	34,358	197,355	9,994	4,116	454	1,494	638
2044	334,252	93,155	67,077	50,538	492	49,628	697,018	2,548	6,374	3,284	588	2,151	34,865	200,112	10,145	4,168	459	1,513	649
2045	338,513	94,562	68,018	51,358	500	50,339	706,230	2,584	6,458	3,335	597	2,186	35,381	202,925	10,299	4,222	465	1,533	660
2046	342,847	95,998	68,980	52,196	509	51,067	715,643	2,621	6,544	3,387	605	2,222	35,907	205,796	10,456	4,277	470	1,553	672
2047	347,256	97,465	69,964	53,053	518	51,812	725,267	2,659	6,633	3,442	614	2,259	36,444	208,729	10,617	4,333	476	1,573	685
2048	351,744	98,964	70,972	53,928	528	52,575	735,117	2,699	6,724	3,499	624	2,297	36,991	211,726	10,781	4,391	482	1,594	698
2049	356,314	100,497	72,006	54,824	538	53,357	745,205	2,740	6,819	3,558	633	2,337	37,550	214,792	10,949	4,451	488	1,616	712
2050	360,969	102,065	73,066	55,740	548	54,160	755,548	2,783	6,916	3,620	643	2,379	38,120	217,930	11,121	4,512	495	1,638	726
2051	365,714	103,670	74,155	56,678	559	54,985	766,163	2,828	7,017	3,685	654	2,423	38,703	221,144	11,297	4,576	501	1,661	742
2052	370,553	105,314	75,273	57,638	571	55,833	777,067	2,874	7,121	3,753	665	2,469	39,299	224,440	11,477	4,641	508	1,685	758
2053	375,490	106,999	76,423	58,622	584	56,705	788,282	2,923	7,230	3,825	676	2,517	39,908	227,821	11,663	4,710	515	1,710	776
2054	380,530	108,728	77,608	59,632	597	57,605	799,829	2,973	7,342	3,901	688	2,568	40,532	231,293	11,853	4,780	522	1,736	795
2055	385,678	110,502	78,828	60,667	611	58,533	811,733	3,027	7,459	3,981	701	2,621	41,170	234,863	12,048	4,853	529	1,763	815
2056	390,940	112,324	80,087	61,729	626	59,491	824,020	3,082	7,580	4,065	714	2,676	41,825	238,537	12,249	4,930	536	1,790	836
2057	396,323	114,198	81,387	62,821	641	60,483	836,720	3,141	7,707	4,154	728	2,735	42,496	242,321	12,455	5,009	544	1,819	859
2058	401,833	116,125	82,731	63,942	658	61,510	849,865	3,202	7,839	4,249	743	2,798	43,185	246,224	12,668	5,092	552	1,850	884
2059	407,476	118,110	84,122	65,095	676	62,575	863,491	3,267	7,978	4,349	758	2,864	43,892	250,255	12,887	5,179	560	1,881	910
2060	413,262	120,156	85,564	66,282	695	63,682	877,635	3,336	8,123	4,456	774	2,934	44,620	254,422	13,113	5,270	569	1,915	938
2061	419,198	122,266	87,059	67,504	716	64,832	892,341	3,408	8,276	4,569	792	3,008	45,368	258,735	13,347	5,365	578	1,949	969

Table 8-7 High Case Peak Demand (MW)

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2011	30.1	11.0	7.6	5.2	0.1	5.6	81.3	0.4	0.8	0.4	0.1	0.3	4.5	23.7	1.4	0.4	0.1	0.2	0.1
2012	36.0	11.3	9.3	5.5	0.1	5.8	84.2	0.4	0.9	0.4	0.1	0.3	4.7	24.3	1.4	0.4	0.1	0.2	0.1
2013	36.8	11.6	9.5	5.7	0.1	5.9	85.7	0.4	0.9	0.4	0.1	0.3	4.9	24.6	1.4	0.4	0.1	0.2	0.1
2014	37.8	11.8	9.5	5.8	0.1	6.1	87.5	0.4	0.9	0.4	0.1	0.3	4.9	25.1	1.4	0.4	0.1	0.2	0.1
2015	38.8	12.1	9.6	6.0	0.1	6.3	89.3	0.4	0.9	0.4	0.1	0.3	5.0	25.4	1.4	0.4	0.1	0.2	0.1
2016	39.4	12.3	9.7	6.1	0.1	6.4	90.6	0.4	0.9	0.5	0.1	0.3	5.0	25.8	1.4	0.4	0.1	0.2	0.1
2017	40.0	12.5	9.9	6.2	0.1	6.5	92.0	0.4	0.9	0.5	0.1	0.3	5.1	26.2	1.5	0.5	0.1	0.2	0.1
2018	40.6	12.7	10.0	6.2	0.1	6.6	93.4	0.4	0.9	0.5	0.1	0.3	5.2	26.6	1.5	0.5	0.1	0.2	0.1
2019	41.2	12.9	10.2	6.3	0.1	6.7	94.8	0.4	0.9	0.5	0.1	0.3	5.3	27.0	1.5	0.5	0.1	0.2	0.1
2020	41.8	13.1	10.4	6.4	0.1	6.8	96.2	0.4	0.9	0.5	0.1	0.3	5.4	27.4	1.5	0.5	0.1	0.2	0.1
2021	42.5	13.3	10.5	6.5	0.1	6.9	97.7	0.4	0.9	0.5	0.1	0.3	5.4	27.8	1.5	0.5	0.1	0.3	0.1
2022	43.1	13.5	10.7	6.6	0.1	7.0	99.1	0.4	1.0	0.5	0.1	0.4	5.5	28.2	1.6	0.5	0.1	0.3	0.1
2023	43.8	13.7	10.8	6.6	0.1	7.1	100.6	0.4	1.0	0.5	0.1	0.4	5.6	28.7	1.6	0.5	0.1	0.3	0.1
2024	44.4	13.9	11.0	6.7	0.1	7.2	102.2	0.4	1.0	0.5	0.1	0.4	5.7	29.1	1.6	0.5	0.1	0.3	0.1
2025	45.1	14.1	11.2	6.8	0.1	7.3	103.7	0.4	1.0	0.5	0.1	0.4	5.8	29.6	1.6	0.5	0.1	0.3	0.1
2026	45.8	14.3	11.3	6.9	0.1	7.4	105.3	0.4	1.0	0.5	0.1	0.4	5.9	30.0	1.7	0.5	0.1	0.3	0.1
2027	46.5	14.5	11.5	7.0	0.1	7.5	106.9	0.4	1.0	0.5	0.1	0.4	6.0	30.5	1.7	0.5	0.1	0.3	0.1
2028	47.2	14.8	11.7	7.1	0.1	7.6	108.6	0.4	1.0	0.5	0.1	0.4	6.0	30.9	1.7	0.5	0.1	0.3	0.1
2029	47.9	15.0	11.9	7.2	0.1	7.8	110.3	0.4	1.0	0.5	0.1	0.4	6.1	31.4	1.8	0.5	0.1	0.3	0.1
2030	48.6	15.2	12.1	7.2	0.1	7.9	112.0	0.4	1.1	0.5	0.1	0.4	6.2	31.9	1.8	0.6	0.1	0.3	0.1
2031	49.4	15.5	12.3	7.3	0.1	8.0	113.7	0.4	1.1	0.6	0.1	0.4	6.3	32.4	1.8	0.6	0.1	0.3	0.1
2032	50.1	15.7	12.5	7.4	0.1	8.1	115.5	0.4	1.1	0.6	0.1	0.4	6.4	32.9	1.8	0.6	0.1	0.3	0.1
2033	50.9	15.9	12.6	7.5	0.1	8.3	117.2	0.4	1.1	0.6	0.1	0.4	6.5	33.4	1.9	0.6	0.1	0.3	0.1
2034	51.7	16.2	12.8	7.6	0.1	8.4	119.0	0.4	1.1	0.6	0.1	0.4	6.6	33.9	1.9	0.6	0.1	0.3	0.1
2035	52.5	16.4	13.0	7.7	0.1	8.5	120.9	0.4	1.1	0.6	0.1	0.4	6.7	34.4	1.9	0.6	0.1	0.3	0.1
2036	53.1	16.7	13.2	7.8	0.1	8.6	122.4	0.5	1.1	0.6	0.1	0.4	6.8	34.9	1.9	0.6	0.1	0.3	0.1
2037	53.8	16.9	13.4	8.0	0.1	8.7	123.9	0.5	1.2	0.6	0.1	0.4	6.9	35.4	2.0	0.6	0.1	0.3	0.1
2038	54.5	17.2	13.6	8.1	0.1	8.9	125.5	0.5	1.2	0.6	0.1	0.5	7.0	35.8	2.0	0.6	0.1	0.3	0.1
2039	55.1	17.4	13.8	8.2	0.1	9.0	127.1	0.5	1.2	0.6	0.1	0.5	7.1	36.3	2.0	0.6	0.1	0.3	0.1

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2040	55.8	17.7	13.9	8.3	0.1	9.1	128.7	0.5	1.2	0.6	0.1	0.5	7.2	36.8	2.1	0.6	0.1	0.3	0.1
2041	56.5	17.9	14.1	8.5	0.1	9.2	130.4	0.5	1.2	0.6	0.1	0.5	7.3	37.3	2.1	0.6	0.1	0.3	0.1
2042	57.2	18.2	14.3	8.6	0.1	9.4	132.1	0.5	1.2	0.6	0.1	0.5	7.4	37.9	2.1	0.6	0.1	0.3	0.1
2043	58.0	18.5	14.5	8.7	0.1	9.5	133.8	0.5	1.2	0.7	0.1	0.5	7.5	38.4	2.2	0.7	0.1	0.3	0.1
2044	58.7	18.8	14.7	8.9	0.1	9.6	135.5	0.5	1.3	0.7	0.1	0.5	7.7	38.9	2.2	0.7	0.1	0.3	0.1
2045	59.5	19.0	14.9	9.0	0.1	9.8	137.3	0.5	1.3	0.7	0.1	0.5	7.8	39.5	2.2	0.7	0.1	0.3	0.1
2046	60.2	19.3	15.1	9.2	0.1	9.9	139.2	0.5	1.3	0.7	0.2	0.5	7.9	40.0	2.3	0.7	0.1	0.3	0.1
2047	61.0	19.6	15.4	9.3	0.1	10.1	141.0	0.5	1.3	0.7	0.2	0.5	8.0	40.6	2.3	0.7	0.1	0.3	0.2
2048	61.8	19.9	15.6	9.5	0.1	10.2	143.0	0.5	1.3	0.7	0.2	0.5	8.1	41.2	2.3	0.7	0.1	0.3	0.2
2049	62.6	20.2	15.8	9.6	0.1	10.4	144.9	0.5	1.4	0.7	0.2	0.5	8.2	41.8	2.4	0.7	0.1	0.4	0.2
2050	63.4	20.6	16.0	9.8	0.1	10.5	146.9	0.5	1.4	0.7	0.2	0.6	8.4	42.4	2.4	0.7	0.1	0.4	0.2
2051	64.2	20.9	16.3	10.0	0.1	10.7	149.0	0.6	1.4	0.7	0.2	0.6	8.5	43.0	2.4	0.7	0.1	0.4	0.2
2052	65.1	21.2	16.5	10.1	0.1	10.8	151.1	0.6	1.4	0.8	0.2	0.6	8.6	43.6	2.5	0.7	0.1	0.4	0.2
2053	65.9	21.5	16.8	10.3	0.1	11.0	153.3	0.6	1.4	0.8	0.2	0.6	8.8	44.3	2.5	0.7	0.1	0.4	0.2
2054	66.8	21.9	17.0	10.5	0.1	11.2	155.5	0.6	1.5	0.8	0.2	0.6	8.9	45.0	2.6	0.8	0.1	0.4	0.2
2055	67.7	22.2	17.3	10.7	0.1	11.4	157.9	0.6	1.5	0.8	0.2	0.6	9.0	45.7	2.6	0.8	0.1	0.4	0.2
2056	68.7	22.6	17.6	10.9	0.1	11.5	160.2	0.6	1.5	0.8	0.2	0.6	9.2	46.4	2.6	0.8	0.1	0.4	0.2
2057	69.6	23.0	17.9	11.1	0.1	11.7	162.7	0.6	1.5	0.8	0.2	0.6	9.3	47.1	2.7	0.8	0.1	0.4	0.2
2058	70.6	23.4	18.2	11.2	0.1	11.9	165.3	0.6	1.6	0.9	0.2	0.6	9.5	47.9	2.7	0.8	0.1	0.4	0.2
2059	71.6	23.8	18.5	11.5	0.1	12.1	167.9	0.6	1.6	0.9	0.2	0.7	9.6	48.7	2.8	0.8	0.1	0.4	0.2
2060	72.6	24.2	18.8	11.7	0.2	12.4	170.7	0.7	1.6	0.9	0.2	0.7	9.8	49.5	2.8	0.8	0.1	0.4	0.2
2061	73.6	24.6	19.1	11.9	0.2	12.6	173.5	0.7	1.6	0.9	0.2	0.7	10.0	50.3	2.9	0.9	0.1	0.4	0.2

Table 8-8 Low Case Annual Energy (MWh)

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2011	189,796	54,750	30,205	29,089	266	28,776	418,018	1,809	4,267	2,203	375	1,218	20,511	121,751	6,418	2,245	337	883	416
2012	202,663	55,403	30,566	30,855	274	29,285	428,206	1,786	4,261	2,184	378	1,241	21,302	123,559	6,379	2,285	330	969	415
2013	205,151	56,120	30,440	31,347	281	29,780	431,056	1,763	4,254	2,165	380	1,263	21,686	123,732	6,338	2,302	323	1,015	415
2014	207,865	56,755	30,020	31,605	289	30,185	434,027	1,739	4,238	2,140	381	1,282	21,597	124,457	6,284	2,289	315	1,009	413
2015	210,027	57,251	29,380	31,911	295	30,443	435,824	1,714	4,209	2,107	379	1,296	21,434	124,337	6,210	2,264	307	998	411
2016	208,778	56,971	28,583	31,279	294	30,017	433,233	1,710	4,166	2,077	372	1,283	21,256	123,764	6,164	2,585	305	981	408
2017	206,172	56,357	27,288	30,389	290	29,250	427,826	1,701	4,093	2,029	359	1,258	20,910	122,487	6,074	2,518	301	953	402
2018	202,391	55,453	25,563	29,197	286	28,186	419,979	1,690	3,995	1,964	343	1,223	20,418	120,599	5,944	2,424	295	916	394
2019	198,884	54,617	23,949	28,082	281	27,191	412,703	1,680	3,903	1,903	327	1,190	19,959	118,855	5,824	2,337	289	881	387
2020	197,521	54,309	23,131	27,528	280	26,735	409,873	1,675	3,859	1,873	319	1,176	19,766	118,224	5,774	2,297	287	864	384
2021	197,999	54,455	22,990	27,451	280	26,740	410,866	1,676	3,856	1,869	318	1,177	19,802	118,551	5,786	2,295	287	861	384
2022	198,944	54,716	23,020	27,495	282	26,863	412,827	1,677	3,863	1,872	318	1,183	19,895	119,120	5,814	2,304	287	863	384
2023	199,936	54,989	23,065	27,549	283	26,996	414,885	1,679	3,870	1,876	319	1,189	19,994	119,714	5,843	2,314	288	864	385
2024	200,935	55,264	23,111	27,604	285	27,131	416,959	1,681	3,878	1,880	320	1,195	20,094	120,313	5,872	2,324	288	866	386
2025	201,940	55,540	23,157	27,659	286	27,267	419,044	1,682	3,886	1,883	320	1,201	20,195	120,914	5,901	2,334	289	868	387
2026	202,950	55,818	23,203	27,715	287	27,403	421,139	1,684	3,893	1,887	321	1,207	20,296	121,519	5,931	2,345	290	869	387
2027	203,964	56,097	23,250	27,770	289	27,540	423,245	1,686	3,901	1,891	321	1,213	20,397	122,126	5,960	2,355	290	871	388
2028	204,984	56,377	23,296	27,825	290	27,678	425,361	1,687	3,909	1,895	322	1,219	20,499	122,737	5,990	2,365	291	873	389
2029	206,009	56,659	23,343	27,881	292	27,816	427,488	1,689	3,917	1,898	323	1,225	20,602	123,351	6,020	2,375	291	875	390
2030	207,039	56,943	23,390	27,937	293	27,955	429,625	1,691	3,925	1,902	323	1,231	20,705	123,967	6,050	2,386	292	876	391
2031	208,074	57,227	23,436	27,993	295	28,095	431,773	1,692	3,933	1,906	324	1,237	20,808	124,587	6,080	2,396	292	878	391
2032	209,115	57,513	23,483	28,049	296	28,236	433,932	1,694	3,940	1,910	325	1,243	20,912	125,210	6,111	2,407	293	880	392
2033	210,160	57,801	23,530	28,105	298	28,377	436,102	1,696	3,948	1,914	325	1,249	21,017	125,836	6,141	2,417	294	882	393
2034	211,211	58,090	23,577	28,161	299	28,519	438,282	1,698	3,956	1,917	326	1,256	21,122	126,465	6,172	2,428	294	883	394
2035	212,267	58,381	23,624	28,217	301	28,661	440,474	1,699	3,964	1,921	327	1,262	21,228	127,098	6,203	2,438	295	885	394
2036	212,710	58,614	23,683	28,358	301	28,747	441,355	1,701	3,968	1,923	327	1,265	21,313	127,479	6,228	2,441	295	886	395
2037	213,155	58,848	23,743	28,500	302	28,833	442,237	1,703	3,972	1,925	327	1,267	21,398	127,861	6,253	2,443	295	887	395
2038	213,600	59,084	23,802	28,643	302	28,920	443,122	1,704	3,976	1,927	328	1,270	21,483	128,245	6,278	2,446	296	888	396
2039	214,046	59,320	23,861	28,786	303	29,007	444,008	1,706	3,980	1,929	328	1,272	21,569	128,630	6,303	2,448	296	889	396

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/ SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2040	214,493	59,558	23,921	28,930	304	29,094	444,896	1,708	3,984	1,931	328	1,275	21,656	129,016	6,328	2,450	296	890	396
2041	214,941	59,796	23,981	29,075	304	29,181	445,786	1,709	3,988	1,933	329	1,277	21,742	129,403	6,353	2,453	297	891	397
2042	215,390	60,035	24,041	29,220	305	29,268	446,677	1,711	3,992	1,935	329	1,280	21,829	129,791	6,379	2,455	297	891	397
2043	215,841	60,275	24,101	29,366	306	29,356	447,571	1,713	3,996	1,937	329	1,282	21,917	130,180	6,404	2,458	297	892	398
2044	216,292	60,516	24,161	29,513	306	29,444	448,466	1,715	4,000	1,939	330	1,285	22,004	130,571	6,430	2,460	297	893	398
2045	216,744	60,758	24,222	29,660	307	29,533	449,363	1,716	4,004	1,941	330	1,287	22,092	130,963	6,456	2,463	298	894	398
2046	217,197	61,001	24,282	29,809	307	29,621	450,262	1,718	4,008	1,943	330	1,290	22,181	131,355	6,481	2,465	298	895	399
2047	217,651	61,245	24,343	29,958	308	29,710	451,162	1,720	4,012	1,944	331	1,293	22,269	131,749	6,507	2,468	298	896	399
2048	218,106	61,490	24,404	30,108	309	29,799	452,064	1,721	4,016	1,946	331	1,295	22,358	132,145	6,533	2,470	299	897	400
2049	218,562	61,736	24,465	30,258	309	29,889	452,969	1,723	4,020	1,948	331	1,298	22,448	132,541	6,559	2,473	299	898	400
2050	219,020	61,983	24,526	30,409	310	29,978	453,874	1,725	4,024	1,950	332	1,300	22,538	132,939	6,586	2,475	299	899	400
2051	219,478	62,231	24,587	30,561	310	30,068	454,782	1,727	4,028	1,952	332	1,303	22,628	133,338	6,612	2,477	300	899	401
2052	219,937	62,480	24,649	30,714	311	30,158	455,692	1,728	4,032	1,954	332	1,306	22,718	133,738	6,638	2,480	300	900	401
2053	220,397	62,730	24,710	30,868	312	30,249	456,603	1,730	4,036	1,956	333	1,308	22,809	134,139	6,665	2,482	300	901	402
2054	220,858	62,981	24,772	31,022	312	30,340	457,516	1,732	4,040	1,958	333	1,311	22,900	134,541	6,692	2,485	300	902	402
2055	221,321	63,233	24,834	31,177	313	30,431	458,431	1,734	4,044	1,960	333	1,313	22,992	134,945	6,718	2,487	301	903	402
2056	221,784	63,486	24,896	31,333	314	30,522	459,348	1,735	4,048	1,962	334	1,316	23,084	135,350	6,745	2,490	301	904	403
2057	222,248	63,740	24,958	31,490	314	30,614	460,267	1,737	4,052	1,964	334	1,319	23,176	135,756	6,772	2,492	301	905	403
2058	222,714	63,995	25,021	31,647	315	30,705	461,187	1,739	4,056	1,966	334	1,321	23,269	136,163	6,799	2,495	302	906	404
2059	223,180	64,251	25,083	31,805	315	30,798	462,110	1,740	4,060	1,968	335	1,324	23,362	136,571	6,827	2,497	302	907	404
2060	223,648	64,508	25,146	31,965	316	30,890	463,034	1,742	4,064	1,970	335	1,327	23,456	136,981	6,854	2,500	302	908	404
2061	224,116	64,766	25,209	32,124	317	30,983	463,960	1,744	4,068	1,972	335	1,329	23,549	137,392	6,881	2,502	303	908	405

Table 8-9 Low Case Peak Demand (MW)

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2011	30.8	10.6	6.6	5.1	0.1	5.6	80.9	0.4	0.8	0.4	0.1	0.3	4.5	23.7	1.4	0.4	0.1	0.2	0.1
2012	35.6	11.2	6.7	5.4	0.1	5.7	82.8	0.4	0.8	0.4	0.1	0.3	4.7	24.0	1.4	0.4	0.1	0.2	0.1
2013	36.0	11.3	6.7	5.5	0.1	5.8	83.4	0.3	0.8	0.4	0.1	0.3	4.8	24.1	1.4	0.4	0.1	0.2	0.1
2014	36.5	11.4	6.6	5.6	0.1	5.9	84.0	0.3	0.8	0.4	0.1	0.3	4.7	24.2	1.4	0.4	0.1	0.2	0.1
2015	36.9	11.5	6.4	5.6	0.1	5.9	84.3	0.3	0.8	0.4	0.1	0.3	4.7	24.2	1.3	0.4	0.1	0.2	0.1
2016	36.7	11.5	6.3	5.5	0.1	5.8	83.8	0.3	0.8	0.4	0.1	0.3	4.7	24.1	1.3	0.4	0.1	0.2	0.1
2017	36.2	11.3	6.0	5.3	0.1	5.7	82.8	0.3	0.8	0.4	0.1	0.3	4.6	23.8	1.3	0.4	0.1	0.2	0.1
2018	35.5	11.2	5.6	5.1	0.1	5.5	81.2	0.3	0.8	0.4	0.1	0.3	4.5	23.5	1.3	0.4	0.1	0.2	0.1
2019	34.9	11.0	5.3	4.9	0.1	5.3	79.8	0.3	0.8	0.4	0.1	0.3	4.4	23.1	1.3	0.4	0.1	0.2	0.1
2020	34.7	10.9	5.1	4.8	0.1	5.2	79.3	0.3	0.8	0.4	0.1	0.3	4.3	23.0	1.2	0.4	0.1	0.2	0.1
2021	34.8	11.0	5.0	4.8	0.1	5.2	79.5	0.3	0.8	0.4	0.1	0.3	4.3	23.1	1.2	0.4	0.1	0.2	0.1
2022	34.9	11.0	5.1	4.8	0.1	5.2	79.9	0.3	0.8	0.4	0.1	0.3	4.4	23.2	1.3	0.4	0.1	0.2	0.1
2023	35.1	11.1	5.1	4.8	0.1	5.2	80.3	0.3	0.8	0.4	0.1	0.3	4.4	23.3	1.3	0.4	0.1	0.2	0.1
2024	35.3	11.1	5.1	4.9	0.1	5.3	80.7	0.3	0.8	0.4	0.1	0.3	4.4	23.4	1.3	0.4	0.1	0.2	0.1
2025	35.5	11.2	5.1	4.9	0.1	5.3	81.1	0.3	0.8	0.4	0.1	0.3	4.4	23.5	1.3	0.4	0.1	0.2	0.1
2026	35.6	11.2	5.1	4.9	0.1	5.3	81.5	0.3	0.8	0.4	0.1	0.3	4.5	23.6	1.3	0.4	0.1	0.2	0.1
2027	35.8	11.3	5.1	4.9	0.1	5.3	81.9	0.3	0.8	0.4	0.1	0.3	4.5	23.7	1.3	0.4	0.1	0.2	0.1
2028	36.0	11.4	5.1	4.9	0.1	5.4	82.3	0.3	0.8	0.4	0.1	0.3	4.5	23.9	1.3	0.4	0.1	0.2	0.1
2029	36.2	11.4	5.1	4.9	0.1	5.4	82.7	0.3	0.8	0.4	0.1	0.3	4.5	24.0	1.3	0.4	0.1	0.2	0.1
2030	36.4	11.5	5.1	4.9	0.1	5.4	83.1	0.3	0.8	0.4	0.1	0.3	4.5	24.1	1.3	0.4	0.1	0.2	0.1
2031	36.5	11.5	5.1	4.9	0.1	5.5	83.5	0.3	0.8	0.4	0.1	0.3	4.6	24.2	1.3	0.4	0.1	0.2	0.1
2032	36.7	11.6	5.2	4.9	0.1	5.5	83.9	0.3	0.8	0.4	0.1	0.3	4.6	24.3	1.3	0.4	0.1	0.2	0.1
2033	36.9	11.6	5.2	4.9	0.1	5.5	84.4	0.3	0.8	0.4	0.1	0.3	4.6	24.5	1.3	0.4	0.1	0.2	0.1
2034	37.1	11.7	5.2	5.0	0.1	5.5	84.8	0.3	0.8	0.4	0.1	0.3	4.6	24.6	1.3	0.4	0.1	0.2	0.1
2035	37.3	11.8	5.2	5.0	0.1	5.6	85.2	0.3	0.8	0.4	0.1	0.3	4.7	24.7	1.3	0.4	0.1	0.2	0.1
2036	37.4	11.8	5.2	5.0	0.1	5.6	85.4	0.3	0.8	0.4	0.1	0.3	4.7	24.8	1.3	0.4	0.1	0.2	0.1
2037	37.4	11.8	5.2	5.0	0.1	5.6	85.6	0.3	0.8	0.4	0.1	0.3	4.7	24.9	1.4	0.4	0.1	0.2	0.1
2038	37.5	11.9	5.2	5.0	0.1	5.6	85.7	0.3	0.8	0.4	0.1	0.3	4.7	24.9	1.4	0.4	0.1	0.2	0.1
2039	37.6	11.9	5.2	5.1	0.1	5.6	85.9	0.3	0.8	0.4	0.1	0.3	4.7	25.0	1.4	0.4	0.1	0.2	0.1

YEAR	KETCHIKAN-SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES/SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PELICAN	TENAKEE SPRINGS
2040	37.7	12.0	5.3	5.1	0.1	5.6	86.1	0.3	0.8	0.4	0.1	0.3	4.8	25.1	1.4	0.4	0.1	0.2	0.1
2041	37.7	12.0	5.3	5.1	0.1	5.7	86.2	0.3	0.8	0.4	0.1	0.3	4.8	25.2	1.4	0.4	0.1	0.2	0.1
2042	37.8	12.1	5.3	5.1	0.1	5.7	86.4	0.3	0.8	0.4	0.1	0.3	4.8	25.2	1.4	0.4	0.1	0.2	0.1
2043	37.9	12.1	5.3	5.2	0.1	5.7	86.6	0.3	0.8	0.4	0.1	0.3	4.8	25.3	1.4	0.4	0.1	0.2	0.1
2044	38.0	12.2	5.3	5.2	0.1	5.7	86.8	0.3	0.8	0.4	0.1	0.3	4.8	25.4	1.4	0.4	0.1	0.2	0.1
2045	38.1	12.2	5.3	5.2	0.1	5.7	86.9	0.3	0.8	0.4	0.1	0.3	4.8	25.5	1.4	0.4	0.1	0.2	0.1
2046	38.1	12.3	5.3	5.2	0.1	5.8	87.1	0.3	0.8	0.4	0.1	0.3	4.9	25.5	1.4	0.4	0.1	0.2	0.1
2047	38.2	12.3	5.3	5.3	0.1	5.8	87.3	0.3	0.8	0.4	0.1	0.3	4.9	25.6	1.4	0.4	0.1	0.2	0.1
2048	38.3	12.4	5.4	5.3	0.1	5.8	87.5	0.3	0.8	0.4	0.1	0.3	4.9	25.7	1.4	0.4	0.1	0.2	0.1
2049	38.4	12.4	5.4	5.3	0.1	5.8	87.6	0.3	0.8	0.4	0.1	0.3	4.9	25.8	1.4	0.4	0.1	0.2	0.1
2050	38.5	12.5	5.4	5.3	0.1	5.8	87.8	0.3	0.8	0.4	0.1	0.3	4.9	25.9	1.4	0.4	0.1	0.2	0.1
2051	38.5	12.5	5.4	5.4	0.1	5.8	88.0	0.3	0.8	0.4	0.1	0.3	5.0	25.9	1.4	0.4	0.1	0.2	0.1
2052	38.6	12.6	5.4	5.4	0.1	5.9	88.2	0.3	0.8	0.4	0.1	0.3	5.0	26.0	1.4	0.4	0.1	0.2	0.1
2053	38.7	12.6	5.4	5.4	0.1	5.9	88.3	0.3	0.8	0.4	0.1	0.3	5.0	26.1	1.4	0.4	0.1	0.2	0.1
2054	38.8	12.7	5.4	5.5	0.1	5.9	88.5	0.3	0.8	0.4	0.1	0.3	5.0	26.2	1.4	0.4	0.1	0.2	0.1
2055	38.9	12.7	5.5	5.5	0.1	5.9	88.7	0.3	0.8	0.4	0.1	0.3	5.0	26.2	1.5	0.4	0.1	0.2	0.1
2056	39.0	12.8	5.5	5.5	0.1	5.9	88.9	0.3	0.8	0.4	0.1	0.3	5.1	26.3	1.5	0.4	0.1	0.2	0.1
2057	39.0	12.8	5.5	5.5	0.1	5.9	89.0	0.3	0.8	0.4	0.1	0.3	5.1	26.4	1.5	0.4	0.1	0.2	0.1
2058	39.1	12.9	5.5	5.6	0.1	6.0	89.2	0.3	0.8	0.4	0.1	0.3	5.1	26.5	1.5	0.4	0.1	0.2	0.1
2059	39.2	12.9	5.5	5.6	0.1	6.0	89.4	0.3	0.8	0.4	0.1	0.3	5.1	26.6	1.5	0.4	0.1	0.2	0.1
2060	39.3	13.0	5.5	5.6	0.1	6.0	89.6	0.3	0.8	0.4	0.1	0.3	5.1	26.6	1.5	0.4	0.1	0.2	0.1
2061	39.4	13.0	5.5	5.7	0.1	6.0	89.8	0.3	0.8	0.4	0.1	0.3	5.2	26.7	1.5	0.4	0.1	0.2	0.1

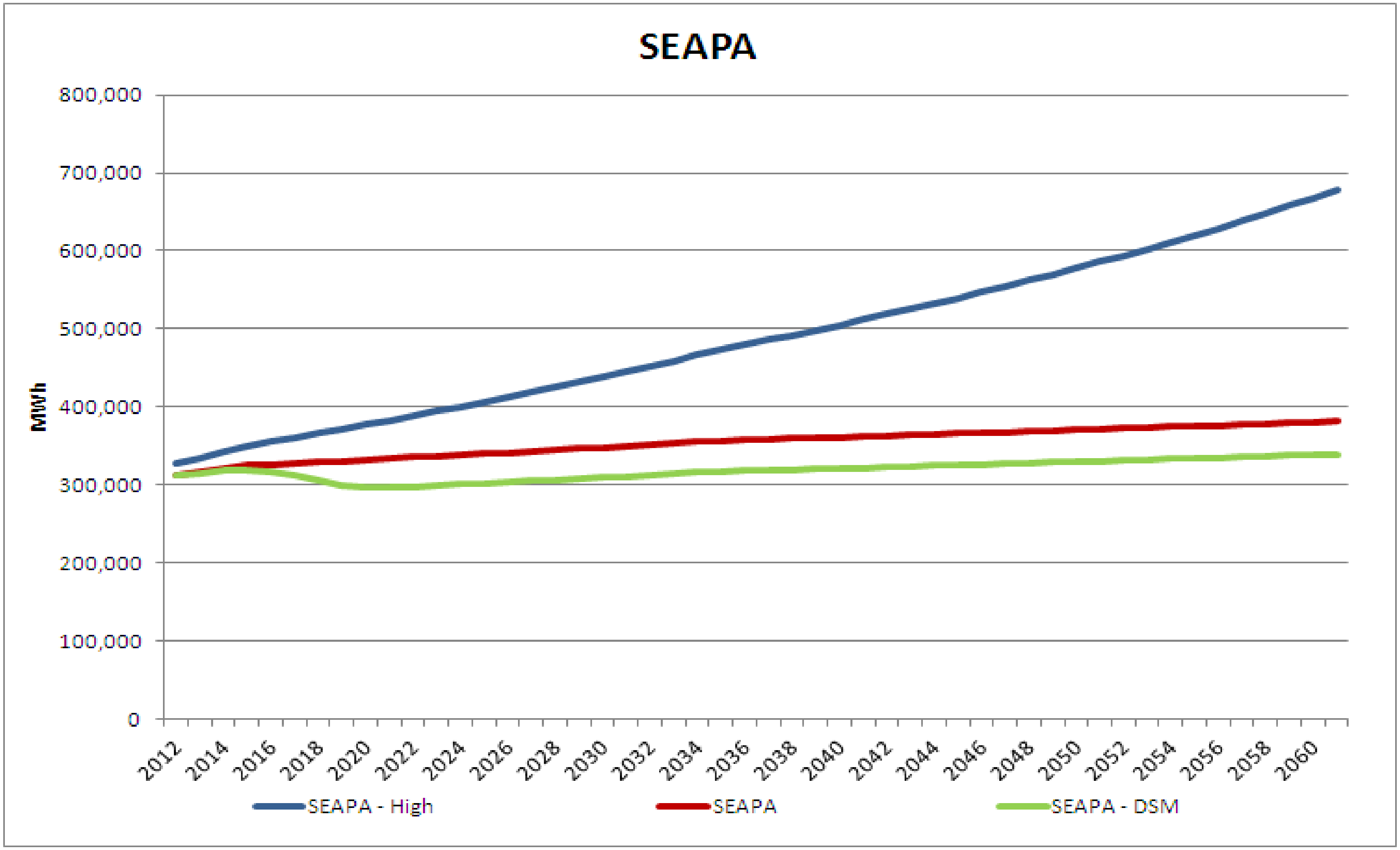

Figure 8-1 SEAPA Energy Forecasts

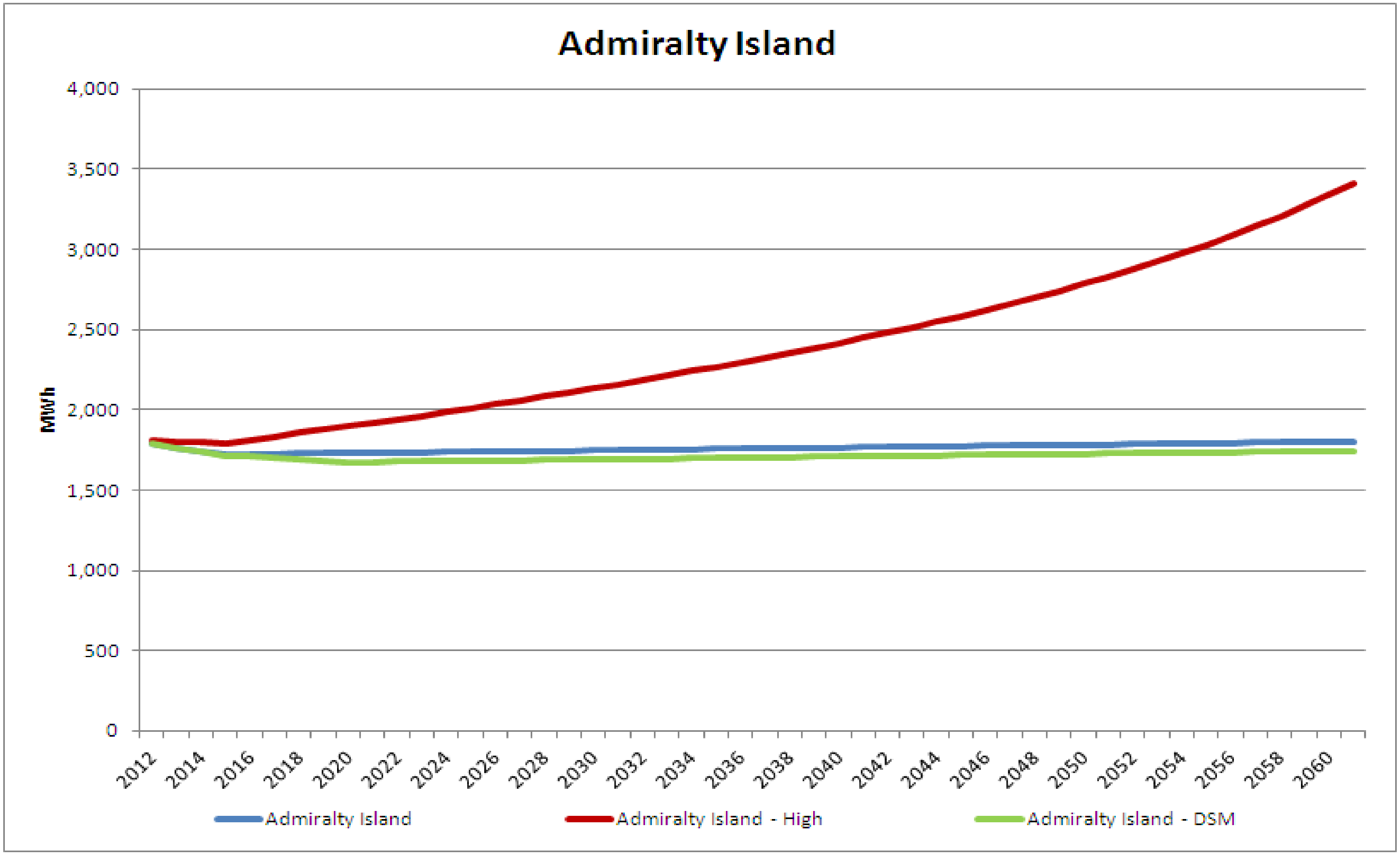

Figure 8-2 Admiralty Island Energy Forecasts

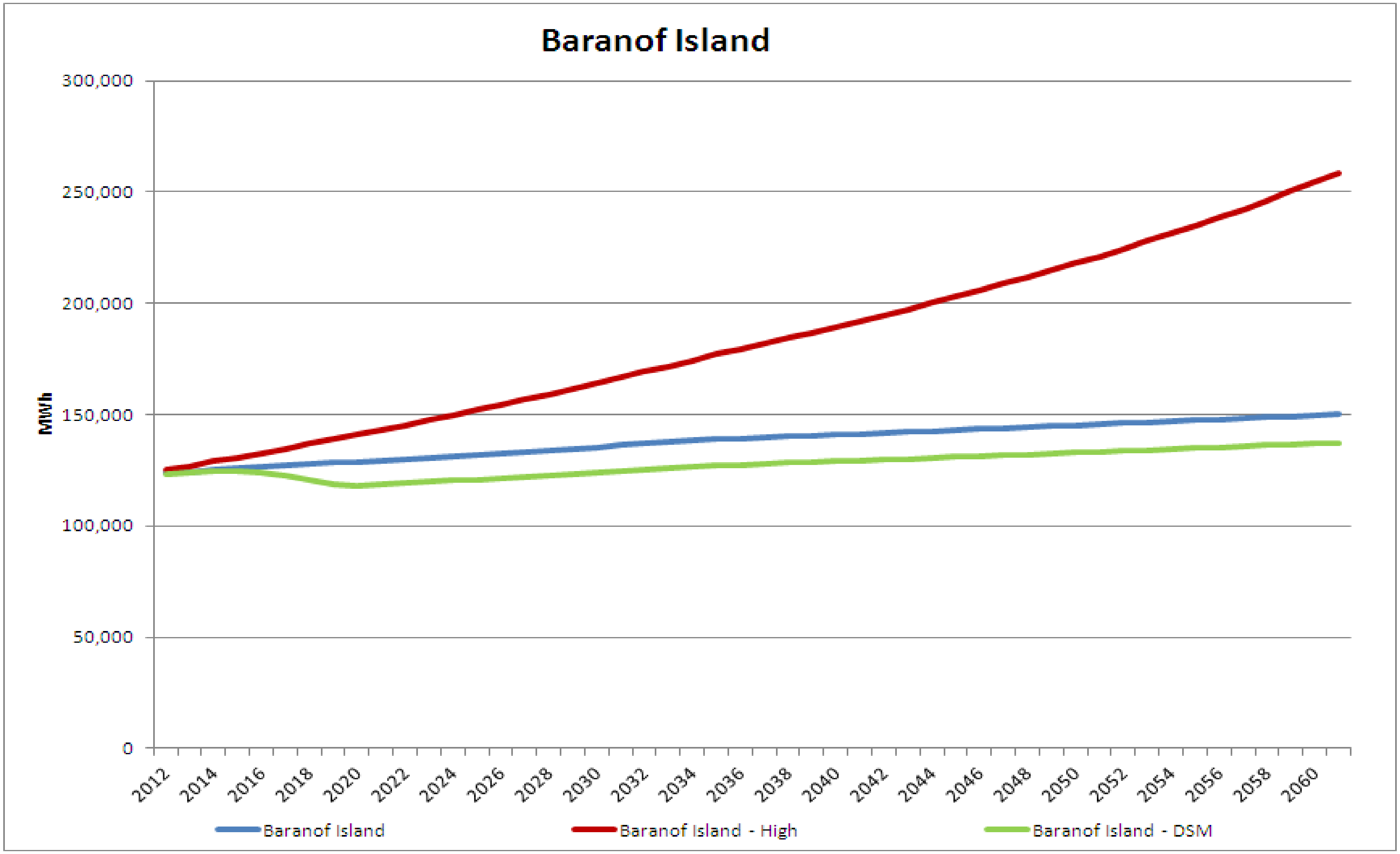

Figure 8-3 Baranof Island Energy Forecasts

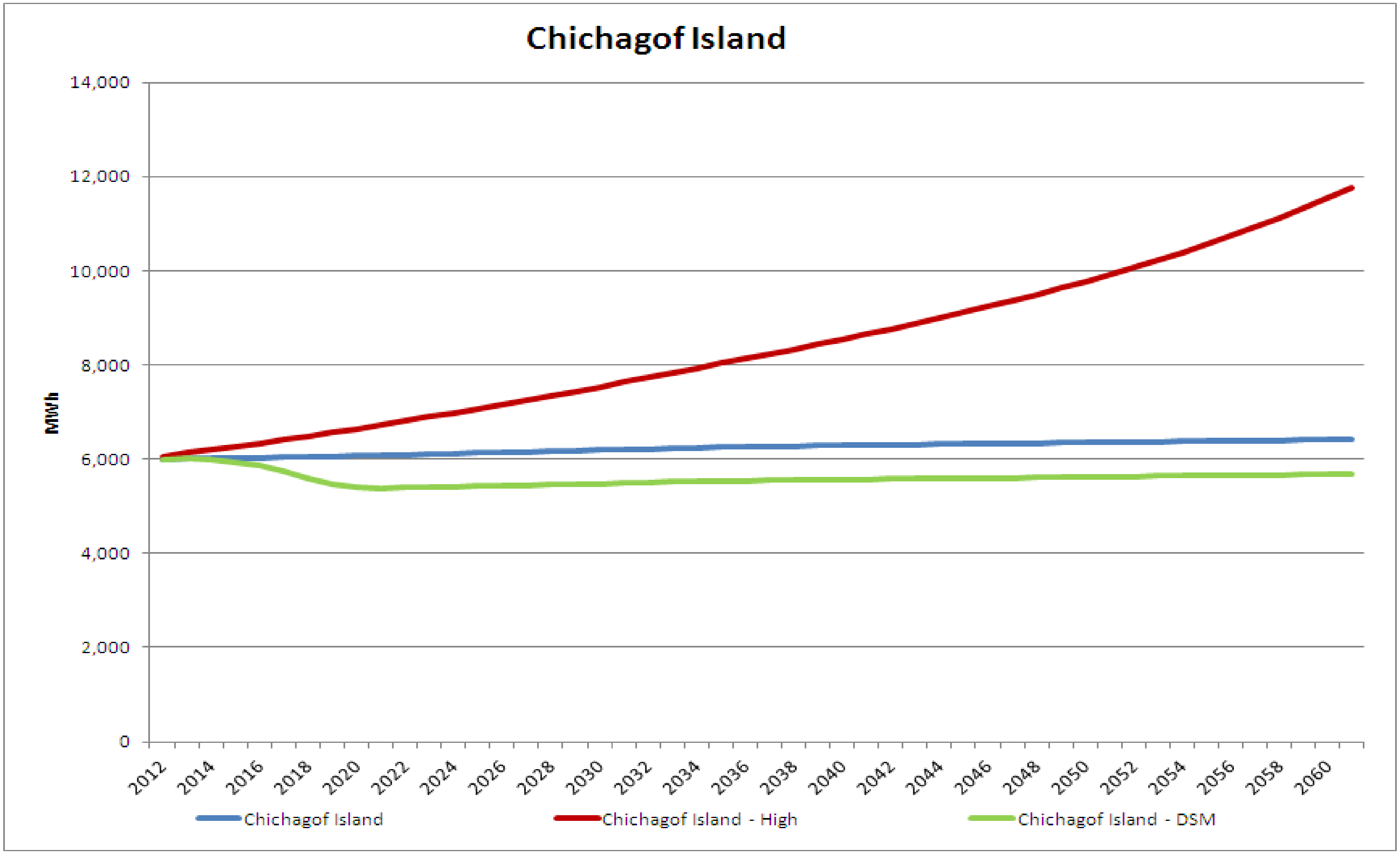

Figure 8-4 Chichagof Island Energy Forecasts

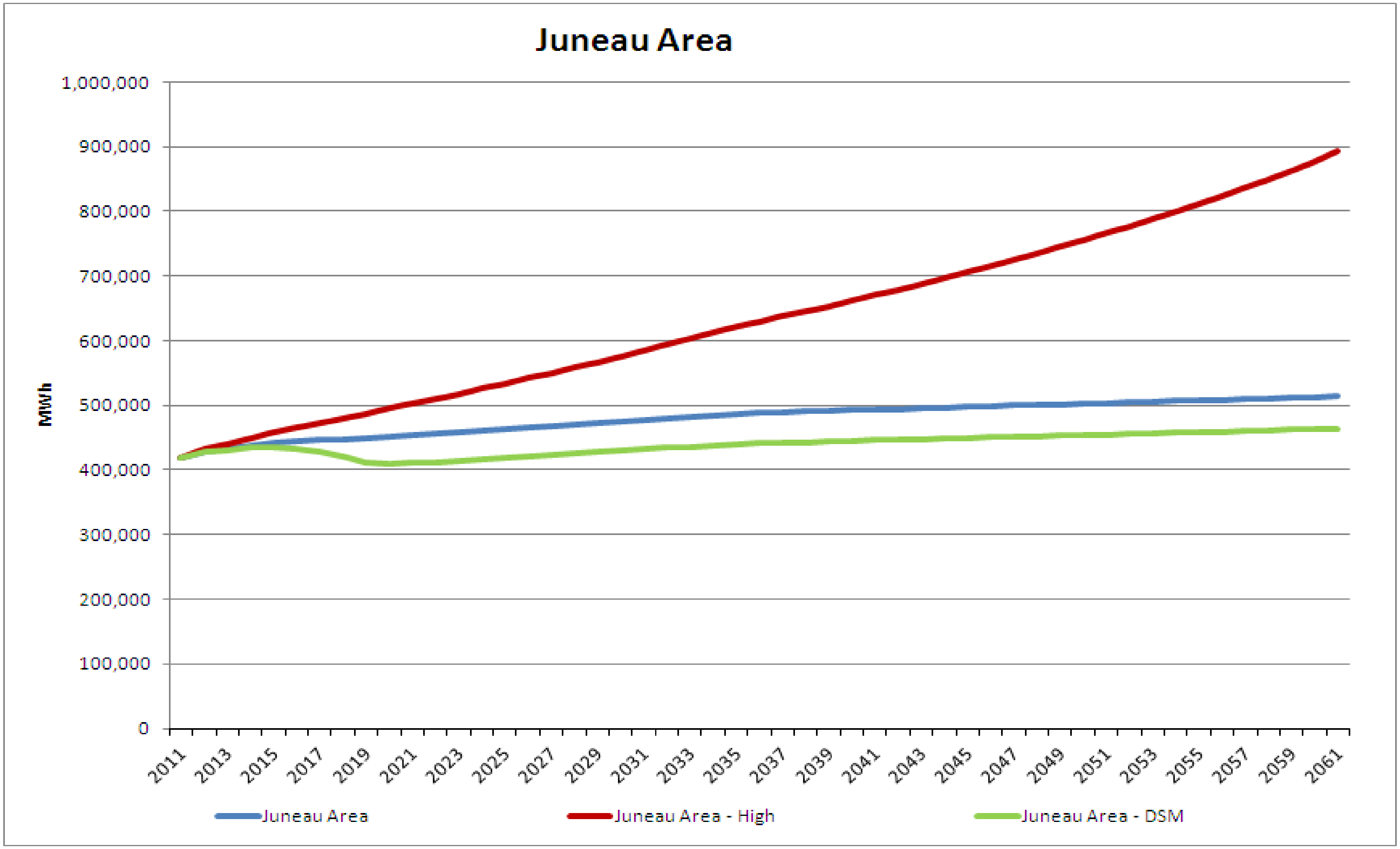

Figure 8-5 Juneau Area Energy Forecasts

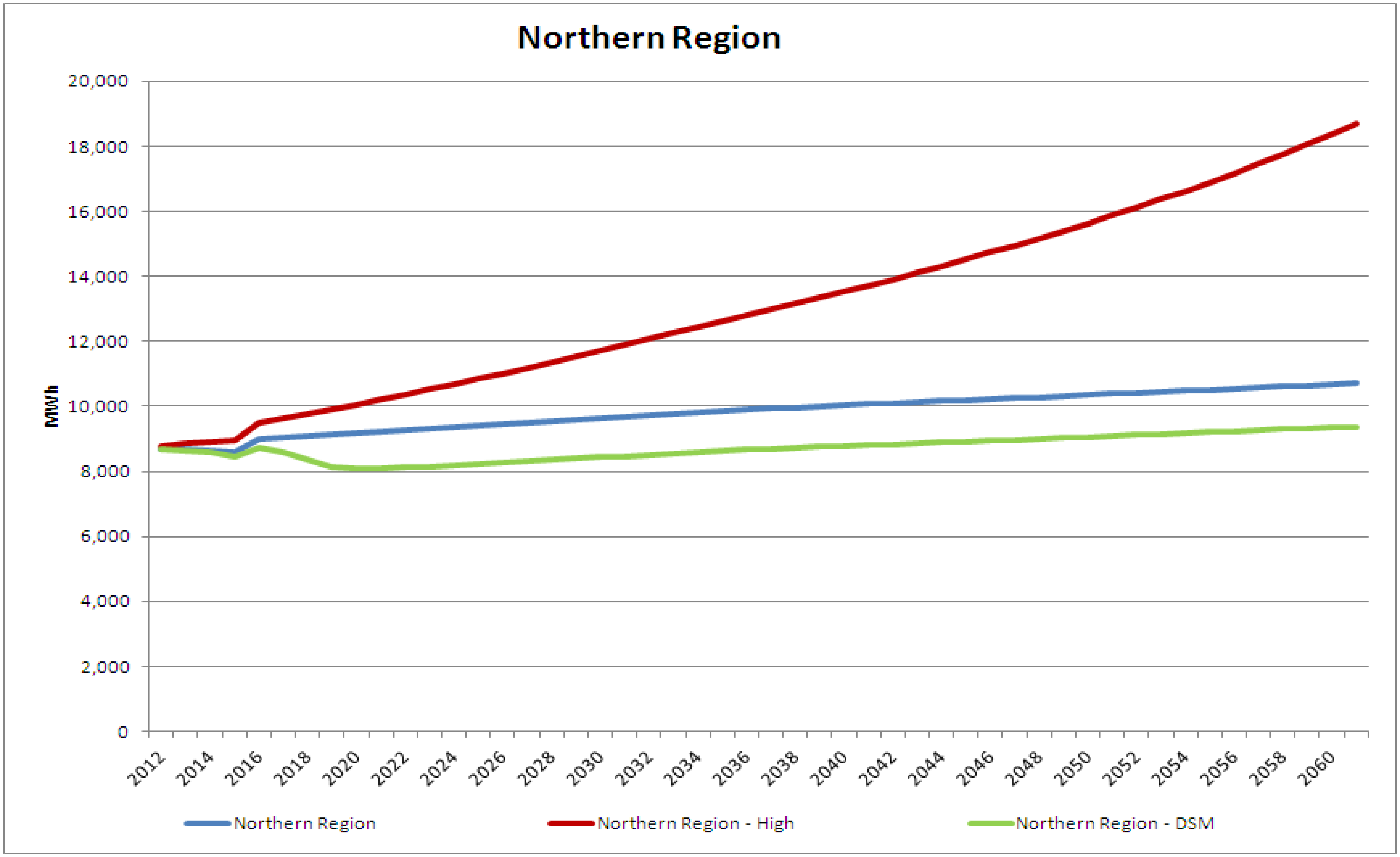

Figure 8-6 Northern Region Energy Forecasts

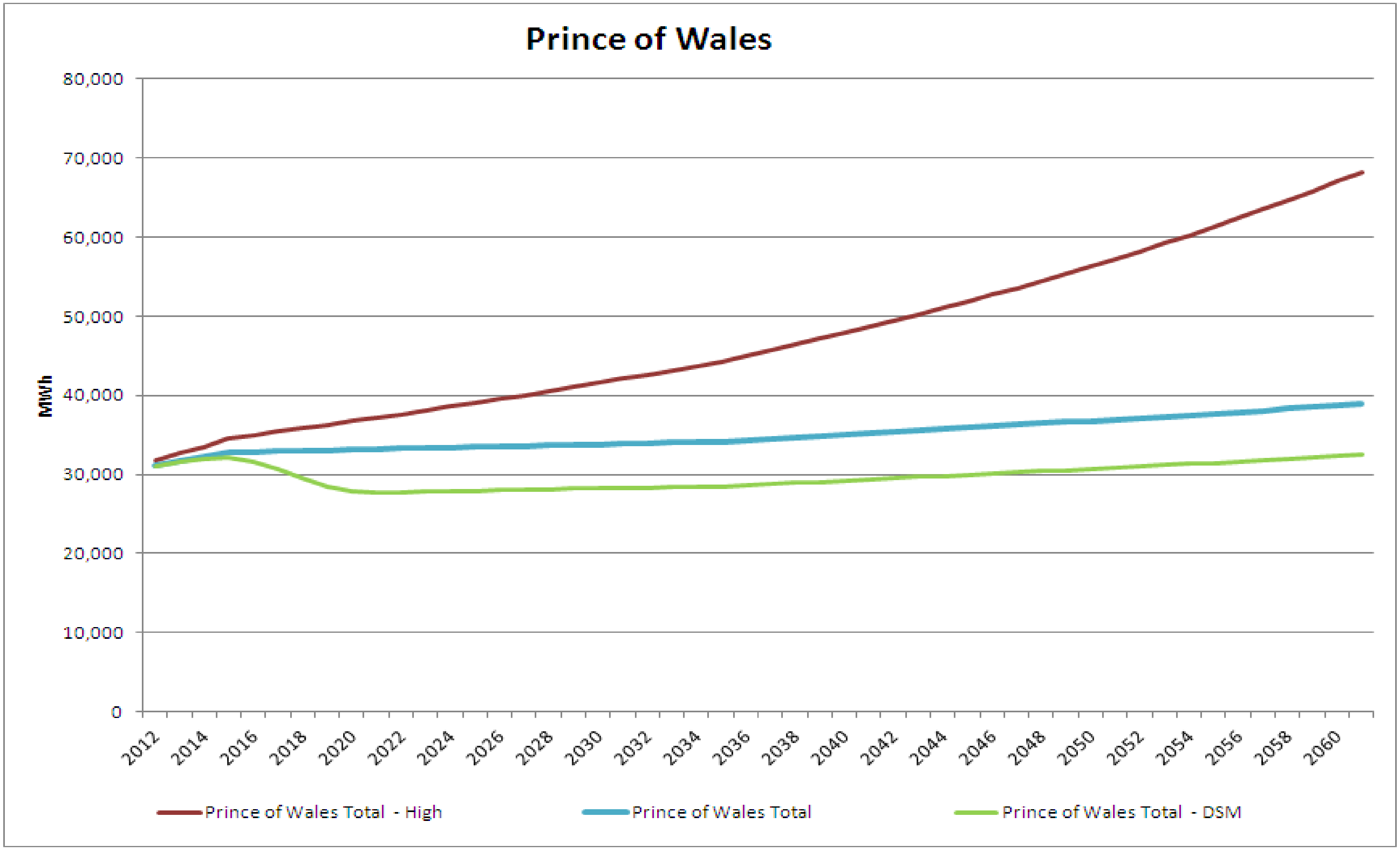

Figure 8-7 Prince of Wales Energy Forecasts

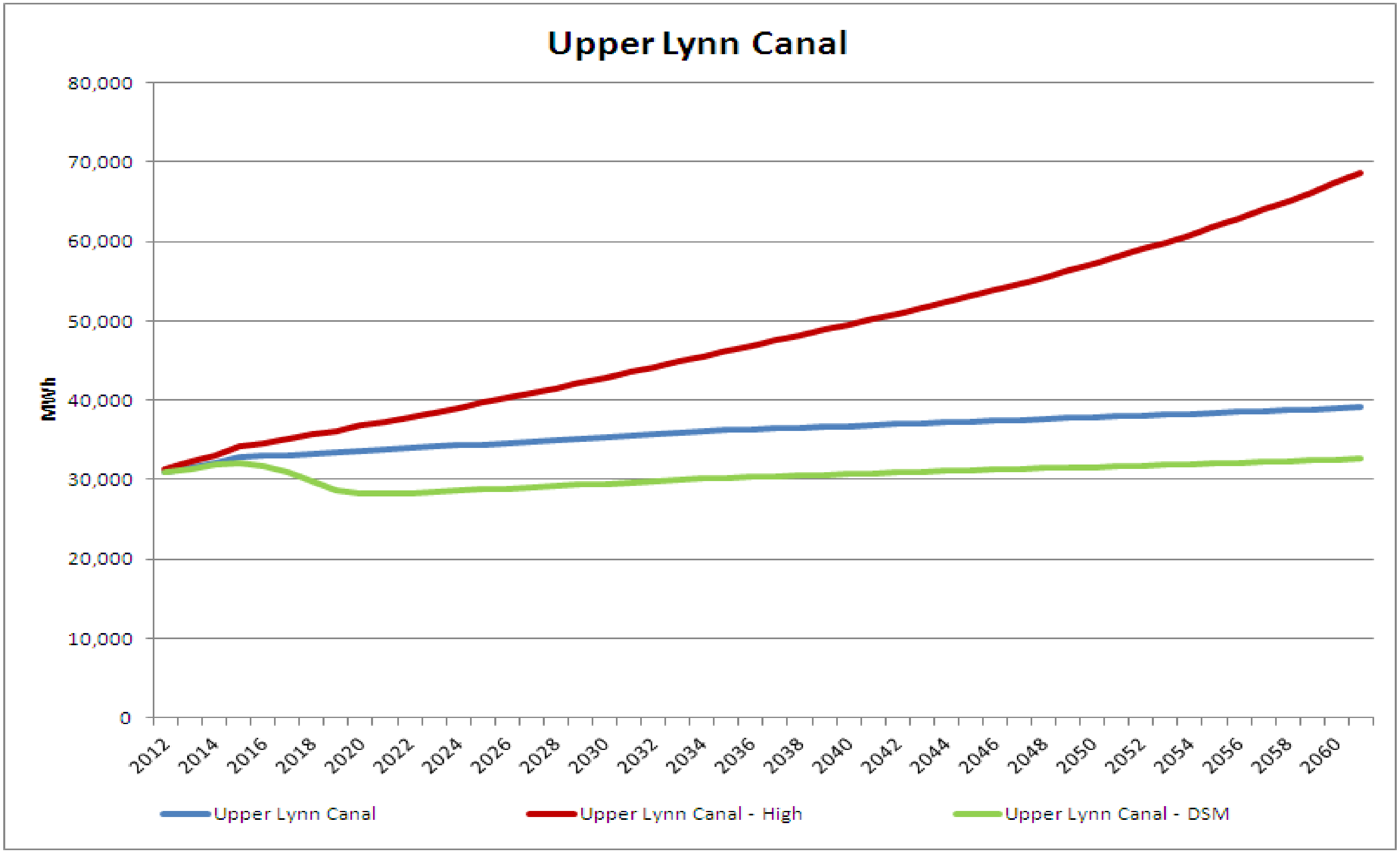

Figure 8-8 Upper Lynn Canal Energy Forecasts

8.2 SOUTHEAST ALASKA POWER AGENCY

8.2.1 Ketchikan Public Utilities

8.2.1.1 Reference Scenario Load Forecast

To develop the Ketchikan load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with Ketchikan Public Utility (KPU). Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. In addition, Black & Veatch assessed the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the ACS data for 2005 to 2009 to develop the energy usage forecast for KPU.

Discussion on Historical Load Growth (2008-2010)

Black & Veatch reviewed the historical annual gross generation figures obtained from KPU for 2000 to 2010. Black & Veatch did not receive any usage data by customer classes or net energy for load (NEL) data and, therefore, developed the load forecast based on the annual gross generation figures only. In doing so, Black & Veatch assumed that there is a direct correlation between net energy for load and annual gross generation. Black & Veatch also assumed that station usage and system losses will not change appreciably from current levels for the duration of the study period.

Though Black & Veatch reviewed historical data from 2000 to 2010, KPU informed Black & Veatch that usage trends and demand levels prior to 2008 are insignificant for predicting recent energy demand for KPU system. This is due to a variety of reasons, which are discussed subsequently in this section. Historical data for the last 3 years only (from 2008) were considered when developing the energy forecast for the region and is presented in this section.

Between 2007 and 2009, the annual gross generation increased by approximately 4.5 percent. The annual gross generation for KPU has increased from 164,114 MWh annually in 2007 to 169,424 MWh in 2008 and to 171,457 MWh in 2009 before falling off to 169,036 MWh in 2010. KPU noted that in absence of good reporting tools, the annual generation figures are not exact, but rather a close approximation of the actual figures for that year.

According to the population forecast developed by the ADL, the population in the region was expected to decrease to 12,836 persons in 2010 from 13,174 in 2006. It is forecasted to decrease to 12,507 by 2015. However, in reality, this area has seen opposite trends in the recent past. The number of customers increased from 7,347 in 2008 to 7,418 in 2010. Most of the customer increases have been due to high growth in commercial and industrial activities. Unlike other areas in Alaska, Ketchikan has seen a recent spurt in commercial and industrial activities which has led to new customers coming into the area.

In the residential sector, a number of customers converted their existing oil-based home heating systems to electrical heating systems during this period. KPU indicated that oil prices above $3.30/gallon tend to increase this conversion trend. During 2008, when oil prices were around $5.00 per gallon, many customers opted to switch, thus increasing the system energy demand. However, the conversion rate has since slowed down.

Based on the above analysis, Black & Veatch broke down the growth in electric energy sales between 2008 and 2010 into the following few main categories:

- Growth in energy sales due to new developments in 2008.
- Growth in energy sales due to new developments in 2009.
- Growth in energy sales due to new developments in 2010.
- Growth in energy sales for existing customers due to switching to electric heating systems and generic growth.
- Sales due to abnormal weather.

KPU provided details of all new load additions by year from 2008 to 2014. The new developments that took place in the years 2008 through 2010 are shown in Table 8-10 along with their transformer ratings. Table 8-11 shows the recent trend in annual usage for existing customers. KPU indicated that it expects all new loads from 2008 and 2009 to have a 30 percent load factor for the period 2008 to 2010. New loads from new developments in 2010 are expected to have a load factor of 25 percent. Black & Veatch developed the historical annual energy sales from the new developments in these years based on this assumption.

The annual use per customer excludes the customers shown in Table 8-10 and is shown in Table 8-11 based on gross generation since NEL was not available.

Table 8-10 New Developments

YEAR	PROJECT NAME	LOAD (KVA)
2008	AMHS Maintenance	75
	Berth 3 (Seasonal) Winter Peak	400
	Cedar Point 21 Jefferson Way	104
	Cedar Point 25 Jefferson Way	172
	Tongass Marine Store	75
2009	Evergreen Terrace	215
	Channel Electric Bldg	75
	Harbormaster Condos	100
	KGB Maintenance Facility	25
	KPU Water UV Plant	200
	Rhineco Inc	150
	Smart Construction	30
	STG Vol Fire Dept	40
	White Cliff Building	220
2010	MUTTC Cape Fox	35
	AK Rainforest Bunkhouse	150
	Eddystone Rock & Readymix	225
	Forest Service Warehouse	300
	KIC Elder Housing	300
	Opportunity House	150
	Schoenbar Park Apts	350
	Saxman Water Station	75

Table 8-11 Annual Usage Trend (2008-2010) for Existing Customers

YEAR	GROSS GENERATION (MWH)	ESTIMATED LOAD FROM TABLE 8-3 (MWH)	EXISTING CUSTOMER LOAD (MWH)	EXISTING CUSTOMERS	ANNUAL USAGE/CUSTOMER (MWH)
2008	169,424	2,171	167,253	7,343	22.78
2009	171,457	4,943	166,513	7,351	22.65
2010	169,036	8,414	160,622	7,396	21.65

The annual heating degree days (HDDs) are shown in Table 8-12. Comparing Tables 8-11 and 8-12 demonstrates the influence of weather on use per customer, confirming the existence of significant levels of electric heat conversion.

Table 8-12 Annual HDD

YEAR	ANNUAL HDD
2001	7,440
2002	7,574
2003	7,436
2004	7,043
2005	6,975
2006	7,797
2007	7,629
2008	7,740
2009	7,588
2010	6,749
Average for the Period (2001-2010)	7,411

KPU indicated that it has not seen much conversion to electric heating systems since 2008. Such conversions are usually cost-effective if oil prices are higher than $3.30/gallon. However, customers also have the option of using inexpensive portable electric space heaters in their homes to reduce oil heating. So even although customers are not converting to electric heating systems, they still have the potential to use electricity to at least partially heat their homes. The use of portable electric space heaters can quickly be discontinued by customers when the price of oil falls.

Load Forecast (2011 to 2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this Reference Scenario Load Forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by wholesale power purchase from SEAPA.

As indicated earlier, Black & Veatch only reviewed the annual gross generation data. Therefore, Black & Veatch developed the forecast based on gross annual generation. In doing so, Black & Veatch assumed that system losses and internal plant usage (station usage) will not change appreciably during this period. Since most of KPU's power is from hydroelectric sources, station service should be relatively small.

2011 to 2015 – Short Term

As 2010 appeared to be an unusually mild weather year, Black & Veatch made an adjustment for a more normal weather year. Additional load from new developments is also considered during this period. The information for new loads was obtained from KPU. It is also assumed that system losses would remain constant compared to 2010.

Black & Veatch divided the load growth analysis in two segments:

- Load growth from new commercial and industrial developments for which specific load information is available.
- Load growth from existing and new customers (other than those considered above).

KPU provided a detailed list of new developments that are expected to become operational between 2011 and 2013. The list of projects is shown in Table 8-13. The project status is also shown in the table. The projects expected to be online in 2013 have not been considered in the load forecast since they are still in the preliminary phases of development. For all other projects, a 25 percent load factor was assumed.

KPU informed Black & Veatch that the governor had vetoed the grant for the electric heat conversion of the Ketchikan schools. Because of the governor's veto of the grant, the electric heat conversion of the schools are no longer included in the list of future projects.

The new city firehouse has made the decision to use pellets for heating, and its load has been reduced accordingly.

KPU also informed Black & Veatch that a new housing subdivision is currently being built in Ketchikan. However, KPU does not currently know the total number of houses and their demand. KPU does not expect significant additional load from this new housing subdivision.

Table 8-13 Expected Load from New Facilities

YEAR	PROJECT NAME	LOAD (KVA)	STATUS
2011	KGB Pool (in addition to Rec Center)	1,000	Construction
	KGB Whitman Booster Station	100	Construction
	KIC A&T Facility	100	Construction
	Northland - Tongass Ave	300	Design
	Pioneer Heights	300	Construction
	Saxman Elder Housing	300	Construction
	OceansAlaska (Phase I)	500	Construction
	Trident Seafoods (Phase I)	3,000	Design
	AP&T Warehouse	500	Design
	Ketchikan Mechanical Warehouse	500	Design
	Marble Construction	300	Design
	USCG Barracks	120	Design
2012	Schools	0	Preliminary
	AMHS Admin & Yard - Ward Cove	750	Design
	ASD Facility		Discussed Separately
	New City Fire Station	-500	Design
	New City Library	300-	Design
	Northland - Stedman St	300	Preliminary
	Trident Seafoods (Phase II)	1,500	Design
	AMHS Admin Ops	35	Design
	Seley 10-Mile Site	200	Design
	USCG Galley & Clinic	260	Design
2013	OceansAlaska (Phase II)	No Data Yet*	Preliminary
	Emerald Forest Subdivision (Phase II)	No Data Yet*	Preliminary
	Hospital (Various Projects)	No Data Yet*	Preliminary

KPU indicated that all load assumptions shown in Table 8-10 and Table 8-13 were in line with expectations.

In addition to the above, KPU is expecting significant load growth from Alaska Ship & Drydock (ASD) due to the increase in the size of its facilities. ASD has estimated its energy needs will increase up to 50 percent annually following construction of its new production facilities. These facilities are scheduled for completion in June 2012. Due to this, KPU expects an additional energy demand of 3,000 MWh.

Apart from energy load growth from the new developments listed in Table 8-13, Black & Veatch also considered load growth from exiting and other new customers in the load forecasts.

KPU also believes that there will be added load growth from people trying to convert to electric heating systems, though the conversion rate is expected to be slow. The conversion rate is expected to be slow because there are no incentives from the local government to convert to electric heating systems. The capital cost of such conversions is also a deterrent, and people who can afford to convert easily have already converted. People who have converted are assumed to use an additional 2,000 kWh in each of the three peak winter months. There is also the possibility of customers using low-cost portable space heaters, which will also increase system energy demand. Because of the high capital investment required for converting to electric heating systems, Black & Veatch expects most people who have not converted to electric heating systems to use electric space heaters instead. Electric space heaters are usually sized 500 watt or 1,000 watt. Assuming each customer of KPU will use two small space heaters (500 watt) for 16 hours a day for 3 months in a year, the total estimated annual increase in energy demand is approximately 1,440 kWh per customer. Black & Veatch has also assumed that this usage pattern will be exhibited by roughly 20 percent of the existing customers of KPU in 2011 and 5 percent in 2012, after which the load from portable space heaters is expected to cease with the assumed return of normal oil prices. For the load forecast, Black & Veatch has also adjusted the 2010 total gross generation to reflect the more normal use per customer of 2009.

Black & Veatch forecasts the growth in number of customers and use per customer for existing customers to both be 1 percent per year from 2010 through 2015.

The Alaska Housing Finance Corporation (AHFC) offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Based on the above assumptions, Black & Veatch projects KPU's annual gross generation will increase to 212,635 in 2015 from 169,036 MWh in 2010. This is equivalent to an annual compound growth rate of 4.0 percent. This is a very high growth rate for energy demand, which reflects the current situation in Ketchikan. However, such trends are unlikely to continue in the long run.

Based on the above assumptions and collected information, Black & Veatch has made the following forecasts for this period:

- The total growth in gross generation requirements is expected to increase an average of 4.0 percent annually.
- This assumes that system losses and station usage will remain unchanged at 2010 levels. However, as the growth rate for energy is high, there is a possibility that existing transmission and distribution infrastructure will not be sufficient to serve load without increased losses in the short term. The annual gross generation requirement will increase even further if system losses or station usage increase.
- Black & Veatch has assumed that the system load factor will, on average, be approximately 65 percent. Based on that assumption, the calculated system peak is expected to increase from about 30.8 MW in February 2011 to 37.3 MW in 2015.

2016 to 2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil will return to the medium ISER projections.

Ketchikan is currently in the midst of an economic boom, contrary to what is seen in rest of Southeast Alaska. However, this economic boom is unexpected based on ADL population projections. According to the population forecast by ADL, the population of the region is likely to reduce from 12,507 people in 2015 to 11,095 people in 2030. Following this trend, Black & Veatch expects that the population will likely go down to approximately 10,603 people by 2035. This shows that the population will shrink by 15 percent in these 20 years. These population projections are indicative of economic decline. While the ADL projections represent a significant forecasting effort, Black & Veatch believes the current economic boom will sustain load growth enough to offset the decline.

Load factors are expected to remain fairly constant through this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual gross generation will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers will remain relatively constant. Use per residential customer will increase due to the ever increasing uses of electricity coupled with some economic sustainability. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly, being mitigated by lack of growth in residential customers.
- System losses are assumed to remain the same throughout the period.

2036 to 2060 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts moderate growth in the number of customers and use per customer for residential and commercial sectors at 0.2 percent for both the number of customers and use per customer.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.2.1.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for KPU based on the assumptions indicated earlier in the general description section. The population of Ketchikan as projected by the ADL is expected to decrease from 12,836 persons in 2010 to 12,581 persons in 2030. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will decrease at the same annual rate as is forecast by ADL for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in load for every year in the study period over the corresponding forecast in the Reference Scenario. This was done to account for increased loads likely to be caused by faster than expected economic growth and development.

The annual gross generation forecast for the high case is 189,796 MWh in 2011, and it increases to 419,198 MWh in 2061. In the Reference Scenario, the gross generation forecast for 2011 was 189,796 MWh in 2011 and 248,054 MWh in 2061. This shows that the gross generation forecast for the High Scenario is 1.0 percent higher in 2011 and 69 percent higher in 2061 compared to the gross generation forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.2.2 Petersburg Municipal Power & Light

8.2.2.1 Reference Scenario Load Forecast

To develop the Petersburg load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with Petersburg Municipal Power and Light (PMPL). Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the ACS data for 2005-2009.

Load Forecast (2011 to 2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this Reference Scenario Load Forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by wholesale power purchase from SEAPA.

2011 to 2015 – Short Term

During this period it was assumed that the peak and energy demand would follow a similar pattern as in 2010; usage pattern is unlikely to change in this time frame. Additional load from new developments was also considered during this period. The information for new loads was obtained in conversation with PMPL. It was also assumed that no new transmission upgrades would be possible within this time frame; therefore, system loss patterns are unlikely to improve during this time frame as compared to 2010.

According to the population forecast by ADL, the population is likely to decrease by approximately 3 percent between 2010 and 2015.

Historically, NEL has grown over the last decade with an annual compound growth rate of 3.1 percent. Within that period, NEL grew at an annual compound rate of 0.5 percent from 2000 to 2005, but increased rapidly at an annual compound rate of 4.1 percent between 2005 and 2010. Sales by sector in 2010 were as follows:

- Residential 40.8 percent
- Small Commercial 13.6 percent
- Large Commercial and Industrial 37.5 percent
- Others 8 percent

As seen, the residential and commercial sectors have the largest influence on NEL.

In the residential sector, the annual average load growth has been 8.3 percent in the recent past (2005-2010). However, during this period, the number of customers has remained almost flat. The demand growth from this sector has been primarily driven by the conversion of oil based heating to electric heating systems in residential houses. PMPL indicates about 60 percent of residential customers have converted to electric heating systems and PMPL expects another 15 to 20 percent to convert soon, especially since oil prices are currently much higher than $3.00/gallon. However, as per population projections from ADL, the population is expected to shrink by 3 percent during this period, which will offset some of the load growth for this sector during this period.

According to the information received from PMPL, the main commercial demand for electricity comes from the fishing industry for refrigeration. Many of the canneries are currently converting from the canning process to a refrigeration process, which is likely to increase the load in the near future. However, this demand is seasonal and dependent on the economics of the fishing industry. There are two canneries in Petersburg. One did not operate last year, but is expected to this year. Large commercial load varies significantly with respect to whether a cannery operates and the volume of fish that it processes. For instance, large commercial sales were over 1,000 MWh more in 2007 than they were in 2010 due to cannery operation.

In the recent past (2005-2010), annual energy demand from small and large commercial customers has increased by approximately 2 percent and 0.5 percent, respectively. These increases were in spite of periods when cannery operation was reduced. This is primarily due to existing customers converting their oil-based heating systems to electric heating systems. PMPL indicates 15 to 20 percent of the commercial customers have converted to electric heating systems. PMPL expects that this conversion process will continue for these classes of customers in the near future, especially if the retail price of oil continues to be above $3.00/gallon. However, compared to the residential sector, the conversion rate for commercial customers is much slower.

As conversion to electric heat becomes more prevalent in Petersburg, the effect of weather on loads will increase, making trends in the load forecast more difficult to discern. Table 8-14 presents the residential load from 2005 through 2010. As shown, the residential sales increase every year except 2010, when the HDDs are substantially less -- all while the number of residential customers is steady or declining. This growth is predominately due to electric heat conversions. PMPL believes the penetration of electric heat is approximately 60 percent.

Analysis of the small and large commercial sectors indicates a similar, but less evident, trend resulting from electric heat conversion. In addition, there has been some growth in the number of customers. Electric heat conversions for commercial customers can take longer than for residential customers due to planning and budgeting considerations. PMPL's estimate of 15 to 20 percent conversion to electric heat for the commercial sector leaves substantial opportunity for additional conversions if the price of oil remains high.

Black & Veatch noted that the total number of customers for PMPL has grown less than 1 percent per year during the last decade. The growth rate of customers has been even slower (less than 0.5 percent) in the last 5 years. The customer growth has primarily been in the large commercial sector where the customers have grown at an annual compound rate if 3.4 percent since 2005.

Table 8-14 Residential Loads

YEAR	RESIDENTIAL SALES (MWH)	INCREMENTAL RESIDENTIAL SALES (MWH)	HDD	RESIDENTIAL CUSTOMERS
2005	13,464	--	6,825	1,359
2006	14,600	1,136	7,753	1,375
2007	15,235	1,772	7,706	1,376
2008	17,767	4,304	7,892	1,368
2009	20,559	7,097	7,657	1,367
2010	18,887	5,414	7,019	1,366
Average 2000 - 2010			7,398	

Sales to harbor customers have grown at an annual compound rate of 5.16 percent in the last 5 years. PMPL expects continued, but slower, growth in this sector in the near future.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase absent additional conservation and energy efficiency efforts, which will be covered separately.

Based on the above analysis, Black & Veatch forecasts that 2011 residential sales will be 1,000 MWh higher than those for 2009 and increase at 1 percent annually thereafter reflecting electric heat conversions in 2011, average weather, and a decreasing number of customers with a continued increase in the use per customer. The 2011 small commercial sales are forecast to be 200 MWh higher than those for 2009 and increase 1 percent annually thereafter reflecting electric heat conversions in 2011, average weather, a steady number of customers, and increase in use per customer. The 2011 sales to large commercial customers is forecast to be 300 MWh higher than 2009 and increase 2 percent annually thereafter reflecting increased loads associated with the fishing industry, and continued conversion to electric heat. Harbor loads are projected to increase 0.5 percent annually applied to the 2009 harbor load reflecting continued increases in the fishing industry. Interruptible sales to the municipal pool are projected to remain at 2010 levels.

Black & Veatch was informed that station service includes the energy consumption from the PMPL office in the Main Street building. Black & Veatch was also informed that annual usage from street lights and lighting are included within the annual system loss figures reported by PMPL. In 2010, the total annual usage from street lights (and reported as part of system losses) was 341 MWh.

Overall, PMPL's NEL is forecast to increase by an annual compound growth rate of 2.4 percent from 2010 to 2015.

Based on the above assumptions and information, Black & Veatch has made the following forecasts for this period:

- The number of residential customers will remain the same or decrease during this period.
- This is consistent with the ADL projections which indicate a loss of 3 percent in population during this period.
- System losses will not improve and will be at the same level as 2010 for every year in the period, which is 8.6 percent of the annual sales forecast.
- The load factor is assumed to be same as 2010 level for all years in this period.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the population forecast by ADL, the population of the region (Wrangell and Petersburg together) is likely to reduce from 5,785 people in 2015 to 5076 people in 2030. Following this trend, Black & Veatch expects that the population will likely go down to approximately 4,900 people by 2035. This shows that the population will shrink by 15 percent in these 20 years. These population projections are indicative of continuing economic decline. While the ADL projections represent a significant forecasting effort, Black & Veatch believes that the fishing industry will continue to improve modestly through this period, subject to ups and downs in the catch each year. Black & Veatch feels that this modest improvement will allow for continuing use per customer for residential customers to be sustained. There will likely be a corresponding increase in the use per customer for commercial loads as the fishing industry continues to modestly improve through time.

Load factors are expected to remain fairly constant through this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- NEL will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers will decline in relation to the ADL population projections.
- Use per residential customer will increase due to the ever increasing uses of electricity coupled with some economic sustainability from the fishing industry. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- System losses will continue to remain at current levels.

2036-2060 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts moderate growth in the number of customers and use per customer for residential and commercial sectors at 0.2 percent for the number of customers and use per customer, resulting in a 0.4 percent annual increase in NEL. System losses will continue to remain at current levels. Load factor will continue to remain at current levels.

The annual energy and peak projections are presented in Table 8-1 and 8-2, respectively.

8.2.2.2 High Scenario Load Forecast

Black & Veatch developed the high scenario load forecast for PMPL based on the assumptions indicated earlier in the general description section. The population of the Wrangell Petersburg Area, as projected by the ADL, is expected to decrease from 5,766 persons in 2010 to 5,076 persons in 2030. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will grow at the same annual rate as is forecast for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high case is 55,630 MWh in 2011 and it increases to 122,266 MWh in 2061. In the Reference Scenario Load Forecast, the NEL forecast for 2011 was 54,750 MWh in 2011 and 70,963 MWh in 2061. This shows that NEL for the high scenario is 1.0 percent higher in 2011 and 72.3 percent higher in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.2.3 Wrangell Municipal Light & Power

8.2.3.1 Reference Scenario Load Forecast

To develop the Wrangell load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with Wrangell Municipal Light & Power (WMLP). Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this Reference Scenario Load Forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by wholesale power purchase from SEAPA.

2011-2015 – Short Term

During this period it was assumed that the peak and energy demand would generally follow a similar pattern as in 2010; the usage pattern is unlikely to change significantly in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained from WMLP. It is also assumed that no significant new distribution upgrades would be possible within this time frame and so, system loss patterns are unlikely to improve during this time frame as compared to 2010.

According to the population forecast by ADL, the population is likely to decrease by approximately 4 percent from 2006 levels between 2010 and 2015.

According to the information received from WMLP, the main commercial demand for electricity comes from the fishing industry for refrigeration. However, this demand is seasonal and dependent upon the price of fuel in the region. Competitive fuel prices compared to other nearby regions are likely to increase activity of the fishing fleet and the increased volume of fish increases the demand for electricity and vice versa. In the past the region has been able to provide fuel at competitive prices, which has resulted in higher demand. Black & Veatch has assumed that this trend is likely to continue during this period.

Trident Seafoods is expanding its fishing operations in Wrangell. They are also developing new bunk houses for workers working in the canneries, which are expected to increase load during this period.

WMLP indicated that approximately 12 percent of small commercial buildings and 8 percent of residential homes have converted to electric heating. It costs about $5,000 to convert to electric boiler heating in homes.

WMLP estimates that 95 percent of customers who installed electric heating took out the oil heating system altogether; so they do not have duel fuel systems. Based on this information, it can be inferred that few houses use electric heating systems, but many houses would likely convert to electric heating if in the future the price of electricity was low compared to fuel oil and people can afford to spend the capital investment required. However, WMLP has indicated that most of the customers who are likely to convert to electric heating systems have probably done so in the last few years, and WMLP does not expect energy demand to grow due to this practice.

In evaluating WMLP's historical residential loads, there are two places that electric resistance heat is evident. First, are the Residential Heat Rate customers. These are customers that are converting to electric heat and need larger service installed and are billed separately for the electric heat. In 2010, of WMLP's 1059 residential customers, 71 or 6.7 percent were on the Residential Heat Rate. Table 8-15 presents data on WMLP's Residential Heat Rate customers.

Table 8-15 Residential Heat Rate Customers

YEAR	NUMBER OF CUSTOMERS	USE PER CUSTOMER (MWH)	HEATING DEGREE DAYS(1)
2007	9	36.00	9,617
2008	51	31.97	9,861
2009	64	27.72	9,743
2010	71	24.77	8,965

(1)HDDs were not available for June and July of 2009. Number of HDDs for 2009 assumes the average for June and July for 2007, 2008, and 2010. The number of HDDs for 2007 through 2010 respectively not including June and July are 9,065, 9,167, 9,132 and 8,109. Annual average HDDs are 8,056.

The data in Table 8-15 indicate the largest heating loads were the first to convert and that HDDs have a significant impact on the use per customer. In addition, high oil prices have the largest impact on the number of customers converting to the Residential Heat Rate. Using 2008 and 2010 for interpolation yields a use per customer at average HDDs of approximately 17.5 MWh per year.

The other place that electric heat is evident is for the customers that do not need larger electric service to install electric heat and those customers that supplement their oil heat by using portable electric heaters. Table 8-16 presents WMLP's Residential Load.

Table 8-16 Residential Load

YEAR	RESIDENTIAL SALES (MWH)	INCREMENTAL RESIDENTIAL SALES (MWH)	RESIDENTIAL HEAT RATE USE PER CUSTOMER (MWH)	POTENTIAL ELECTRIC HEAT CUSTOMERS	TOTAL RESIDENTIAL CUSTOMERS	PERCENT WITH ELECTRIC HEAT
2006	7,836	--	--	--	--	
2007	8,857	921	36.00	26	1,050	2,4
2008	9,632	1,696	31.97	53	1,054	5.0
2009	11,098	3,162	27.72	114	1,050	10.9
2010	10,001	2,665	24.77	108	1,053	10.3

Therefore, considering the Electric Heat Rate customers, it is estimated that a total of approximately 17 percent of WMLP's customers had electric heat in 2010. This estimate is higher than the 8 percent estimated by WMLP due to the inclusion of residential customers that are using electric heat, but not on the Residential Heat Rate.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase absent additional conservation and energy efficiency efforts, which will be covered separately.

Black & Veatch also discussed the possibility of users replacing incandescent bulbs with energy efficient bulbs, which would reduce lighting loads. Based on that discussion, Black & Veatch assumed that only a small number of people will actually do this without an external program during this time frame, and the demand will not be significantly impacted on account of this. However, WMLP indicated that there is a plan to convert city lights to LED lighting systems over the next couple of years. This will likely reduce the system energy demand, as LED bulbs are more energy efficient.

Historically, NEL has grown over the last decade with an annual compound growth rate of 3.6 percent. Within that period, NEL grew at an annual compound rate of 0.1 percent from 2000 to 2005, but increased rapidly at an annual compound rate of 7.2 percent between 2005 and 2010. Sales by sector in 2010 were as follows:

- Residential 44.2 percent
- Small Commercial 25.5 percent
- Large Commercial and Industrial 15.0 percent
- City Facilities 13.5 percent
- Others 1.8 percent

As seen, the residential and commercial sectors have the largest influence on NEL. The commercial sector is heavily driven by the fishing industry with commercial sales declining since 2007 corresponding to high cost of fuel in 2008 and the economic crisis. Residential sales, excluding Residential Heat Rate customers, decreased an average of 1.9 percent per year from 2000 through 2005. For 2005 through 2010, when the effects of switching to electric heat due to high oil prices is more prevalent, residential sales excluding Residential Heat Rate customers increased an average of 8.1 percent per year. During the same period, residential customer sales increased only 0.2 percent per year.

Black & Veatch reviewed the historical trends in number of customers by customer class and their annual electricity usage trends. Historical data for customers and their usage were available since 2004. Residential and large commercial and industrial customers have remained fairly constant during the period 2004 and 2010. The usages for residential customers have increased 7 percent during this period, while usage for large commercial customers has decreased by 1.2 percent in the same period.

Small commercial customers have grown by 4.5 percent between 2004 and 2010. However, use per customer has declined by 3.4 percent during this period for this customer class.

New classes of customers were created in 2007 for those who use electric heating systems in their houses. These customers would pay 8 cents/kWh for using electricity to heat their homes. So far, 71 of the 1,059 residential customers have converted to electric heating systems under the Residential Heat Rate. Though the number of customers have increased to 71 during this period, the use of electricity per customer for heating homes have decreased from 36 MWh annually in 2007 to 24.8 MWh in 2010, probably indicating that the largest heating customers converted first since they had the most to save.

Small commercial customers have also shown same trends in converting to electric heating systems. Only 27 of the 605 small commercial customers have converted to electric heating systems during the last three years.

Overall, the total numbers of customers have increased by 4 percent between 2004 and 2010, which is driven primarily by increase in small commercial customers. Usage per customer for all customer classes has increased by 2 percent. This increase includes the impact of additional use by some customers for converting their home heating systems to electric heating systems.

In conversation with WMPL, Black & Veatch also obtained some preliminary usage data for the first eleven months of 2011. According to WMPL, the annual energy demand for the WMPL fiscal year 2010-2011, which ends on June 30, 2011, is expected to be around 32,000 MWh. In the first 11 months of the fiscal year, the annual usage has been 30,800 MWh approximately. The total number of residential customers in 2011 remained mostly the same as that of 2010. However, residential heat rate customers declined by 10 percent in April 2011 from 2010 levels (71 customers). Commercial customers have declined from 605 in 2010 to about 544 customers in April 2011. Other categories of customers have remained fairly flat except city small commercial customers. The number of customers in this class has increased to 165 from 134 in 2010.

Black & Veatch also compared the monthly total usage data for the first five months of 2010 and 2011 (Table 8-17). On a month-to-month comparison, the total monthly energy demand has gone up significantly in 2011 compared to 2010. In March 2011 usage was almost 44 percent higher than the corresponding figure of 2010. In general the usage has been 15-25 percent in the higher months.

Table 8-17 Comparison of Monthly Usage in 2010 and 2011 (January-May)

MONTH	2011 USAGE (MWH)	2010 USAGE (MWH)	ADDITIONAL USAGE IN 2011 (MWH)	PERCENTAGE INCREASE IN 2011
January	3,573	3,009	564	18.7%
February	2,976	2,595	381	14.7%
March	3,154	2,191	963	44.0%
April	2,895	2,316	579	25.0%
May	2430	2,079	351	16.9%

The increase in annual energy demand for 2011 can be mainly attributed to two different factors:

- More severe weather conditions in 2011.
- Additional load from new or expanding facilities.

Black & Veatch compared the HDD data for the first five months of 2011 to those of 2010. The comparison is shown in Table 8-18.

Table 8-18 Comparison of Monthly HDD in 2010 and 2011 (January-May)

MONTH	2011 HDD	2010 HDD	ADDITIONAL HDD IN 2011	PERCENTAGE INCREASE IN HDD IN 2011
January	1,136	1,015	121	11.9%
February	1,102	866	236	27.3%
March	1,049	947	102	10.8%
April	850	787	63	8.0%
May	615	566	49	8.7%

Based on the comparison of monthly HDDs, it can be inferred that the winter and spring months in 2011 experienced more severe weather compared to 2010. In general, HDD in 2011 was about 10 percent more than 2010 in all months compared except February, when the number of HDD increased by approximately 27 percent. The severe weather conditions impacted customer usage as more people used electricity to heat their homes more often compared to 2010.

At the same time the oil prices in 2011 are higher compared to 2010. The current oil price is around $4.44/gallon and this is almost 25 percent higher than that of last year, when oil prices were on average $3.40/gallon. Therefore, due to higher oil prices, more people switched to electric heating systems from oil based heating systems. While many customers have switched to electric resistance heating systems at home, many customers are likely to use small inexpensive space heaters which increased the load on the system for 2011. However, these customers using electric space heaters would revert back to using oil based heating systems when oil prices dip down in future. So some of this demand increase is temporary and is due to reactive customer response to increasing oil prices.

In addition to increased usage due to weather, monthly usage in 2011 has gone up because of new commercial facilities becoming operational in the area. Black & Veatch learned from WMPL that Trident Seafood load has gone up by approximately 30 percent this year due to an increase in the commercial activities mentioned above. Trident generally uses around 1,400 MWh annually; additional 30 percent usage will be likely to increase the annual energy usage by another 420 MWh. A new harbor, Heritage Harbor, has been set up and will have a likely load of 500 kW. However, the harbor facility is only going to be operational for the summer months. In addition to the above, a fire building and a school building are also operational, which is impacting the annual energy sales of WMPL.

Based on the above analysis, Black & Veatch projects WMPL's NEL from existing customers to increase by approximately 2.3 percent in 2011, followed by a 1.5 percent growth in 2012. The 2.3 percent increase is the same as from 2009 to 2010, but represents a larger increase when normal weather is considered since 2010 HDDs were still 11.2 percent above normal. The projected 2011 and 2012 increases are assumed to be driven by further conversion to electric heat resulting from high oil prices. Black & Veatch assumes that much of this conversion will be through the use of portable electric space heaters and will not be as permanent as much of the prior conversion. The 2013 NEL for existing customers is projected to be flat relative to 2012 and 2014 and 2015 are projected to each decrease 0.5 percent annually as oil prices return to normal and customers discontinue the use of portable electric space heaters. These projections are based on assumed short-term oil prices, which are impossible to accurately predict. In addition, as electric heat load grows on WMLP's system, the influence of weather significantly outweighs actual growth and makes it very difficult to determine actual growth trends. Non-heating loads are generally predicted to decline with decreases in population as forecast by ADL. This generally reduced load associated with decrease in population is offset by gains in the fishing industry. NEL could be steady towards the end of the period if the economy strengthens.

In addition to load growth from existing customers, Black & Veatch forecasts load growth from new customers as well. Trident's new facility is expected to use an additional 420 MWh in 2011. According to WMLP, Trident load is expected to increase by 1,500 kW in 2012, after which it is expected to remain flat until 2015. The new load is expected to have a load factor of 85 percent in the months of July and August every year, but will have no usage in the other 10 months of the year.

The Heritage Harbor, which has an expected demand of 600 kW, is expected to have a load factor of 25 percent as it is going to be operational in summer months only. Based on this assumption, Black & Veatch forecasts that the additional load from the harbor facility would be approximately 1,314 MWh in 2011. The harbor load is also expected to go up by 2 percent in 2012, after which it is expected to remain flat until 2015.

A new public safety building is expected to be completed in 2011. The expected demand from this new building is 350 kW with an annual load factor of 42 percent in 2011. The energy usage in this building is expected to increase by 2 percent in 2012 and 2013 and is then expected to remain flat until 2015.

The AICS building expected to be completed in 2011 is expected to have an additional demand of 300 kW with a load factor of 42 percent in 2011. The energy usage in this building is expected to increase by 2 percent in 2012 and 2013 and is then expected to remain flat until 2015.

A new school is expected to begin operations in 2011, and the new expected load in 2011 is 750 kW with a load factor of 42 percent. The annual energy usage is expected to remain flat until 2015.

The James and Elsie Nolan Center (Nolan Center) is a state-of-the-art facility that houses the Wrangell Museum, the Wrangell Visitor Center, and the Convention Facility. The Nolan Center facility is expected to have additional load of 350 kW in 2011 with an expected load factor of 42 percent. Black & Veatch expects this load to increase by 2 percent in 2012 and to remain flat until 2015.

A new hospital is expected to be operational in 2012. The new load from the hospital is expected to be 500 kW with a load factor of 42 percent in 2012. Black & Veatch expects the annual energy usage to go up 5 percent in 2013 and by 2 percent in 2014 as the hospital expands its services and has higher number of patients. However, the energy usage is likely to remain flat in 2015 as the energy usage from the hospital stabilizes.

All new developments that are expected to be operational in 2011 will do so in the second half of the year. Therefore, Black & Veatch has only considered 50 percent of their expected annual load for 2011 to forecast their annual energy usage for the year.

According to the "The Alaska Village Electric Load Calculator" Report published by National Renewable Energy Laboratory (NREL) in October 2004, the average annual electricity consumption in a large city or government offices in rural Alaska is approximately 21,400 kWh. Assuming that the new fire building will be a large city office type building and assuming that the usage rate has increased by 20 percent since 2004, the annual energy demand for the school is expected to be approximately 25,675 kWh per year. This demand is expected to remain flat until 2015.

Based on the above assumptions and information, Black & Veatch has made the following forecasts for this period:

- The number of customers will decrease during this period. This is consistent with the ADL projections which indicate only a loss of 4 percent in population during this period from 2006 levels.
- As number of customers decreases, it will offset the increased usage by continuing customers on account of using electric heating systems in homes.

- Expanding operations by Trident Seafoods will likely increase the energy demand for all years in this period.
- No significant increase in demand is expected due to more homes.
- Conversion to electric heat will continue primarily through the use of portable electric heaters corresponding to high oil prices during the early portions of the period.
- System losses will not improve and will be at the same level as 2010 for every year in the period, which is 6 percent of the annual sales forecast.
- The resulting NEL reduces during the end of the period due to the discontinuance of use or portable electric heaters due to oil prices returning to normal levels.
- Usage by small commercial customers will likely remain flat, unless the economy of the region improves significantly.
- Load factors are assumed to remain at historical levels. No data on historical annual system peak or load factor was available to us. Black & Veatch assumed an average annual load factor of 52 percent for all years and estimated the annual peak demand based on this assumption.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the population forecast by ADL, the population of the region is likely to reduce from 5,785 people in 2015 to 5,076 people in 2030. Following this trend, Black & Veatch expects that the population will likely go down to approximately 4,900 people by 2035. This shows that the population will shrink by 15 percent in these 20 years. These population projections are indicative of continuing economic decline. While the ADL projections represent a significant forecasting effort, Black & Veatch believes that the fishing industry will continue to improve modestly through this period subject to ups and downs in the catch each year. Black & Veatch feels that this modest improvement will allow for continuing use per customer for residential customers to be sustained as new residential loads develop. There will likely be a corresponding increase in the use per customer for commercial loads as the fishing industry continues to modestly improve through time.

Load factors are expected to remain fairly constant through this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual energy demand will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers will continue to decline in relation to the ADL population projections. By end of 2035, population is expected to decrease by 15 percent from 2006 levels.
- Use per residential customer for non-electric heat loads will likely increase due to oil prices going back to medium levels and the ever increasing uses of electricity coupled with some economic sustainability from the fishing industry. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- Use per commercial customer will likely increase slowly as a direct effect of being mitigated by fewer residential customers.

- System losses will remain at historical levels of approximately 6 percent.
- Resulting NEL will increase very modestly during this period by an average of approximately 0.2 percent per year.
- Load factors are assumed to remain at historical levels. No data on historical annual system peak or load factor was available to us. So Black & Veatch assumed an average annual load factor of 52 percent for all years and estimated the annual peak demand based on this assumption.

2036-2061 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts moderate growth in the number of customers and use per customer for residential and commercial sectors. Black & Veatch has therefore assumed that the overall energy sales will grow at 0.25 percent per year. System losses are assumed to remain at historical levels.

Load factors are assumed to remain at historical levels. No data on historical annual system peak or load factor was available to Black & Veatch. So an average annual load factor of 52 percent was assumed for all years; and the annual peak demand estimate was based on this assumption.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

It should be noted that as electric heat becomes a larger component of WMLP's load, variances in weather will have a greater and greater influence on loads making it more difficult to determine actual trends. While there was no attempt to specifically provide the impact from weather in this forecast because experience has indicated that the small sample size would preclude statistically significant results, it may be prudent to attempt to quantify the impact from weather as electric heating becomes a more significant part of WMPL's load.

8.2.3.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for WMLP based on the assumptions indicated earlier in the general description section. The population of the Wrangell Petersburg Area, as projected by the ADL is expected to decrease from 5,766 persons in 2010 to 5,076 persons in 2030. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will decrease at the same annual rate as is forecast for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high scenario is 34,849 MWh in 2011, and it increases to 87,059 MWh in 2061. In the Reference Scenario, the NEL forecast for 2011 was 34,501 MWh in 2011 and 49,630 MWh in 2061. This shows that NEL for the high case is 1.0 percent higher in 2011 and 75.42 percent higher in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.3 ALASKA POWER AND TELEPHONE (AP&T)

8.3.1 Prince of Wales Island

8.3.1.1 Reference Scenario Load Forecast

The following communities are located within the Prince of Wales Island region and included in Black & Veatch's Prince of Wales load forecasts:

- Coffman Cove
- Craig
- Hollis
- Hydraburg
- Kasaan
- Klawock
- Naukiti Bay
- Thorne Bay
- Whale Pass

All communities except Coffman Cove, Naukiti Bay, and Whale Pass are interconnected with each other. The interconnection for Coffman Cove is under construction, and Naukiti Bay will be interconnected in 2012. The forecast developed for Prince of Wales Island is exclusive of the load for Whale Pass, which is presented separately.

To develop the forecast, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with AP&T, which serves the above communities on the POW Island. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this Reference Scenario Load Forecast, Black & Veatch assumes that there are no significant changes in the cost of power, and power continues to be supplied by the same resource generation mix as in 2010.

2011-2015 – Short Term

During this period, it is assumed that the peak and energy demand would follow a similar pattern as in 2010; usage pattern is unlikely to change in this time frame. Black & Veatch considered additional load demand from any potential new projects that are expected to be operational within this time frame. It is assumed that no significant new distribution upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

Historically, NEL from the interconnected part of the Prince of Wales Island has grown with an annual compound growth rate of 0.8 percent in during the last decade.

The annual sales to residential customers have grown at an annual compound rate of 1.5 percent over the last decade and have grown steadily every year, except for dropping off in 2008 and 2010. While residential sales have shown growth in the last decade, demand from commercial sector sales has dropped from those of the earlier portions of the decade. However, sales to the commercial sector have increased the last 3 years. The number of total customers has grown an average of 1.7 percent annually during the last decade and has increased every year indicating modest, but continued, growth.

According to the population count developed by the ADL, the population of the region, which includes outer Ketchikan, has declined by 4 percent between 2006 and 2010. ADL has forecast that the population will decrease by approximately 5.0 percent of 2010 levels between 2010 and 2015. While AP&T agrees that the population declined from 2005 to 2010, AP&T believes the population is likely to increase in the near term due to a surge in recent economic activities in the region. The region has the only large operating sawmill in Southeast Alaska. The timber industry, which was badly affected by the recent economic downturn, has started to grow again and this has started to attract people from other areas to move into the community. Moreover this saw mill site has been marked for development of biomass and wood waste products, which would also create new employment opportunities in the region. Activities in the fishing industry have also picked up. Due to high oil prices, seafood companies are moving the fish processing activities closer to the fishing areas from bigger cities to avoid transportation costs associated with transporting raw fish from fishing sites to processing plants. As such, most of the fish processing activities these days are done near the fishing sites. This shift in processing activities to local fishing regions is expected to bring in people from outside and increase population in the near term. Recent trends also show that there is a growing market for protein from lower value salmon. The processing and shipping of pink salmon is a relatively new commercial activity, which is likely to grow rapidly during this period and then slow down subsequently after the industry matures in 4 to 5 years.

Based on the above discussion, Black & Veatch believes that the population will grow approximately 3 percent of 2010 levels by 2015. Current population on the island is around 5,560 people. With a 3 percent increase in population, the total population is expected to increase around 5,700 people by 2015. It is assumed that the total number of customers will also increase by the same figure.

While it is believed that electric heat is minimal on Prince of Wales, in order to understand the usage pattern of customers, HDDs still need to be analyzed. Table 8-19 shows the HDD for years 2000 to 2010 for Craig. Table 8-19 also shows the annual usage per customer by year from 2000 to 2010.

Table 8-19 HDD and Usage Per Customer

YEAR	ANNUAL HDD	USAGE PER CUSTOMER MWH/YEAR
2000	7,162	12.70
2001	7,227	11.67
2002	7,387	10.97
2003	7,196	10.53
2004	6,835	10.52
2005	6,769	10.54
2006	7,573	10.67
2007	7,391	11.00
2008	7,563	10.58
2009	7,446	10.51
2010	6,598	10.24
Average (2000-2010)	7,195	

In evaluating Table 8-19, it is noted that in 2010, the usage per customer was the lowest of the decade, but HDDs were also the lowest of the decade. In 2010, use per customer was only 3 percent lower than that of 2009 even though the annual number of HDD was 10 percent lower indicating the potential for underlying growth. The economic downturn occurred in 2008, as well as the high run up in oil prices. The high oil prices were also coincident with a much larger than normal use of oil by AP&T due to lower hydroelectric generation which resulted in higher electric rates. The economic down turn and the higher cost of electricity served to outweigh the high number of HDD days and reduced use per customer.

Based on the above analysis and assuming continued economic recovery, Black & Veatch projects that the average usage per customer in an average weather year in 2011 to be 10.5 MWh/year. Black & Veatch has assumed that this to be the base usage of customers.

The base usage is likely to increase because of a number of factors. AP&T informed Black & Veatch that it has observed changes in usage patterns among customers due to lifestyle changes. Customers are now using more lights and other electric and electronic gadgets than they have ever used before. This is causing additional load demand on AP&T system. In discussion with AP&T, Black & Veatch forecasts that the usage per customer will increase by 1.5 percent every year through 2015.

According to information received from AP&T, only 1 percent of the customers have switched from oil fired home heating systems to electric resistance heating systems. Unlike some of the other regions, where retail electric rates are as low as 7 cents/kWh, the retail electricity rate in POW is around 21 cents/kWh. Due to the higher electricity rates, most people in the region have not converted their existing oil or wood fired heating systems to electric heating systems. However, some use of portable electric space heaters is likely if oil prices are extremely high and electricity rates remain relatively low due to ample hydroelectric generation reducing the amount of diesel burned. People are likely to turn down their whole house oil heat and supplement in individual rooms with portable electric space heaters. Black & Veatch projects 10 percent of the customers will supplement to a small degree with portable electric space heaters in 2011 and 2012 with the number reducing to 5 percent in 2013 and back to 0 thereafter as oil prices return to normal. The average annual use for this supplement space heating is estimated to be 1.5 MWh per customer.

Black & Veatch discussed with AP&T potential new load that is likely to be added on to the AP&T system during this period. AP&T informed Black & Veatch that one fish processing plant will convert their mechanical driven refrigeration to electrical 2012 with the total sales to the facility 1000 MWh annually. Black & Veatch has considered this load growth in its forecast. Black & Veatch has assumed that this new load will grow at 2 percent every year until 2015.

Growth is further bolstered by the interconnection of Coffman Cove in 2011 and Naukiti Bay in 2012, the existing loads of which are already included in AP&T's existing load data. The lower cost power after interconnection will increase per use customer and enhance economic development in these communities. There may be slight decreases in sales for the rest of the system due to the slight increase in cost for the rest of the system due to the interconnections, but overall there should be some increase in load. This increase has not been explicitly included in the projections.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Losses on a percentage basis will increase with the interconnection of Coffman Cove and Nautiki Bay due to their relatively longer transmission line interconnections. Based on evaluation of historical losses, Black & Veatch projects losses to be 8 percent in 2011, 8.5 percent in 2012, and 9 percent in 2013 and beyond, reflecting the interconnections being placed in service during the 2011 and 2012 calendar years.

Based on the above analysis, Black & Veatch projects AP&T's NEL to increase from 27,921 MWh in 2010 to 32,599 MWh in 2015. This is equivalent to an annual compound growth rate of 3.0 percent.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the population forecast by ADL, the population of the region is likely to decrease from 4,996 people in 2015 to 3,894 people in 2030. If this trend is followed, the population will likely go down to approximately 3,500 people by 2035. This shows that the population will decrease by approximately 22 percent in these 20 years. These population projections are indicative of expected economic growth in the region. While the ADL projections represent a significant forecasting effort, Black & Veatch believes that the expected growth of the economy in the region in the period 2011-2015 will continue to improve modestly or hold steady throughout this period subject to ups and downs in the fish catch each year. Because of this, Black & Veatch is of the opinion that the population in this period will either hold steady or increase slowly rather than decrease. Load factors are expected to remain fairly constant through this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- New mining activity is expected in the system at the Bokan Mountain and Niblack mines. The development of new mining loads is subject to the mines receiving all necessary permits and decisions and investments made to proceed with the development. There is also uncertainty as to whether AP&T will supply the mines and development of transmission or distribution lines to the mines. Based on discussions with AP&T, for forecasting purposes a new 2 MW mine load is projected to start in 2018. A 60 percent load factor has been assumed, resulting in total annual energy sales of 10,512 MWh. This load is expected to remain flat during this period. Because of the speculation associated with new mine development, this scenario assumes that no new mining loads develop.
- The annual sales to all customers, except the new mining facility, will increase at 0.2 percent annually from 2016-2035.
- The number of residential customers is expected to begin to decline, based on the ADL population projections, but at a slower rate than the ADL population projections due to carryover from the more robust economic development projected in the short term.
- Use per person will likely increase because of the ever-increasing uses of electricity, coupled with some economic sustainability from the industries in the region. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- System losses are expected to remain at 9 percent of annual sales
- Load factor on the system is expected to remain constant during this period, but would be significantly influenced by mining loads.

2036-2061 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts flat or declining growth in number of customers. Use per customer for residential and commercial sectors is expected to grow slowly. Black & Veatch has, therefore, assumed that the total annual energy sales will grow at 0.5 percent per year during this period, reflecting static economic development. System losses are assumed to remain at 9 percent per year and the load factor to remain constant throughout the period.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.3.1.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Prince of Wales based on the assumptions indicated earlier in the general description section. The population of Prince of Wales, as projected by the ADL, is expected to decrease from 5,261 persons in 2010 to 3,894 persons in 2030. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will grow at the same annual rate as is forecast for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1 percent load growth in every year in the study period over the corresponding forecast for the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high case is 29,382 MWh in 2011, and it increases to 97,504 MWh in 2061. In the Reference Scenario, the NEL forecast for 2011 was 29,089 MWh in 2011 and 38,512 MWh in 2061. This shows that the additional energy demand for the high case is 1.0 percent higher in 2011 and 75.3 percent in 2061 compared to the energy demand forecast in the original case for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.3.2 Whale Pass

8.3.2.1 Reference Scenario Load Forecast

The Whale Pass community is a standalone community on Prince of Wales Island and is not interconnected with any other communities in Prince of Wales.

To develop the Whale Pass load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with AP&T, which serves Whale Pass and all other communities on Prince of Wales Island.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by the same resource generation mix as in 2010.

2011-2015 – Short Term

During this period, it is assumed that the peak and energy demand would follow a similar pattern as in 2010; usage pattern is unlikely to change in this time frame. Black & Veatch considered additional load demand from any potential new projects that are expected to be operational within this time frame. It is assumed that no significant new distribution upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

NEL for Whale Pass peaked in 2005 and has steadily declined since. Overall, the total number of customers has remained fairly flat since 2004.

In conversation with AP&T, Black & Veatch established that ecotourism is on the increase in the region right now. Apart from the tourism industry, there is not much commercial development in the region, and there are not many opportunities for long term population increase. Currently there are only 69 customers for AP&T in this community. Due to growth in ecotourism, Black & Veatch expects that the number of customers will increase to 80 customers by 2015.

Black & Veatch expects the use per customer for 2011 to be the average of the usage in 2009 and 2010, which is 3.03 MWh/year. It is expected to remain constant until 2015.

With Whale Pass's high rates, there will not be any significant use of electric heat. The low use per customer minimizes any savings for weatherization or energy efficiency. The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts which will be covered separately.

Black & Veatch noted that system losses in 2010 were approximately 23.3 percent of annual sales, which is much higher compared to other regions on Prince of Wales Island served by AP&T. Since Whale Pass is not interconnected to other communities on Prince of Wales, Black & Veatch is of the opinion that the system losses will not improve in this period.

Based on the above analysis, Black & Veatch projects AP&T's NEL to increase from 253 MWh in 2010 to 299 MWh in 2015 because of additional customers and economic development associated with eco tourism. This is equivalent to an annual compound growth rate of 3.2 percent.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual sales to all customers will increase at 0.5 percent annually from 2016-2035.
- The number of customers is expected to remain flat at the 2015 levels.
- Use per person is likely increase due to the ever-increasing uses of electricity, coupled with some economic sustainability. Naturally occurring conservation will mitigate large increases in use per customer as customers slowly become able to afford more conservation.
- System losses are expected to remain at 23 percent of annual sales.
- Load factor on the system is expected to remain constant during this period.

2036-2061 – Long Term

Black & Veatch forecasts slow growth in the number of customers and use per customer for residential and commercial sectors. Black & Veatch has, therefore, assumed that the total annual energy sales will grow at 0.2 percent per year during this period. System losses are assumed to remain at 23 percent per year and the load factor to remain constant throughout the period.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.3.2.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast scenario for Whale Pass based on the assumptions indicated earlier in the general description section. The population of Whale Pass was approximately 69 persons in 2010. As in the Reference Scenario assumptions, Black & Veatch has assumed that in this case, too, the population will increase to 80 persons by 2015. Beyond 2015, the population is expected to increase by 0.5 percent annually until 2020 and then remain flat until the end of the study period. Black & Veatch used this population projection and the other assumptions as indicated in the general description section to forecast the additional loads from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional one percent growth in load for every year in the study period over the corresponding loads in the original case. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL for the High Scenario is forecast to be 268 MWh in 2011 and 716 MWh in 2061. In the Reference Scenario the NEL forecast was 266 MWh in 2011 and 347 MWh in 2061. This shows that the additional energy for the high case is 1.0 percent higher in 2011 and 106 percent in 2061 compared to the energy forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.3.3 Haines-Skagway

8.3.3.1 Reference Scenario Load Forecast

To develop the load forecasts for Haines and Skagway, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with AP&T, which serves both communities. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by the same resource generation mix as in 2010.

2011-2015 – Short Term

During this period, it is assumed that the peak and energy demand would follow a similar pattern as in 2010; usage pattern is unlikely to change in this time frame. Black & Veatch considered additional load demand from any potential new projects that are expected to be operational within this time frame. It is assumed that no significant new distribution upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

Historically, NEL from the two communities together has grown with an annual compound growth rate of 2.2 percent in during the last decade. Within that period, NEL grew at an annual compound rate of 0.32 percent between 2000 and 2005, and grew at an annual compound rate of 2.23 percent between 2005 and 2010.

The annual sales to residential customers have grown at an annual compound rate of 1.3 percent over the last decade, and at 2.2 percent during the last 5 years. Sales to the commercial sector have also grown over the last decade at an annual average compound rate of 1.9 percent. These commercial sales generally grew through 2008 and then declined in 2009 and 2010.

Total number of customers has grown by 2.23 percent annually since 2000. The growth in customers has been fairly consistent across all years in the period.

According to the population count developed by ADL, the population of the Skagway Hoonah and Angoon areas together has declined by approximately 5 percent between 2006 and 2010. ADL has forecast that the population is likely to decrease by approximately 7.0 percent of 2010 levels between 2010 and 2015. AP&T indicated that the population in Skagway has been decreasing, and the population in Haines has been increasing in recent years. So while the forecast developed by ADL may be true for the whole region, including Hoonah and Angoon, the Skagway and Haines region has seen growth in population as indicated by the increase in customers. The tourism industry has contributed to the growth in population. Skagway, and to a lesser extent Haines, are very dependent upon the cruise ship industry. Recently, retirees have started moving to Haines, and there are several new houses being built in the region. Population is also expected to grow in the region as a new mine is expected to become operational in the next 5 years. In addition, there is an ore terminal in Skagway that accumulates ore from the Southeast and British Columbia. AEDIA owns the terminal is working to expand it. The timber industry, which was badly affected by the recent economic downturn, has started to grow again and this has started to attract people from other areas to move into the area. Although it has less of an impact on Haines and Skagway than some parts of the Southeast, activities in the fishing industry have also picked up. Due to high oil prices, seafood companies are moving the fish processing activities closer to the fishing areas from bigger cities to avoid transportation costs associated with transporting raw fish from fishing sites to processing plants. Because of this, most of the fish processing activities are now done near the fishing sites. This shift in processing activities to local fishing regions is expected to bring in people from outside and increase population in the near term.

Based on the above discussion, Black & Veatch believes that the population in the region will grow approximately 5 percent of 2010 levels by 2015. It is assumed as a result of the increase in population, the total number of customers will also increase by 5 percent during the same period.

While it is believed that electric heat is minimal, HDDs still merit some analysis. Table 8-20 shows the HDD for years 2000 to 2010 for Skagway, and the average annual HDD over the period. The table also shows the annual usage per person by year from 2000 to 2010.

From above, it can be observed that the average annual HDD for the area is 8,461. HDD days for 2010 were significantly below normal, and the use per customer was also down; however, a bigger factor contributing to its downturn was the lower commercial sales which could be attributed to the specifics of the fishing industry. While 2008 was a very severe year for HDDs, the use per customer did not increase appreciably. This would verify the lack of electric heat. The high oil prices in 2008 may have influenced some change in customer behavior with respect to heating and there may have been some purchase and use of portable electric space heaters for minor supplement of oil heat. This could account for the downturn in residential sales in 2010 despite a 2.9 percent increase in number of customers from 2009.

Based on the above analysis, Black & Veatch feels that in 2011, the average annual usage per customer in an average weather year is likely to be approximately 10.25 MWh, accounting for some recovery in commercial sales. Black & Veatch has assumed this to be the base usage of customers.

AP&T informed Black & Veatch that it has observed changes in usage patterns among customers due to lifestyle changes. Customers are now using more lights and other electric and electronic gadgets than they ever used before. This is creating additional demand on the AP&T system. Black & Veatch forecasts that the base usage per customer will increase by 1 percent annually due to these lifestyle changes.

Table 8-20 HDD and Usage Per Customer

YEAR	ANNUAL HDD	USAGE PER CUSTOMER MWH/YEAR
2000	8,401	11.12
2001	8,379	10.75
2002	8,257	10.60
2003	8,082	10.18
2004	7,681	10.17
2005	7,814	10.20
2006	8,908	10.29
2007	8,810	10.33
2008	10,043	10.34
2009	8,650	10.26
2010	8,048	9.65
Average (2000-2010)	8,461	

Black & Veatch discussed with AP&T new loads that are likely to be added on to the AP&T system during this period. AP&T informed that no new developments other than housing developments were planned in the region for this period.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Wholesale sales are projected to increase at 1 percent per year from the 2010 level or approximately half of the rate of increase in retail sales.

System losses are projected to remain at the 2010 levels. Load factor is expected to be the average load factor of 2008-2010 (58.8 percent) and is expected to remain constant throughout this period.

AP&T does not have adequate firm hydroelectric power at this time to serve the peak demand. Haines and Skagway are connected by a submarine cable with all the hydroelectric generation in the Skagway region. AP&T is working to place hydroelectric generation in the Haines region so that if the submarine cable fails, Haines will not be completely dependent upon diesel generation.

Based on the above analysis, Black & Veatch projects APT's NEL to increase from 26,808 MWh in 2010 to 31,098 MWh in 2015. This is equivalent to an annual compound growth rate of 2.7 percent.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the population forecast by ADL, the population of the region is likely to decrease from 4,996 people in 2015 to 3,894 people in 2030. If this trend is followed, the population will likely go down to approximately 3,500 people by 2035. This shows that the population will decrease by approximately 22 percent in these 20 years. These population projections are indicative of economic decline. While the ADL projections represent a significant forecasting effort, Black & Veatch believes that the expected growth of economy in the region in the period 2011-2015 will continue to improve modestly with mining development and the associated ore terminal. As such Black & Veatch is of the opinion that the population in this period will either be steady or decrease slowly. Load factors are expected to remain fairly constant through this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- New mining activity expected to start in 2016 is expected to create an additional 2 MW load on the system. Assuming a 60 percent load factor, the total annual energy demand is expected to be 10,512 MWh and is expected to remain flat during this period. This new mining load is not included in the forecast because of the uncertainty of its development and since many mines are served by dedicated facilities.
- The annual sales to all customers except the new mining facility will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers is expected to remain flat at the 2015 level in contrast to the decreasing ADL population projections due to economic stimulus associated with the new mine development. Use per person will likely increase as oil prices return to medium levels and the ever increasing uses of electricity coupled with some economic sustainability from the industries in the region continue. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- System losses are expected to continue to remain at the same levels.
- Load factor on the system is expected to remain constant during this period.

2036-2061 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts moderately slow growth in the number of customers and use per customer for residential and commercial sectors. Black & Veatch has therefore assumed that the total annual energy sales to all customers will grow at 0.3 percent per year during this period. System losses and load factor will remain constant.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.3.3.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Skagway and Haines based on the assumptions indicated earlier in the general description section. Skagway and Haines areas are served by AP&T. As per ADL, the population of Haines area was approximately 2,095 persons in 2010 and is expected to reduce to 1,571 persons by 2030. The population of Skagway Hoonah and Angoon areas combined was approximately 2,862 persons in 2010 and is expected to reduce to 1,945 persons by 2030. Netting out the population forecast for Hoonah and Angoon areas, Black & Veatch estimated that the population of the Skagway was 1,672 persons in 2010, and that is expected to reduce to 952 persons in 2030. Combining the populations of Haines and Skagway areas, Black & Veatch estimated that the combined population of the two regions would likely decrease from 3,767 persons in 2010 to 2,523 persons in 2030. Beyond 2030, Black & Veatch assumed that the population will decline at the same annual rate as is forecast for the period 2025 to 2030. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional from the penetration of PHEVs. In addition to forecasting the additional load for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in load for every year in the study period over the corresponding load forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL for the high scenario forecast is 29,064 MWh in 2011 and 84,813 MWh in 2061. In the Reference Scenario the NEL forecast was 28,776 MWh in 2011 and 49,441 MWh in 2061. This shows that the additional energy for the high case is 1.0 percent higher in 2011 and 71.6 percent higher in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.4 ALASKA ELECTRIC LIGHT & POWER

8.4.1 Reference Scenario Load Forecast

To develop the Juneau load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with Alaska Electric Light & Power (AEL&P), which serves the cities of Juneau, Douglas, Auke Bay, and the adjacent Greens Creek mine. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing the Reference Scenario Load Forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by the same resource generation mix as in 2009.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2009 as usage pattern is unlikely to change in this time frame. No new information for additional load from new developments was available to Black & Veatch, and so it was not considered for developing the forecast for this period. It is assumed that no significant new distribution upgrades would be possible within this time frame and, therefore, system loss patterns are unlikely to improve during this time frame as compared to 2010.

Black & Veatch looked at historical data from 2000 to 2009. Some historical data was available for 2010, which was also reviewed by Black & Veatch. However for analysis of historical trends Black & Veatch analyzed the data for 2000 to 2009. Historically annual sales for AEL&P have grown with an annual compound growth rate of 1.5 percent in the period 2000 to 2009. Within that period, annual sales grew at an annual compound rate of 0.7 percent from 2000 to 2005, and at an annual compound rate of 0.9 percent from 2005 and 2009.

According to the population forecast by the ADL, the population is likely to increase by approximately 1.1 percent from 2010 and 2015. Population is expected to increase from 31,691 people in 2010 to about 32,078 in 2015. Black & Veatch has assumed that AEL&P customers will also increase by 1.1 percent during this period.

In developing the load forecast for AEL&P for this period, Black & Veatch broken down the causes of growth into five broad areas as follows:

- Change in consumption due to increase in total number of customers.
- Change in sales due to conversion of oil based electric heating system to electric heating system.
- Change in consumption due to people using portable space heaters.
- Change in consumption due to new developments.
- Change in consumption due to local weather conditions.

In order to understand the usage pattern of customers, the HDDs is a key variable that needs to be analyzed. Table 8-21 shows the HDD for years 2000 to 2009 and the average annual HDD over the period and also the annual average HDD of the region from 1961 to 1990. The table also shows the total sales per person excluding Harbor customer sales, Greens Creek sales, and sales to AEL&P themselves (other than station use) by year.

Table 8-21 Annual HDD and Usage per Customer (2000-2009)

YEAR	ANNUAL HDD	USAGE PER CUSTOMER MWH/YEAR
2000	8,332	20.96
2001	8,257	20.56
2002	8,329	20.58
2003	8,303	20.19
2004	7,769	20.12
2005	7,752	20.09
2006	8,946	21.74
2007	8,663	21.64
2008	9,008	20.09
2009	8,588	21.99
2010	8,053	19.71
Average (2000-2010)	8,364	
Average (1961-1990)	8,839	

From the table above, it can be seen that years 2000 to 2003 were close to the average for this period in terms of annual HDD. The usage per customer has remained fairly flat during this period. 2004 and 2005 were relatively warmer years with mild winters. But the usage per customer remained at almost the same level as in previous years, indicating that customers were using more energy during this period for non-heating purposes. This increase in demand correlates well with the boom period of the US economy in that period and therefore the increased usage in electricity per customer is likely to be due to higher economic activities. The economic boom continued until 2007. The years 2006 through 2008 were the coldest in the past decade. In 2006 and 2007, the usage per customer increased and it can be attributed to increased economic activities and the effects of more severe weather conditions. Oil prices also increased in 2006 and 2007 before peaking in 2008 and dropping off in 2009.

It is noted that 2008 was the most severe year in the decade, yet the sales per person was the lowest for this period. This anomaly in the sales trend is due in large part to the avalanche which caused an outage of the transmission line from Juneau's largest hydroelectric plant for six weeks with high cost diesel generation used for the replacement power. A very significant energy reduction plan was placed into service as a result of this outage significantly reducing usage. This reduction in usage carried over even after the transmission line returned to service. In 2010, use per customer decreased due to lower HDDs. Based on the above analysis, Black & Veatch feels that 20 MWh represents a reasonable use per customer in 2011 for a normal weather year. Black & Veatch has used this figure in the forecast to estimate the baseline growth in sales due to increases in population and assumed it to remain flat between 2011 and 2015 since conversion to electric heat is considered separately.

No information for additional load from new developments was available to Black & Veatch and so it was not considered separately for developing the forecast for this period.

According to information received from AEL&P, around 3,500 out of 15,377 customers have switched from oil fired home heating systems to electric resistance heating systems. That shows that around 22.7 percent of the occupied houses have converted to electric heating systems. AEL&P also indicated that the conversion of existing oil based heating systems is heavily dependent on the existing retail price of oil. The tipping point for oil prices for conversions to pick up is around $4.00/gallon.

Currently oil prices are very high. Retail heating oil prices are forecast to be over $4.00/gallon during 2011 and maybe in 2012. However, the prices are unlikely to remain high for long as the case for the last high cycle in oil prices showed in summer of 2008. Back in 2008, the prices off oil fell off by over 75 percent within a year after it reached the peak in May 2008. Black & Veatch expects similar trends, though it is difficult to predict how low the prices will fall. Black & Veatch expects oil prices to come down after 2012. In keeping with this assumption, Black & Veatch expects a high rate of conversion to electric heating systems in 2011 and 2012, but slower rate of conversion after 2012. Black &Veatch forecasts that additional 20 percent customers are likely to convert to electric heating systems between 2011 and 2012, (10 percent every year) after which the conversions would cease. So between 2011 and 2015, an additional 20 percent of the occupied homes would convert to electric heating systems, which indicates that overall, about 42.7 percent of the customers would have converted to electric heating systems by 2015.

Black & Veatch estimated increased sales per customer for concerting to electric heating system from information provided by AEL&P to be 4.4 MWh/year. This allocation per person would also include conversion loads from the commercial sector as well.

In addition to customers converting their oil-based heating systems to electric heating systems, some additional customers are likely to use portable space heaters to heat their homes when oil prices remain high. Unlike converting to electric heating systems, which require high capital investment, portable space heaters are available at very low costs at local stores. This allows for people to buy the space heaters very easily. A 1,000 watt space heater typically uses approximately 244 kWh per month based on 8 hours per day usage. Assuming space heaters will be used typically for 4 months in a year; Black & Veatch estimates the annual space heater use per customer to be 1 MWh. With the high cost of oil in 2011, Black & Veatch estimates that 10 percent of the customers will employ portable space heaters in 2011 with the number dropping to 5 percent in 2012 and going to 0 thereafter.

According to the information received from AEL&P, the main commercial demand for electricity comes from the fishing industry for refrigeration. However, this demand is seasonal and dependent upon the price of fuel in the region. Competitive fuel prices compared to other nearby regions are likely to increase activity of the fishing fleet and the increased volume of fish increases the demand for electricity and vice versa. In the past the region has been able to provide fuel at competitive prices, which has resulted in higher demand. Black & Veatch has assumed that this trend is likely to continue during this period.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

According to AEL&P, the Greens Creek mine is undergoing expansion and after expansion is complete the annual demand from the mine would be 67,000 MWh in 2011. Black & Veatch has assumed that the demand from this mine would remain constant throughout this forecast period as no further development is expected.

Black & Veatch expects harbor customer sales to increase by 2 percent every year until 2015 as there is a general boom in the tourism industry in Alaska, which is likely to continue in the near term.

Black & Veatch has also assumed that the sales to AEL&P themselves (other than station load) will increase by 1 percent every year until 2015.

Since Black & Veatch has estimated the additional use of electricity by customers from using electric heating systems and space heaters, Black & Veatch has kept the usage by dual fuel customers constant at 2009 levels.

Black & Veatch has assumed that system losses will remain constant throughout this period and is expected to be the average of 2008 through 2010 (5.6 percent).

Black & Veatch has assumed that the load factor to be the average of the load factors of 2008 through 2010 (59 percent) and also assumed it to be constant throughout this period.

Based on the above analysis, Black & Veatch projects AEL&P's NEL to increase from 395,271 MWh in 2010 to 441,237 MWh in 2015 including loads for Greens Creek Mine. This is equivalent to an annual compound growth rate of 1.9 percent.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the population forecast by ADL, the population of the region is likely to increase from 32,078 people in 2015 to 32,260 people in 2030. Following this trend Black & Veatch expects that the population will likely grow to approximately 32,325 people by 2035. This shows that the population will grow by 0.8 percent in these 20 years. These population projections are indicative of continuing economic growth in the region.

Based on the above assumptions, Black & Veatch has forecast the following:

- NEL will increase at 0.5 percent annually from 2016-2035.
- System losses will remain constant at present levels.
- Use per customer will likely increase due to oil prices going back to medium levels and the ever increasing uses of electricity coupled with some economic sustainability from the industries in the region. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- Load factor is expected to remain constant at present levels.

2036-2061 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts moderate growth in number of customers and use per customer for residential and commercial sectors. Black & Veatch has therefore assumed that the overall NEL will grow at 0.2 percent per year. System losses and load factors will remain constant at present levels.

The annual energy and peak projections are presented in Table 8-1 and 8-2, respectively.

8.4.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for AEL&P based on the assumptions indicated earlier in the general description section. The population of Juneau as projected by the ADL is expected to increase from 31,691 persons in 2010 to 36,580 persons in 2030. Black & Veatch used this population figure and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will grow at the same annual rate as is forecast for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high scenario is 418,018 MWh in 2011 and it increases to 892,341 MWh in 2061. In the Reference Scenario the NEL forecast for 2011 was 418,018 MWh in 2011 and 513,516 MWh in 2061. This shows that the additional energy demand for the high scenario is approximately 1.0 percent higher in 2011 and 73.8 percent higher in 2061 compared to the energy forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.5 INSIDE PASSAGE ELECTRIC COOPERATIVE

8.5.1 Angoon

8.5.1.1 Reference Scenario Load Forecast

To develop the city of Angoon (Angoon) load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with Inside Passage Electric Co-operative (IPEC). Angoon is a member of IPEC. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by diesel generation. This however could change if the Thayer Hydroelectric Project is successfully developed.

2011-2015 – Short Term

During this period, it is assumed that the peak and energy demand would follow a similar pattern as in 2010; usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in conversation with IPEC. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

Black & Veatch noted that the population forecast by ADL did not specifically include any trends for Angoon only. However, it provides population data for the Skagway Hoonah and Angoon areas together. According to the projections, the population for the whole area is expected to decline 8 percent in this period. According to the US Census data the population for Angoon has decreased from 638 people in 1990 to 572 in 2000 and then to 459 in 2010. Based on the ADL projections and the Census trend, Black & Veatch expects the population to decrease around 10 percent during this period.

Historically, annual sales have decreased slightly over the last decade with an increase in 2010. Sales by sector in 2010 were as follows:

Residential	53.2 percent
Small Commercial	18.0 percent
Large Commercial and Industrial	13.1 percent
Large Community Facilities	9.0 percent
Interruptible	4.2 percent
Others	3.0 percent

As seen, the residential and commercial sectors have the largest influence on NEL.

In the residential sector, the annual sales have decreased in the recent past (2005-2010) at an annual compound rate of 0.34 percent. The annual sales for this sector have decreased at an annual compound rate of 2.9 percent during the last decade. The decrease in annual sales from this sector is attributable to the general decrease in population as more and more people are moving to bigger cities for better employment opportunities.

Unlike some of the other regions in Southeast Alaska, Angoon is served entirely by diesel generation and its retail electricity rates averages about 60 cents/kWh. Due to the high electricity rates, Angoon is unlikely to see rapid conversion of wood or oil based heating systems to electric heating systems in the near future. Therefore, Black & Veatch does not expect energy sales from this sector to increase significantly during this period.

In the small commercial sector, the annual energy sales have grown at an annual compound rate of 4.7 percent during the last five years and at 2.7 percent during the last decade. During these periods, the number of customers has increased by 2.8 percent and 3.6 percent respectively. According to the information received from IPEC, the main commercial demand for electricity comes from the schools, store, and fishing lodge on Kiillisnoo Island. The high electricity rates are a big deterrent for new developments in the region. IPEC informed Black & Veatch that there are no significant upcoming commercial projects during this period, which are likely to have a material impact on the energy sales from this sector. There is no fish processer in Angoon with only a handful of commercial fishermen and several charter boat operators. Black & Veatch expects that as population declines during this period, commercial activities will also slow down. Therefore the sales to this sector are projected to remain flat or decrease during this period. Black & Veatch has assumed that the sales to the commercial sector will decrease to 2009 levels during this period.

Sales to large industrial customers have shrunk by 0.32 percent in the last 5 years, while the number of customers has remained fairly flat. Black & Veatch expects the sales to this sector to follow a similar trend during this period.

In the recent past (2005-2010) annual sales to large community facilities has increased by approximately 5.0 percent even though there has been no increase in the number of such facilities during this period. Information was not available from IPEC explaining the reasons behind the rapid growth in sales to this sector, but Black & Veatch does not expect the load from this sector to grow further.

Black & Veatch noted that the total number of customers for Angoon has remained fairly flat during the last decade. The customer growth has primarily been in the small commercial sector where the customers have grown at an annual compound rate if 2.8 percent since 2005. Customers in other categories have either declined or remained flat during the last five years.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Based on the above analysis, Black & Veatch has forecast that the annual sales to fall back to 2009 level by 2015. Black & Veatch has made the following forecasts for this period:

- The number of residential customers will continue to decrease during this period.
- This is consistent with the trends seen in the US Census data which indicate a 25 percent decline in population since 2000.
- The load factors in 2009 and 2010 were 58.1 percent and 57.9 percent, respectively. The load factor for 2011-2015 is assumed to be constant for all years and is expected to be the average of 2009 and 2010, which is 58 percent.
- The peak load on the system is expected to decrease from 361 kW in 2010 to 339 kW in 2015.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the US Census population data, it seems that population in the region is declining due to lack of employment opportunities and new economic developments in the region causing people to move to bigger cities for better employment opportunities. IPEC, too, indicated that such a trend is likely to continue.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual sales will increase at 0.1 percent annually from 2016-2035.
- The number of residential customers will decline consistent with the population projections.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- Load factors are expected to be constant at current levels through this period.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.5.1.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Angoon based on the assumptions indicated earlier in the general description section. The population of Angoon was approximately 430 persons in 2010. As in the Reference Scenario assumptions, Black & Veatch has assumed that the population will decrease by 10 percent (of 2010 levels) by 2015. Beyond 2015, the population is expected to decline by 0.5 percent annually until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL for the high scenario is forecast to be 1,827 MWh in 2011 and 3,408 MWh in 2061. In the Reference Scenario the NEL forecast was 1,809 MWh in 2011 and 1,802 MWh in 2061. This shows that the additional energy for the high scenario is 1.0 percent higher in 2011 and 89.1 percent in 2061 compared to the energy forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.5.2 Hoonah

8.5.2.1 Reference Scenario Load Forecast

To develop the city of Hoonah (Hoonah) load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with IPEC. Hoonah is a member of IPEC, Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by diesel generation.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2010 as usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in conversation with IPEC and Hoonah. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

Black & Veatch noted that the population forecast by ADL did not specifically include any trends for Hoonah only. However, it provides population data for the Skagway, Hoonah, and Angoon areas together. According to the projections, the population for the whole area is expected to decline 8 percent in this period. According to the US Census data the population for Hoonah has increased from 795 people in 1990 to 860 in 2000 and then decreased to 760 in 2010. This shows that over the last decade the population has decreased by approximately 12 percent. Black & Veatch expects the population to decrease around 10 percent during this period.

Historically, annual sales have decreased over the last decade at an annual compound rate of 1.7 percent. Within that period, annual sales decreased at an annual compound rate of 4.0 percent from 2000 to 2005, and at an annual compound rate of 2.6 percent between 2005 and 2010. Sales by sector in 2010 were as follows:

- Residential 41.7 percent
- Small Commercial 13.7 percent
- Large Commercial and Industrial 7.3 percent
- Large Community Facilities 8.9 percent
- Interruptible 25.1 percent
- Others 3.5 percent

As seen, the residential, commercial and interruptible customers have the largest influence on NEL.

In the residential sector, sales have decreased in the recent past (2005-2010) at an annual compound rate of 2.19 percent. The sales for this sector have decreased at an annual compound rate of 0.8 percent during the last decade. The decrease in annual sales to this sector is attributable to the general decrease in population as more and more people are moving to bigger cities for better employment opportunities.

Unlike many of the other regions in Southeast Alaska, Hoonah is served entirely by diesel generation and their retail electricity rate averages about 60 cents/kWh. Due to the high electricity rates, Hoonah is unlikely to see rapid conversion of wood or oil based heating systems to electric heating systems in the near future. Therefore, Black & Veatch does not expect energy demand from this sector to increase significantly during this period.

In the small commercial sector, the annual sales have decreased at an annual compound rate of 2.8 percent during the last five years and at 2.2 percent during the last decade. During these periods, number of customers has increased by 5.9 percent and 2.4 percent respectively. According to the information received from IPEC, the main commercial demand for electricity comes from the fishing industry, the schools, and the swimming pool. The commercial activities in the region are heavily subsidized in order to offset the high electricity rates in the region. The high electricity rates are a big deterrent for new developments in the region. IPEC informed Black & Veatch that there are no significant upcoming commercial projects during this period other than the possible addition of a saw mill, which are likely to have a material impact on the energy demand from this sector. Moreover, this demand is seasonal and dependent upon the price of fuel in the region. Black & Veatch expects that as population declines during this period, commercial activities will also slow down. Therefore sales to this sector will remain flat or decrease during this period. Black & Veatch has assumed that sales will remain at 2010 levels during this period.

Sales to large industrial customers have almost doubled in the last ten years even though the number of customers in this category has not changed. The increase in sales is primarily due to the ISP cruise ship destination. However, Black & Veatch expects the sales to remain flat during this period.

Black & Veatch expects sales to community facilities to remain flat during this period. Black & Veatch also expects sales to interruptible customers to remain flat during this period.

Black & Veatch noted that the total number of customers for Hoonah has remained fairly flat during the last decade. The customer growth has primarily been in the small commercial sector where the customers have grown at an annual compound rate of 5.9 percent since 2005. Customers in other categories have either declined or remained flat during the last five years.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Based on the above analysis, Black & Veatch has forecast that the NEL to remain at the 2010 level until 2015. Black & Veatch has made the following forecasts for this period:

- The number of residential customers will decrease during this period.
- This is consistent with the trends seen in the US Census data which indicate a 12 percent decline in population since 2000.
- The load factor is assumed to be same as 2010 level for all years in this period.
- The load factor is assumed to be the average of the load factors for 2009 and 2010, which is 57.6 percent. It is assumed to remain constant throughout this period.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the US Census population data, it seems that population in the region is declining due to lack of employment opportunities and new economic developments in the region people moving to bigger cities for better employment opportunities. IPEC too indicated that such a trend is likely to continue.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual energy sales will increase at 0.2 percent annually from 2016-2035.
- The number of residential customers will decline in relation to the population projections.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- Load factors are expected to remain constant at current levels through this period.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period. Load factors are expected to remain constant at current levels through this period.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.5.2.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Hoonah based on the assumptions indicated earlier in the general description section. The population of Hoonah was approximately 760 persons in 2010. As in the Reference Scenario assumptions, Black & Veatch has assumed that the population will decrease by 10 percent (of 2010 levels) by 2015. Beyond 2015, the population is expected to decline by 0.5 percent annually until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL for the high scenario is forecast to be 4,267 MWh in 2011 and 8,276 MWh in 2061. In the Reference Scenario, the NEL forecast was 4,267 MWh in 2011 and 4,558 MWh in 2061. This shows that the additional energy for the high scenario is 1.0 percent higher in 2011 and 81.6 percent higher in 2061 compared to the energy forecast in the original case for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.5.3 Kake

8.5.3.1 Reference Scenario Load Forecast

To develop the city of Kake (Kake) load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with IPEC. Kake is a member of IPEC. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by diesel generation.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2010 as usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in conversation with IPEC. It is also assumed that no new transmission upgrades would be possible within this time frame and so, system loss patterns are unlikely to improve during this time frame as compared to 2010.

Black & Veatch noted that the population forecast by ADL did not specifically include any trends for Kake City only. According to the US Census data the population for Kake has decreased from 710 people in 2000 to 557 in 2010. This shows that over the last decade the population has decreased by approximately 22 percent. Black & Veatch expects the population to continue to decrease during this period. Following the trend seen over the last decade, Black & Veatch expects population to decrease by another 10 percent by 2015.

Historically, annual sales have decreased over the last decade with an annual compound rate of 6.4 percent. Within that period annual sales decreased at an annual compound rate of 8.1 percent from 2000 to 2005, and at an annual compound rate of 2.9 percent between 2005 and 2010. Sales by sector in 2010 were as follows:

Residential	44.3 percent
Small Commercial	12.3 percent
Large Commercial and Industrial	8.6 percent
Interruptible	28 percent
Others	6.8 percent

As seen, the residential, commercial, and interruptible customers have the largest influence on NEL.

In the residential sector, the annual sales have decreased in the recent past (2005-2010) at an annual compound rate of 3.3 percent. The annual sales for this sector have decreased at an annual compound rate of 5.3 percent during the last decade. The decrease in annual sales to this sector is attributable to the general decrease in population as more and more people are moving to bigger cities for better employment opportunities.

Unlike many of the other regions in Southeast Alaska, Kake is served entirely by diesel generation and their retail electricity rates averages about 60 cents/kWh. Due to the high electricity rates, Kake is unlikely to see rapid conversion of wood or oil based heating systems to electric heating systems in the near future. So Black & Veatch does not expect sales to this sector to increase significantly during this period. Black & Veatch expects the sales to residential customers to reduce by 1 percent every year. This takes into account that the population is likely to decrease until 2015.

In the small commercial sector, the annual sales have decreased at an annual compound rate of 2.3 percent during the last five years and at 2.7 percent during the last decade. During these periods, number of customers has decreased by 5.0 percent and 1.4 percent respectively. The high electricity rates are a big deterrent for new developments in the region. IPEC informed Black & Veatch that there are no significant upcoming commercial projects during this period, which are likely to have a material impact on the energy sales to this sector. Black & Veatch expects that as population declines during this period, commercial activities will continue to decline. Therefore, the sales to this sector will decrease during this period. Black & Veatch has assumed that sales to this sector will decrease by 0.5 percent per year.

Sales to large industrial customers have shrunk by almost 50 percent in the last 10 years, even though the number of customers in this category has not changed much. During 2005-2010, the energy sales to this sector reduced by an annual compound rate of 12.8 percent. This shows that the industrial activities have slowed down considerably in the region. Black & Veatch expects this trend to continue in this period. However, the Kake Fish Processing Plant is attempting to reopen and Black & Veatch forecasts the demand from this segment to decrease more slowly by 2 percent every year during this period.

Interruptible sales are a significant part of the total annual sales. However interruptible sales have decreased by a compound rate 0.14 percent in the last 5 years. During this period the city lost one of the 3 customers in this category, Black & Veatch expects the sales to this sector to remain flat during this period.

Black & Veatch expects sales to community facilities to remain flat during this period.

Black & Veatch noted that the total number of customers for Kake has decreased during the last decade. Black & Veatch expects this trend to continue and has considered this factor in developing the forecast for this period.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Based on the above analysis, Black & Veatch has forecast that the total annual sales will reduce by 3.3 percent of 2010 levels by 2015. Black & Veatch has made the following forecasts for this period:

- The number of residential customers will decrease during this period.
- This is consistent with the trends seen in the US Census data which indicate a 22 percent decline in population since 2000.
- The load factor is assumed to be the average of 2009 and 2010 (56.8 percent) and is expected to remain constant during this period.
- System losses and station usage is assumed to remain constant at current levels throughout this period.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the US Census population data, it seems that population in the region is declining due to lack of employment opportunities and new economic developments in the region people moving to bigger cities for better employment opportunities. IPEC too indicated that such a trend is likely to continue.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual sales will increase at 0.2 percent annually from 2016-2035.
- The number of residential customers will decline in relation to the population projections.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- Load factors, station service, and system losses are expected to remain constant at current levels throughout this period.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period. Load factors, station service and system losses are expected to remain constant at current levels throughout this period

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.5.3.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Kake based on the assumptions indicated earlier in the general description section. The population of Kake was approximately 710 persons in 2010. As in the Reference Scenario assumptions, Black & Veatch has assumed that the population will decrease to 700 persons by 2015. Beyond 2015, the population is expected to decline by 0.5 percent annually until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased energy loads caused by faster than expected economic growth and development.

The annual NEL for the high scenario is forecast to be 2,203 MWh in 2011 and 4,569 MWh in 2061. In the Reference Scenario the NEL forecast was 2,203 MWh in 2011 and 2,291 MWh in 2061. This shows that the additional energy for the high scenario is 1.0 percent higher in 2011 and 99.5 percent higher in 2061 compared to the energy forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.5.4 Klukwan

8.5.4.1 Reference Scenario Load Forecast

To develop the city of Klukwan (Klukwan) load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with IPEC. Klukwan is a member of IPEC. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by diesel generation.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2010 as usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in conversation with IPEC. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

Black & Veatch noted that the population forecast by ADL did not specifically include any trends for Klukwan only. According to the US Census data the population for Klukwan has increased from 129 people in 1990 to 139 in 2000 and then reduced to 95 in 2010. This shows that over the last decade the population has decreased by approximately 32 percent. IPEC indicated to Black & Veatch that they do not expect any growth in population in the region. As such Black & Veatch expects the population to remain fairly flat during this period.

Historically annual sales have increased over the last decade with an annual compound rate of 1.1 percent. Within that period, annual sales decreased at an annual compound rate of 1.4 percent from 2000 to 2005, and increased at an annual compound rate of 1.5 percent between 2005 and 2010. Sales by sector in 2010 were as follows:

- Residential 59.0 percent
- Small Commercial 14.8 percent
- Large Commercial and Industrial 15.4 percent
- Small Community Facilities 7.6 percent
- Others 3.5 percent

As seen, the residential and commercial customers have the largest influence on NEL.

In the residential sector, the annual sales have decreased in the recent past (2005-2010) at an annual compound rate of 1.7 percent. The annual sales for this sector have decreased at an annual compound rate of 1.0 percent during the last decade. The decrease in annual sales to this sector is attributable to the general decrease in population as more and more people are moving to bigger cities for better employment opportunities. Black & Veatch expects the sales to this sector to remain flat at 2009 levels throughout this period.

Unlike most of the other IPEC communities, Klukwan is served entirely by hydroelectric and purchase power from AP&T; however retail electricity rates average about 60 cents/kWh due to IPEC's postage stamp rate. Due to the high electricity rates, Klukwan is unlikely to see rapid conversion of wood or oil based heating systems to electric heating systems in the near future. So Black & Veatch does not expect energy sales to this sector to increase significantly during this period.

In the small commercial sector, the annual energy sales have increased at an annual compound rate of 10.0 percent during the last five years and at 16.5 percent during the last decade: however, there are only 6 small commercial customers. Overall the increase in sales has been only 28 MWh annually between 2005 and 2010 and 40 MWh between 2000 and 2010. During these periods, there were very few customers. It is also noted that the sales to this sector declined in 2010 compared to 2009. The high electricity rates are a big deterrent for new developments in the region. IPEC informed Black & Veatch that there are no significant upcoming commercial projects during this period, which are likely to have a material impact on sales to this sector. Black & Veatch expects that as population declines during this period, commercial activities will also slow down. Black & Veatch has assumed that sales to this sector will increase back to 2009 levels during this period.

Sales to large commercial customers have increased by 0.38 percent in the last ten years. Black & Veatch expects sales to remain flat during this period. Large commercial customers include the school and a new lodge.

Black & Veatch also expects sales to community facilities to remain flat during this period.

Black & Veatch noted that the total number of customers for Klukwan has remained fairly flat during the last decade. The customer growth has primarily been in the small commercial sector. However, even after the increase in commercial customers, the total number of small commercial customers at end of 2010 was only 6 compared to a total of 62 customers.

The AHFC offers Weatherization and Energy Rebate programs. Even though qualifying customers can participate in the Weatherization program at no cost, very few customers are participating in either the Weatherization or Energy Rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase absent additional conservation and energy efficiency efforts which will be covered separately.

Based on the above analysis, Black & Veatch has forecast sales to increase to the 2009 level by 2015. Black & Veatch has made the following forecasts for this period:

- The number of residential customers will be flat or slightly increasing during this period.
- This is consistent with the trends seen by IPEC recently.

- The load factor is assumed to be same as the average of 2009 and 2010 levels (45.9 percent) for all years in this period.
- System losses are expected to remain constant at current levels.
- Station service is expected to remain constant at current levels throughout the period.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the US Census population data, it seems that population in the region is declining in the region due to lack of employment opportunities and new economic developments in the region people moving to bigger cities for better employment opportunities. IPEC too indicated that such a trend is likely to continue.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual energy sales will increase at 0.2 percent annually from 2016-2035.
- The number of residential customers will decline in relation to the population projections.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- Load factor, station use and system losses are expected to remain constant at current levels through this period.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period. Load factor, station use and system losses are expected to remain constant at current levels through this period.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.5.4.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Klukwan based on the assumptions indicated earlier in the general description section. The population of Klukwan was approximately 95 persons in 2010. As in the Reference Scenario assumptions, Black & Veatch has assumed that in this case too, the population will remain flat until 2015. Beyond 2015, the population is expected to decline by 0.5 percent annually until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in energy for every year in the study period over the corresponding energy forecast in the original case. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL for the high scenario is forecast to be 375 MWh in 2011 and 792 MWh in 2061. In the Reference Scenario the NEL forecast was 375 MWh in 2011 and 416 MWh in 2061. This shows that the additional energy for the high case is 1.0 percent higher in 2011 and 90.5 percent higher in 2061 compared to the energy demand forecast in the Reference for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.5.5 Chilkat Valley

8.5.5.1 Reference Scenario Load Forecast

To develop the city of Chilkat Valley (Chilkat Valley) load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with IPEC. Chilkat Valley is a member of IPEC. Black & Veatch reviewed the projected population growth as projected by the ADL but it did not have any historical data for Chilkat Valley. No historical population data was available separately for Chilkat Valley.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by hydroelectric generation and purchase power from AP&T with rates continuing to be the IPEC postage stamp rate. Black & Veatch understands that there may be changes to postage stamp rate concept in the future, but those potential changes have not been considered in the development of the reference forecast.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2010 as usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in conversation with IPEC. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

Unlike the other IPEC communities, Chilkat Valley has been growing due to it being on the road system with cheaper land prices. Historically, annual sales have increased over the last decade with an annual compound rate of 2.7 percent. Within that period, annual sales increased at an annual compound rate of 1.02 percent from 2000 to 2005, and at an annual compound rate of 3.1 percent between 2005 and 2010. Sales by sector in 2010 were as follows:

- Residential 59.4 percent
- Small Commercial 11.6 percent
- Large Commercial and Industrial 3.2 percent
- Interruptible 25.6 percent

As seen, the residential, small commercial and interruptible customers have the largest influence on NEL.

In the residential sector, the annual sales have increased in the recent past (2005-2010) at an annual compound rate of 3.0 percent and the annual sales for this sector have increased at an annual compound rate of 2.4 percent during the last decade. Going forward, the growth in annual sales to residential customers are likely to continue to increase as a result of schools, border stations, and farms.

Even though Chilkat Valley is served by hydroelectric and purchased power from AP&T, retail electricity rates average about 60 cents/kWh due to IPEC's postage stamp rates. Due to the high electricity rates, Chilkat Valley is unlikely to see conversion of wood or oil based heating systems to electric heating systems in the near future. So Black & Veatch does not expect sales to this sector to increase significantly during this period. Use per residential customer has gone up by at an annual compound rate of 1.5 percent per year since 2005. During this period the number of residential customers has increased from 186 to 203 customers. Some growth in residential customers is expected to continue. Taking into account the increase in consumption by residential customers and some expected growth in the number of residential customers in the near future, Black & Veatch expects the sales to residential customers to increase by 2 percent every year during this period.

In the small commercial sector, the annual sales have decreased at an annual compound rate of 1.7 percent during the last five years and at 1.4 percent during the last decade. During these periods, number of customers has increased by 1.4 percent and 2.5 percent, respectively. However the sales to this sector dropped to 138 MWh annually in 2010 from 159 MWh in 2009. The high electricity rates will be a big deterrent for new developments in the region. IPEC informed Black & Veatch that there are no significant upcoming commercial projects during this period, which are likely to have a material impact on the energy demand from this sector. Therefore annual energy sales to this sector are expected to increase at a slower pace during this period compared to the last 5 years. Black & Veatch has assumed that sales to this sector will return back to 2009 levels by 2015.

There are only 2 large commercial customers and overall the sales to this sector accounts for 3.3 percent of the total retail sales in the region. Black & Veatch has assumed that sales to large commercial customers will have a similar growth pattern as the small commercial customers during this period. Sales to this sector are likely to increase to 2009 levels by the end of this period. There are one or more potential small mine projects in the near term. These mine projects have not been explicitly included in the future loads since they are often served by dedicated facilities.

Interruptible sales are a significant part of the total annual sales. However interruptible sales have decreased by a compound rate 2.7 percent in the last 5 years. During this period the city had only 2 customers in this category for all years. Interruptible customers are generally involved in large industrial activities. IPEC expects commercial activities to slow down and therefore Black & Veatch expects the sales to this sector to decrease 1 percent every year.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Based on the above analysis, Black & Veatch has forecast that the total annual sales will grow from 1,194 MWh in 2010 to 1,318 MWh in 2015. This is equivalent to an annual compound growth rate of 2.0 percent. Black & Veatch has made the following forecasts for this period:

- The number of residential customers will continue to increase during this period.
- The usage for residential customers will also increase.
- The load factors in 2009 and 2010 were 49.2 percent and 49.6 percent respectively. The load factor for 2011-2015 is assumed to be constant for all years and is expected to be the average of 2009 and 2010, which is 49.4 percent. .
- The peak load on the system is expected to increase from 275 kW in 2010 to 305 kW in 2015.

2016-2035 – Intermediate Term

According to the US Census population data, it seems that population in the region is declining due to lack of employment opportunities and new economic developments in the region people moving to bigger cities for better employment opportunities. The Chilkat Valley, however, has been bucking this regional trend with some growth.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual sales will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers will be flat or continue to grow slowly.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will be flat or increase slowly.
- Load factors are expected to remain fairly constant through this period.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.2 percent per year during this period.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.5.5.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Chilkat Valley based on the assumptions indicated earlier in the general description section. In 2010, the total number of IPEC customers in Chilkat Valley was 238. Assuming that there are two persons for each customer account, Black & Veatch estimates that the population of Chilkat Valley is approximately 475 persons in 2010. Black & Veatch forecasts that the population growth for Chilkat Valley will be higher than in other regions served by IPEC. Based on this assumption, Black & Veatch forecasts that the population of Chilkat Valley will remain steady through 2015. Beyond 2015, the population is expected to decline by 0.5 percent annually until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional

1.0 percent growth in energy for every year in the study period over the corresponding energy forecast in the original case. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL for the high scenario is forecast to be 1,218 MWh in 2011 and 3,008 MWh in 2061. In the Reference Scenario the NEL forecast was 1,218 MWh in 2011 and 1,534 MWh in 2061. This shows that the additional energy for the high case is 1.0 percent higher in 2011 and 96.0 percent higher in 2061 compared to the energy forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.6 METLAKATLA POWER & LIGHT

8.6.1 Reference Scenario Load Forecast

To develop the Metlakatla load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with Metlakatla Power & Light (MPL).

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by hydroelectric generation.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2010 as usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in discussions with MPL. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

No population forecasts were developed for this region by ADL, so Black & Veatch relied on MPL to estimate population growth in the region. According to MPL, the population is likely to remain constant or decrease during this period. Metlakatla's current population is between 1,100 and 1,400. However, 80 percent of the population is unemployed. The community is heavily government subsidized and there are no good job opportunities in the region. So people in the work force tend to move out to bigger cities for job opportunities.

According to the information received from MPL, the main demand for electricity comes from the fishing industry for refrigeration. However, this demand is seasonal and dependent upon the price of fuel, the market for fish, and the catch in the region. Competitive fuel prices compared to other nearby regions are likely to increase activity of the fishing fleet and an increased volume of fish increases the demand for electricity and vice versa. In the past the region has been able to provide fuel at competitive prices, which has resulted in higher energy demand. Black & Veatch has assumed that this trend is likely to continue during this period.

Since 2007, MPL has observed an increase in energy demand due to rapid conversion to electric heating systems in residential homes and commercial buildings. The rapid change was due to the high price of oil during this period. MPL estimates that on account of the above, energy demand has been going up 6.0-7.5 percent for the last 3 years. Actual increases in NEL were 7.7, 6.4, and 3.9 percent for 2008, 2009, and 2010, respectively. MPL expects 7 percent in 2011. MPL estimates that 60 to 75 percent of the customers have converted to electric heat. MPL indicates that conversions to electric heating systems have slowed in 2010 due to falling oil prices. However MPL expects the conversion rate to be high in 2011, as fuel oil prices have gone up again. There is little actual data relative to penetration of electric heat and the use of portable electric heaters can cause the electric heating load to be very volatile. Black & Veatch's analysis of load and HDD data leads to a conclusion that existing penetration of electric heat may be less than estimated by MPL and therefore there may be greater opportunities for electric heating loads to increase.

Table 8-22 presents analysis of HDD data for Metlakatla. The average HDDs for 2000 through 2010 are 7,195. As shown in Table 8-22, 2007 through 2009 were above average for HDDs while 2010 was 8.3 percent below average. Thus while the growth rate in NEL in 2010 was slower than in 2008 and 2009, part of that lower growth could be attributed to fewer HDDs.

Table 8-22 Heating Degree Day Data

YEAR	HDD	HDD ABOVE AVERAGE	ESTIMATED ANNUAL HEATING LOAD (MWH)
2010	6,598	-597	14
2009	7,446	251	18
2008	7,563	363	19
2007	7,391	196	-

Table 8-23 presents analysis of residential customers and residential sales.

Table 8-23 indicates there has been significant growth in number of customers, use per customer except for the weather impacted 2010, and total residential sales.

Table 8-23 Residential Customers and Sales

YEAR	NUMBER OF CUSTOMERS	USE PER CUSTOMER (MWH)	RESIDENTIAL SALES (MWH)
2010	635	11.81	7,498
2009	608	12.15	7,386
2008	604	11.15	6,956
2007	582	10.62	6,180

Table 8-24 attempts to estimate the number of electric heating customers. The baseline residential sales assume that 2007 use per customer is the baseline and that there were no incremental electric heating customers in the baseline. The incremental load due to heating is the difference between actual sales and baseline sales. The estimated number of electric heating customers is developed from the incremental load due to heating and the estimated annual heating load from Table 8-22. The estimated increase in the number of electric heating customers slows in 2010 as stated by MLP, but the overall estimated penetration is only 9 percent compared to the 60 to 75 percent estimated by MLP.

Table 8-24 Estimated Residential Electric Heating Customers

YEAR	BASELINE RESIDENTIAL SALES (MWH)	INCREMENTAL LOAD DUE TO HEATING (MWH)	NUMBER OF ELECTRIC HEATING CUSTOMERS
2010	6,744	754	54
2009	6,457	929	52
2008	6,414	542	29
2007	6,180	0	0

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs due to the lack of raters. As such, Black & Veatch does not estimate a significant reduction in NEL due to weatherization and energy efficiency without an external program to increase participation.

Black & Veatch also discussed the possibility of users replacing incandescent bulbs with energy efficient bulbs, which would reduce lighting loads. Based on that discussion, Black & Veatch assumed that only a small number of people will actually do this without an external program during this time frame and the demand will not be significantly impacted on account of this.

Historically NEL has increased over the last decade with an annual compound annual growth rate of 1.2 percent. Within that period, NEL decreased from 2000 to 2005, increased slightly in 2006 and 2007, and then increased rapidly from 2008 onwards. Sales by sector in 2010 were as follows:

- Residential 39.3 percent
- Commercial 27.4 percent
- Community Centers 18.9 percent
- Others 4.2 percent

As seen, the residential sector has the largest influence on NEL. The residential sector has seen rapid growth in demand since 2008 due to conversion to electric heating systems. This conversion is driven by MPL's declining block rates, the lowest block being 8 cents/kWh. The sales to the commercial sector have also increased during the last 3 years. The commercial sector is heavily driven by the fishing industry, and demand from this sector varies significantly depending upon the harvest in the fishing season.

The total number of customers for MPL is 917. Out of which 635 are residential customers and 115 commercial customers. The number of residential customers has increased from around 563 customers in 2000 to 635 in 2010, at annual average growth rate of 3.1 percent. The number of commercial customers has dropped from 128 customers in 2000 to 115 customers in 2010. However, the number of commercial customers has remained fairly constant since 2008. The number of commercial customers lags the economic conditions to some extent since plans for new commercial establishments are often made at least a year before opening of the establishment.

Use per customer responds quicker to economic conditions and high oil prices. Use per customer for commercial and residential customers has increased an average of nearly 3.6 percent and 2.1 percent respectively per year from 2005 to 2010. At present the unemployment rate in the region is very high. High unemployment is prevalent throughout the US as a result of the recession, but not to the extent evident in Metlakatla.

Based on the above analysis, Black & Veatch projects MPL's NEL to increase by 7.5 percent in 2011 from 2010 levels, with increases of 4 percent in 2012 and 2 percent in 2013 and remaining flat in 2014 and 2015 as oil prices are expected to return to more normal levels. The 2011 NEL for load reflects approximately 20 percent residential electric heating penetration. This increase assumes the continued conversion to electric heating systems by customers of MPL. However, in discussion with MPL, Black & Veatch expects that the conversion will slow and the number of residential customers will remain relatively steady due to very high unemployment rates. The commercial sector is projected to remain fairly constant keeping the recent gains. NEL could increase towards the end of the period if oil prices moderate and the economy strengthens.

Based on the above assumptions and information, Black & Veatch has made the following forecasts for this period:

- The number of customers will remain fairly steady through the period.
- Use per customer is assumed to increase for the residential sector due to electric heating conversion. The commercial sector is projected to remain relatively stable for both number of customers and use per customer.
- System losses will not improve and will be at the same level as 2010 for every year in the period, which is 9.9 percent of the annual sales forecast.
- Black & Veatch did not get any load factor data or peak demand data from MPL. As such Black & Veatch assumed that the annual load factor for all years in the period would be approximately 52 percent. This number is based on the load factor seen in other utilities in the region.
- Black & Veatch assumed that MPL has sufficient hydroelectric generation capabilities to meet all near term load requirements resulting in relatively stable power costs.
- Station use is expected to be the average for the period 2000-2010 and is expected to remain constant throughout the period.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

Black & Veatch believes that the population will slowly decline for this region during this period. This is consistent with trends forecasted by ADL for other neighboring regions.

Load factors are expected to remain fairly constant through this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- The NEL will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers will slowly decline in relation to the ADL population projections for other neighboring regions in Alaska.
- Use per residential customer will increase due to oil prices going back to medium levels and the ever increasing uses of electricity coupled with some economic sustainability from the fishing industry. Naturally occurring conservation will mitigate large increases in use per customer as residential customers are slowly able to afford more conservation.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- System losses will remain at 2010 levels.
- The annual load factor for all years is forecast to remain constant at 52 percent.
- Station use will remain constant at current levels throughout the period.

2036-2060 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts moderate growth in number of customers and use per customer for residential and commercial sectors at 0.2 percent for number of customers and use per customer resulting in an approximately 0.4 percent annual increase in NEL. System losses are expected to remain same at 2010 levels. Station use will remain constant at current levels throughout the period.

The annual energy and peak projections are presented in Table 8-1 and 8-2, respectively.

8.6.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for MPL based on the assumptions indicated earlier in the general description section. The current population of Metlakatla is around 1,100 to 1,400 persons. However, there was no population growth forecast available from ADL for this region. Black & Veatch is of the opinion that the economic development of the region will be similar to that of the Yakutat region and so the population trend for Metlakatla is also likely to follow a similar trend as in the Yakutat region. As per ADL forecast the population in the Yakutat region is expected to decline by approximately 11.2 percent in the period 2010 to 2030. Black & Veatch has assumed that Metlakatla's population too will reduce by 11.2 percent in the same period. Along with the other assumptions indicated in the general description section Black & Veatch has forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will decline at the same annual rate as is forecast for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased load caused by faster than expected economic growth and development.

The annual NEL forecast for the high case is 20,512 MWh in 2011 and it increases to 45,368 MWh in 2061. In the Reference Scenario the NEL forecast was 20,511 MWh in 2011 and 26,670 MWh in 2061. This shows that the additional NEL for the high case is 1.0 percent higher in 2011 and 70.1 percent in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.7 CITY OF SITKA ELECTRIC (SITKA)

8.7.1 Reference Scenario Load Forecast

To develop the Sitka load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities Sitka. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by primarily by self owned hydroelectric plants and some generation from self owned diesel units during emergency or peak demand periods.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2010 as usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in conversation with Sitka. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

According to the population forecast by ADL, the population is likely to remain fairly flat between 2010 and 2015. The population in Sitka in 2010 is 8,964 and is expected to be 8,948 in 2015. Between 2006 and 2010, Sitka has seen some population growth as population has increased from 8,833 in 2006 to 8,964 in 2010. Black & Veatch expects the population trends for 2010 to 2015 will follow the projections made by ADL.

Historically NEL has grown over the last decade with an annual compound growth rate of 2.4 percent. Within that period, NEL grew at an annual compound rate of 1.6 percent from 2000 to 2005, but increased rapidly at an annual compound rate of 2.9 percent between 2005 and 2010. Sales by sector in 2010 were as follows:

- Residential 42.4 percent
- Commercial 28.0 percent
- Public Authority 20.4 percent
- Harbor Customers 3.1 percent
- Others 4.6 percent

As seen, the residential and commercial sectors have the largest influence on NEL.

In the residential sector, the annual average load growth has been 3.8 percent in the recent past (2005-2010). However during this period number of customers has only grown at an average annual rate of 1.44 percent. This shows that the residential customers are becoming more energy intensive and are using more energy in the household for day to day activity. This is probably driven by the conversion of oil based heating to electric heating systems in residential houses. According to Sitka, such conversions happen when oil prices are high and Sitka expects this conversion to continue in the near future, especially since oil prices are currently much higher than the previous two years.

To understand the usage trends of residential customers, the energy usage needs to be compared with the weather trends during these years. One way to assess the severity of the weather in a given year is to look at the annual HDDs for all years. Table 8-25 shows the HDD and usage per residential customers for the period 2001-2010.

Table 8-25 Annual HDD and Usage per Residential Customers (2000-2010)

YEAR	HDD	USAGE/RESIDENTIAL CUSTOMERS (MWH)
2000	8,332	11.51
2001	8,257	11.68
2002	8,329	11.60
2003	8,303	11.07
2004	7,769	11.32
2005	7,752	11.38
2006	8,945	11.81
2007	8,663	12.70
2008	9,008	12.81
2009	8,588	13.49
2010	8,053	12.74
Average (2000-2010)	8,364	12.01

As per Table 8-25, the average annual HDD for 2000 to 2010 is 8,364. Years 2000 to 2003 were average weather years, while 2006 to 2009 were more severe weather years. 2010 was a relatively mild weather year and years 2004 and 2005 were unusually and extremely mild weather years.

From the above analysis, 2009 is the closest to normal of the last 5 years and Black & Veatch expects that the average annual consumption per residential customer in an average weather year to be close to the 2009 consumption level, which is approximately 13.5 MWh. However, Black & Veatch also expects additional usage per customer going forward as they show behavioral changes and use electricity more often for heating purposes. This behavioral change would be necessitated due to the high prices of heating oil.

Most houses in the region traditionally use heating oil for heating their homes. However, as oil prices went up in 2008, many residential customers converted their heating systems to electric heating systems to avail themselves of the relatively cheap retail electricity rates and lower the cost of heating their homes. According to Sitka, the pace for such conversions picks up when the price of oil exceeds approximately $3.00/ gallon. Current prices of oil are much higher than $3.00/gallon and so some people are expected to convert to electric heating systems. However, the high capital expenditure required initially to setup the electric heating systems acts as a barrier for rapid conversions to such systems. Sitka estimated that about 30 percent of residential customers have already converted to electric heating systems but expects future conversions to be slow. Black & Veatch forecasts that the current high oil prices will remain high through 2012 before falling off from 2013 onwards. Because of this, Black & Veatch assumed that an additional 10 percent of 2010 residential customers will convert to electric heating systems in 2011 and 5 percent in 2012 and there will be no further conversions from 2013 to 2015. Based on Sitka's Energy Usage Estimator, conversion of a 2,000 square foot house uses 2,434 kWh/month for 6 hours per day of use. For evaluation purposes, it is assumed that conversion to electric heat results in 7.5 MWh annually of additional use per customer. People who convert to electric heating systems are expected to continue using the new system even when price of oil falls to more normal levels.

According to a City Ordinance, all new homes are required to have dual heating systems and so, customers are expected to revert back to using oil for heating their homes when oil prices come down. As such, use per customer could reduce if oil prices dropped enough. Black & Veatch expects oil prices to reduce enough to discourage additional conversions to electric heat beginning in 2013, but Black & Veatch expects that oil prices will still be high enough that customers that have converted to electric heat will continue to use the electric heat.

In addition to people converting to electric heating systems, people have the option to use portable space heaters which are available at low cost. Sitka's Energy Usage Estimator indicates a 1,500 watt space heater uses 274 kWh per month based on 6 hours per day usage. Based on the Energy Usage Estimator, Black & Veatch estimates the annual space heater use per customer to be 1 MWh. With the high cost of oil in 2011, Black & Veatch estimates that 20 percent more residential customers will employ portable space heaters in 2011, with the number dropping to 5 percent in 2012 and going to 0 thereafter.

This forecast is based on average weather conditions and average conditions with respect to electricity costs. Based on average conditions Sitka currently can supply average loads with hydroelectric under average water conditions. As stated above, this situation is projected to continue for the purpose of this reference forecast. Sitka has a unique energy management system that manages customer usage through a green, yellow, and red traffic light process. Sitka is also unique with its City ordinance mandating dual fuel heating when electric heat is installed. Discussions held with members of the public in Sitka indicate that the green, yellow, and red light system is effective. Since the coincidence of average weather and average water conditions seldom occurs, Sitka's energy management system serves to reduce actual loads compared to forecast loads. This reduction can occur even when average weather and water occur for the year, but variances occur during the year which causes implementation of the energy management system. The forecast, however, has not been reduced to reflect potential impacts of the energy management system.

Based on the above analysis Black & Veatch expects sales to residential customers to increase to 53,046 MWh in 2011 from 46,756 MWh in 2010.

According to the information received from Sitka, the main commercial demand for electricity comes from the fishing industry for refrigeration. Many of the canneries are currently converting from the canning process to a refrigeration process which is likely to increase the load in the near future. Black & Veatch has assumed that this trend is likely to continue during this period. Besides the normal fishing season, Sitka also has a cannery that cans herring. The electric loads from the herring canning occur in March and April.

In the recent past (2005-2010) annual energy usage per commercial customers has decreased from 49.68 MWh in 2005 to 48.79 MWh in 2010. This equates to an annual compound declining rate of approximately 1.7 percent respectively. During this period, the number of commercial customers has increased from 597 customers to 634 customers, which equates to an annual compound growth rate of 3.5 percent. Overall the total annual energy demand from commercial customers increased by 0.7 percent during this period. Commercial sales in 2008 were significantly above normal most likely attributed to the fishing industry.

In discussions with Sitka, Black & Veatch noted that there are no specific commercial projects in the pipeline in the next few years. Because of this, Black & Veatch expects that the number of commercial customers will remain flat for the period 2011-2015.

Black & Veatch was also informed that only about 15 percent of the commercial customers have converted to electric heating systems and future conversions are expected to be very slow. Usually commercial customers tend to convert at a much slower rate than residential customers. So Black & Veatch has assumed that only a small number of commercial customers will convert during this period and the additional load from those conversions are unlikely to have a significant impact on the sales to this class of customers.

As discussed above, Black & Veatch believes that 2009 was a relatively normal weather year. So Black & Veatch has assumed that the annual usage per commercial customer for 2011 will be approximately equal to 48.12 MWh, which is equal to the 2009 usage level for commercial customers. Black & Veatch forecasts sales to the commercial sector to increase 2 percent annually from 2011 to 2015 due to general growth in use per customer and slow conversion to electric heat.

Based on the above analysis, the annual sales to commercial customers is forecast to increase from 30,932 MWh in 2010 to 33,022 MWh in 2015.

Harbor customers have increased from 754 customers in 2005 to 772 customers in 2010. This shows that the harbor customers have increased at an annual compound growth rate of approximately 1 percent. During the same period, annual usage per harbor customers have grown at an annual compound rate of 7 percent. This growth in demand has been due to rapid growth in the number of tourists visiting the area each year. Sitka expects continued but slower growth in this sector in the near future. This demand is seasonal as most tourists visit the area during summer.

Based on the above analysis, Black & Veatch expects that harbor customers will grow at 1 percent per year for the period 2011-2015, which is as per trends seen in the period 2005-2010. Black & Veatch however believes that the 2011 usage per harbor customer will remain at 2009 level as 2009 was an average weather year. Subsequently sales to the harbor sector will increase by 1 percent annually until 2015.

Based on the above analysis, the sales to the harbor customers sector are forecast to increase from 3,447 MWh in 2010 to 3,959 MWh in 2015.

Usages for other categories of customers are expected to remain flat at 2009 levels throughout this period.

Overall, Sitka's NEL is forecast increase from 115,398 MWh in 2010 to 125,692 in 2015. This is equivalent to an annual compound growth rate of 1.7 percent.

Following is the summary of key assumptions and forecasts made by Black & Veatch:

- The number of customers will remain flat at 2010 levels during this period. ADL projections indicate that there will be a small decline in population during this period. However Black & Veatch expects the population to remain flat as there are opportunities for growth in tourism industry and other areas.
- Sales to residential customers will increase from 46,756 MWh in 2010 to 53,872 MWh in 2012 before falling off to 53,688 in 2013 and remaining flat thereafter. This equates to an annual compound growth rate of 2.8 percent from 2010 to 2015.
- Sales to commercial sector will grow at an annual compound rate of 2.0 percent during this period.
- Sales to Harbor customers will increase by an annual compound growth rate of 1.0 percent.
- System losses will be at the same level as 2010 for every year in the period, which is 4.6 percent of the annual sales forecast.
- The load factor is assumed to remain at 58.7 percent which is the average for 2008 through 2010 for all years in this period.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the population forecast by ADL, the population of the region is likely to reduce from 8,948 people in 2015 to 8,658 people in 2030. Following this trend Black & Veatch expects that the population will likely go down to approximately 8,576 people by 2035. This shows that the population will shrink by 4.2 percent in these 20 years. These population projections are indicative of continuing economic decline. While the ADL projections represent a significant forecasting effort, Black & Veatch believes that the fishing industry will continue to improve modestly through this period subject to ups and downs in catch each year. Black & Veatch feels that this modest improvement will allow for continuing use per customer for residential customers to be sustained. There will also likely be a corresponding increase in the use per customer for commercial loads as the fishing industry continues to modestly improve through time.

Load factors are expected to remain fairly constant at 2015 levels throughout this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- The total annual sales will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers will decline slowly in relation to the ADL population projections.

- Use per residential customer will increase due to oil prices going back to medium levels and the ever increasing uses of electricity coupled with some economic sustainability from the fishing industry. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.
- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- System losses and load factor will continue to remain at existing levels.

2036-2060 – Long Term

Long term projections are not available from the ADL. Black & Veatch forecasts moderate growth in number of customers and use per customer for all sectors combined. Overall the total annual sales are forecast to increase by 0.3 percent annually for this period. System losses and load factor will continue to remain at existing levels.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.7.2 High Scenario Load Forecast

Black & Veatch developed the Sitka High Scenario Load Forecast based on the assumptions indicated earlier in the general description section. The population of Sitka as projected by the ADL is expected to reduce from 8,984 persons in 2010 to 8,658 persons in 2030. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will decline at the same annual rate as is forecast for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in energy requirements for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL for the high scenario is 121,754 MWh in 2011, and it increases to 258,735 MWh in 2061. In the Reference Scenario the NEL for 2011 was 121,751 MWh in 2011 and 150,124 MWh in 2061. This shows that the additional energy for the high case is 1.0 percent higher in 2011 and 72.4 percent higher in 2061 compared to the energy forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.8 YAKUTAT POWER

8.8.1 Reference Scenario Load Forecast

To develop the Yakutat load forecasts, Black & Veatch initially reviewed the historical trends in energy and peak demand and discussed possible load growth opportunities with Yakutat Power. Black & Veatch also reviewed the projected population growth as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the American Community Survey ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by diesel generation.

2011-2015 – Short Term

During this period it is assumed that the peak and energy demand would follow a similar pattern as in 2010 as usage pattern is unlikely to change in this time frame. Additional load from new developments is also considered during this period. The information for new loads was obtained in conversation with Yakutat Power. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2010.

According to the population forecast by ADL, the population is likely to remain constant during this period.

According to the information received from Yakutat Power, the main demand for electricity comes from the fishing industry for refrigeration. However, this demand is seasonal and dependent upon the price of fuel in the region. Competitive fuel prices compared to other nearby regions are likely to increase activity of the fishing fleet and the increased volume of fish increases the demand for electricity and vice versa. In the past the region has been able to provide fuel at competitive prices, which has resulted in higher energy demand. Black & Veatch has assumed that this trend is likely to continue during this period.

Yakutat Power estimates that only 20 percent of the houses use wood for heat. Few houses use electric heating system, but most houses would likely convert to electric heating if in the future the price of electricity was low compared to fuel oil. Black & Veatch does not envision significant conversion to electric heat in the foreseeable future for Yakutat Power.

The AHFC offers weatherization and energy rebate programs. Even though qualifying customers can participate in the weatherization program at no cost, very few customers are participating in either the weatherization or energy rebate programs. Black & Veatch does not believe that penetration in these programs will significantly increase without additional conservation and energy efficiency efforts, which will be covered separately.

Black & Veatch also discussed the possibility of users replacing incandescent bulbs with energy efficient bulbs, which would reduce lighting loads. Based on that discussion, Black & Veatch assumed that only a small number of people will actually do this without an external program during this time frame and the demand will not be significantly impacted on account of this.

Historically NEL has declined over the last decade with an annual compound growth rate of -1.7 percent. Within that period, NEL steadily decreased from 2000 to 2005, increased in 2006 and 2007, decreased again in 2008 and 2009, and slightly increased in 2010. Sales by sector in 2010 were as follows:

- Residential 23.6 percent
- Commercial 57.8 percent
- Community Centers 7.3 percent
- Federal/State Facilities 11.2 percent

As seen, the commercial sector has the largest influence on NEL. The commercial sector is heavily driven by the fishing industry with commercial sales declining in 2008 and 2009 corresponding to high cost of fuel in 2008 and the economic crisis. Residential sales have generally declined throughout the last decade.

The number of commercial customers peaked in 2008 and dropped in both 2009 and 2010. The number of commercial customers lags the economic conditions to some extent since plans for new commercial establishments are often made at least a year before opening of the establishment. The number of residential customers have been relatively flat, but trended down in 2009 and 2010.

Use per customer responds quicker to economic conditions and high oil prices. Use per customer has for commercial and residential customers decreased an average of nearly 2 percent per year from 2005 to 2010. At present the unemployment rate in the region is very high. High unemployment is prevalent throughout the US as a result of the recession, but not to the extent evident in Yakutat.

Based on the above analysis, Black & Veatch projects Yakutat's NEL to be approximately equal to the 2009 level in 2015. This generally reflects reduced load associated with the effects of high oil prices offset by gains in the fishing industry. NEL could increase towards the end of the period if oil prices moderate and the economy strengthens.

YPL also stated that they have a very high base load demand of approximately 850 kW compared to their peak demand, which was approximately 1,450 kW in 2010. This information is supported by the fact that the load factor on the system has been around 52-54 percent for the last 5 years.

Based on the above assumptions and information, Black & Veatch has made the following forecasts for this period:

- The number of customers will remain steady through the period. This is consistent with the ADL projections, which indicate only a loss of 2 in population during this period.
- Use per customer is assumed to decrease slightly for the residential sector and increase slightly for the commercial sector such that the net impact of use per customer and a stable number of customers results in relatively flat sales.
- System losses will not improve and will be at the same level as 2010 for every year in the period, which is 8 percent of the annual sales forecast.
- The resulting NEL reduces to the 2009 level and remains relatively constant through the period.
- The annual load factor for all years is forecast to be the average of the last 5 years, which is 52.86 percent.
- The peak load forecast was calculated based on the forecast system load factor and projected NEL.

2016-2035 – Intermediate Term

For the intermediate term, Black & Veatch assumes that the price of oil returns to the medium ISER projections.

According to the population forecast by ADL, the population of the region is likely to reduce from 644 people in 2015 to 574 people in 2030. Following this trend Black & Veatch expects that the population will likely go down to approximately 550 people by 2035. This shows that the population will shrink by 15 percent in these 20 years. These population projections are indicative of continuing economic decline. While the ADL projections represent a significant forecasting effort, Black & Veatch believes that the fishing industry will continue to improve modestly through this period subject to ups and downs in catch each year. Black & Veatch feels that this modest improvement will allow for continuing use per customer for residential customers to be sustained. There will likely be a corresponding increase in the use per customer for commercial loads as the fishing industry continues to modestly improve through time.

Load factors are expected to remain fairly constant through this period.

Based on the above assumptions, Black & Veatch has forecast the following:

- The annual energy sales will increase at 0.5 percent annually from 2016-2035.
- The number of residential customers will decline in relation to the ADL population projections.
- Use per residential customer will increase due to oil prices going back to medium levels and the ever increasing uses of electricity coupled with some economic sustainability from the fishing industry. Naturally occurring conservation will mitigate large increases in use per customer as residential customers slowly become able to afford more conservation.
- The number of commercial customers will remain relatively constant with the return of medium oil prices.

- Use per commercial customer will increase slowly being mitigated by fewer residential customers.
- System losses will remain constant at current levels.
- Resulting NEL will increase very modestly during this period by an average of approximately 0.5 percent per year.
- The annual load factor for all years is forecast to remain constant at 52.86 percent.

2036-2060 – Long Term

Long-term projections are not available from the ADL. Black & Veatch forecasts moderate growth in the number of customers and use per customer for residential and commercial sectors at an annual rate of 0.2 percent for number of customers and use per customer. Overall the system NEL is expected to grow at an annual rate of 0.4 percent. The system losses and load factor are assumed to remain constant at current levels.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.8.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for YP based on the assumptions indicated earlier in the general description section. The population of the Yakutat Area, as projected by the ADL is expected to decrease from 646 persons in 2010 to 574 persons in 2030. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, Black & Veatch assumed that the population will grow at the same annual rate as is forecast for the period 2025 to 2030. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the original case. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high scenario is 6,418 MWh in 2011 and it increases to 13,347 MWh in 2061. In the Reference Scenario the NEL forecast for 2011 was 6,418 MWh in 2011 and 7,718 MWh in 2061. This shows that NEL for the high scenario is 1.0 percent higher in 2011 and 72.9 percent in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.9 EXCURSION INLET

Excursion Inlet is home to the Ocean Beauty Seafood processing plant. The plant supplies its own electric generation as well as to some homes and businesses. All other homes and businesses supply their own power. Currently there are approximately 20 homes in Excursion Inlet. The Borough is planning to have a land sale in the future. After the land sale and if the lots are developed, there is expected to be between 50 and 100 homes in Excursion Inlet. Excursion Inlet is a bedroom community for Juneau.

Since there is no utility system currently in Excursion Inlet, load forecasts have not been developed for Excursion Inlet.

8.10 GUSTAVUS ELECTRIC

8.10.1 Reference Scenario Load Forecast

Black &Veatch initially requested detailed historical energy usage and demand data to develop the load forecasts for the Gustavus region. However detailed historical data was not available and so Black & Veatch referred to the publicly available data from Form EIA-861 filings by Gustavus Electric on the EIA website.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by existing generation resources.

Black & Veatch reviewed the annual sales and system loss data from 2001 through 2009 based on information available from the EIA-861 filings. Black & Veatch calculated the NEL from the above two figures. Black & Veatch noted that the system loss figures for 2002 and 2003 were not available.

Black & Veatch was informed that there was a new 300 kW hydroelectric generation project that started operations in late 2009. Shifting to hydroelectric power lowered the retail electric rates in the community and as a result energy sales increased during 2010. Total generation in 2010 was 1,967 MWh.

2011-2015 – Short Term

No specific data for new load from committed new developments were available to Black & Veatch. So Black & Veatch relied on recent historical trends to forecast the energy need for this period.

Gustavus Electric informed Black & Veatch that as of 2010, there were 394 residential customers, 139 commercial customers, 6 Local Government offices and 23 State or Federal Government offices. While there have been no changes in the number of local, state and federal offices, the number of residential customers have increased from 383 in 2008 to 394 in 2010. Number of commercial customers also increased from approximately 112 customers in 2008 to 139 customers in 2010. Gustavus Electric informed Black & Veatch that it did not expect much growth in the commercial sector as that sector was almost saturated in the region. As a result Black & Veatch expects total number of customers to remain flat during this period.

Historically, annual sales for the region have increased at an annual compound rate of approximately 0.8 percent between 2001 and 2009. Sales grew from 2001 through 2005 increased by 0.1 percent and by 2.1 percent between 2005 and 2009. In 2010, the annual sales increased further to 1,967 MWh. Annual sales grew substantially in 2008 and 2009 compared to previous years due to new businesses (related to the fishing industry) starting operations at that time.

The current average retail electricity rate for residential customers is 26 cents/kWh without any assistance under the State sponsored Power Cost Equalization (PCE) Program. With the assistance the rates go down to about 18 cents/kWh. Rates for commercial customers were around 54 cents/kWh and they were not eligible for any assistance under the PCE Program. The rates are high enough to discourage people to convert their existing oil or wood based home heating systems to electric heating systems. Gustavus Electric has historically seen little or no such conversions, so Black & Veatch does not expect any significant load growth due to converting existing heating systems to electric heating systems. Current diesel prices are above $3.50 per gallon, and prices are still increasing.

Gustavus Electric explained to Black & Veatch that customers in the region have started to become more energy intensive and are using more electrical gadgets and appliances now than before. That was the main driver for the increase in generation from 2009 to 2010.

Based on the above, Black & Veatch has forecast that the annual energy sales for 2011 and 2012 will grow by 2 percent every year, as residential customers continue to keep changing their lifestyles during this period. They are expected to use electrical gadgets and appliances which will increase the load on the system. In 2013, the growth rate is expected to slow down to 1 percent as the new energy usage pattern of the customers stabilizes. Black & Veatch forecasts that there will be no further increase in sales in 2014 and 2015 as customer usage would have peaked by then.

Historical system loss data shows that system loss was approximately 14 percent (of annual sales) between 2004 and 2008, but reduced to 5 percent in 2009. Black & Veatch believes that the system loss data for 2009 is an anomaly, although the reduction could be related to the installation of the hydroelectric unit, so Black & Veatch has assumed that the system losses for 2011-2015 will be the average of the system losses recorded each year between 2004 and 2008, which is approximately 12 percent of annual sales. System loss data likely includes station service usage and unmetered.

Based on the above analysis, Black & Veatch expects that the NEL would increase from 2,201 MWh in 2010 to 2,313 MWh in 2015.

System peak for Gustavus Electric in 2010 was 350 kW in winter and 310 kW in summer. This shows that the annual load factor in 2010 was approximately 72 percent. Black & Veatch has assumed that the annual load factor would remain constant at current levels throughout this period. Black & Veatch expects the peak demand to increase from 350 kW in 2010 to 368 kW in 2015.

2016-2035 – Intermediate Term

Black & Veatch discussed the possibility of new load development in the region. Black & Veatch was informed that there was a possibility that the National Park in the region, which currently uses its own diesel generators for powering the facilities within the park, would build new transmission and distribution lines to connect to the new hydroelectric generation facility. The total new load from the National Park is expected to be 300 kW. However, this development activity is not within the control of Gustavus Electric, and therefore, Gustavus Electric could not provide a definite time frame by which this conversion would take place. Because of this, Black & Veatch assumed that this new load will occur in 2016. Black & Veatch has also assumed that the load factor for National Park load will be 25 percent as it will remain open for about 4 months in the year.

Black & Veatch did not have other data to make a detailed forecast for this period. As such in keeping with the general forecast trends for other neighboring regions and cities, Black & Veatch has forecast the annual sales other than the sales to the National Park will increase at 0.2 percent annually from 2016-2035. System losses and load factor are projected to remain at current levels throughout this period.

Based on this assumption NEL is expected to increase from 2,692 MWh in 2016 to 2,923 MWh in 2035. Peak demand is expected to increase from 428 kW in 2016 to 465 kW in 2035.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period. System losses, station use and load factor are projected to remain at current levels. Based on this assumption NEL is expected to grow from 2,926 MWh in 2036 to 3,000 MWh in 2061. Peak demand is expected to increase from 465 kW in 2036 to 477 kW in 2061.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.10.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Gustavus Electric based on the assumptions indicated earlier in the general description section. The population of Gustavus in 2009 was around 340 persons and the population had declined by approximately 19.3 percent since 2000. Black & Veatch assumed that this declining population trend will continue for another 10 years after which the population is expected to remain flat until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high scenario is 2,247 MWh in 2011 and it increases to 5,365 MWh in 2061. In the Reference Scenario the NEL forecast for 2011 was 2,958 MWh in 2011 and 3,000 MWh in 2061. This shows that NEL for the high case is 1.0 percent higher in 2011 and 78.8 percent in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.11 CHICHAGOF ISLAND COMMUNITIES

8.11.1 Elfin Cove

8.11.1.1 Reference Scenario Load Forecast

Black &Veatch initially requested detailed historical energy usage and demand data to develop the load forecasts for Elfin Cove. However detailed historical data was not available and so Black & Veatch referred to the publicly available data from Form EIA-861 filings by Elfin Cove on the EIA website. Black & Veatch also reviewed the projected population growth for surrounding areas as projected by the ADL in order to estimate future peak and energy demand. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by existing generation resources.

Black & Veatch reviewed the annual sales and system loss data from 2001 through 2009 based on information available from the EIA 861 filings. Black & Veatch calculated the NEL from the above two figures. Black & Veatch noted that the system loss figure for 2003 was not available.

2011-2015 – Short Term

No specific data for new load from committed new developments were available to Black & Veatch. So Black & Veatch relied on recent historical trends to forecast the energy need for this period.

According to the US Census data, the population for Elfin Cove has decreased from 32 people in 2000 to 20 in 2010. Black & Veatch expects the population to continue to decrease during this period.

Historically, annual sales for the region have decreased at an annual compound rate of approximately 1.0 percent between 2001 and 2009. Sales fell from 2003 until 2008 when they increased and reached 334 MWh and then fell again in 2009.

The average retail electricity rate was around 41 cents/kWh in 2009. The rates are high enough to discourage people to convert their existing oil or wood based home heating systems to electric heating systems. So Black & Veatch does not expect any load growth due to converting existing heating systems to electric heating systems.

As population is decreasing, Black & Veatch has forecast that the annual sales in the region will decrease by 2 percent every year until 2015. Historical System loss data shows that system loss has varied from 10 and 14 percent (of annual sales) between 2005 and 2008, but reduced to 7.6 percent in 2009. Black & Veatch believes that the system loss data for 2009 is an anomaly.

Black & Veatch has assumed that the system losses for 2011-2015 will be the average of the system losses recorded each year between 2005 and 2009, which is approximately 11 percent of annual sales.

Assuming that load factor is approximately 52 percent, Black & Veatch expects the peak demand to decrease from 76 kW in 2011 to 68 kW in 2015.

2016-2035 – Intermediate Term

Black & Veatch did not have much data to make a detailed forecast for this period. Because of this, in keeping with the general forecast trends for other neighboring regions and cities, Black & Veatch has forecast the annual sales will increase at 0.2 percent annually from 2016-2035. System losses and load factor are projected to remain at current levels. Based on this assumption peak demand is expected to increase from 68 kW in 2016 to 71 kW in 2035.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period. System losses and load factor are projected to remain at current levels. Based on this assumption peak demand is expected to increase from 71 kW in 2036 to 73 kW in 2061.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.11.1.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Elfin Cove based on the assumptions indicated earlier in the general description section. The population of Elfin Cove in 2010 was around 20 persons. During the last decade the population had decreased from 32 people in 2000 to about 20 people in 2010. For this scenario, Black & Veatch assumed that population will remain flat until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high scenario is 337 MWh in 2011 and it increases to 578 MWh in 2061. In the Reference Scenario, the NEL forecast for 2011 was 337 MWh in 2011 and 392 MWh in 2061. This shows that NEL for the high scenario is 1.0 percent higher in 2011 and 74.1 percent higher in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.11.2 Pelican

8.11.2.1 Reference Scenario Load Forecast

Black &Veatch initially requested detailed historical energy usage and demand data to develop the load growth forecast for the region. However, detailed historical data was not available, and so Black & Veatch referred to the publicly available data from Form EIA 861 filings by Pelican Electric on the EIA website. Black & Veatch also reviewed the projected population growth surrounding areas as projected by the ADL in order to estimate future peak demand and energy. Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000 and 2010 and the ACS data for 2005-2009.

Load Forecast (2011-2061)

In developing the peak and energy demand forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by existing generation resources.

Black & Veatch reviewed the annual sales system loss data from 2001 through 2009 based on information available from the EIA 861 filings. Black & Veatch noted that the system loss figures reported for some years appeared to be outliers and so Black & Veatch ignored those data for this analysis.

Black & Veatch received annual sales data for 2010 from Pelican separately. Pelican informed Black & Veatch that they lost their biggest industrial customer at the end of 2009 and so the annual energy demand for 2010 dropped to approximately 755 MWh.

2011-2015 – Short Term

No specific data for new load from committed new developments were available to Black & Veatch. So Black & Veatch relied on recent historical trends to forecast the energy need for this period.

According to the US Census data, the population for Pelican has decreased from 163 people in 2000 to 88 in 2010. Black & Veatch expects the population to continue to decrease during this period.

As Pelican lost its major customer in 2010, the annual sales for 2010 was substantially different from those of the previous years. Therefore, Black & Veatch analyzed only the 2000-2009 historical data to estimate historical trends. Historically annual sales for the region have decreased at an annual compound rate of 4.7 percent between 2001 and 2009. Within that period, annual sales decreased at an annual compound rate of 5.7 percent from 2001 to 2005, and at an annual compound rate of 6.9 percent between 2005 and 2009. The annual sales declined even further in 2010 as the largest industrial customer closed down their facility.

Pelican informed Black & Veatch that they were relying entirely on diesel generation in 2010 to meet their load. Black & Veatch noted from data received from Pelican that the sales to residential and industrial customers reduced in 2010 compared to 2009. This is due to the fact that customers were forced to conserve in 2010 due to higher retail electricity rates. According to the AEA, the

Pelican Hydro project is not expected to resume operation before October 2012. As hydroelectric generation is cheaper compared to diesel generation, retail electricity rates are expected to come down on account of this switch and Pelican expects customers to use more electricity which will drive growth in energy sales from October 2011onwards. Taking into account that increase in usage by customers will be offset to a certain extent by decrease in number of customers, Black & Veatch has forecast that annual sales for 2011 are expected to increase by 1 percent from 2010 levels as Pelican will move to hydroelectric generation in October 2011 and customers will likely use additional energy for the last three months of the year only. Annual energy sales will increase by 5 percent in 2012 over 2011 levels as people will conserve less and use more electricity for the whole year. The usage for 2013 is expected to increase by another 5 percent as people continue to use more electricity. However, the usage is expected to remain flat in 2014 and 2015 as usage by customers stabilizes again.

The average retail electricity rate was around 26 cents/kWh in 2009. The rates are high enough to discourage people from converting their existing oil or wood based home heating systems to electric heating systems. However, if Pelican shifts to hydroelectric generation in October 2011 as is expected, the retail electricity rates are likely to come down appreciably, and it may be more economical to use electricity to heat homes compared to using heating oil. As a result Black & Veatch expects additional energy usage by customers. Converting oil based heating systems to electric heating systems usually requires high capital investment and it is unlikely that many customers will convert to electric heating systems immediately. However, most customers are likely to use electric space heaters which are available at very low costs at retail stores. Customers will continue to use electric space heaters unless oil prices come down from their current levels. At present oil prices have peaked but are expected to come down in around 2013. Electric space heaters are usually sized 500 watt or 1,000 watt. Assuming each customer of Pelican will use two small space heaters (500 watt) for 16 hours a day for 3 months in a year, the total estimated annual increase in energy demand is expected to be approximately 1,440 kWh per customer. Black & Veatch assumed that this usage pattern will increase the annual energy sales for 2011 and 2012 by an additional 2 percent and 5 percent respectively. Once oil prices come down in 2013, customers using space heaters are expected to revert back to using heating oil for heating their homes. As such Black & Veatch does not expect any additional load from using space heaters from 2013 onwards.

As population is decreasing, Black & Veatch has forecast that the annual sales in the region will decrease by 2 percent every year until 2015. System losses will remain at 2009 levels during this period, which is approximately 13.5 percent of annual sales.

Assuming that load factor is approximately 52 percent, Black & Veatch expects the peak demand to decrease from 188 kW in 2011 to 224 kW in 2015. Average demand is currently between 100 and 125 kW.

2016-2035 – Intermediate Term

Black & Veatch did not have much data to make a detailed forecast for this period. Because of this, in keeping with the general forecast trends for other neighboring regions and cities, Black & Veatch has forecast the annual sales will increase at 0.2 percent annually from 2016-2035. System losses and load factor will remain at current levels. Based on this assumption peak demand is expected to increase from 224 kW in 2016 to 233 kW in 2035.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period. System losses will continue to remain at current levels. Based on this assumption peak demand is expected to increase from 233 kW in 2036 to 239 kW in 2061.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.11.2.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Pelican Electric based on the assumptions indicated earlier in the general description section. The population of Pelican in 2010 was around 88 persons. During the last decade the population had decreased from 163 people in 2000 to about 88 people in 2010. For this scenario, Black & Veatch assumed that population will remain flat until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high scenario is 883 MWh in 2011 and it increases to 1,949 MWh in 2061. In the Reference Scenario the NEL forecast for 2011 was 883 MWh in 2011 and 1,089 MWh in 2061. This shows that NEL for the high scenario is 1.0 percent higher in 2011 and 79 percent higher in 2061 compared to the NEL forecast in the Reference Scenario for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

8.11.3 Tenakee Springs

8.11.3.1 Reference Scenario Load Forecast

Black &Veatch initially requested detailed historical energy usage and demand data to develop the Tenakee Springs load forecasts for the region. However, detailed historical data was not available, and so Black & Veatch referred to the publicly available data from Form EIA 861 filings by Tenakee Springs on the EIA website. Black & Veatch also reviewed the projected population growth for surrounding area as projected by the ADL in order to estimate future peak demand and NEL Black & Veatch also assessed the historical trends in population and housing from the published US Census Data for 2000, 2010 and the ACS data for 2005-2009.

While the Census data for 2010 indicates the population to be 131, this population if based on voter eligibility and many part time residents register to vote in Tenakee Springs. The actual population count is around 60 in winter increasing to around 110 in summer, but many of the homes do not have city power. Electric loads are increasing as many of the small cabins are remodeled with 100 amp service, but these increased loads are being offset by conservation and energy efficiency being implemented due to the high cost of electricity.

Load Forecast (2011-2061)

In developing the peak demand and energy forecast, Black & Veatch broke down the forecast period into three different time frames:

- Short Term – 2011 to 2015.
- Intermediate Term – 2016 to 2035.
- Long Term – 2036 to 2061.

In developing this reference case forecast, Black & Veatch assumes that there are no significant changes in the cost of power and power continues to be supplied by existing generation resources. The current cost for residential service averages about $0.40/kWh due to the PCE program. There are plans for a hydroelectric project to be implemented by 2015 or 2016 which will lower power costs to about $0.40/kWh. The hydroelectric project is dependent upon obtaining AEA grants. As stated above, for purposes of the reference forecast, Black & Veatch has not considered these changes. The changes in cost of electricity are not expected to result in any significant changes to the load forecast.

Black & Veatch reviewed the annual sales and system loss data from 2001 through 2009 based on information available from the EIA-861 filings. Black & Veatch calculated the NEL from the above two figures. Black & Veatch noted that the system loss figures reported for some years appeared to be outliers, and Black & Veatch ignored those data for this analysis.

2011-2015 – Short Term

No specific data for new load from committed new developments were available to Black & Veatch, and Black & Veatch relied on recent historical trends to forecast the energy need for this period. It is also assumed that no new transmission upgrades would be possible within this time frame. System loss patterns, therefore, are unlikely to improve during this time frame as compared to 2009.

According to the US Census data, the population for Tenakee Springs has increased from 104 people in 2000 to 131 in 2010. Based on the discussions Black & Veatch had with the city of Tenakee Springs, population growth is unlikely in the near term. Black & Veatch expects the population to remain flat during this period.

Historically, annual sales for the region has decreased at an annual compound rate of approximately 1.6 percent between 2001 and 2009. Within that period, annual sales decreased at an annual compound rate of 3.3 percent from 2001 to 2005, and increased at an annual compound rate of 1.2 percent between 2005 and 2009.

The average retail electricity rate was around $0.63/kWh in 2009 before PCE and are about $0.30/kWh with PCE. The rates are high enough to discourage people to convert their existing oil or wood based home heating systems to electric heating systems. So Black & Veatch does not expect any load growth on account of converting existing heating systems to electric heating systems.

As population is expected to remain flat, Black & Veatch has forecast that the annual sales in the region will remain flat until 2015. Historical system loss data shows that system loss has varied from 12 and 15 percent (of annual sales) between 2005 and 2009. Black & Veatch has assumed that the system losses for 2011-2015 will be the average of the system losses recorded each year between 2005 and 2009, which is approximately 13.7 percent of annual sales.

Assuming that load factor is approximately 52 percent, Black & Veatch expects the peak demand to remain flat at 91 kW throughout this period.

2016-2035 – Intermediate Term

Black & Veatch did not have much data to make a detailed forecast for this period. As such in keeping with the general forecast trends for other neighboring regions and cities, Black & Veatch has forecast the annual sales will increase at 0.2 percent annually from 2016-2035. System losses and load factor are expected to remain at current levels. Based on this assumption peak demand is expected to increase from 92 kW in 2016 to 95 kW in 2035.

2036-2060 – Long Term

Black & Veatch forecasts slow growth in long-term annual sales from 2036 onwards until 2061. Black & Veatch forecasts that the annual sales for the region will grow at 0.1 percent per year during this period. System losses and load factor are expected to remain the same. Based on this assumption peak demand is expected to increase from 95 kW in 2036 to 98 kW in 2061.

The annual energy and peak projections are presented in Tables 8-1 and 8-2, respectively.

8.11.3.2 High Scenario Load Forecast

Black & Veatch developed the High Scenario Load Forecast for Tenakee Springs based on the assumptions indicated earlier in the general description section. The population of Tenakee Springs in 2010 was around 131 persons. During the last decade the population had increased from 104 people to 131 people. For this scenario, Black & Veatch assumed that population remain flat until 2015 and then increase by 0.5 percent annually until 2036 and then remain flat until the end of the study period. Black & Veatch used this population and the other assumptions as indicated in the general description section to forecast the additional energy required from the penetration of PHEVs. For population growth beyond 2030, In addition to forecasting the additional energy required for charging PHEVs, Black & Veatch has also forecast an additional 1.0 percent growth in annual energy for every year in the study period over the corresponding energy forecast in the

Reference Scenario. This was done to account for increased loads caused by faster than expected economic growth and development.

The annual NEL forecast for the high case is 416 MWh in 2011 and it increases to 969 MWh in 2061. In the Reference Scenario the NEL forecast for 2011 was 416 MWh in 2011 and 444 MWh in 2061. This shows that NEL for the high scenario is 1.0 percent higher in 2011 and 118.2 percent in 2061 compared to the NEL forecast in the original case for those years.

The High Scenario energy and peak forecasts are presented in Tables 8-6 and 8-7, respectively.

9.0 Financing Alternatives

This section discusses a financial model that was developed to evaluate the ability of alternative financing scenarios to minimize the initial cost impact of hydroelectric and transmission projects. Minimizing initial rate impacts can be especially challenging for small hydroelectric projects given the high installed cost per kilowatt (kW) and the possible inability of participants to fully utilize the project output early in the project life. To demonstrate this, the financial model was used to evaluate a representative hydroelectric project under four different financing scenarios.

The financial model is in the form of a discounted cash flow pro forma. This model establishes a revenue level sufficient to offset project costs each year, provide adequate debt service coverage, and provide the target return on equity investment, where applicable. Figure 9-1 shows how the model is constructed conceptually. The model cash flow sequence begins with annual revenues and then subtracts operating expenses, debt service, and taxes (if applicable) to arrive at the net cash flow each year. The net cash flow, which is essentially the equity return, is then discounted to the start of the project and this discounted cash flow is compared to the value of equity put into the project.

The model is structured to generate a net present value (NPV) for the project. If the discounted equity return is just equal to the value of equity input, the project NPV is zero. The model can solve for the revenue level needed to yield a zero NPV. The model can also generate a project internal rate of return (IRR) given a specific revenue level. The IRR is the discount rate at which the project NPV equals zero.

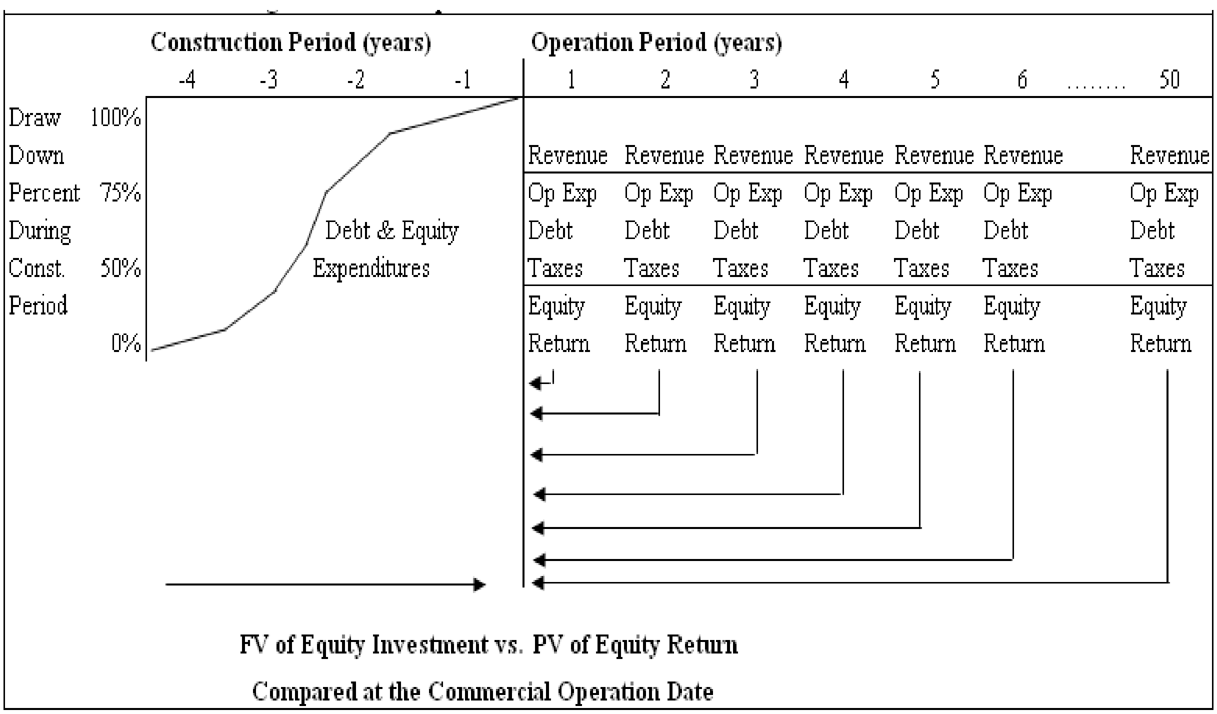

Figure 9-1 Conceptual View of the Discounted Pro Forma Financial Model

The four financing scenarios consist of the following:

- **Case 1: Conventional Financing** -- Assumes 100 percent, tax-exempt utility bond financing.
- **Case 2: Grant Financing** -- Assumes State grant financing of 50 percent of the turnkey project cost and tax-exempt utility bond financing for 50 percent of the turnkey project cost.
- **Case 3: Bradley Lake Model** -- Similar (but not identical) to the Bradley Lake financing approach in that it assumes that the turnkey project cost is financed 50 percent by tax-exempt utility bond financing and 50 percent by State equity financing. Currently, the model is set up assuming that the State is paid back its original equity investment over the remaining life of the project following the 30-year debt service period.
- **Case 4: Inflation-Indexed Bradley Lake Model** -- Similar to Case 3, but assumes a higher level of State equity financing as well as that the cost of power is indexed to one half of the inflation rate of 3 percent (1.5 percent) over the operating term such that the rate escalates in nominal terms but decreases in real terms. Similar to Case 3, the State is paid back its original equity investment over the life of the 50-year project period.

Additional information about the four financing cases is discussed in Section 9.1 through Section 9.4, and the detailed pro forma worksheets are included in Appendix B. These cases include several common assumptions related to the financing assumptions and to the cost and performance assumptions for the hypothetical unit, as shown in Table 9-1. These cost and performance parameters can be further refined as specific projects are identified and modeled.

Table 9-1 Assumptions Common to the Four Financing Scenarios

FINANCIAL ASSUMPTIONS		TECHNICAL ASSUMPTIONS FOR HYPOTHETICAL HYDRO UNIT	
General inflation rate	3 percent	Construction period	48 months
Tax-exempt debt interest rate	5.5 percent	Operating period	50 years
Debt term	30 years	Commercial operation date	January 2018
Debt payments	2 per year	MW output	25 MW
Debt reserve fund	1 year principle and interest	EPC cost/kW	$10,000
Debt issuance costs	1.5 percent of debt	Initial FOM cost	$50/kW-year
Minimum debt coverage ratio	1.2 (fund build up in first year of operation)	Initial VOM cost	$3/MWh
Return on State equity investment	Case 1 – Not applicable Case 2 – None (the grant is not repaid) Case 3 – Original equity repaid, no rate of return on equity Case 4 – Original equity repaid, no rate of return on equity	Capacity factor	65 percent
Working capital fund	45 days O&M		

One potential source of financing is AEA's Power Project Loan Program. The Program provides loans to local utilities, local governments, and independent power producers for the development or upgrade of electric power facilities including conservation, bulk fuel storage, and waste energy conservation. The loan term is based on the economic life of the project and cannot exceed 50 years. The interest rate varies between the rate that is equal to the average weekly yield of municipal bonds for the 12 months preceding the date of the loan as determined by AEA from the municipal bond yield rates reported in the 30 year revenue index of The Bond Buyer or a rate determined by AEA that allows the project to be financially feasible with a minimum interest rate of 0 percent. Loans are limited to projects that are 10 MW or less.

9.1 CONVENTIONAL FINANCING

The Conventional Financing model assumes 100 percent, tax-exempt utility financing. This scenario serves as a baseline against which alternatives are compared. The pro forma model is established such that the revenue each year is set to a level high enough to recover all variable and fixed O&M costs, plus debt service costs. In this manner, when the cash flow begins with annual revenues and then subtracts fixed and variable O&M costs, contribution to project funds (working and debt reserve), and debt costs, the net cash flow in the model is zero for each year.

One of the complications in the pro forma cash flow sequence just described is the need to set revenues high enough to provide an adequate debt service coverage ratio (assumed to be 1.2 coverage of annual debt costs) and the eventual return of the debt reserve fund (assumed to be equal to one year's worth of principle and interest). In a project with equity investment, the revenue over and above project costs needed to arrive at the required coverage ratio is normally counted as equity return each year and is swept from the project cash flows at the end of the year. With 100 percent debt financing, however, the revenues over and above annual project costs would accumulate and result in cumulative revenues significantly in excess of actual project costs over the debt term. To keep project costs to a minimum, the initial approach taken in the pro forma is to establish a "debt service coverage buildup fund" (this is in addition to the one year debt reserve fund) in year 1 that is maintained as a liquid fund during the 30-year project debt period. Thus, in year 1 of operation, the project cost is higher than in years 2 through 30, which benefit from the liquid reserve fund already established the first year.

Following the retirement of project debt at the end of year 30, the debt reserve fund and the debt service coverage buildup fund are no longer required. In the pro forma, this is shown as a transfer of funds to the project and, simultaneously, as a refund to the project's participating utilities. In this manner, the sizable debt-related funds are paid out and not retained at the project level. This results in a zero NPV over the entire operating period as intended for the Conventional Financing case.

The details of the inputs and annual cash flows for the Conventional Financing case are seen in Appendix B. The key output from the pro forma is shown in Figure 9-2 and Figure 9-3. These figures show the net capacity cost and the net cost per kWh during the 50-year project operating period. During years 2 through 30, the capacity cost is nearly $815/kW-year and the net cost per kWh begins at approximately 16.0 cents/kWh and ends at approximately 17.5 cents per kWh (as noted previously, the slightly higher cost in year 1 is related to the debt service coverage buildup fund, and the negative costs during the 31st year of operation (2048) reflect the refund to the participating utilities of the debt reserve fund and the debt service coverage buildup fund). Starting in year 32, the net cost is once again positive, but the cost is sharply reduced (to approximately 3 cents/kWh) compared to the first 30 years of operation as revenues are only needed to offset operating and maintenance costs (debt has been retired).

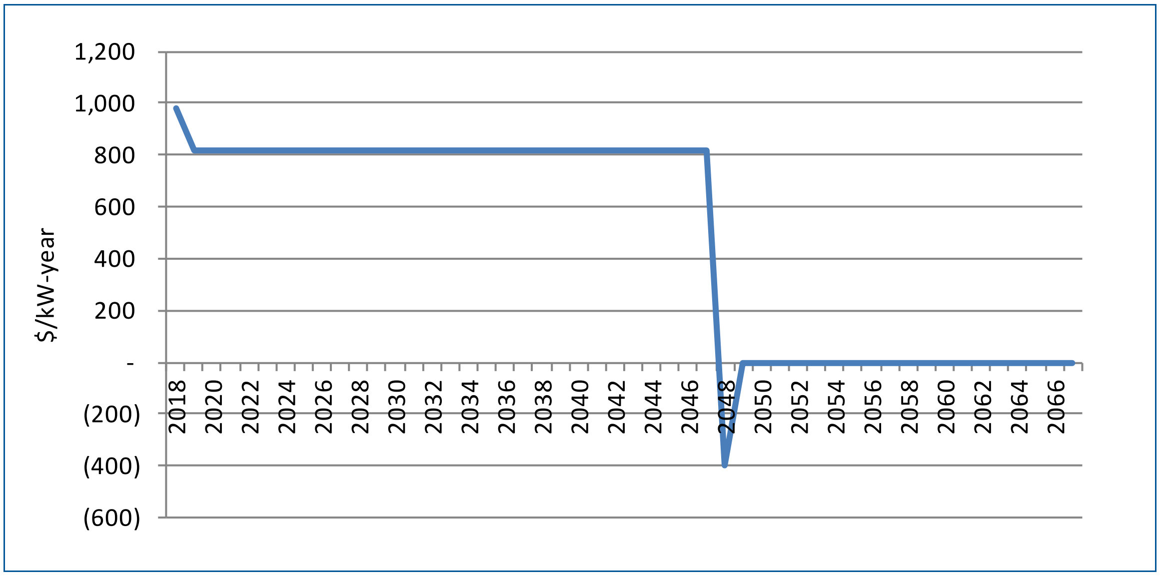

Figure 9-2 Conventional Financing Case - Net Capacity Cost ($/kW-year)[1]

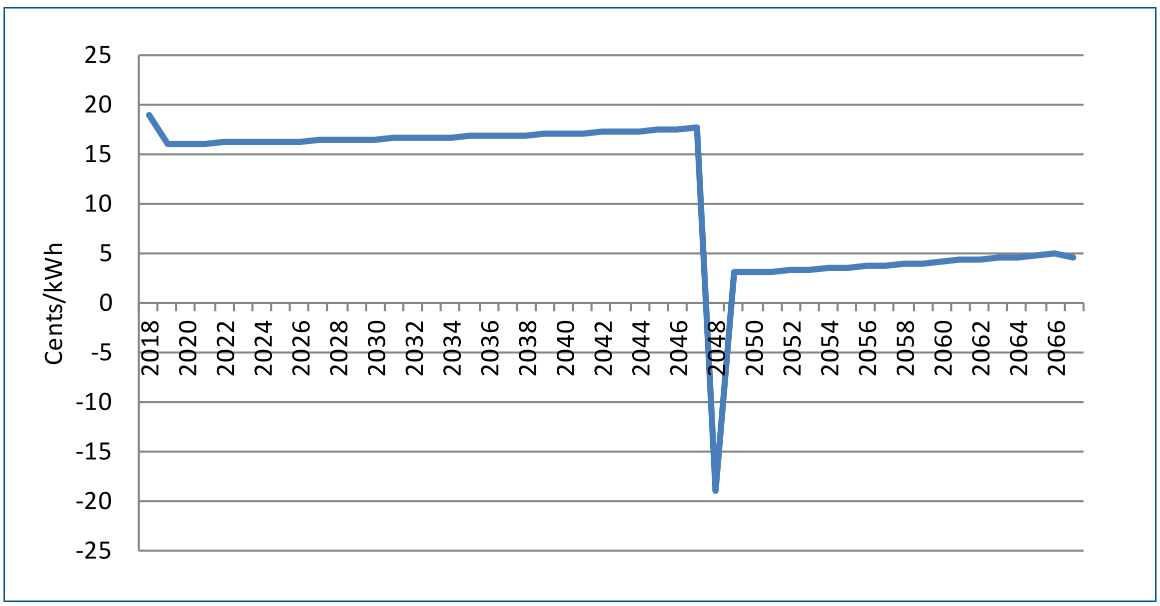

Figure 9-3 Conventional Financing Case - Net Cost/kWh[1]

[1] The "net" cost refers to net cost after reserve funds are funded or refunded.

In terms of levelized costs, the levelized net cost of the project over the 50-year operating life is 14.5 cents/kWh. The levelized fixed charge rate over the operating period is 5.7 percent.[2] As stated previously, this case assumes that no funds will be acquired from the State; the project will be 100 percent debt financed with no State funds to repay.

The net cost of the Conventional Financing case on Figure 9-2 and Figure 9-3 are typical cost patterns seen in utility-funded projects. The purpose of the three subsequent financing scenarios is to determine if the initial cost impact can be reduced compared to the Conventional Financing case.

9.2 GRANT FINANCING

The second financing case assumes that the State of Alaska provides a grant for 50 percent of the project turnkey cost and that the participating utilities fund the remaining capital cost through tax-exempt debt financing. Intuitively, it would be expected that the general cost pattern would remain essentially the same as in the previous case, but the cost level would be cut in half since the grant funds from the State would not be repaid.

Figure 9-4 and Figure 9-5 show the resulting costs of the project; the detailed input and cash flow sheets for this case are included in Appendix B. Results indicate that, as would be expected, with 50 percent grant funding from the State, the capacity cost and net cost per kWh are approximately cut in half compared to the Conventional Financing Case. The capacity cost in years 2 through 30 is nearly $408/kW-year and the net cost of energy begins at approximately 8.6 cents/kWh in the second year of operation (as with the Conventional Financing case, the Grant Financing case shows elevated costs in year 1 and negative costs in year 31 due to the respective funding and refund of debt-related reserve funds).

In terms of levelized costs, the levelized net cost of the project over the 50 year operating life is 8.25 cents/kWh. The levelized fixed charge rate over the operating period is 5.7 percent for the utility financed portion of the project. The amount of funds granted to the project would be $125 million. Since these funds are in the form of a grant, they are assumed not to be repaid.

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[2] A fixed charge rate is defined as the percentage rate that, when applied to the total capital cost, yields sufficient revenue to offset that year's capital-related costs financed through debt and equity. The annual fixed charge rates can be levelized to yield a single percentage rate that, on a present value basis, yields sufficient revenue to offset all capital-related costs financed through debt and equity.

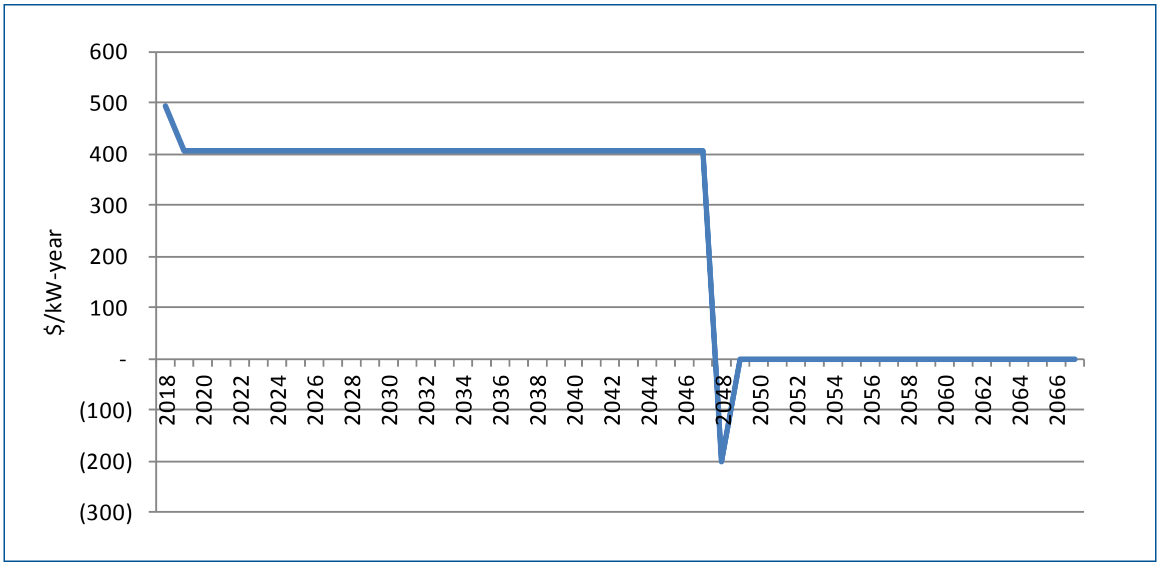


Figure 9-4 Grant Financing Case - Net Capacity Cost ($/kW-year)[3]

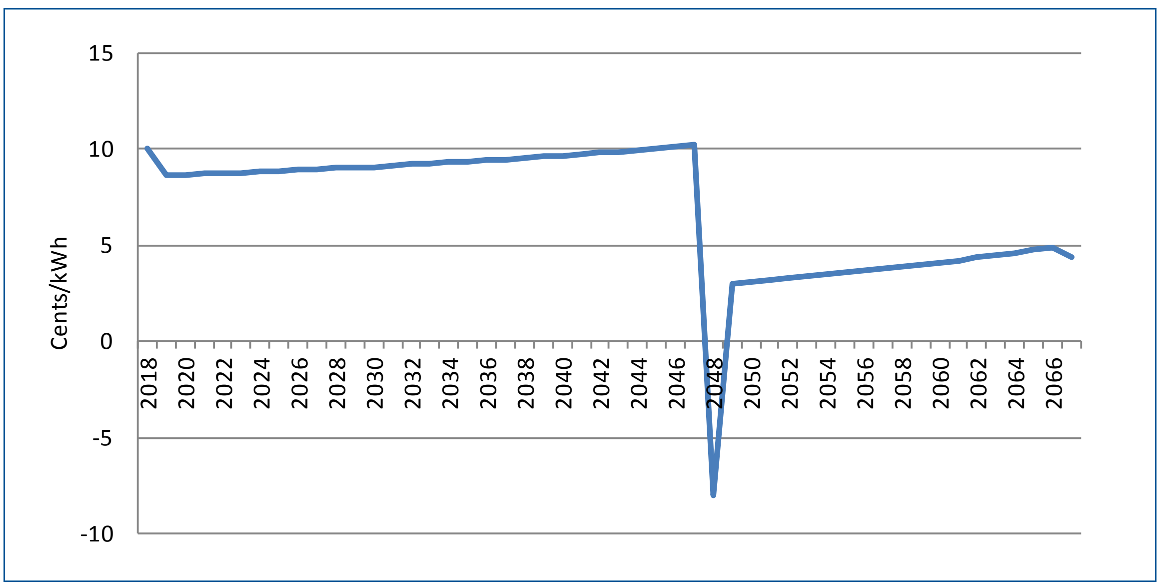


Figure 9-5 Grant Financing Case - Net Cost, Cents/kWh Sales Price[3]

[3] The "net" cost refers to net cost after reserve funds are funded or refunded.

9.3 BRADLEY LAKE MODEL

The Bradley Lake model assumes an equity contribution from the State of Alaska equal to 50 percent of the turnkey project cost and 50 percent funding of the turnkey cost through tax-exempt utility financing. The model assumes that the State of Alaska is paid back its original equity investment, on a dollar-for-dollar basis with no return on equity. It is assumed that equity repayment begins once the project debt is paid off over a 20-year period, beginning in year 31 of operation. Also in year 31, the two debt reserve funds are given to the State as part of the equity payback.

The results of the Bradley Lake model are shown on Figure 9-6 and Figure 9-7. Detailed input and cash flow results are included in Appendix B. As indicated on Figure 9-6, the net capacity cost under the Bradley Lake model is nearly $408/kW-year beginning in year 2 and this is equal to the capacity rate in the Grant Financing scenario. The cost of energy during the year 2 through year 30 period is also equal to that in the Grant Financing scenario. Note in this case the debt reserve funds are used to pay back the State equity investment in year 31 (2048) and so there is not the one-year negative cost to participants as in the first two models. Also, since the model is structured to pay back the State loan over the 20 years of remaining life after debt is repaid, the capacity payment drops beginning in year 31 of operation and is approximately $217/kW-year during the final 20 years of operation.

Comparing the Bradley Lake model with the Grant Financing model, the Bradley Lake model has the same capacity cost during the first 30 years when debt is paid off, but then has a higher capacity cost during the last 20 years when the State equity is returned. In terms of levelized costs, the levelized net cost of the project over the 50 year operating life is 8.9 cents/kWh. The levelized fixed charge rate over the operating period is 6.2 percent. The amount of funds lent to the project would be $125 million. These funds are lent to the project with a zero percent debt rate for the project; as stated before the funds are repaid dollar for dollar with no return on equity for the State.

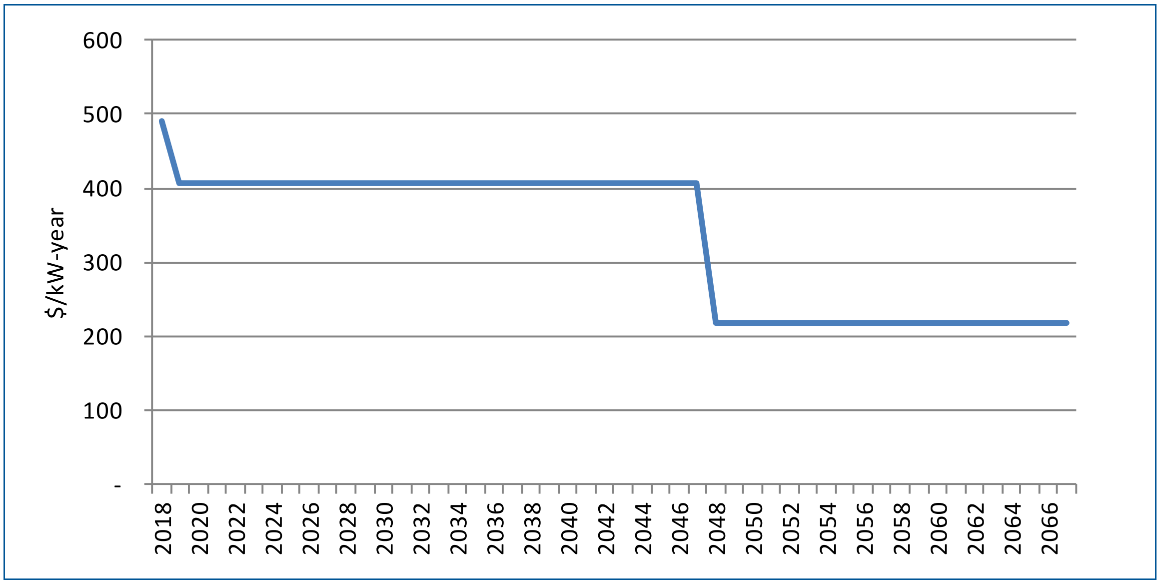


Figure 9-6 Bradley Lake Model Case - Net Capacity Cost ($/kW-year)[4]

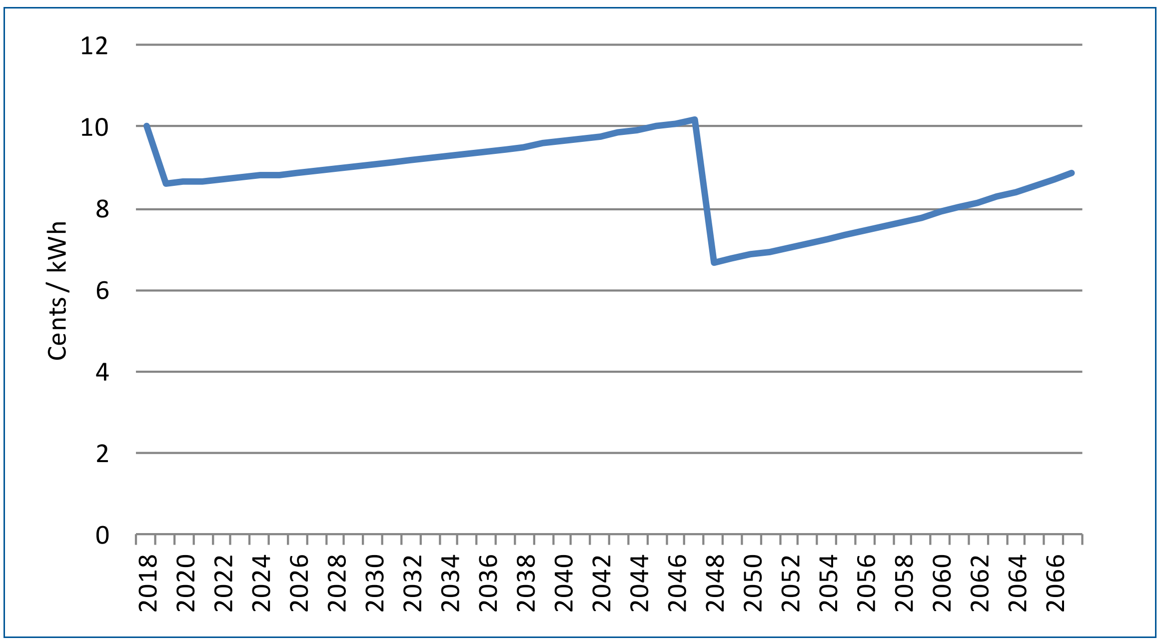


Figure 9-7 Bradley Lake Model Case - Net Cost, Cents/kWh Sales Price[4]

[4] The "net" cost refers to net cost after reserve funds are funded or refunded.

9.4 INFLATION-INDEXED BRADLEY LAKE MODEL

The Inflation-Indexed Bradley Lake financing model assumes a lower percentage (25 percent) of tax-exempt debt financing of the project turnkey cost and a higher percentage (75 percent) equity contribution from the State of Alaska with the intent of minimizing the capacity charge required to maintain positive cash flows for the project. The model assumes that the State of Alaska is paid back its original equity investment, on a dollar-for-dollar basis with no return on equity. It is assumed that equity repayment begins with positive, although minimized, cash flows in the first year of operation.

The results of the Inflation-Indexed Bradley Lake model are shown on Figure 9-8 and Figure 9-9. The initial capacity payment is significantly lower than the Bradley Lake model since the capacity payment is indexed and the percentage of project debt (with interest) is lower. The model calculates the minimum capacity payment at approximately $176/kW-year, which increases at 1.5 percent thereafter during over the life of the project. The escalated capacity payment over and above the debt service during the 30-year debt term becomes equity return to the State.

In terms of levelized costs, the levelized cost of the project over the 50-year operating life is 6.5 cents/kWh. The levelized fixed charge rate over the operating period is 9.0 percent. The amount of funds lent to the project would be $197 million. These funds are lent to the project with a zero percent debt rate for the project; as stated before the funds are repaid dollar for dollar with no return on equity for the State.

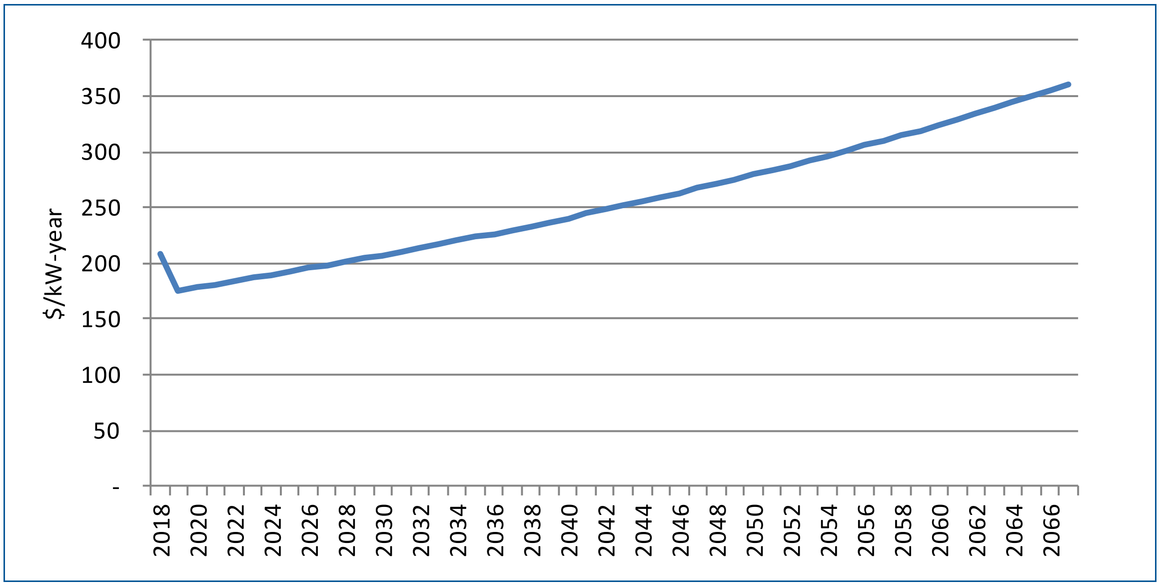


Figure 9-8 **Inflation-Indexed Bradley Lake Model Case - Net Capacity Cost ($/kW-year)[5]**

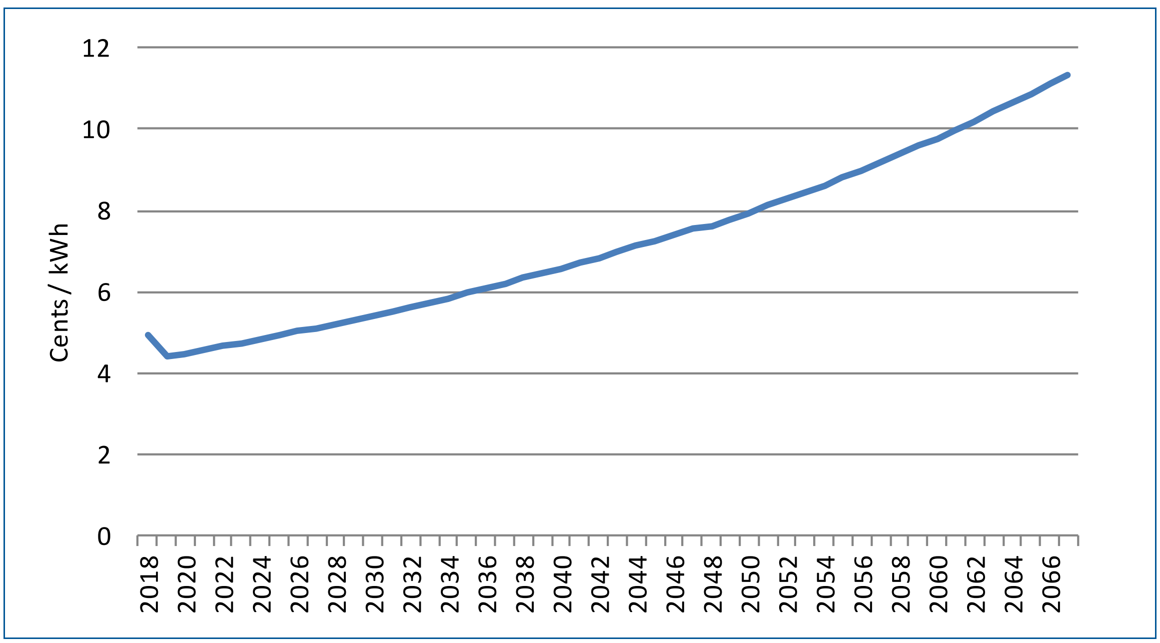


Figure 9-9 **Inflation-Indexed Bradley Lake Model Case - Net Cost, Cents/kWh Sales Price[5]**

[5] The "net" cost refers to net cost after reserve funds are funded or refunded.

9.5 COMBINED MODEL RESULTS

Figure 9-10 and Figure 9-11 compare the four financing scenarios on a capacity cost and net cost of energy basis. As seen in the figures, the Conventional Financing scenario has a high up-front cost compared to the other three scenarios.

The modeling results reported in this section are based on generic assumptions and will be refined as the project progresses and actual cost and performance inputs are developed for potential projects.

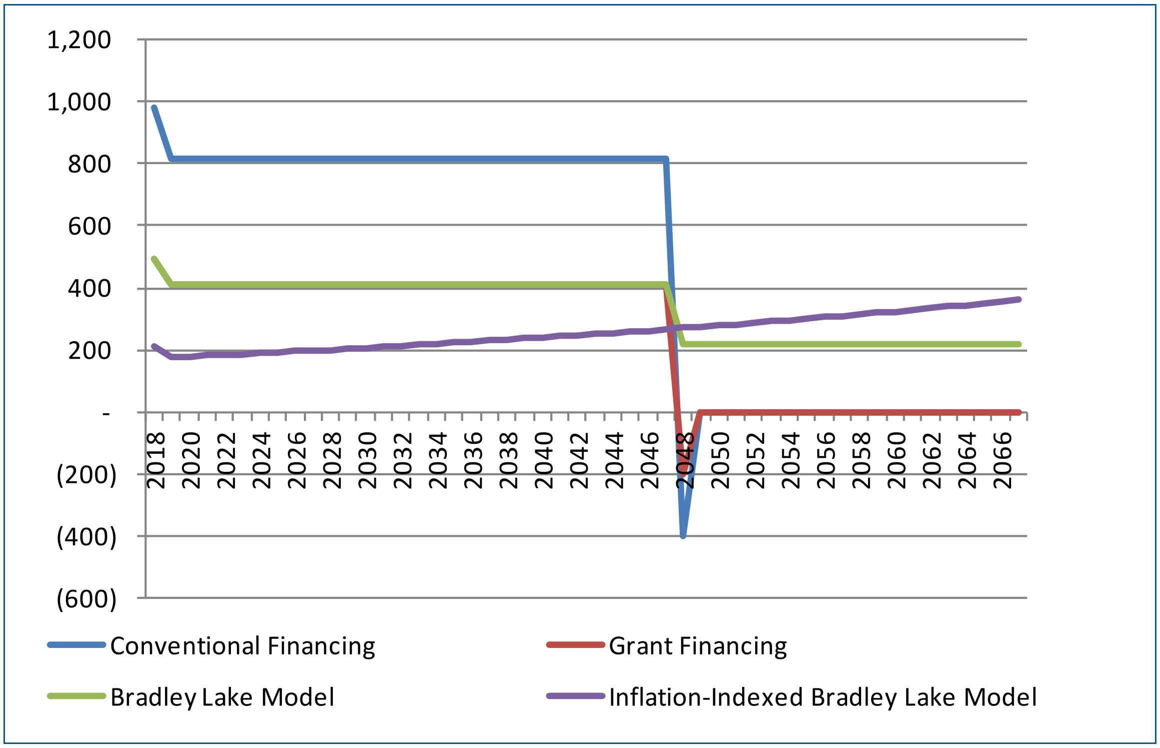


Figure 9-10 Combined Model Results - Net Capacity Cost ($/kW-year) [6]

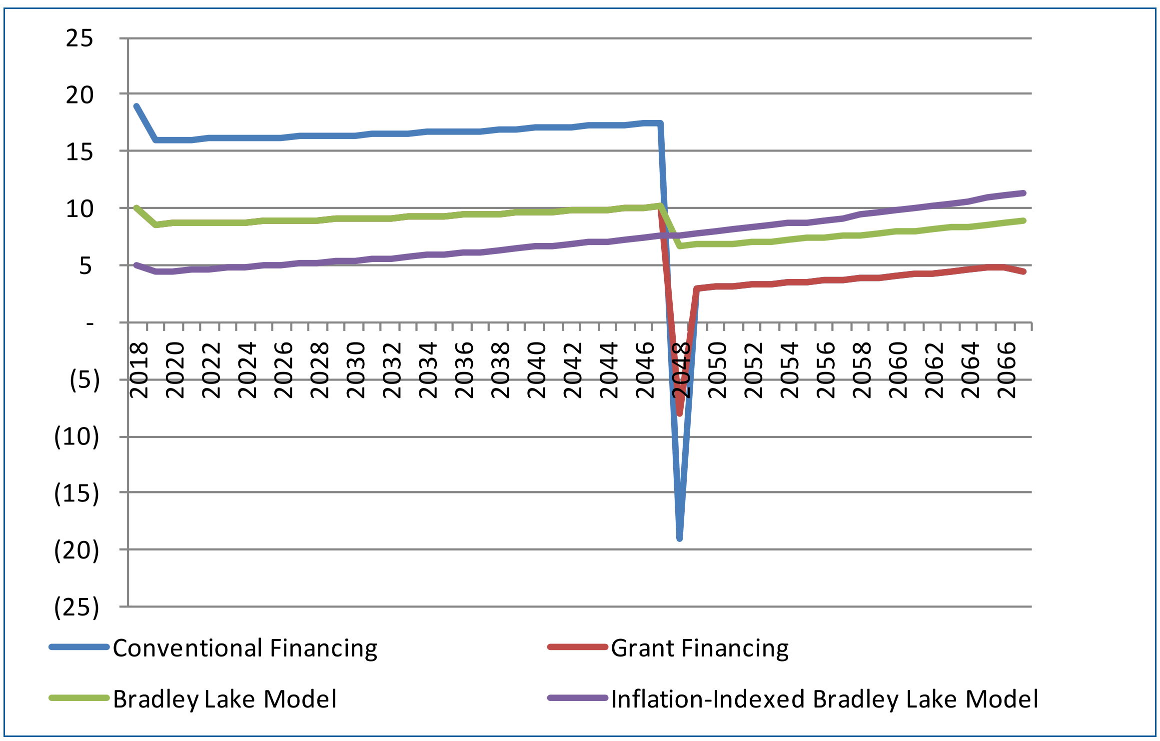


Figure 9-11 Combined Model Results - Net Energy Cost, Cents/kWh Sales Price[6]

[6] The "net" cost refers to net cost after reserve funds are funded or refunded.

10.0 Potential Hydroelectric Projects

10.1 INTRODUCTION

The development of hydroelectric projects in the Southeast region is a dynamic process. Currently, projects are being proposed by both utilities and independent power producers (IPPs). Many potential hydroelectric projects have a long history and have evolved in size and configuration through the years, and much is known about them, while other potential projects have undergone little development and there is little information about them.

One significant impediment to the completion of the SEIRP was the wide variety in the quality and inclusiveness of information available to evaluate specific hydro projects, including:

- Realistic commercial operation dates (CODs).
- Capital costs.
- Energy output (in wet, average, and dry years).
- Environmental, permitting, and licensing issues.
- Business structure and agreements, including ownership, project development capabilities, and power sale and interconnections agreements.

As a result of this wide variation in data quality across the spectrum of potential hydro projects in the Southeast region, it is impossible to conduct a true “apples to apples” comparison of projects. To get all projects to a comparable level of data quality requires a significant amount of further study that is outside the scope of this effort; consequently, it is impossible at this time to make a definitive selection of which hydro projects should be developed within each subregion to meet future electric requirements. This reality is reflected in the methodology, described in the following subsection, that Black & Veatch used to evaluate specific hydroelectric projects.

Need to Develop Standardized Decision Package for Potential Hydro Projects and Linkage to Renewable Energy Grant Fund

As noted above, the wide variation in the quality and inclusiveness of information available across the spectrum of potential hydroelectric projects prevents a definitive decision as to which hydroelectric projects should be developed to meet the future electric requirements of each subregion. Due to the significant number of potential projects that could be developed, and the lack of consistent information available on each project upon which to make long-term investment decisions, the AEA is proposing a policy requiring developers of each potential project to develop a standard set of information, at an appropriate level of detail and quality, prior to any decisions being made with regard to which projects should be developed. The AEA proposes that this policy would apply to all projects for which the State will be providing financial assistance.

This standard "decision package" should, at a minimum, include the following information:

- Realistic commercial operation date.
- Feasibility study level capital cost estimate, based upon a 20 to 30 percent design and standard State financing requirements.
- Adequately measured water flows, over a sufficient period of time, and defined storage capabilities, where applicable, to develop realistic monthly energy output and spill estimates under different water conditions (e.g., wet year, average year, and dry year).
- Potential environmental, permitting and licensing challenges and requirements identified, along with detailed strategies to address these challenges and requirements.
- Well-developed business plan that includes ownership structure, project management capabilities, preliminary power sales agreement- and interconnection-related terms and conditions that have been discussed and are generally agreeable to all affected parties.
- Fatal flaw analysis.
- Estimate of likely rate impact.

Black & Veatch believes that this information will effectively address the issues associated with the quality and inclusiveness of information available on specific projects, and enable the region to make more informed decisions regarding which hydro projects should be developed.

Typically, this type of information is the responsibility of the project proposer to develop and bear the related costs. Whether the State should provide financial assistance to project proposers to gather information required for this type of standard package decision is for the Governor's Office and State Legislature decide. Additionally, it is a policy question for the Governor's Office and State Legislature to determine whether the AEA, or some other entity, should be given the oversight responsibility to ensure that these standard decision packages are developed for all proposed projects.

Additionally, the AEA plans to require similar information for all potential projects that have submitted applications for financial assistance under the State's Renewable Energy Grant Fund. Black & Veatch believes that this common approach is the appropriate way to move forward.

10.2 SUMMARY OF METHODOLOGY

Consistent with the discussion in Section 10.1, the process used by Black & Veatch and HDR to identify and screen potential hydro projects, as well as the evaluation of generic hydro projects, to develop a list of screened projects that could meet the region's future needs is summarized on Figure 10-1, and discussed below.

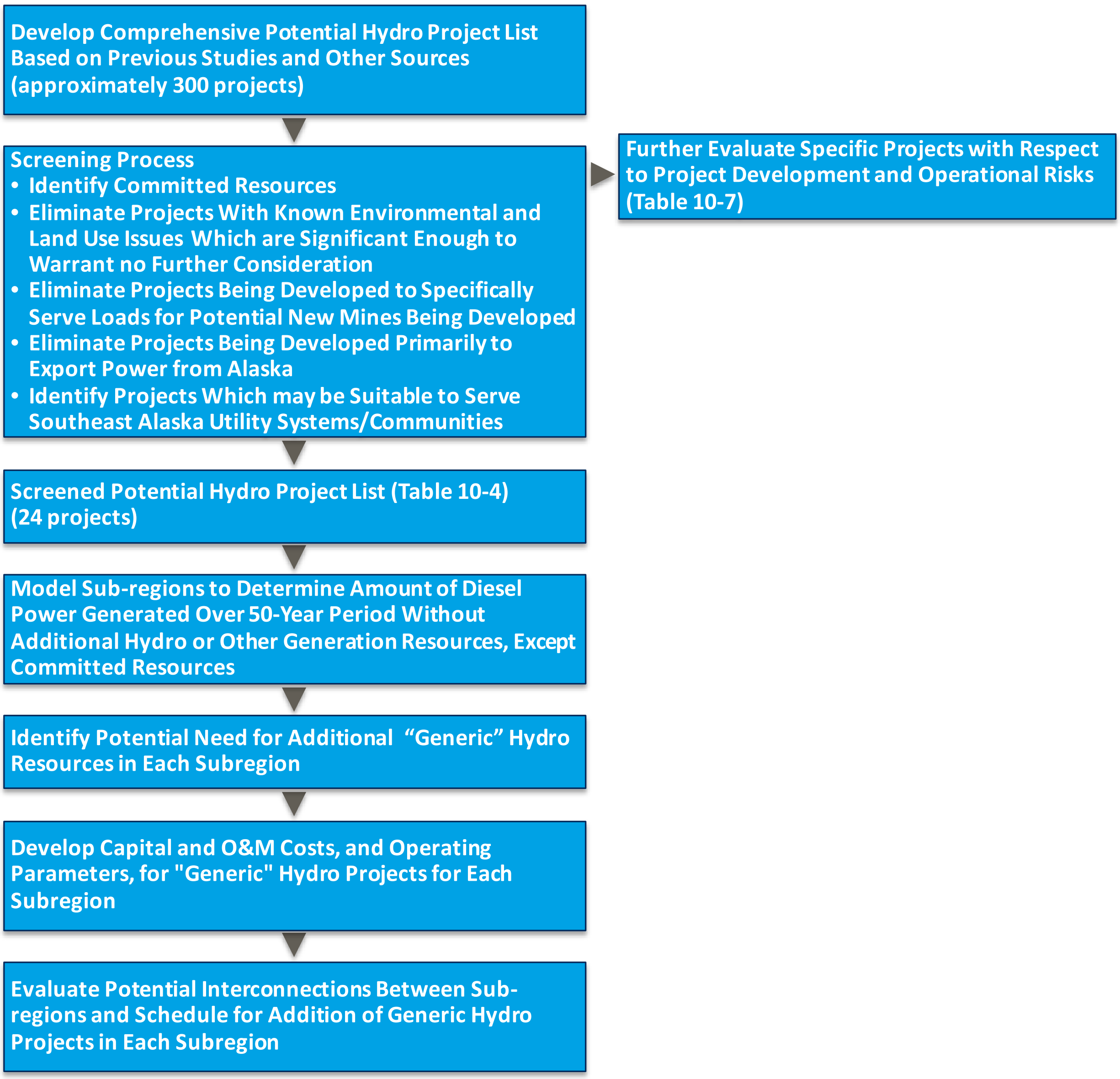


Figure 10-1 Hydro Project Evaluation Process

10.2.1 Screening

The screening process starts with developing a comprehensive list of potential hydro projects in the region. Black & Veatch, and its subcontractor HDR, developed a comprehensive list (hereafter referred to as the Comprehensive Potential Hydro Project List), which is presented in Appendix C. The Comprehensive Potential Hydro Project List contains the projects that Black & Veatch and HDR have become aware of from numerous sources. One of the main sources of potential projects is the 1947 Water Powers of Southeast Alaska Report prepared by the Federal Power Commission. This report contained 200 hydro projects, some of which have already been constructed. Appendix C contains data on the projects from this report, as well as data obtained from other sources. Where more than one source of information was available, data from the additional sources were also included. Some of this data were conflicting and some became more refined and potentially more accurate as projects developed. In all, nearly 300 projects are presented in Appendix C. There likely is some duplication in the list as project names and their characteristics changed, through time making it difficult to track some of the individual projects.

The next step of the process was to conduct a high-level evaluation of the Comprehensive Potential Hydro Project List in Appendix C that yielded a list of potential projects that could supply future power needs, subregion by subregion. The criteria for screening are a practical set of gates that projects must pass through to be considered a potential generation resource. Screening narrows potential projects to be considered and is structured so that all reasonable projects can be considered as generation resources, typically, acceptable projects include those currently under development or that have had a significant level of development work conducted for them (hereafter referred to as the Screened Potential Hydro Projects List). Section 10.3 discusses the screening process and list in more detail, and separates the screened list developed into several parts including:

- Projects where the decision to develop them has already been made (i.e., Committed Resources).
- Projects that would otherwise be viable resource candidates, but are deemed to have significant environmental and land use issues are identified and set aside for potential consideration later in the planning.
- Projects that are being developed to specifically serve loads for potential new mines being developed and, therefore, not generally intended to be interconnected in any meaningful fashion to the utility grid system.
- Projects that are primarily being developed to export power from Alaska.
- Projects that may be suitable for development to serve the utility systems of the Southeast Alaska communities.

10.2.2 Economic Implications of "No New Hydro"

The next step of the process was to utilize Strategist® including the Committed Resources to model the Southeast region, including the subregions presented on Figure 4-3, to determine the amount of diesel power that would be generated by the end of the study period (i.e., 2061) if no additional hydro projects for utility systems were constructed other than the Committed Resources. Section 10.4 presents the results of this evaluation, which represents the maximum amount of hydro generation that would merit installation to meet the utility system needs of the region. Section 10.4 also compares the potential need for hydro generation with the projects that may be suitable for development from Section 10.4.

10.2.3 Addition of Generic Hydro Projects

Section 10.5 discusses the approach taken to identify "generic" hydro projects for use by Strategist® in developing: 1) an expansion plan to evaluate potential interconnections between subregions, and 2) a schedule for the addition of generic hydro projects. Integrated planning with identified generic projects establishes the need for new generation projects, and explores whether the benefits of less expensive "run-of-the-river" projects will satisfy future energy needs, or whether the more expensive storage hydro projects must be found.

To model the range of potential projects existing in the region, Black & Veatch developed an array of projects with both storage and run-of-the-river physical characteristics. Black & Veatch examined the actual costs of projects that have been recently constructed in the region as part of forming this project array.

Strategist® will identify increments of new hydro generation necessary for each subregion that will reduce the amounts of diesel generation to economic levels. Three sets of Strategist® runs are based on the: 1) Reference Scenario Load Forecast, 2) High Scenario Load Forecast, and 3) Low Scenario Load Forecast. This array of Strategist® analyses is designed to identify the extent of new generation development for the different energy futures portrayed by each of the forecasts. Black & Veatch then conducted additional analyses on these runs as a basis for its recommendations.

In particular, the Low Scenario Load Forecast embraces a vigorous program to reduce energy consumption over the long run with DSM/EE measures. One key demand-side management issue is fuel conversion to move the region away from the use of electric resistance heating. Loads in all networks employing low-cost power have seen their hydro reserve capacities reduced significantly. Fuel conversions could reserve this effect, and DSM/EE could alter the immediate need for an expensive hydro project.

10.2.4 Risk Assessment of Hydro Projects

Finally, as discussed in Section 10.6, Black & Veatch further evaluated the projects included in the Screened Potential Hydro Project List, identified in Section 10.3, with respect to project development and operational risks, recognizing the constraints associated with the quality and inclusiveness of information available. The information provided in this section provides a foundation that can be used in channeling development funds.

10.3 SCREENED POTENTIAL HYDRO PROJECT LIST

The development of a hydroelectric project requires the careful evaluation of many factors such as hydrology, energy, cost, transmission, access, financing, and environmental impact. The vast majority of the projects contained in the Comprehensive Potential Hydro Project List have had little to no consideration of these factors and the development concept is cursory at best. As such, a need existed to reduce this list to the projects that likely have some merit in this planning process.

The screening criteria used to reduce the Comprehensive Potential Hydro Project List were based, in part, on the level of development a project has undergone, the general logic being that the better projects will be the focus of development activities by utilities and IPPs.

The first criterion considered for being on the Screened Potential Hydro Project List was the resolution passed by the Advisory Work Group, and presented in Appendix D, supporting the following hydro projects that have been considered Committed Resources for the purposes of the SEIRP, as described in Section 4.0. The Gartina Falls project was not included in the original

Resolution passed by the Advisory Work Group, but was subsequently added by the Advisory Work Group to the list of Committed Resources.

- Blue Lake Expansion Hydro
- Gartina Falls
- Reynolds Creek Hydro
- Thayer Creek Hydro
- Whitman Lake Hydro

As stated in the resolution, these "projects have been under development for many years, have completed or nearly completed exhaustive FERC licensing or similar process, and have broad public support." Table 10-1 presents summary information on the Committed Resources.

Table 10-1 Committed Resources

PROJECT NAME	CATEGORY	CAPACITY (MW)	LOCATION
Blue Lake Expansion	Storage	8.00	Sitka
Gartina Falls	Run-of-river	0.455	Hoonah
Reynolds Creek	Storage	5.00	Prince of Wales
Thayer Creek	Run-of-river	1.00	Angoon
Whitman Lake	Storage	4.60	Ketchikan

For the other potential projects, a significant measure of the ultimate validity of a project is its license or permitting status. Projects that have obtained their FERC license and/or authorizing permits have invested significant effort in project development, have a proven public benefit, and have been reviewed and approved by the numerous agencies involved. As such, projects that have a FERC license were included on the Screened Potential Hydro Project List. Additionally, projects that are currently under development as evidenced by a FERC preliminary permit were also included in the Screened Potential Hydro Project List. Also, projects that have been determined to not be under FERC jurisdiction but had ongoing development were included in the Screened Potential Hydro Project List due to the significant benefit of not requiring a FERC license. These projects include Thayer Creek, Triangle Lake, and Indian River. Crooked Creek and Jim's Lake plan to request a FERC license exemption.

Projects that are not currently being pursued but have been identified in previous regional studies were also included in the Screened Potential Hydro Project List. Finally, projects that were specifically brought to Black & Veatch's attention through the consultation process were included in the Screened Potential Hydro Project List.

The initial Screened Potential Hydro Project List presented in Table 10-2 is dynamic and continues to change as development work occurs for new projects, resulting in their addition to the list and, in some cases, the continuing development of some of the projects on the list will result in them being deleted from the list due to environmental, licensing, or economic reasons. Table 10-2 represents the more promising potential hydro projects in the Southeast region based on information provided and available at the time of this study.

Table 10-2 Initial Screened Potential Hydro Project List

PROJECT NAME	CATEGORY	CAPACITY (MW)	LOCATION
Anita - Kunk Lake	Storage	8.60	Wrangell
Blue Lake Expansion	Storage	8.00	Sitka
Cascade Creek	Storage	70.00	Petersburg
Connell Lake	Storage	1.70	Ketchikan
Connelly Lake	Storage	12.00	Haines
Crooked Creek and Jim's Lake	Storage/Run-of-River	0.16	Elfin Cove
Game Creek	Storage		Hoonah
Gartina Falls	Run-of-river	0.445	Hoonah
Indian River	Run-of-river	0.25	Tenakee Springs
Lace - Lake 3160	Storage	6.00	Juneau
Lake Dorothy Expansion	Storage	28.00	Juneau
Lake Shelokum	Storage	10.00	Wrangell
Mahoney Lake	Storage	9.60	Ketchikan
Moira Sound			
Lower Kugel		4.10	South POW
Middle Kugel		4.80	South POW
Upper Kugel		0.90	South POW
Aiken		0.40	South POW
Dickman		2.20	South POW
Lower Luelia		2.20	South POW
Middle Luelia		2.30	South POW
Upper Luelia		0.40	South POW
Lower Niblack Creek		0.40	South POW
Middle Niblack		2.10	South POW
Upper Niblack		0.60	South POW
Orchard Lake	Storage	10.00	Meyers Chuck
Reynolds Creek	Storage	5.00	Hydaburg
Ruth Lake	Storage	20.00	Petersburg

PROJECT NAME	CATEGORY	CAPACITY (MW)	LOCATION
Scenery Creek	Storage	30.00	Petersburg
Schubee Lake	Storage	4.90	Skagway
Soule River	Storage	78.40	Near Hyder
Sunrise Lake	Storage	4.00	Wrangell
Swan Lake Expansion - Lake Grace Diversion	Storage		Ketchikan
Sweetheart Lake	Storage	30.00	Juneau
Takatz Lake	Storage	27.70	Sitka
Thayer Creek	Run-of-river	1.00	Angoon
Thoms Lake	Storage	7.50	Wrangell
Triangle Lake	Storage	3.50	Metlakatla
Tyee New Dam Construction	Storage	1.40	Wrangell
Tyee New Third Turbine	Storage	10.00	Wrangell
Virginia Lake	Storage	12.00	Wrangell
Walker Lake	Run-of-river	1.00	Chilkat Valley
Water Supply Creek	Run-of-river	0.40	Hoonah
West Creek	Storage	25.00	Skagway
Yeldagalga Creek	Run-of-river	8.00	Juneau

Two of the projects listed in Table 10-2 were removed from further consideration due to significant environmental and land use issues. The first is Game Creek, which is deemed to have significant fish issues. The second is Swan Lake Expansion – Lake Grace, which neighbors the Misty Fjords National Monument and would be a cross-basin diversion of Grace Creek into the existing Swan Lake project via a 6 to 8 mile tunnel. Both of these projects would likely be adamantly opposed by agencies and environmental groups.

Table 10-3 presents a subset of the projects in Table 10-2 that are primarily being developed to serve potential mine loads and that are not generally being considered for interconnection to the Southeast Alaska utility grid. While projects developed to serve isolated mine loads may merit consideration for inclusion in the preferred project list, their development is tied to the potential development of the mines, which is beyond the scope of this IRP. These projects face potential development challenges in part based on the likely difference in lifetimes between the mines and the hydro projects. Mine lifetimes are generally expected to be significantly less than the lifetime of hydro projects. This difference in lifetimes makes it more difficult to amortize the cost of the hydro project over the life of the mine. If developed, it may be possible to construct an interconnection to the utility transmission system once the mine is depleted. Such speculation on potential development and future interconnection is beyond the scope of this IRP, but can be addressed in future studies if the mines develop.

Table 10-3 Projects Intended to Serve Mine Loads

PROJECT NAME	CAPACITY (MW)	LOCATION	ANNUAL ENERGY
Lace - Lake 3160	6.00	Juneau	49,000
Moira Sound			
Lower Kugel	4.10	South POW	21,500
Middle Kugel	4.80	South POW	14,000
Upper Kugel	0.90	South POW	2,500
Aiken	0.40	South POW	800
Dickman	2.20	South POW	11,500
Lower Luelia	2.20	South POW	11,800
Middle Luelia	2.30	South POW	6,700
Upper Luelia	0.40	South POW	1,100
Lower Niblack Creek	0.40	South POW	2,100
Middle Niblack	2.10	South POW	6,000
Upper Niblack	0.60	South POW	1,700
Yeldagalga Creek	8.00	Juneau	31,000

One project shown in Table 10-2 is being primarily developed to export its generation to Canada. That project is the Soule River Project near Hyder. It is not being included on the list of potential projects for this IRP since it is not serving the loads of Southeast Alaska, and Hyder was not included in the scope of this study. Since the Soule River Project is not being evaluated as part of the Southeast Alaska IRP, this study makes no findings relative to it.

Based on these exclusions, Table 10-4 shows the refined Screened Potential Hydro Project List, along with the cost and energy assumptions used in this analysis.

Figure 10-2 provides a map that shows the location of the screened hydro projects listed in Table 10-4, along with the Committed Resources and potential transmission segments.

For this regional planning study, information related to energy and cost is required for each of the potential hydroelectric projects. As stated earlier, the information for the projects presented in Table 10-4 was obtained from a variety of sources such as license applications and feasibility studies. Often information on the same project from different sources conflicted, which is not surprising given the dynamic process of project development. In general, the more recent available information was considered to be the most accurate information if it was based on further development work; consistent with previous comments regarding the variability in the quality and inclusiveness of information available across the potential projects, it is recognized that this approach is not the same as concluding that the most recent available information is accurate. Where no information was available, generic estimates were developed. Capital costs were adjusted to 2011 dollars. For cost estimates developed prior to 2011, the following IHS CERA Power Capital Cost Index for North America without Nuclear, was used to escalate the capital cost estimates to 2011 dollars (e.g., for capital cost estimates stated in 2007 dollars, the estimate was increased by a factor of 180/178 to result in 2011 dollars).

Year	Index
2007	178
2008	189
2009	177
2010	177
2011	180

For cost estimates in future dollars, the escalation rate in Section 6.0 was used to adjust to 2011 dollars. For projects for which no cost information was available, generic cost estimates were developed. Ranges were placed around all capital cost estimates to reflect the uncertainty that exists with respect to the cost estimates, with the widest ranges being used for the generic cost estimates.

Table 10-4 Refined Screened Potential Hydro Project List

PROJECT NAME	LOCATION	CATEGORY	CAPACITY (MW)	CAPITAL COST ($ MILLIONS)	CAPITAL COST $/KW	ANNUAL ENERGY (MWH)
SEAPA						
Anita - Kunk Lake	Wrangell	Storage	8.60	90.54-135.82	10,528-15,793	28,100
Cascade Creek	Petersburg	Storage	70.00	146.35-219.53	2,091-3,136	202,300
Connell Lake	Ketchikan	Storage	1.70	5.40-10.80	3,176-6,353	10,600
Lake Shelokum	Wrangell	Storage	10.00	39.00-91.00	3,900-9,100	40,000
Mahoney Lake	Ketchikan	Storage	9.60	34.50-51.76	3,594-5,392	46,066
Orchard Lake	Meyers Chuck	Storage	10.00	34.20-79.80	3,420-7,980	56,000
Ruth Lake	Petersburg	Storage	20.00	84.54-126.82	4,227-6,341	70,700
Scenery Creek	Petersburg	Storage	30.00	128.98-193.48	4,299-6,449	128,700
Sunrise Lake	Wrangell	Storage	4.00	16.64-24.96	4,160-6,240	13,500
Thoms Lake	Wrangell	Storage	7.50	110.11-135.17	14,681-18,023	24,200
Triangle Lake	Metlakatla	Storage	3.50	12.63-18.95	3,609-5,414	13,100
Tyee New Dam Construction	Wrangell	Storage	1.40	36.60-85.4	26,143-61,000	9,100
Tyee New Third Turbine	Wrangell	Storage	10.00	13.20-30.80	1,320-3,080	-
Virginia Lake	Wrangell	Storage	12.00	103.21-154.81	8,601-12,901	43,800
Baranof Island						
Takatz Lake	Sitka	Storage	27.70	117.04-175.56	4,225-6,338	106,900
Chichagof Island						
Crooked Creek and Jim's Lake	Elfin Cove	Storage/Run-of-River	0.16	1.48-2.22	9,250-13,875	666
Indian River	Tenakee Springs	Run-of-river	0.25	2.02-3.02	8,080-12,080	916
Water Supply Creek	Hoonah	Run-of-river	0.40	5.49-8.23	13,725-20,575	1,480

PROJECT NAME	LOCATION	CATEGORY	CAPACITY (MW)	CAPITAL COST		ANNUAL ENERGY (MWH)
				($ MILLIONS)	$/KW	
Juneau Area						
Lake Dorothy Expansion	Juneau	Storage	28.00	71.40-166.60	2,550-5,950	96,000
Sweetheart Lake	Juneau	Storage	30.00	82.82-124.08	2,761-4,136	136,000
Upper Lynn Canal						
Connelly Lake	Haines	Storage	12.00	36.80-55.20	3,067-4,600	39,762
Schubee Lake	Skagway	Storage	4.90	36.00-54.00	7,347-11,020	25,000
Walker Lake	Chilkat Valley	Run-of-river	1.00	6.08-9.12	6,080-9,120	2,750
West Creek	Skagway	Storage	25.00	112.00-168.00	4,480-6,720	76,600

Note: This table is provided for general information purposes. The information shown in this table was gathered from multiple sources, and the quality and inclusiveness of this information varies significantly across the projects shown. The range of capital costs shown for each project to reflect the uncertainties associated with the available information. As a result of the wide variation in the quality and inclusiveness of project-specific information, <u>the AEA believes that this information should not be used, in its current form, to make any investment decisions</u>.

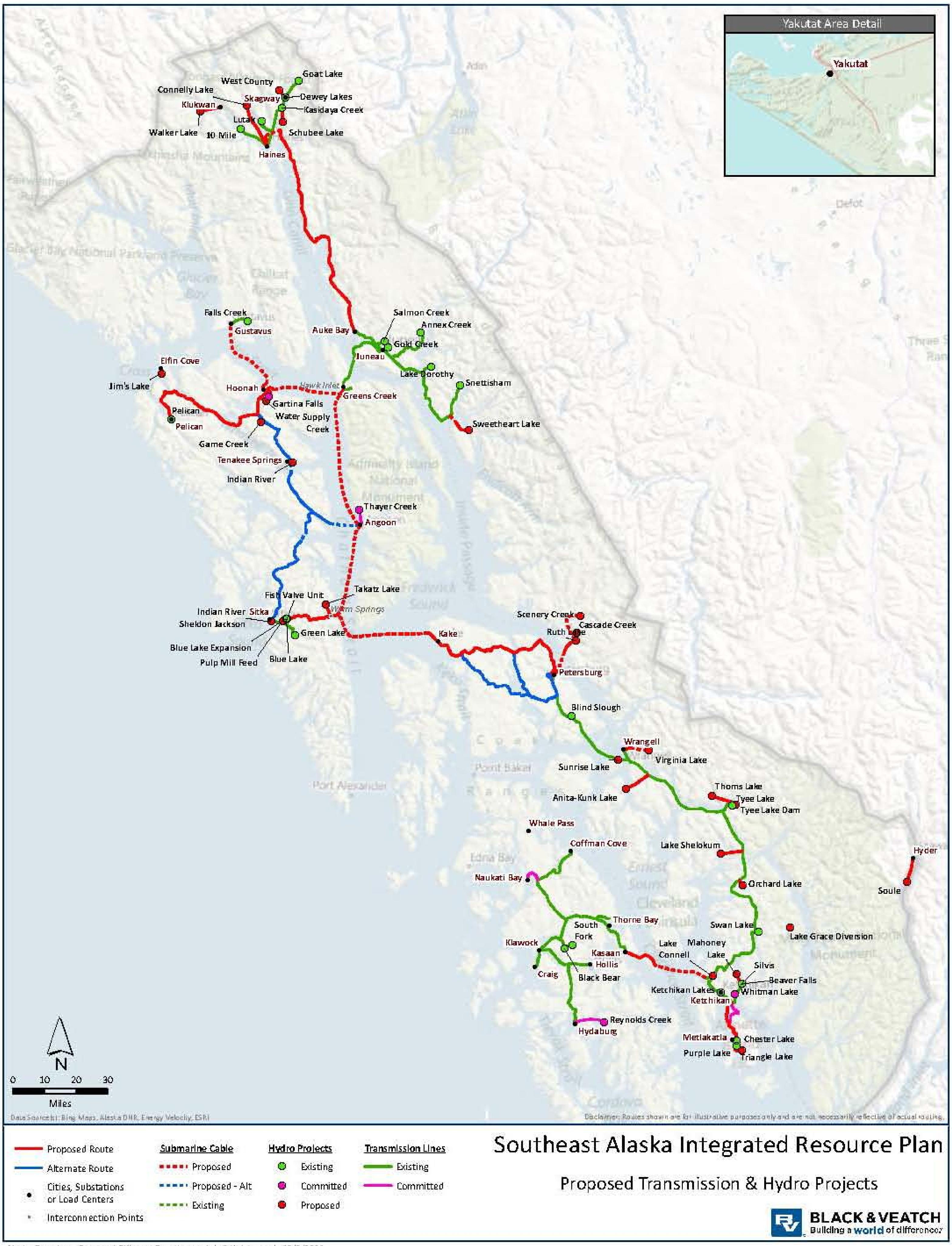


Figure 10-2 Location of Screened Potential Hydro Projects

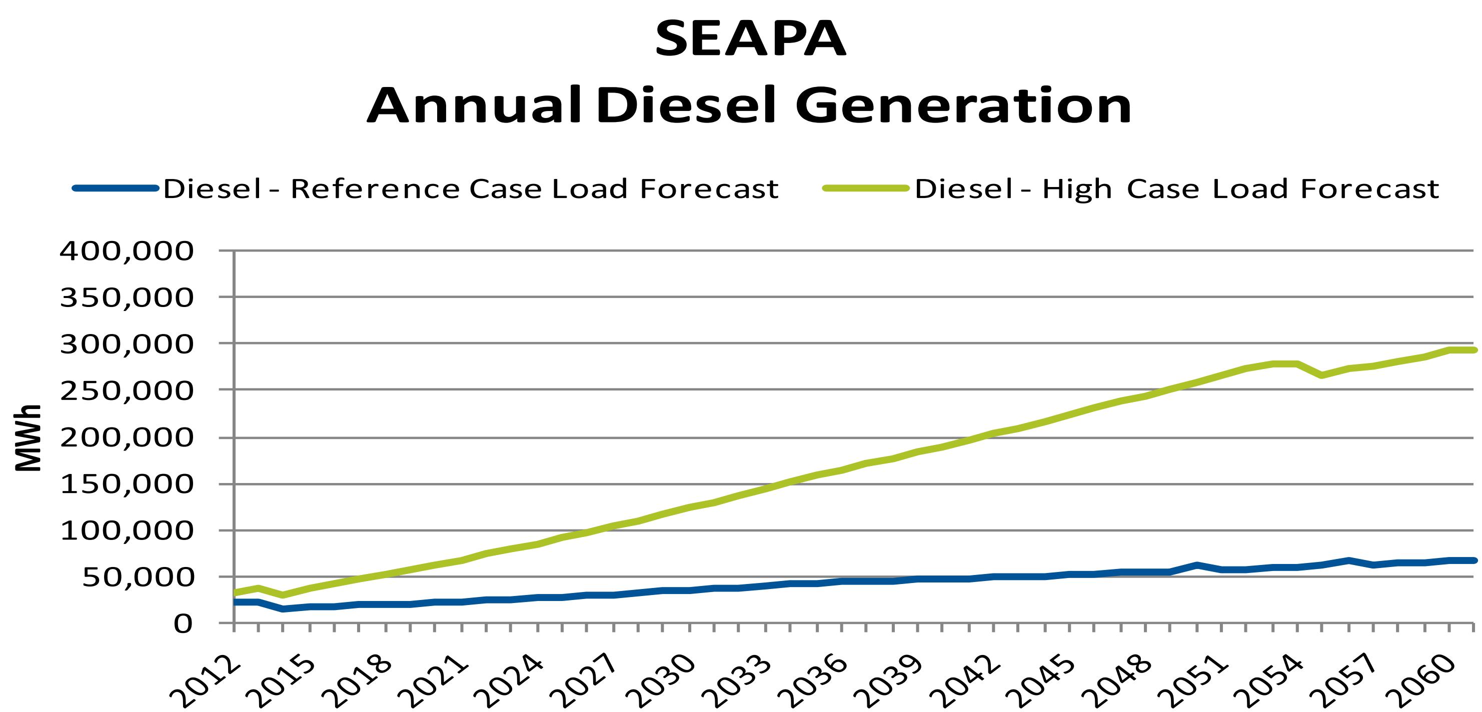
The annual and monthly energy output estimates shown in Table 10-4 are assumed to be average estimates. Many of the projects would likely be underutilized in the early years or produce energy during periods such as the summer when it is not needed. In such cases, the cost of energy from a project would be adversely affected.

10.4 HYDRO REQUIREMENTS FOR THE SOUTHEAST REGION

Figures 10-3 through 10-10 show the projected diesel energy requirements through the planning period, for the Reference Case Load Forecast and High Case Load Forecast, for each of the eight transmission planning subregions shown in Figure 4-3, assuming only the Committed Resources listed in Section 4.0 are installed, as follows:

- Figure 10-3 – SEAPA
- Figure 10-4 – Admiralty Island
- Figure 10-5 – Baranof Island
- Figure 10-6 – Chichagof Island
- Figure 10-7 – Juneau Area
- Figure 10-8 – Northern Region
- Figure 10-9 – Prince of Wales
- Figure 10-10 – Upper Lynn Canal

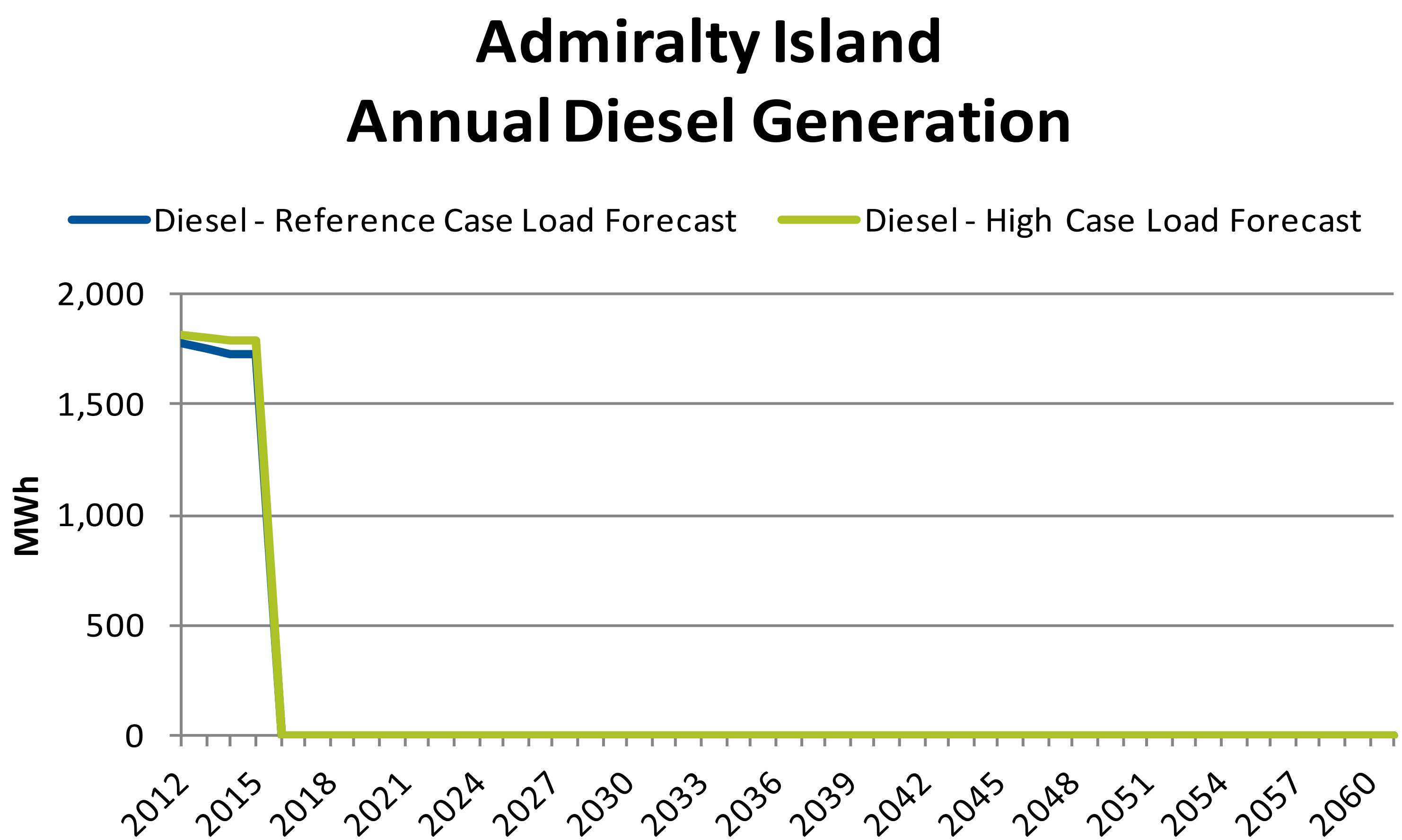
Figures 10-3 through 10-10 also show average annual energy that potentially could be provided by the Screened Potential Hydro Projects listed in Table 10-4. The projected diesel generation is developed by modeling the Southeast utility systems using Strategist® an optimal generation expansion program that is discussed in more detail in Appendix E. In viewing Figures 10-3 through 10-10, it should be noted that the average annual energy that could be provided by the projects will likely not displace an equal amount of diesel generation due to the varying seasonal generation characteristics of each project. In other words, a project could have a high annual generation due to high levels of generation in the summer while the diesel generation requirements are due to low hydro generation levels in the late winter and early spring.



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)	Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)
Anita - Kunk Lake	28,100	Scenery Creek	128,700
Cascade Creek	202,300	Sunrise Lake	13,500
Connell Lake	10,600	Thoms Lake	24,200
Lake Shelokum	40,000	Triangle Lake	13,100
Mahoney Lake	46,066	Tyee New Dam Construction	9,100
Orchard Lake	56,000	Tyee New Third Turbine	N/A
Ruth Lake	70,700	Virginia Lake	43,800

Note: The potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

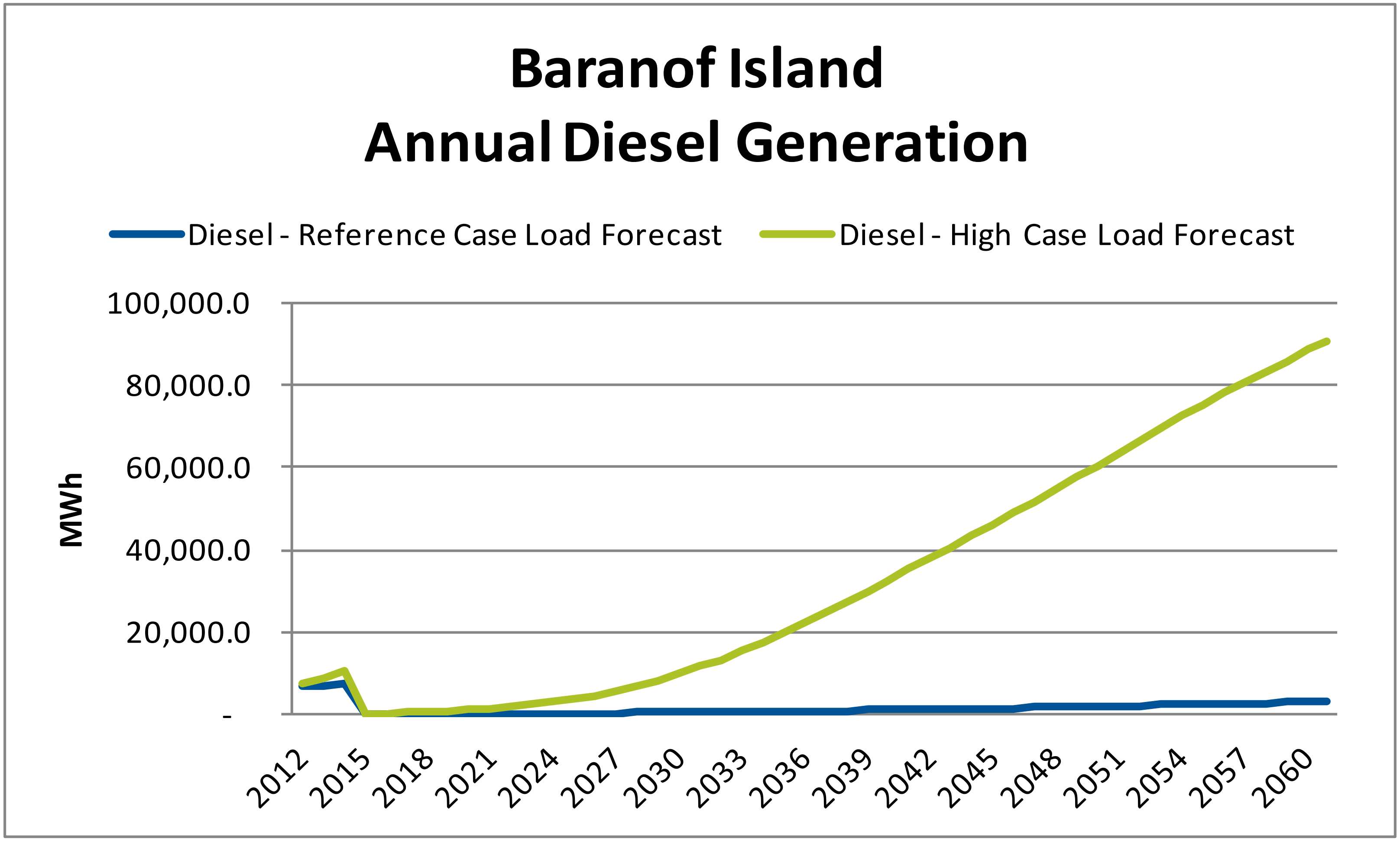
Figure 10-3 SEAPA



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWH)
None	N/A

Note: the potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

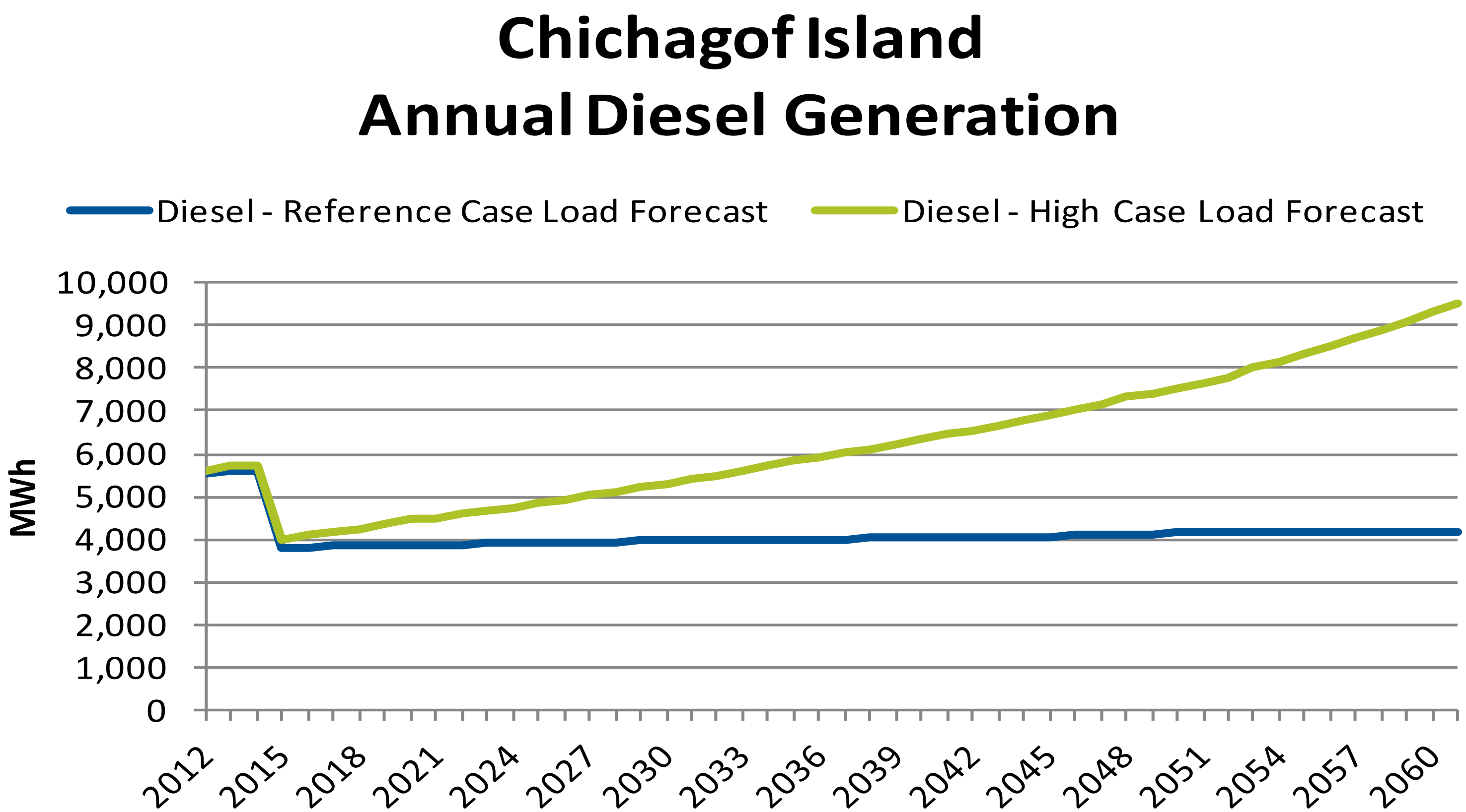
Figure 10-4 Admiralty Island



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)
Takatz Lake	106,900

Note: The potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

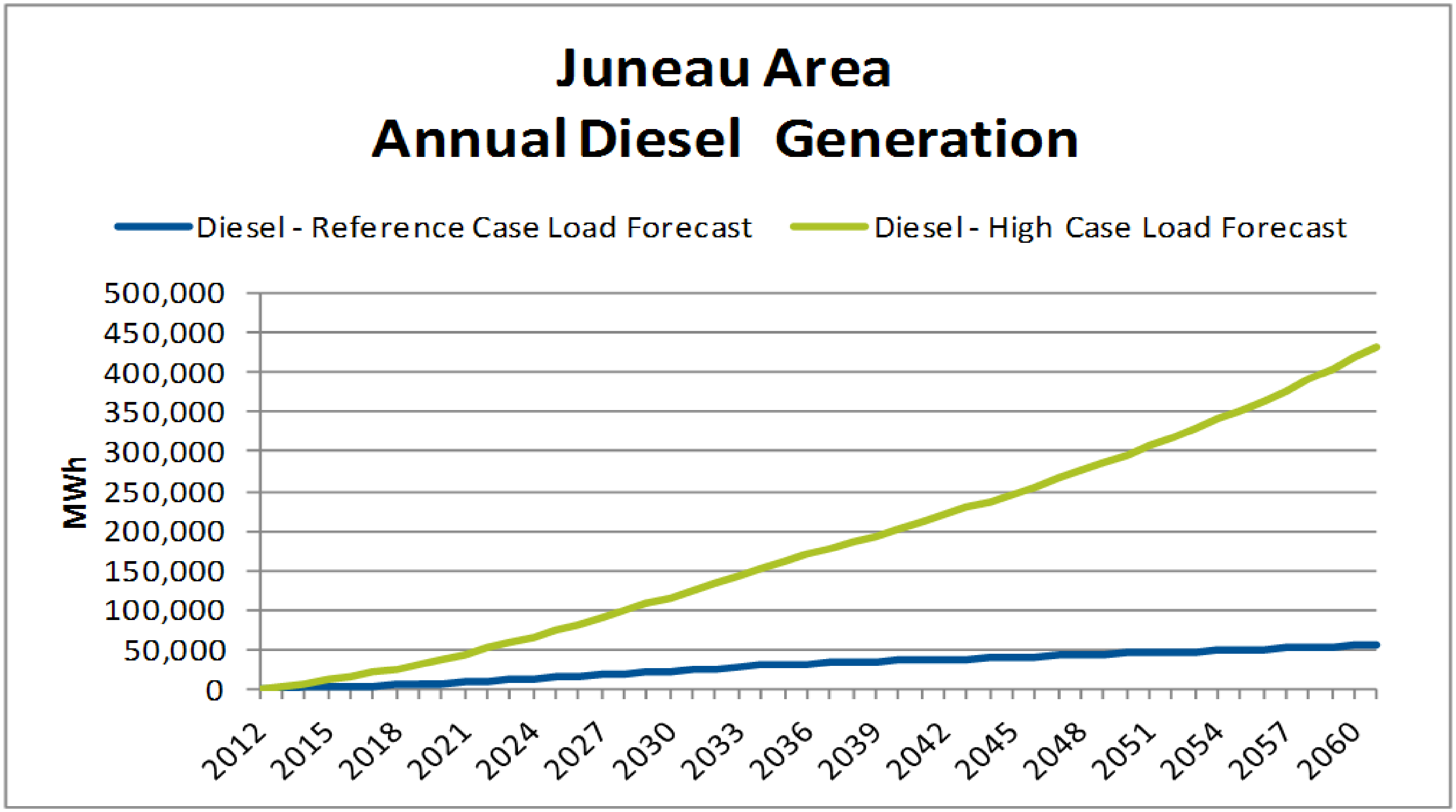
Figure 10-5 Baranof Island



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)
Crooked Creek and Jim's Lake	666
Indian River	916
Water Supply Creek	1,480

Note: The potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

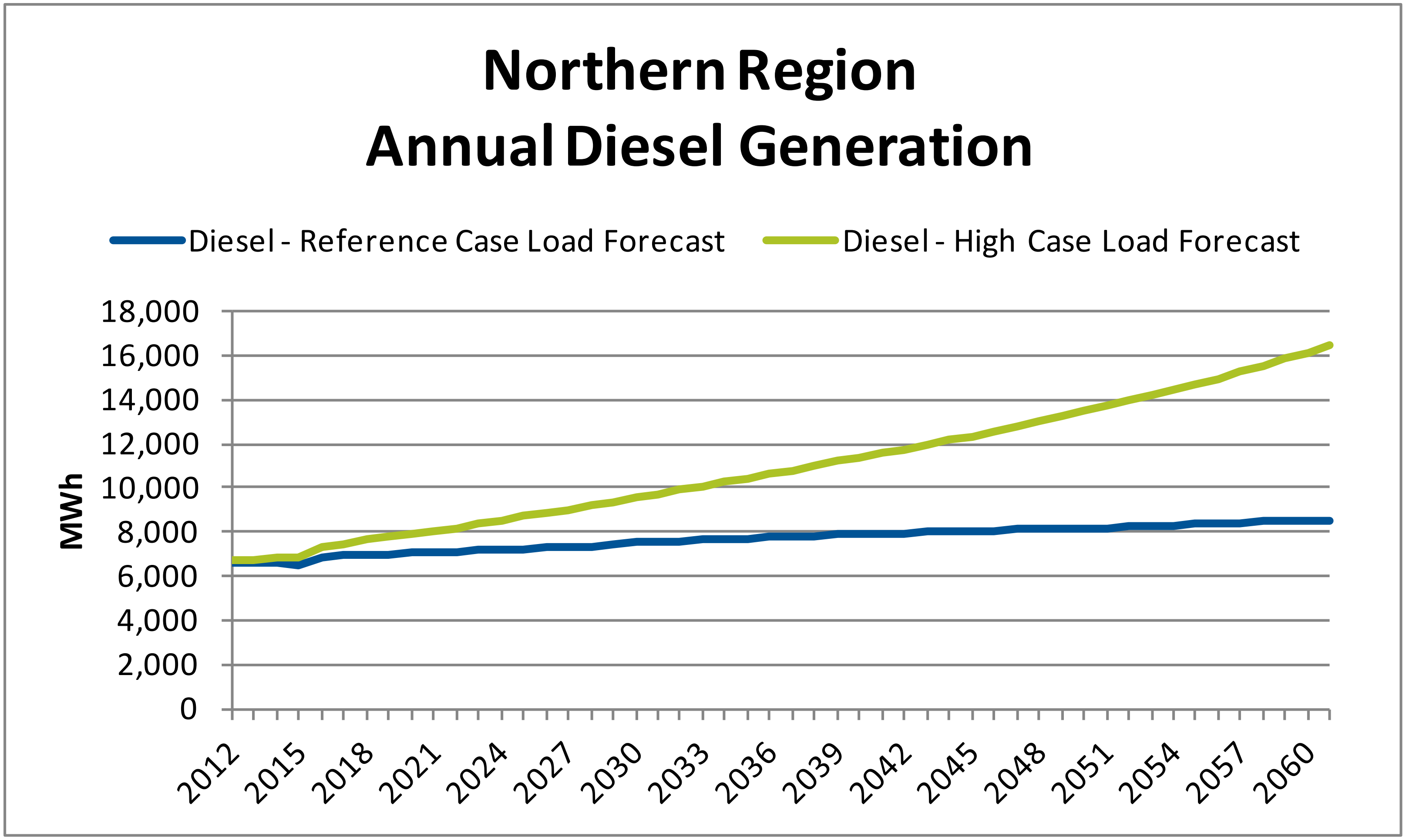
Figure 10-6 Chichagof Island



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)
Lake Dorothy Lake Expansion	96,000
Sweetheart Lake	136,000

Note: The potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

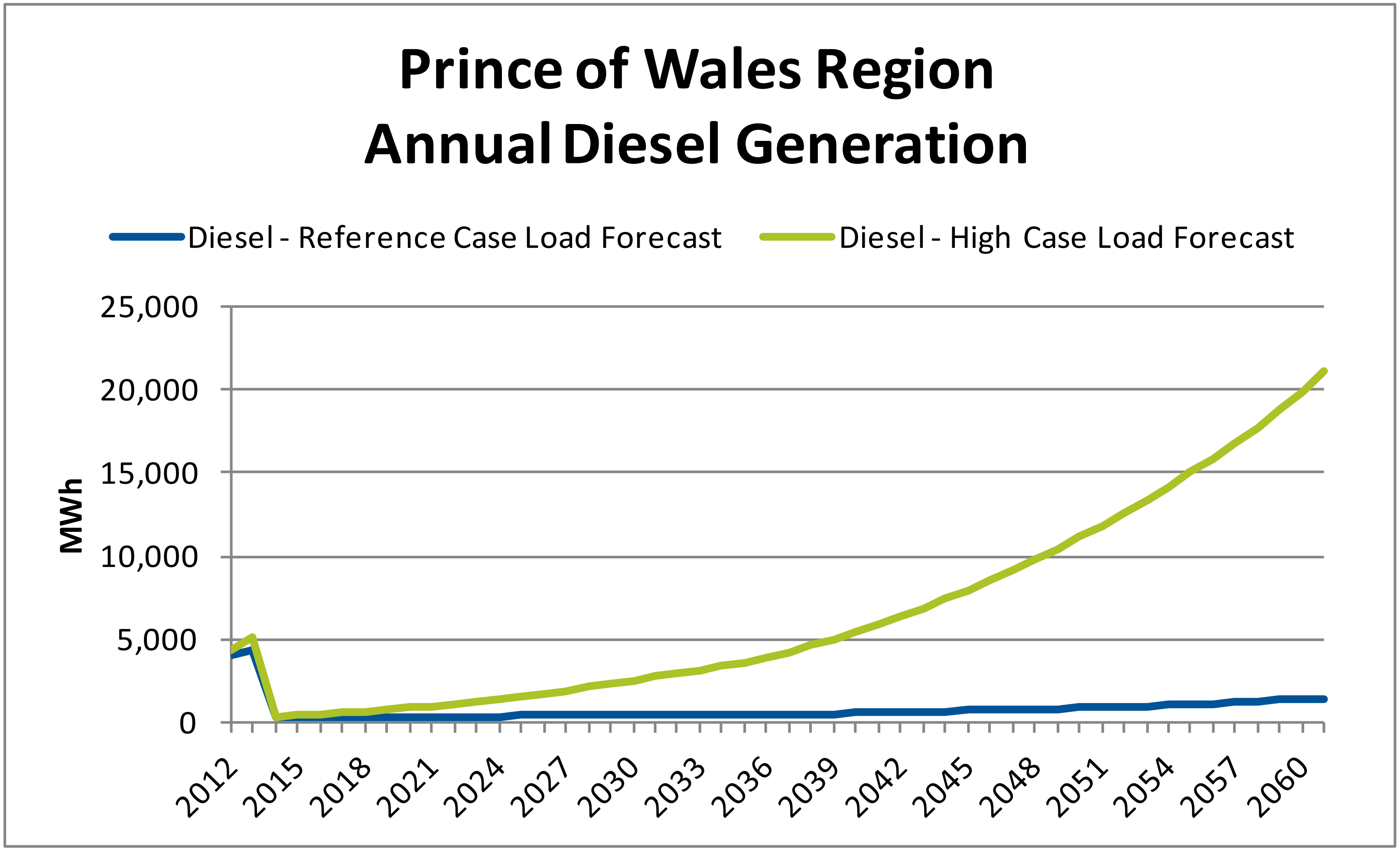
Figure 10-7 Juneau Area



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)
None	N/A

Note: The potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

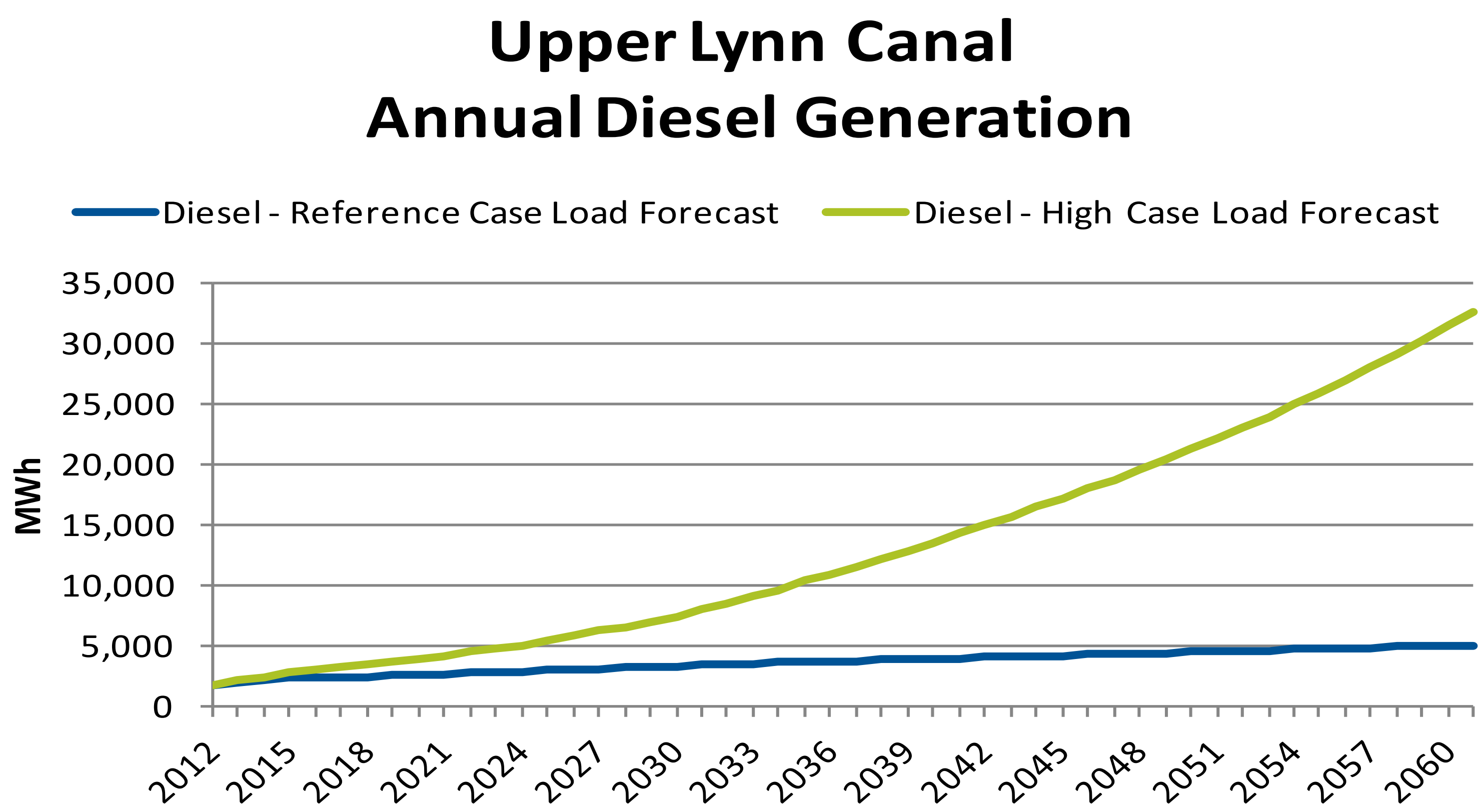
Figure 10-8 Northern Region



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)
None	N/A

Note: The potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

Figure 10-9 Prince of Wales



Available Projects from Screened Potential Hydro Project List	Potential Annual Generation (MWh)
Connelly Lake	39,762
Schubee Lake	25,000
Walker Lake	2,750
West Creek	76,600

Note: The potential annual generation figure(s) shown in the table will differ from actual generation, and that variation will differ from project to project based on the actual timing of flows, and storage capabilities, relative to the subregion's seasonal load profile.

Figure 10-10 Upper Lynn Canal

10.5 DEVELOPMENT OF GENERIC HYDRO PROJECTS

Generic hydro projects were developed for use in modeling expansion plans in Strategist® to evaluate: 1) the proper sizing and timing of additional hydro projects that could be added to each subregion, and 2) transmission interconnections and other alternative generation and demand-side projects. The generic projects are developed for use in the modeling to avoid having to model with the specific projects identified in Table 10-4 with their attendant issues of the quality and inclusiveness of cost and performance estimates. The generic projects developed for each subregion are presented in Table 10-5. It should be noted that these generic hydro projects are not based on actual projects that are available within each subregion. They represent a more idealistic view of the type of hydro projects that would best match the capacity and storage needs of each subregion.

Figures 10-11 through 10-18 include a series of graphs that compare, for each subregion, future electric load projections to existing and potential generic hydro projects, as follows:

- Figure 10-11 – SEAPA
- Figure 10-12 – Admiralty Island
- Figure 10-13 – Baranof Island
- Figure 10-14 – Chichagof Island
- Figure 10-15 – Juneau Area
- Figure 10-16 – Northern Region
- Figure 10-17 – Prince of Wales
- Figure 10-18 – Upper Lynn Canal

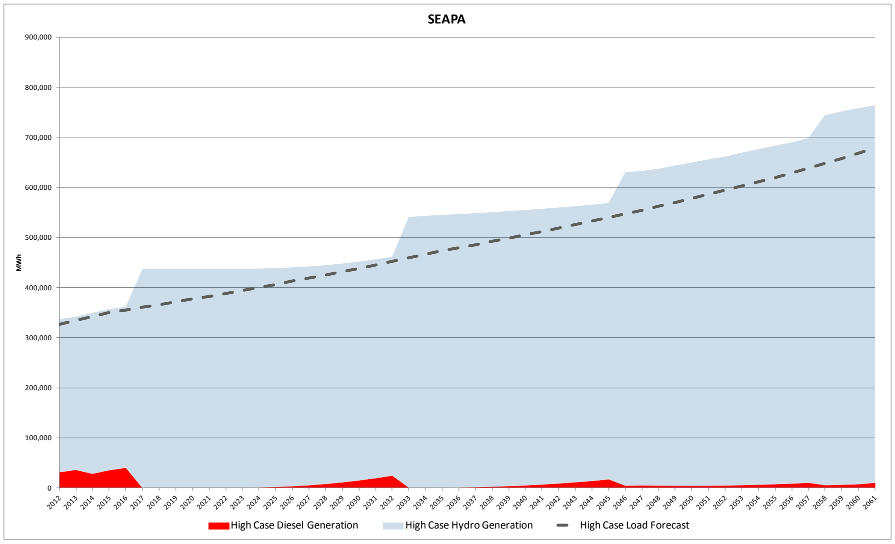
Three graphs are shown in each figure. The top graph shows the total hydro generation (including existing hydro facilities, Committed Resources, and additional generic hydro projects), and resulting diesel generation, based upon the High Case Load Forecast. The middle graph shows the same information based upon the Reference Case Load Forecast and the bottom graph shows the same information based on the Low Case Forecast.

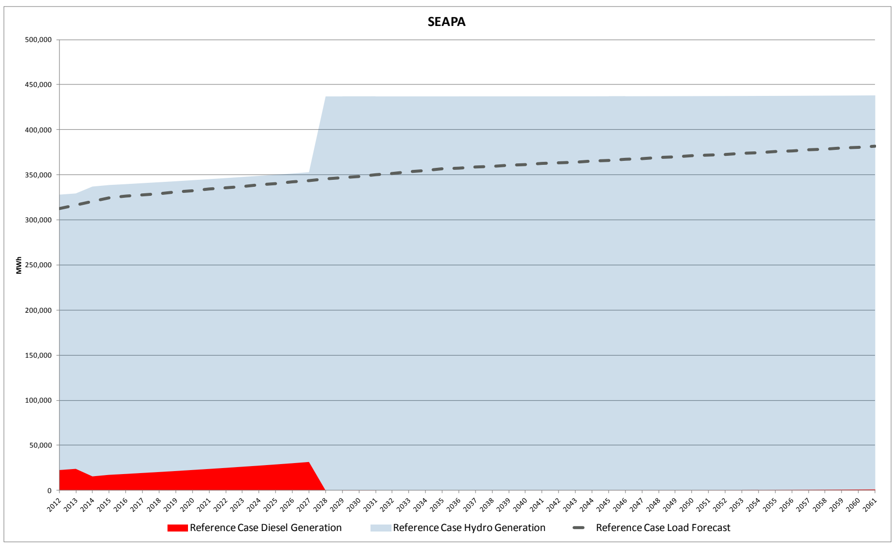
The following considerations need to be kept in mind when reviewing these graphs:

- The hydro generation levels shown include generation from generic hydro projects; as stated earlier, these generic hydro projects are not based on actual potential hydro projects available within each subregion.
- The shaded area above the load forecast in each graph represents spilled hydro, resulting from the fact that the loads in the subregion are not large enough to use all of the hydro capability in many of the years shown.

Table 10-5 Generic Hydro Projects

CAPACITY MW	CAPITAL COST $M	ANNUAL O&M $1,000	IDC 5.5% $1,000	R&R $1,000	$/KW	CAPACITY FACTOR	ANNUAL ENERGY MWH	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
RUN-OF-RIVER																			
1	$11	$200	$920	$103	11000	0.45	3,978	258	231	247	391	544	369	189	182	353	508	380	326
STORAGE																			
1	$16	$200	$1,338	$103	16000	0.66	5,771	703	599	447	423	464	369	351	369	300	412	601	735
5	$46	$900	$3,847	$516	9200	0.66	28,856	3513	2996	2233	2114	2318	1845	1753	1843	1502	2058	3006	3675
10	$75	$900	$6,272	$1,032	7500	0.66	57,712	7026	5992	4466	4229	4636	3690	3507	3685	3004	4116	6012	7349
20	$97	$900	$8,112	$2,064	4850	0.66	115,424	14052	11983	8931	8458	9273	7379	7014	7371	6007	8232	12024	14699
25	$108	$900	$9,031	$2,580	4320	0.66	144,280	17566	14979	11164	10572	11591	9224	8767	9213	7509	10291	15030	18374





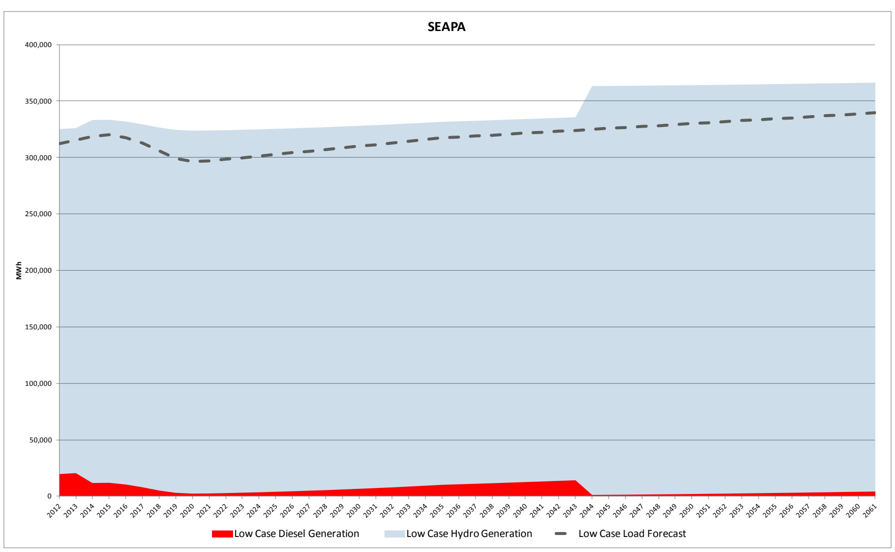
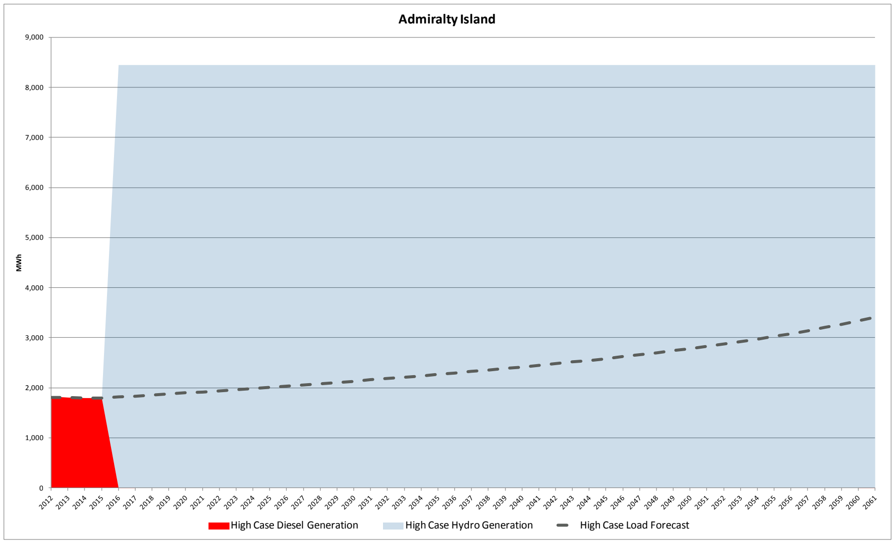
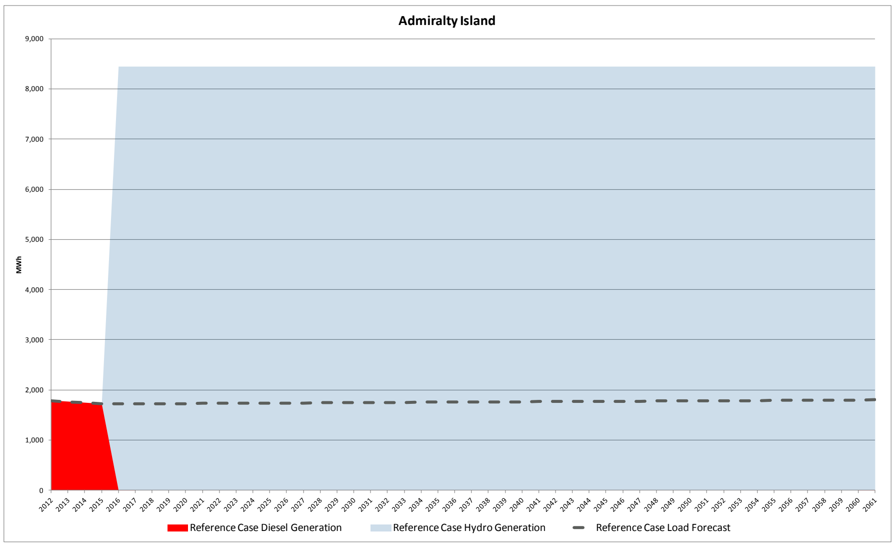


Figure 10-11 SEAPA





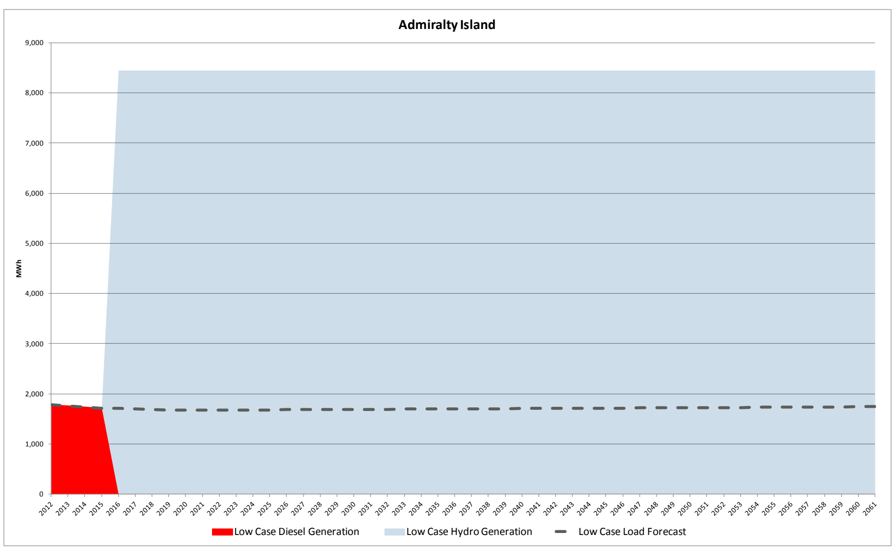
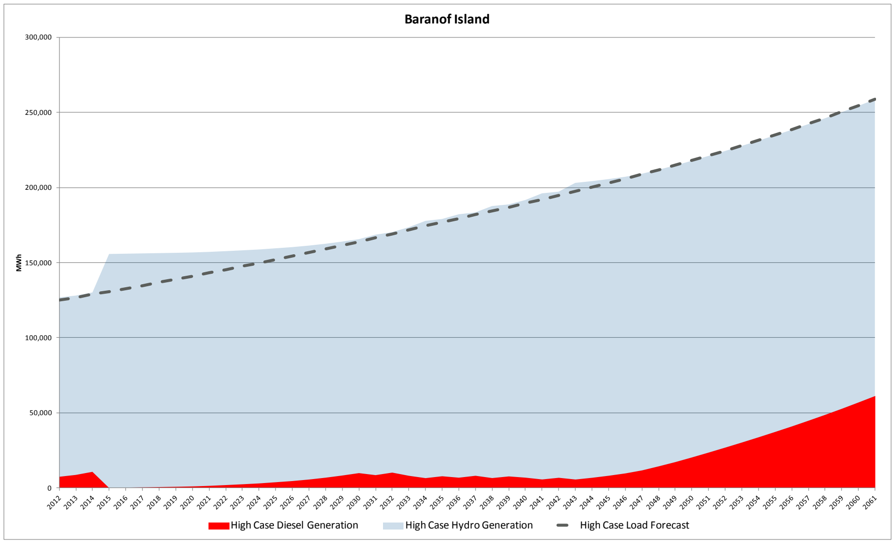
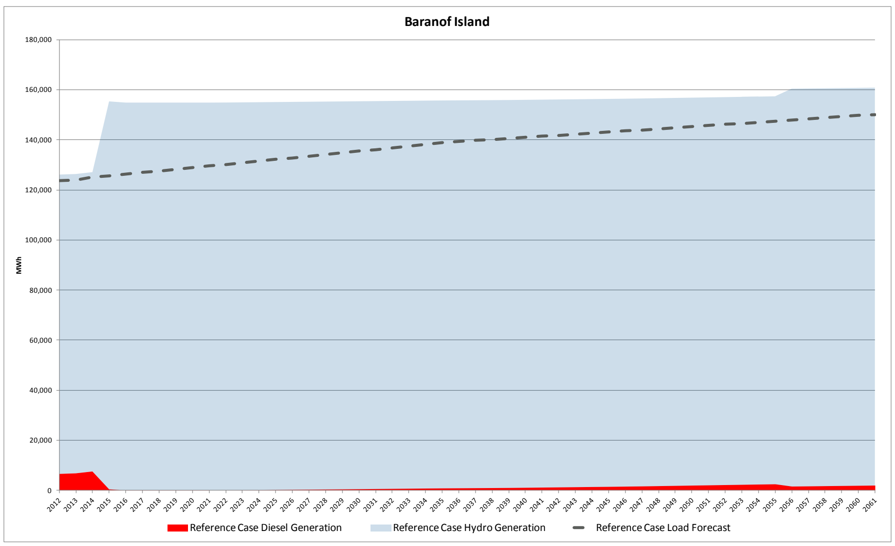


Figure 10-12 Admiralty Island





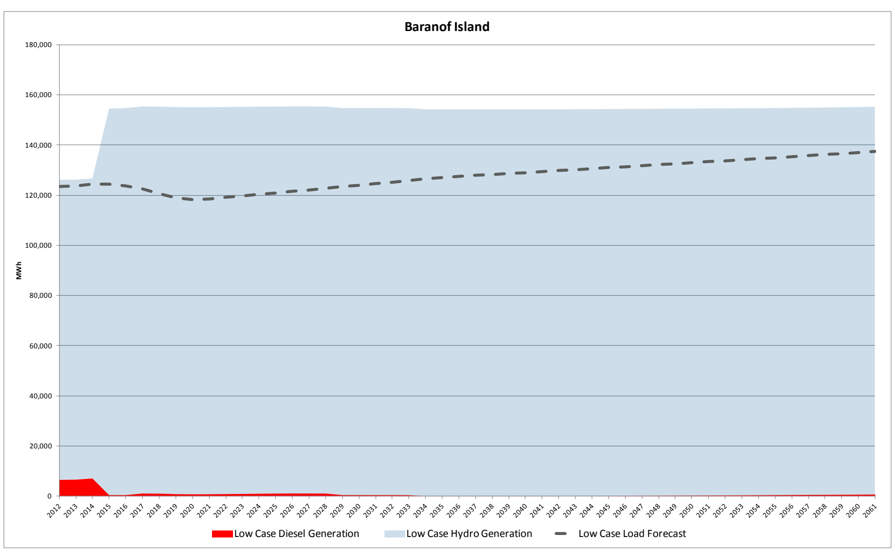
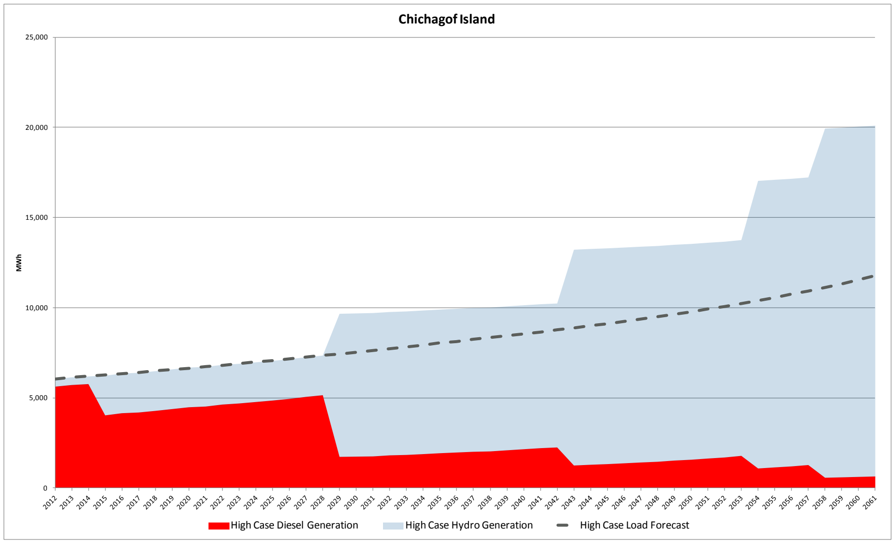
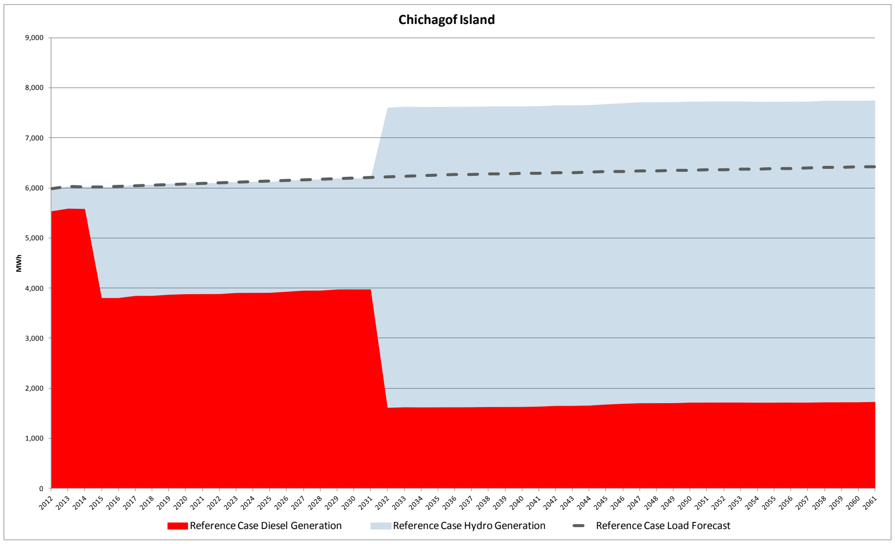


Figure 10-13 Baranof Island





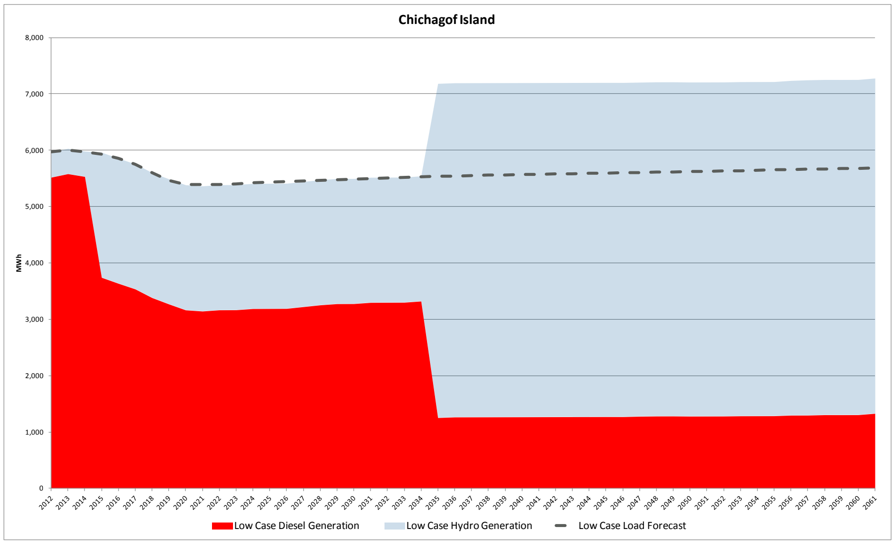
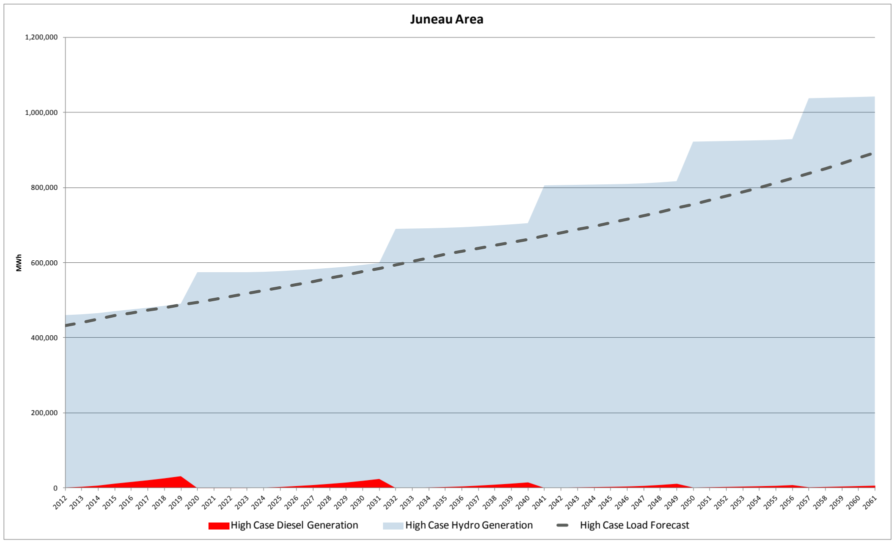
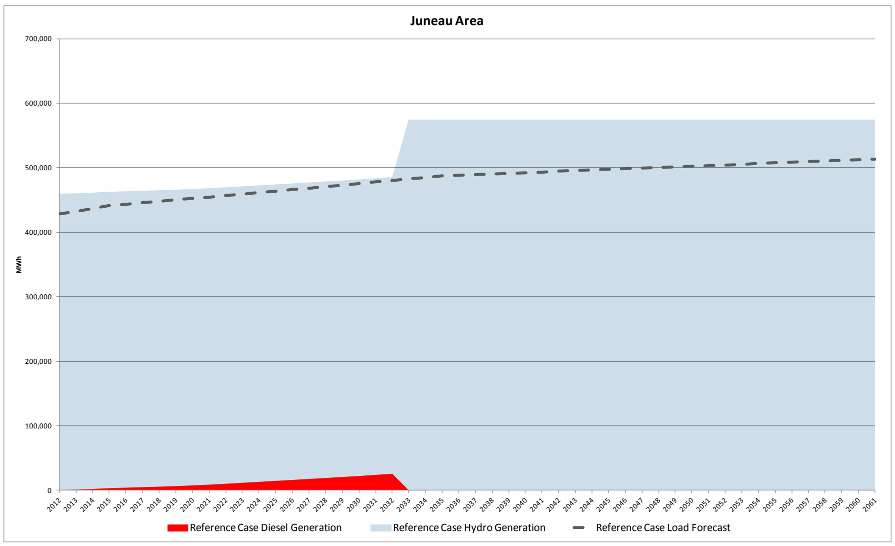


Figure 10-14 Chichagof Island





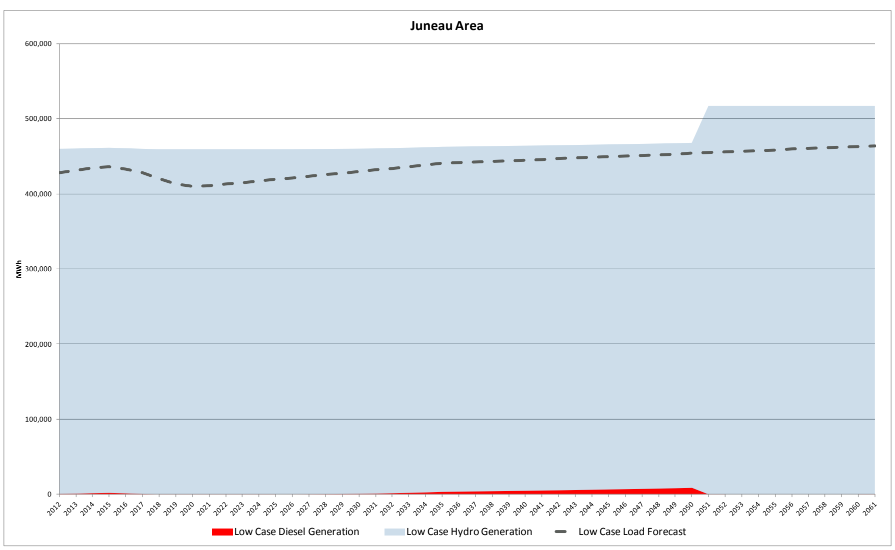
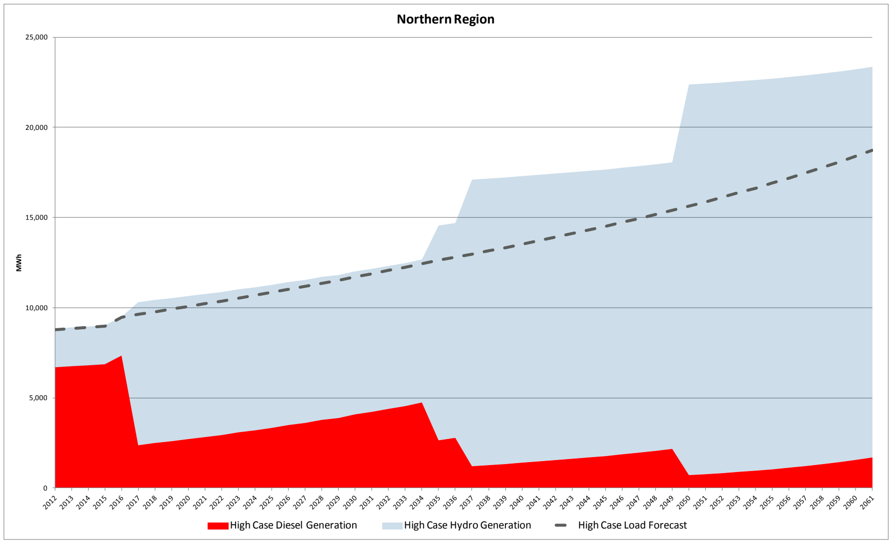
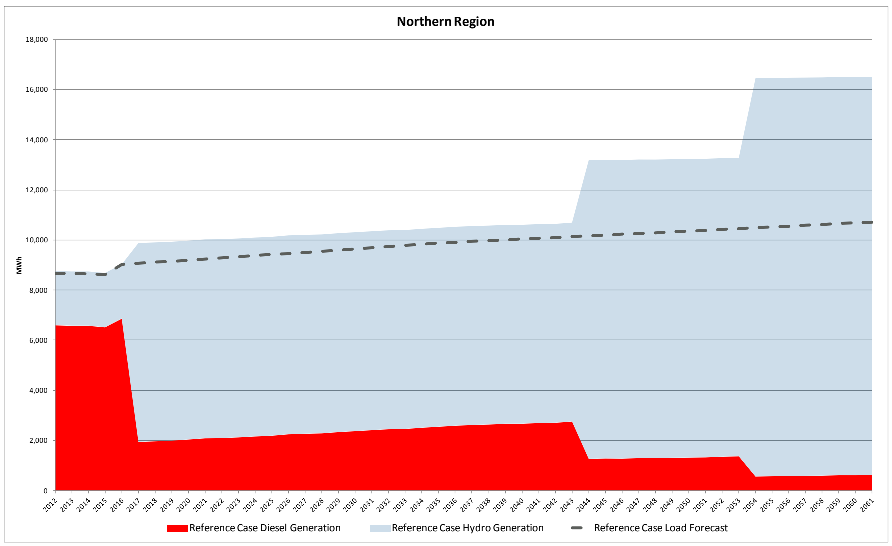


Figure 10-15 Juneau Area





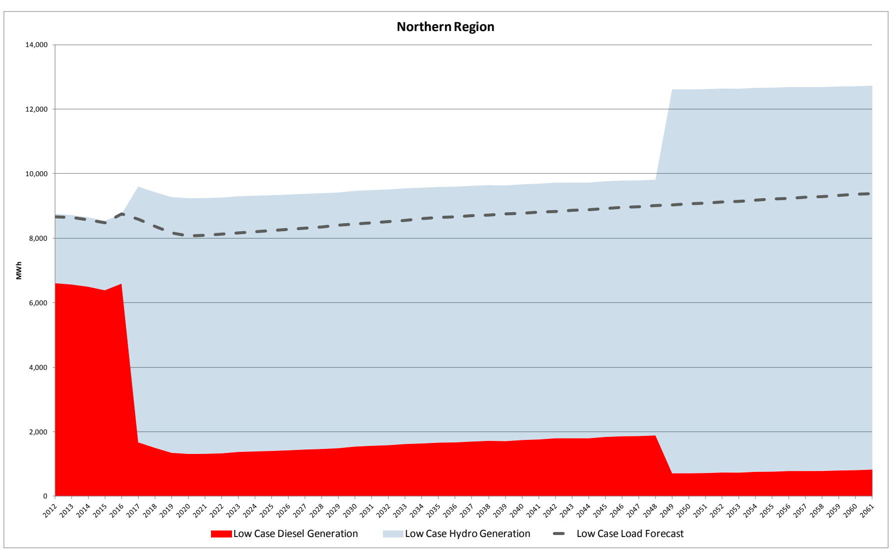


Figure 10-16 Northern Region

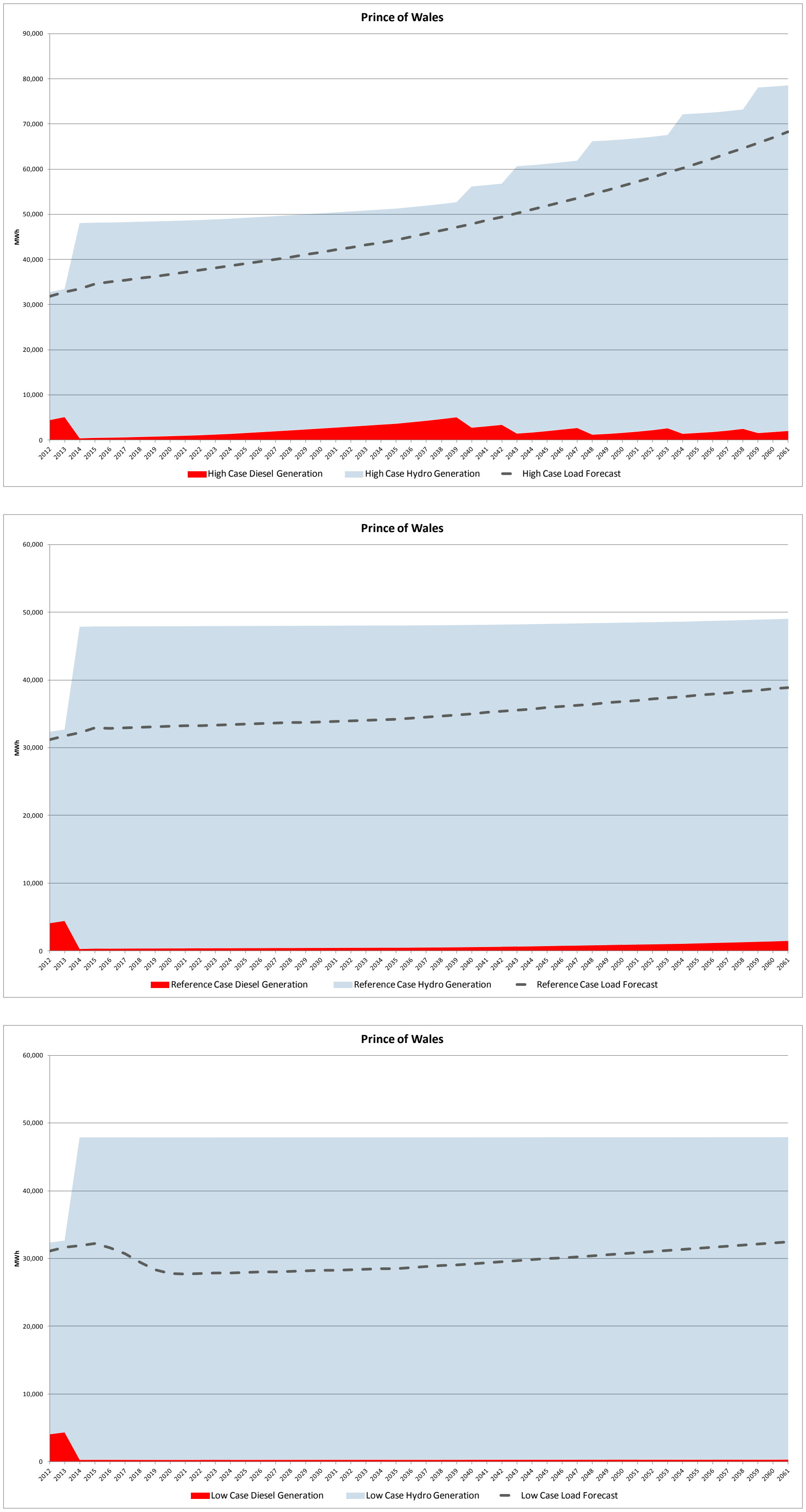
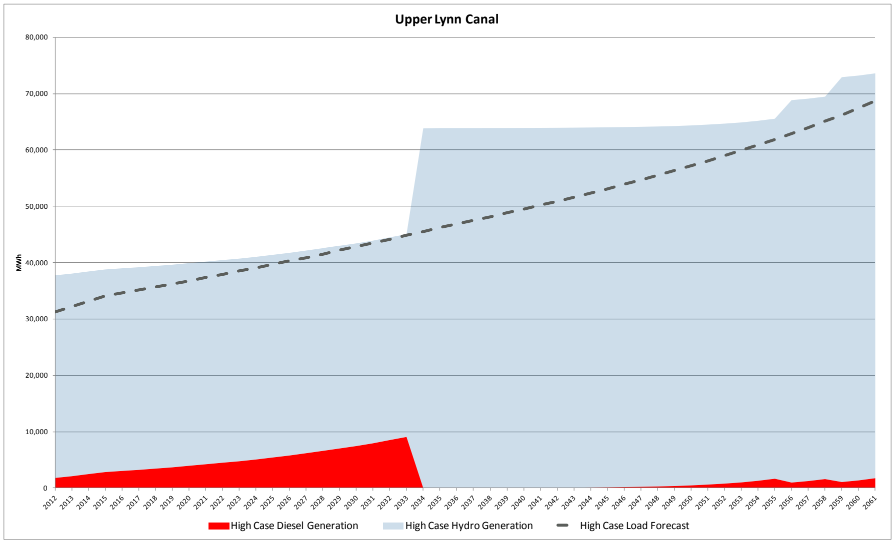
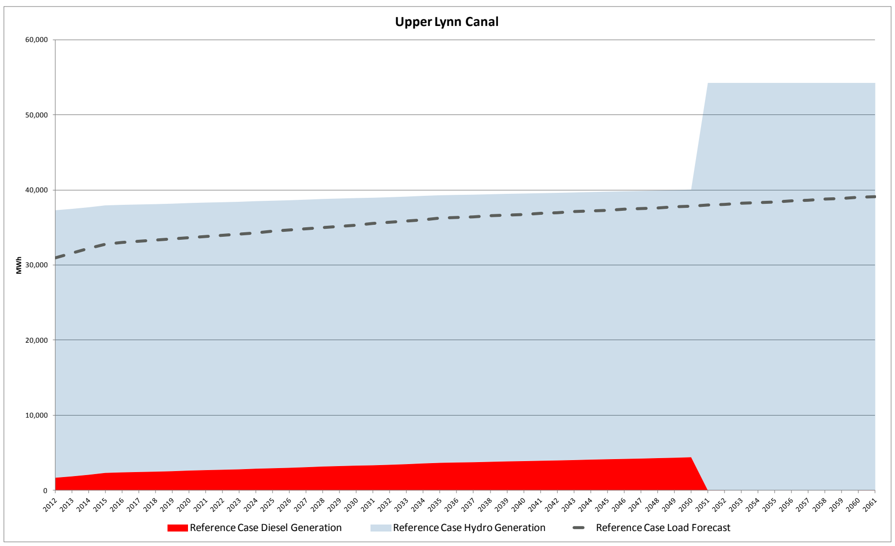


Figure 10-17 Prince of Wales





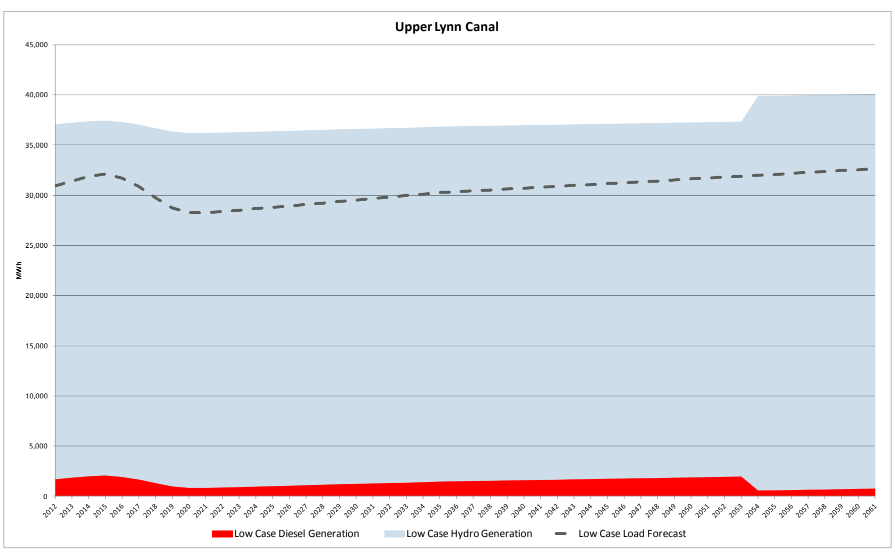


Figure 10-18 Upper Lynn Canal

10.6 HYDRO PROJECT RISK EVALUATION

The ultimate development of any potential project will require the management of certain risks that are inherent with hydro projects. This study identified eight risk areas that could affect both the probability of success as well as the cost to develop a potential hydro project, the potential energy that could be available, and the ability to construct and operate the project. The first two of these categories relate primarily to the current status of projects within the development cycle. In general, the more developed a project is, the lower the risk profile and, thus, greater certainty in the cost and energy assumptions. While not directly used in the economic evaluation of alternatives, this information should be considered when making future investment decisions.

The relative rankings for each risk factor are shown in Table 10-6 and briefly discussed below.

Table 10-6 Hydro Economic and Risk Analysis

DEVELOPMENT LEVEL (1) Design Level - geology known, engineering advanced: high confidence for cost estimate. (2) Feasibility level of information. (3) Reconnaissance level of information of current design. (4) Previous study information is outdated. (5) Superficial: low confidence for cost estimate.	**HYDROLOGY** (1) Low - existing gage data, detailed hydrologic study resulting in high confidence for energy estimate. (3) High - minimal site specific hydrologic data resulting in low confidence for energy estimate.
LICENSING/PERMITTING (1) Advanced-terms and conditions of resources agencies known (evidenced by 2nd stage consultation, Draft License Application, or FERC License). (3) Minimal (evidenced by Preliminary Permit, Preliminary Application Document, 1st stage consultation). (5) None.	**OPERATING FLEXIBILITY** (1) More than 25 percent of project's energy is available in February through April. (3) More than 20 percent of project's energy is available in February through April. (5) Less than 20 percent of project's energy is available in February through April.
CONSTRUCTABILITY/RELIABILITY ACCESS (1) Existing road access, nearby community. (3) No road access, nearby community. (5) No road access, remote location.	**PROJECT LINE MAINTENANCE** (1) Project is near a community, overhead transmission line. (3) Project is remote or overhead transmission line. (5) Connected by submarine cable.
BUSINESS AND FINANCIAL STRUCTURE (1) Financing in place. (2) Power Sales and Wheeling Agreements in place. (3) Power Sales and Wheeling Agreements in active negotiation. (4) Ownership established. (5) Ownership not established.	

Development Level

The level of development of the project determines the confidence that the project is technically feasible and that the cost and operation are appropriate.

Licensing/Permitting

The level of permitting completed determines the confidence that project can be ultimately licensed and determines the risk to schedule and costs associated with addressing potential permitting issues for both capital and operating costs.

Constructability/Reliability Access

Access to the site governs the difficulty of construction and operation and determines potential risks in the levels of capital and operating costs.

Business and Financial Structure

The level of development of the ownership and financial structure of the project measures its risk of being developed. Even good projects will not happen without financing, even if it is grant funding, since grants require minimum levels of ownership and business development.

Hydrology

The quality of the hydrologic data for the potential projects is one the most important parameters for determining the potential generation from the projects. The lesser the detail on the hydrology, the greater the uncertainty that the project can produce the estimated energy.

Operating Flexibility

The relative amount of storage a project has determines the flexibility of its operation. For projects with limited storage capacity and or limited available measured flow data, operating flexibility is a significant uncertainty. Even in the case of projects with substantive storage capacity, surpluses will go over the spillway in an unconnected, islanded system.

Project Line Maintenance

Reliability of projects is of utmost importance. Projects without good access to transmission and the plant can be subject to extended outages and attendant high costs associated with diesel operation during the outage. Projects with single contingency submarine cables are especially vulnerable to extended outages if the submarine cable fails. In addition to the cost of diesel replacement power, the cost of repair can be very significant.

Table 10-7 presents the results of the risk screening of the potential hydro projects presented in Table 10-4. It should be noted that the risk-related ratings of potential hydro projects is not a static ranking. It is expected that the merits of specific projects will change as more defined information is developed for them. The uncertainty in the quality of the data for the projects in Table 10-4 casts uncertainty in the results of the risk evaluation; however, at a minimum, it identifies some the issues that potential projects must address in order to fulfill the generic hydro needs presented in Figures 10-11 through 10-18.

As a final note, it is important to evaluate the expected system integration, or utilization, of potential hydro projects prior to making a decision to develop them. In this regard, system integration relates to the ability to utilize the output of a potential hydro project, which reflects the actual fluctuations in output of a hydro project relative to the load pattern within the load center that uses the power. Generally speaking, the ability to match output with load requirements is greatest with storage projects, which therefore leads to higher utilization of the power generated. Due to the issues related to the quality and inclusiveness of current information on the majority of the potential hydro projects, it is impossible to evaluate the expected system integration at this time. Once better information is available, this analysis can be and should be completed prior to moving forward with a specific hydro project.

Table 10-7 Results of Economic and Risk Screening

PROJECT NAME	LOCATION	PROJECT DEVELOPMENT				OPERATIONAL		
		DEVELOPMENT LEVEL (1-5)	LICENSING/ PERMITTING (1,3,5)	CONSTRUCTABILITY/ RELIABILITY ACCESS (1,3,5)	BUSINESS AND FINANCIAL STRUCTURE (1-5)	HYDROLOGY (1,3)	OPERATING FLEXIBILITY (1,3,5)	PROJECT LINE MAINTENANCE (1,3,5)
SEAPA								
Anita - Kunk Lake	Wrangell	4	5	5	5	5	5	5
Cascade Creek	Petersburg	2	3	5	4	1	5	5
Connell Lake	Ketchikan	4	3	1	5	1	5	1
Lake Shelokum	Wrangell	5	3	5	4	1	5	5
Mahoney Lake	Ketchikan	1	1	1	4	1	3	1
Orchard Lake	Meyers Chuck	5	5	5	5	1	5	1
Ruth Lake	Petersburg	4	3	5	4	5	5	5
Scenery Creek	Petersburg	4	3	5	4	5	5	5
Sunrise Lake	Wrangell	3	3	3	5	1	5	3
Thoms Lake	Wrangell	4	5	3	5	1	5	3
Triangle Lake	Metlakatla	3	5	3	4	1	5	3
Tyee New Dam Construction	Wrangell	4	5	5	5	1	1	1
Tyee New Third Turbine	Wrangell	4	5	5	5	1	5	1
Virginia Lake	Wrangell	4	5	5	5	1	5	5
Baranof Island								
Takatz Lake	Sitka	3	3	5	4	1	1	5
Chichagof Island								
Crooked Creek and Jim's Lake	Elfin Cove	2	5	1	5	1	3	3
Indian River	Tenakee Springs	3	5	5	4	1	5	3
Water Supply Creek	Hoonah	3	5	1	4	1	5	1
Juneau Area								
Lake Dorothy Expansion	Juneau	2	5	3	2	1	1	1
Sweetheart Lake	Juneau	2	3	5	4	1	1	5
Upper Lynn Canal								
Connelly Lake	Haines	3	3	3	2	1	5	3
Schubee Lake	Skagway	5	3	5	2	5	3	5
Walker Lake	Chilkat Valley	4	5	1	5	1	5	3
West Creek	Skagway	5	5	1	4	5	5	3

Note: The risk-related ratings shown in this table are based upon the project-specific information available at this time and subject to change as projects move through the development process. These ratings are not additive for the purpose of a competitive ordering of projects. Consequently, the AEA believes that this information should not be used, in its current form, to make any investment decisions.

11.0 Other Generating Unit Alternatives

This section summarizes the input assumptions and technologies that Black & Veatch used related to the various supply-side resource options considered in the study except for conventional hydro which is discussed in Section 10.0. Figure 11-1 illustrates some of the resources available to the Southeast Alaska communities as researched by the Alaska Department of Natural Resources (DNR) and the Alaska Energy Authority (AEA).

Legend: **Number** = Wind Speed **H** = Hydro **W** = Biomass **C** = Coal **Ge** = Geothermal **Ga** = Gas **T** = Tidal

Figure 11-1 Summary of Resources Available to Southeast Alaska

11.1 GEOTHERMAL

According to the *Renewable Energy Atlas of Alaska*[1] developed by the Renewable Energy Alaska Project (REAP) in conjunction with AEA, Southeast Alaska has several opportunities for geothermal electric production. Unfortunately, the area only has low to moderate temperature geothermal systems. As shown on Figure 11-2, moderate geothermal resource temperatures top out at around 200° F. Flash steam hydrothermal plants require fluids above 360° F to make electricity. Since there are no resources that have been identified in Southeast Alaska with 360° F or above fluids, any projects developed in Southeast Alaska would likely need to be modeled after the Chena Hot Springs system, which is a binary-cycle system.

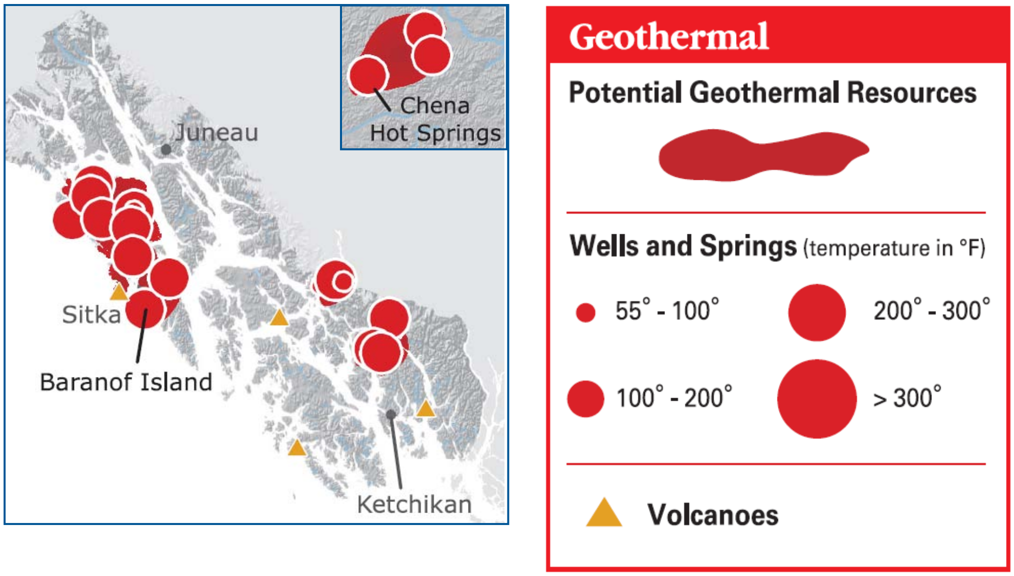


Figure 11-2 Geothermal Resources in Southeast Alaska

[1] http://www.akenergyauthority.org/Reports%20and%20Presentations/EnergyAtlas2009.pdf

11.1.1 Flash Steam Geothermal

In a flash steam system, hot fluids from the geothermal well are extracted and pumped into a tank where the pressure is much lower than the fluid. The result causes some of the fluid to rapidly vaporize, or flash. The resulting vapor drives a turbine, which in turn, drives a generator. Any liquid remaining can be flashed again in a second tank to produce more energy. Since it is a closed-loop system, there are virtually no emissions, and the vapors sent through the turbine condense back into liquid and are injected back into the well, helping to maintain the resource. Figure 11-3 illustrates the flash steam system. Note that there are some dry steam geothermal systems that do not require the use of the flash tank to produce high-pressure steam.

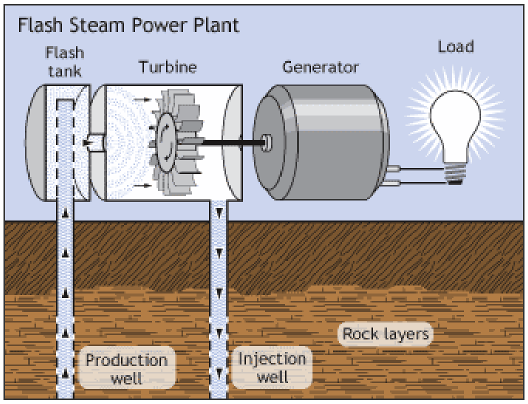


Figure 11-3 Flash Steam Geothermal Technology

11.1.2 Binary-Cycle Geothermal

Since all of the geothermal areas identified in Southeast Alaska contain moderate to low temperature resources, a binary-cycle technology will be required to produce electricity from a geothermal resource. Figure 11-4 illustrates the binary-cycle geothermal technology. As shown, hot liquid from the production well passes through a heat exchanger. The heat from the production well liquid is not hot enough to boil, but it is hot enough to boil other liquids with lower boiling points, such as R-134a, a common refrigerant found in many air conditioning systems that is also used in the Chena Hot Springs geothermal system. As the production well liquid passes through the exchanger, the heat is transferred to the secondary fluid, causing it to boil. The resulting vapor turns the steam turbine, which in turn spins the generator.

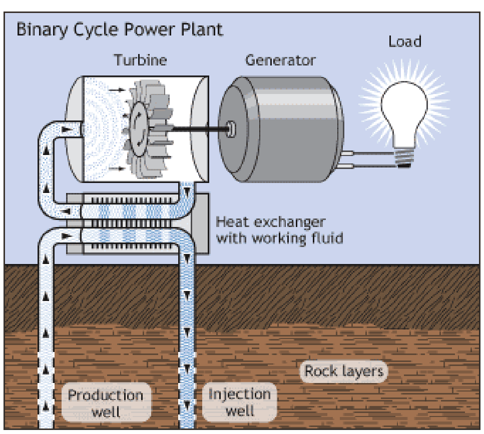


Figure 11-4 Binary-Cycle Geothermal Technology

11.1.3 Chena Hot Springs Geothermal

The Chena Hot Springs system is slightly different than the basic binary-cycle system and is illustrated in Figure 11-5. The production well liquid at Chena is 165° F. In the first step of the process, the production well liquid is sent to the evaporator (heat exchanger). The R-134a is used as the secondary liquid and has a boiling point of negative 15.34° F. Once the heat energy is transferred, the R-134a begins to boil and vaporize. Upon the initial startup at Chena, the vapor bypasses the turbine and is sent directly to the condenser. The loop is continued until there is sufficient vaporizing to continuously run the turbine. The valve is opened, the vapor gets routed to the turbine, causing the turbine to spin at 13,500 rpm. The connected generator, in turn, spins at 3,600 rpm. Cooling water enters the condenser from a cooling water well located 3,000 feet away where the water cools down the R-134a and condenses back to liquid form through heat exchanging. The liquid is then sent back to the evaporator, completing the closed-loop cycle. At the end of the production well liquid cycle, some of the warm liquid is used to heat buildings onsite prior to being reinjected into the geothermal well.

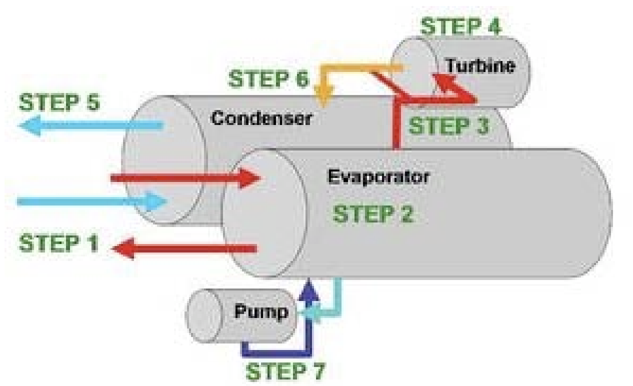


Figure 11-5 Chena Hot Springs Geothermal System

11.1.4 Potential Geothermal Projects

A few potential sites have been identified for geothermal projects in Southeast Alaska. Tenakee Springs Inlet has gone through the AEA Renewable Energy Grant Fund (REGF) process and has received some support. The Forest Service has also listed two other projects, one at Neka and the other at Bell Island. Black & Veatch was not able to obtain any further information besides project names and, therefore, did not consider Neka and Bell Island as specific potential resources in this study. The Swan-Tyee interconnection passes over the Bell Island site. Proximity to transmission is a benefit to geothermal projects.

11.1.4.1 Tenakee Springs Inlet

The REGF website[2] listed an application for a grant for reconnaissance of a potential utility-scale geothermal project near the Tenakee Springs Inlet, which is only a few miles from the logging roads that lead to Hoonah, approximately 20 miles away. This appears to be the second hottest resource in the Southeast, and at 80° C by geothermometry. The application was submitted by the Inside Passage Electric Coop for the funding of approximately $2.6 million to support reconnaissance and exploratory drilling. Documents on the AEA website indicate that the project is likely uneconomical, but, in Round 4 of the funding cycle, AEA did recommend partial funding of

[2] http://www.akenergyauthority.org/RE_Fund_Applications-IV.html

approximately $600,000 to support reconnaissance and feasibility activities. The project could benefit Hoonah, Pelican, and Tenakee Springs and range between 3 and 6 MW. According to the REGF site, construction costs were estimated at $27 million before roads and transmission lines. The Alaska Department of Transportation (DOT) estimates $2 to $3 million per mile for roads in the area, which would cost in excess of $200 million to connect all three communities. Opposition to the project has been voiced by Tenakee Springs officials.

11.2 WIND

According to the *Renewable Energy Atlas of Alaska*[3] Southeast Alaska has only a few opportunities for wind-generated power near load centers. Figure 11-6 was taken from the *Renewable Energy Atlas* and a map of the Tongass National Forest Energy Projects. and illustrates the resource potential throughout the region. In general, wind plants are typically installed in areas with a wind power class rating of 3 or above. As shown in the upper portion of the figure, the most potential for wind exists north of Juneau and east of Skagway, and east of Yakutat. Unfortunately, these areas are not coincident with population areas, and the transmission lines required would need to be installed over very difficult terrain.

The lower portion of Figure 11-6 illustrates the two wind resource-rich areas mentioned with respect to Roadless Rule coverage. As shown in the left-hand portion, the wind rich area east of Yakutat is currently covered under the Roadless Rule. In the right-hand portion, the entire area north of Juneau is also covered under the Roadless Rule regulations. While the Roadless Rule is still being contested, the current state of the rule would make it difficult to construct wind projects and their corresponding transmission lines within these areas. There are small areas sprinkled throughout the region which may possess wind resource capabilities, but most of the utility-scale resources are in areas that are inaccessible due to terrain or Roadless Rule restrictions, or are too far from population areas to interconnect economically.

One advantage of wind generation in Southeast Alaska is that it may be coordinated with hydro generation. If feasible, the wind could displace hydro generation and maintain more water in the reservoirs for use when loads are highest. A secondary benefit is that if more water is retained in the reservoirs, the head increases further increasing the energy that be generated during specified periods. This hydro coordination should be consider where feasible when evaluating specific wind projects.

11.2.1 Wind Studies in Southeast Alaska

In Round 5 of the REGF, there have been three applications for grant funding pertaining to wind resources in the Southeast region. Two of the applications are for studies in the SEAPA region, and one is for a feasibility study for the city of Angoon. The SEAPA Phase I Wind Site Reconnaissance Study and the Wind Resource Assessment and Economic Feasibility Study have requested funding in the amount of $72,630 and $215,130, respectively, while the City of Angoon Wind to Energy Feasibility Study has a request for $40,000.

[3] http://www.akenergyauthority.org/Reports%20and%20Presentations/EnergyAtlas2009.pdf

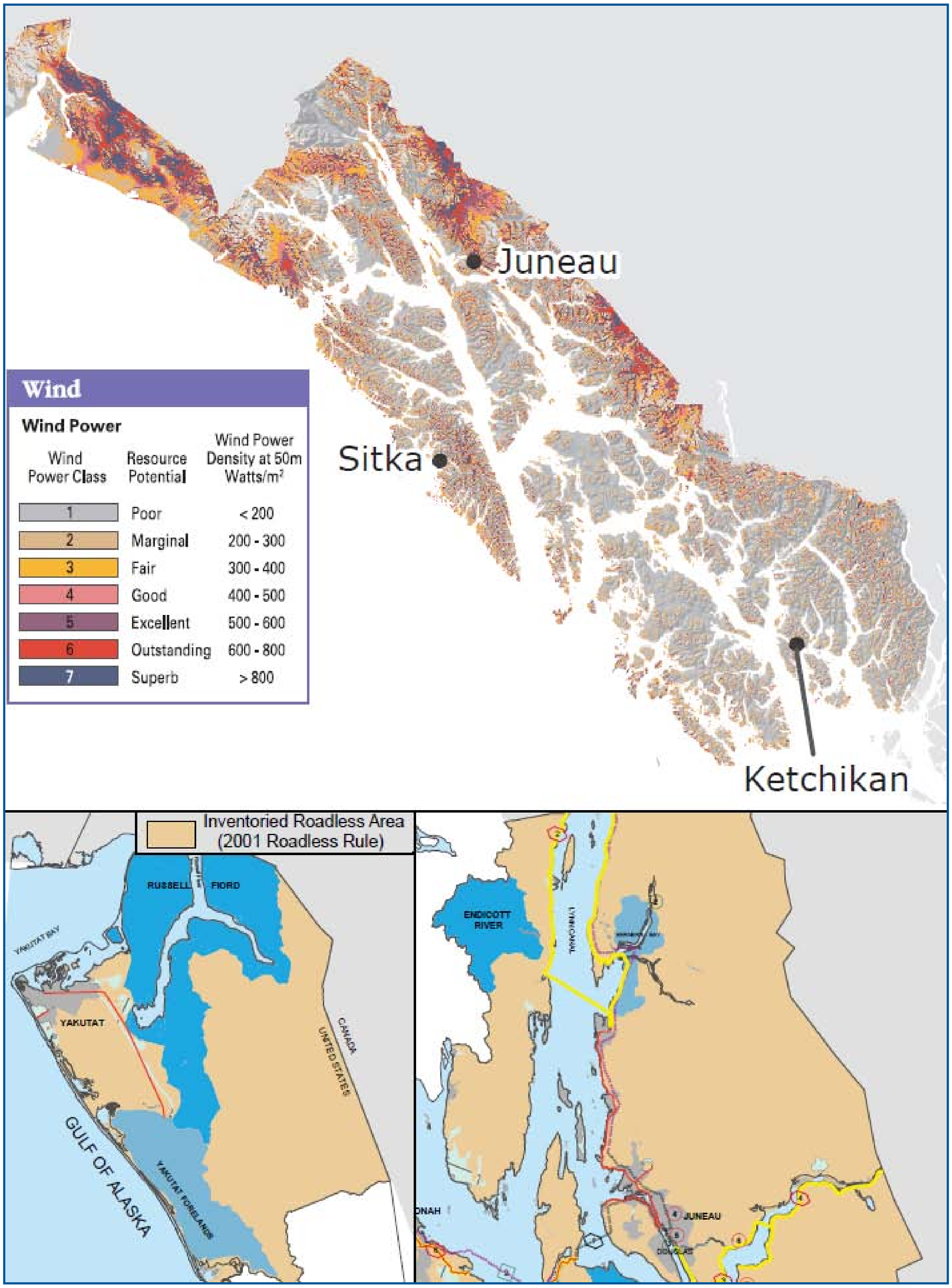


Figure 11-6 Wind Energy Resources in Southeast Alaska

11.2.1.1 SEAPA Phase I Wind Site Recon

The Phase I Wind Site Reconnaissance will determine if there are viable wind resources along the SEAPA transmission system that will eventually stretch from Kake to Metlakatla. SEAPA estimates that Phase I of the feasibility study will begin in August 2012 and end in January 2013. The study will evaluate the resources in the area, land use/permitting, environmental issues, the preliminary design costs, the cost of energy, and other economic analyses. SEAPA estimates the total cost of the study to be $80,700, will match 10 percent of that cost, and has requested AEA funding for the remainder.

11.2.1.2 SEAPA Wind Resource Assessment and Economic Feasibility Study

SEAPA has also submitted a grant funding application for what is essentially the Phase II follow-up for the Phase I Wind Site Reconnaissance, the Wind Resource Assessment and Economic Feasibility Study. The study covers the Ketchikan region and the area surrounding High Mountain on Gravina Island. The project will involve the installation of wind-measuring meteorological towers and other geotechnical tasks necessary to further evaluate the resources identified in Phase I and develop a conceptual design. The study will also focus on High Mountain, an area that the AEA has determined has Class 4 wind capabilities. SEAPA estimates that the study will begin in August 2012 and end in December 2013, which is concurrent with the Phase I reconnaissance study. SEAPA estimates the total cost of the study to be $150,000, will match 5 percent of that cost, and has requested AEA funding for the remainder.

11.2.1.3 City of Angoon Wind Energy Feasibility Study

The City of Angoon has submitted an application to determine the feasibility of installing wind turbines at a water treatment facility to offset the electrical costs of the facility. The requested grant of $40,000 will help cover a reconnaissance of the area around the facility, study of the resource viability, conceptual design, identifying of land easements, and an economic analysis of alternatives. Angoon proposes to match AEA's funding with $8,500 of its own funds. The total project cost is estimated at $48,500. Angoon estimates the project to begin in August 2012 and end July 2013.

11.2.2 Other Identified Wind Potential in Southeast Alaska

A portion of the Comprehensive Renewable Energy Feasibility Study for Sealaska Corporation, dated December 31, 2005, analyzed the potential for wind in the region. The wind portion of the study evaluated 23 potential wind sites based on macro wind data, probability of viable winds based on topography, the schedule involved in bringing interties to candidate sites, and wildlife considerations. Five of those sites were chosen for further evaluations via site visits. The visits included meetings with local community leaders to identify the requirements, costs, and benefits of having local renewable energy facilities. Ultimately, Hoonah and Yakutat were the only areas chosen for further study. Further study of detailed wind data at Hoonah[4] concluded that a wind turbine could have a capacity factor of less than 10 percent, which indicated that Hoonah did not have sufficient wind resources. Further study of Yakutat[5] indicated that a wind turbine could have an annual gross capacity factor of around 12 percent.

[4] Wind Data Report for the Hoonah White Alice Site April 2005 – September 2005, dated November 15, 2005, by John Wade, Wind Consultant LLC.

[5] Wind Data Report for the Yakutat July 2004 – July 2005, dated November 7, 2005, by John Wade, Wind Consultant LLC.

Recently, there has been activity across the region to measure wind resources in areas with potential for wind generation. Macro-level wind data has been collected for areas near Ketchikan, Juneau, Sitka, Skagway, Haines, Taku Inlet, and Lynn Canal. Anemometers have been used to collect more detailed data in the Kake Wind Project, and the preliminary numbers indicate resources are marginal to good, but more data are needed concerning consistency and direction of the wind. Wind blowing from different directions or overly gusty creates difficulty generating power. Areas near Gravina Island and Metlakatla have also been identified as needing refined evaluation.

Overall, the amount of interest in wind is growing in the region, but there are several areas that warrant more involved analysis. Currently, wind is opportunistic at best. It is possible that wind resources can be implemented in the region in the future, and Black & Veatch encourages the continued study of resources, but specific impacts from wind resources have not been included in this IRP.

11.3 WAVE ENERGY CONVERSION

A wave energy conversion (WEC) project has been identified for the Yakutat area and proposed by Aquamarine Power, based in Scotland. The project has gone through the reconnaissance and feasibility study phases and received a recommendation from the AEA for full funding in the amount of $1.2 million for the final design and permitting phase during Round 3 of the REGF[6] process. The feasibility study conducted by the Electric Power Research Institute (EPRI) titled, "Yakutat Conceptual Design, Performance, Cost and Economic Wave Power Feasibility Study," dated November 30, 2009, indicated that the wave energy near Yakutat was ideal for WEC.

11.3.1 Project Overview

Given Yakutat's relatively low generation needs, it was decided that the project should utilize near-shore technology rather than deepwater technology. With the small-scale technology, the majority of the costs of the project are attributed to installation and operation of the subsea cable, as opposed to capital cost of the power generating equipment. The major project elements include: (1) the Aquamarine Oyster WEC device, (2) a high-pressure (120 bar) supply subsea pipeline and low pressure (3 bar) return subsea pipeline, (3) an onshore turbine generator power station, and (4) a distribution line extension to connect the power station to the city electrical grid network.

The Aquamarine Oyster was chosen as the equipment to be used at the site. The Oyster is a wave-actuated hydraulic pump that pumps fresh water to shore at a pressure level of about 120 bars, where it is converted into electricity using a conventional hydroelectric system and then returns it to the Oyster in a closed loop. Figure 11-7, taken from the EPRI study illustrates the Oyster technology and proposed application at Yakutat. Figure 11-8, also taken from the EPRI study, illustrates an overhead view of the project site and project elements relative to the shoreline and Yakutat Airport.

[6] http://www.akenergyauthority.org/RE_Fund_Applications-III.html

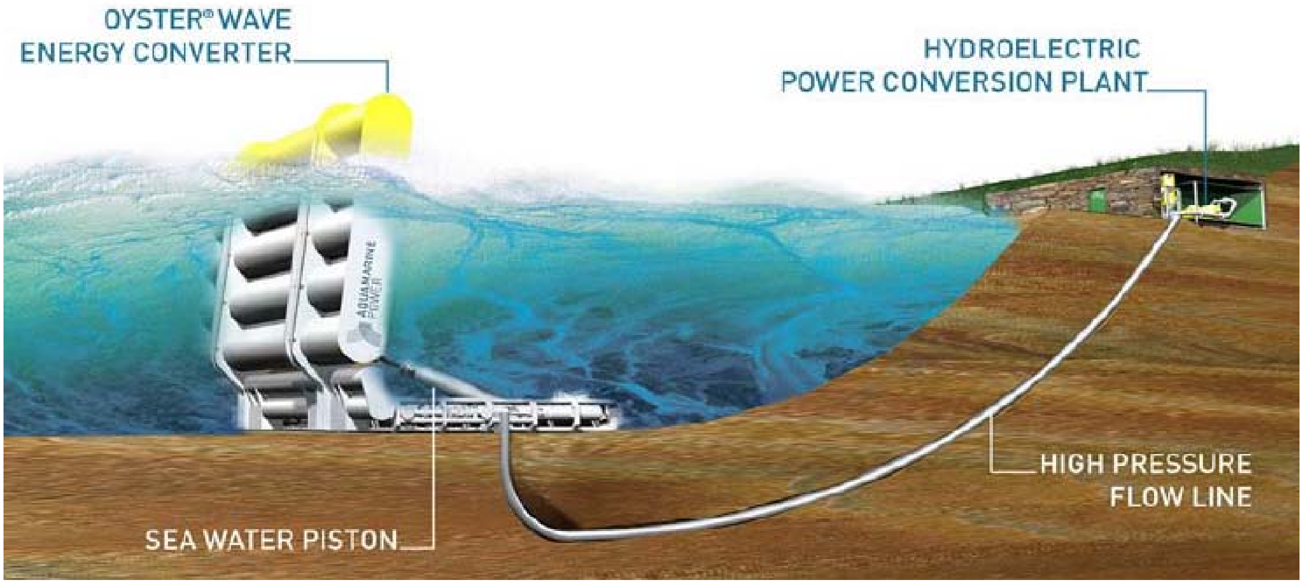


Figure 11-7 Oyster Wave Energy Converter Yakutat Application

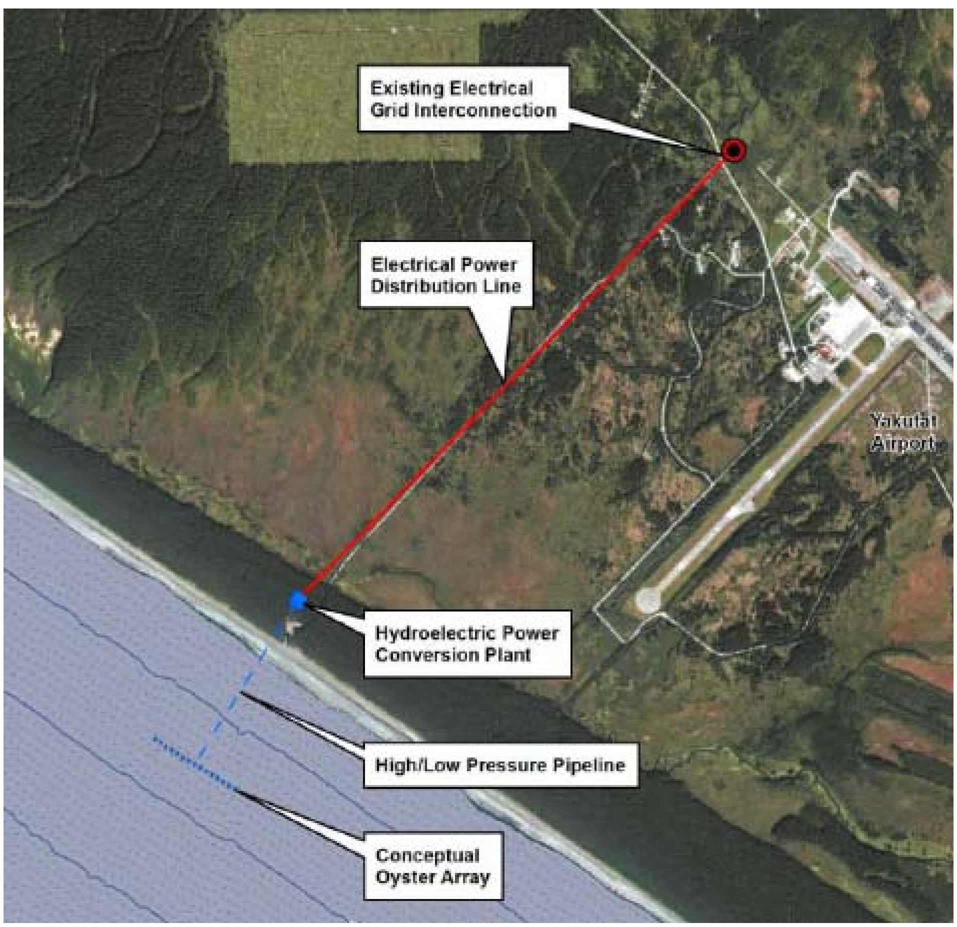


Figure 11-8 Project Site Overhead View

11.3.1.1 Technology Description

As shown in Figure 11-7, the Oyster has a buoyant flap that oscillates with the surge found in near-shore waves. The flap is attached to two hydraulic cylinders that pump water at high pressure to a modified hydroelectric plant located on land. A key part of the technology's design is to keep the components located offshore as few and as simple as possible. There are no major electrical components or active control functions operating offshore. The technology is anchored to the sea floor and can operate in relatively shallow water.

The feasibility study evaluated costs and performance for four sizes of installations consisting of 1, 2, 4, and 8 units. These configurations comprise 650 kW, 1,300 kW, 2,600 kW, and 5,200 kW, respectively. Table 11-1, extracted from the EPRI study, summarizes the cost and performance characteristics of the four evaluated installations. Costs were presented in 2010 dollars in the EPRI study, but have been escalated to 2011 dollars for use in this study.

11.4 WAVE ENERGY/SEQUESTRATION TECHNOLOGY

In Round 5 of the REGF process, AEA received an application for a Wave Energy/Sequestration Technology (WEST) project for use in the Yakutat region. The project is proposed by Atmocean, based out of Santa Fe, New Mexico. WEST is a technology that is scalable and could provide Yakutat with approximately 6.6 million kWh of annual energy, which is approximately 90 percent of its energy needs. Atmocean has estimated the total cost of the project to be $4.96 million and has pledged $77,355 for the project. Atmocean has requested a grant for the remaining $4.89 million through the REGF Round 5 process to fund design, permitting, and construction.

11.4.1 Project Overview

WEST is an offshore technology that operates in waters of 25 meters or above and utilizes the steepness of a wave to create hydraulic pressure. The resulting pressure is transmitted by a seafloor pipe to hydraulic motors that drive electrical generators onshore. Atmocean would deploy around 600 devices off the Yakutat shore that are similar to the ones shown on Figure 11-9. The arrays will be placed 1 to 2 miles off the Yakutat shore as shown on Figure 11-10.

11.4.2 Technology Description

The technology utilizes wave steepness, height, and period to create the hydraulic pressure. Atmocean is also proposing to directly attach the WEST hydraulic motor to the existing generator shafts that Yakutat owns and install a controller that would cycle between the dominant wave source and secondary diesel energy source.

The sequestration portion of the application is a byproduct of the method used to generate the hydraulic pressure. As the buoys bob up and down in a wave, the tubes that extend toward the ocean floor use valves to upwell nutrients from the seafloor to the surface. This creates a positive reaction on the local food chain that will enhance the ability of plankton and other marine life to flourish near the surface. Larger amounts of plankton will absorb more carbon dioxide from the ocean's surface and the surrounding air, and bring it to the bottom of the ocean when the plankton dies. This plankton cycle creates the carbon dioxide sequestration effect mentioned.

The grant application states that the maximum power rating of the WEST application is approximately 1,600 kW, but claims that this maximum is achieved in the winter months when the Yakutat demand is lower. As stated in Section 8.0, the projected 2012 Yakutat peak demand is 1,300 kW. The project's estimated $4.96 million capital cost results in about $3,100/kW of installed capacity. The grant estimates the projects annual O&M cost at $200,000.

Table 11-1 Yakutat Wave Energy Cost and Performance Characteristics

CAPITAL COST	1 UNIT		2 UNITS		4 UNITS		8 UNITS	
	$	$/KW	$	$/KW	$	$/KW	$	$/KW
Device Structure	$3,955,200	$5,071	$7,119,360	$4,564	$12,814,848	$4,108	$23,066,726	$3,697
Water Pipeline	$1,384,320	$1,775	$2,491,776	$1,598	$4,485,197	$1,438	$8,073,354	$1,294
Power House	$1,399,770	$1,794	$2,552,340	$1,636	$4,857,480	$1,557	$9,467,760	$1,517
Installation Cost	$2,417,616	$3,099	$3,386,640	$2,171	$4,866,132	$1,559	$7,153,350	$1,146
Total Cost	$9,156,906	$14,087	$15,550,116	$11,961	$27,023,657	$10,394	$47,761,191	$9,185
Annualized OpEx	$339,900	$523	$525,300	$404	$834,300	$321	$1,442,000	$277
Performance								
Rated Power	650	kW	1,300	kW	2,600	kW	5,200	kW
Capacity Factor	48%		48%		48%		48%	
Availability	95%		95%		95%		95%	
Annual Energy Output	2,596	MWh	5,193	MWh	10,386	MWh	20,772	MWh
Cost of Electricity (constant $)	46.5	cents/kWh	39.1	cents/kWh	33.3	cents/kWh	29.3	cents/kWh

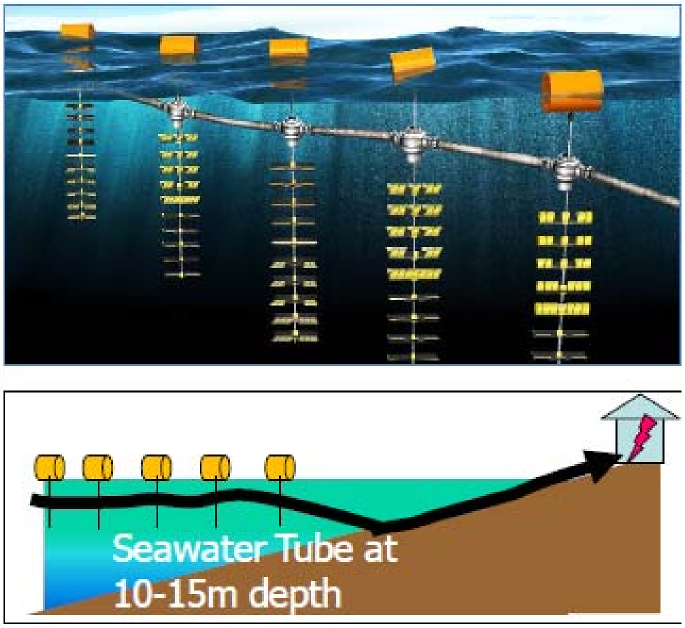


Figure 11-9 WEST Application

Figure 11-10 Project Site

11.5 TIDAL

The *Renewable Energy Atlas* describes tidal energy as a concentrated form of the gravitational energy exerted by the moon and, to a lesser extent, the sun. The energy can be converted to electricity by either dams or impoundments that cause water to flow through turbines at high and low tidal stages, or by underwater turbines that are turned by kinetic tidal flow. Although tidal impoundments were studied in Alaska in the 1990s, as of 2009 only kinetic tidal projects are being investigated, in accordance with the *Renewable Energy Atlas*. One of the significant benefits of tidal energy is that the tides are predictable for centuries in advance; however, they do not produce continuous power and present additional challenges in integrating the intermittent power into the grid.

Since 2006, the AEA has partnered with EPRI to study wave and tidal energy potential in Alaska. Figure 11-11 is from the *Renewable Energy Atlas* and provides an overview of the tidal energy potential in Southeast Alaska. The map is based on the assumption that 15 percent of the available energy is available for power generation.

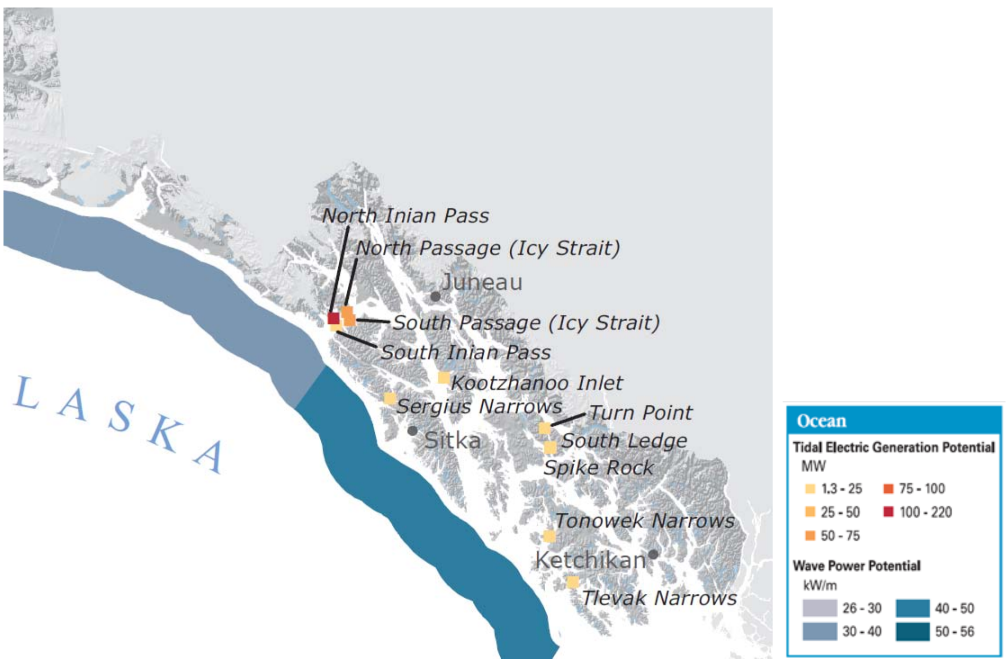


Figure 11-11 Tidal Potential in Southeast Alaska

During Round 1 of the AEA REGF, the Gustavus/Angoon/Wrangell/Nikiski Tidal Feasibility Study was proposed. This application was for a combination of selective reconnaissance, prototype testing, conflict assessment and comprehensive feasibility assessment to establish the feasibility of prospective pilot tidal energy development projects at four sites. Preliminary permits have been issued by the FERC. The four sites and respective communities served are: Icy Passage Icy Straits, serving the community of Gustavus; Angoon, serving the local Kootznoowoo community; Wrangell Narrows, potentially serving the community of Petersburg; and Central Cook Inlet near Nikiski, potentially supplying the communities in the service area of the Homer Electric Association. The AEA did not approve this application for funding.

During Round 3 of the Alaska REGF, funds were allocated to two tidal projects. Both projects were approved for reconnaissance and feasibility studies. The Port Frederick Tidal Power Project received partial funding in the amount of $64,000, and the Angoon Commercial Demonstration Tidal Power Project received partial funding in the amount of $193,200. Both projects are in the study phase as of 2011.

One additional project, the Gastineau Channel Tidal project, has a preliminary FERC permit and it is currently in the study phase. As part of the preliminary permit requirement issued by FERC, the project is required to submit progress reports to FERC every 6 months. The most recent progress report submitted in April 2011 states that the initial stages of the baseline environmental monitoring and field work for a tidal energy assessment of site location current speeds will be completed in the summer of 2011. During this time frame, the project sponsor will also discuss the submission of a Pilot License application for the site with its stakeholders. Performance testing of the prototype (1/10 of a 100 kW system) was completed in 2010. The report provided diagrams depicting the full buildout of the system.

11.5.1 Port Frederick Tidal Power Project Overview

The Alaska Power & Telephone Company submitted an application for the reconnaissance and feasibility analysis of developing a 400 kW two-basin tidal energy project in Port Frederick to serve Hoonah. AEA's analysis shows that the permitting risk appears high due to limiting inflow and outflow of the marine basins. Also, due to high estimated development costs and relatively low energy generation, the project economics did not appear promising. The project was, granted partial funding of $64,000 of the total amount of $400,000 for reconnaissance assessment. The project received a FERC preliminary permit; however, an April 2011 FERC filing reports that the Port Frederick Project has requested that its preliminary permit be terminated.

11.5.2 Angoon Commercial Demonstration Tidal Power Project Overview

Blue Energy Canada, Inc., submitted an application for the reconnaissance, feasibility, design, and construction of a 375 kW tidal energy project near Angoon. The project would include three 125 kW vertical axis turbines mounted in a steel frame. In accordance with AEA's assessment of the application, the technology would be supplied by Blue Energy and is still in development. AEA's comments state that there is minimal detail about the technology. AEA notes that another company, Natural Currents Energy Ser, LLC., currently holds a preliminary FERC permit for a tidal energy project in this location. The project, however, lost its preliminary permit in 2009 due to delays in submitting a license renewal application. In addition, all but one of the 6 month progress reports required were not submitted on time. Subsequent requests for a new preliminary permit have been denied; however, a request was made again in November 2010 stating that the cause for delayed submittals has been rectified. There are no further updates on this project.

The local utility Inside Passage Electric Cooperative has provided a letter of support to the project. In addition, Angoon Native Corporation Kootznoowoo, Inc., has submitted another application that proposes power supply to Angoon.

In accordance with the AEA, the reconnaissance phase of the project would develop tidal, bathymetric, and fisheries information that would be useful for siting any tidal energy project. Given the proposed development of the Thayer Creek Hydro project, the AEA limited funding to reconnaissance studies to assess resources, impacts, and economics before proceeding to more in-depth development. Of the total $4 million requested, partial funding of $193,200 was granted.

11.6 BIOMASS

Alaska's primary biomass fuels are wood, sawmill wastes, fish byproducts, and municipal waste according to the *Renewable Energy Atlas*. Wood is the key source for renewable energy, and over 100,000 cords per year are used for space heating. Since the closure of the major pulp mills in Sitka and Ketchikan in the 1990s, large-scale wood fired power generation in Alaska came to an end. With the increased price of oil, there is renewed interest in using sawdust and wood wastes as fuel for lumber drying, space heating, and small-scale power production.

Current projects are mostly geared toward heating facilities. Alaska has also seen renewed interest in converting low-value wood and wood wastes to liquid fuels such as ethanol.

In 2001, with assistance from the State of Alaska, processor UniSea Inc., conducted successful tests of raw fish oil/diesel blends in a 2.2 MW engine generator. Since then, the company has expanded the operation and now uses approximately 1 million gallons of up to 70 percent fish oil for power production each year.

Other initiatives include converting fish oil from processing waste and waste fry oil into fuel. Alaska Waste has commissioned its first large-scale biodiesel refinery in Anchorage. Another initiative includes the processing of the paper portion of recycled waste in the region. The waste would be densified into bricks and burned in a biomass plant for energy production. It is also possible that Alaska's agricultural lands may be used to produce energy crops, such as rapeseed, to produce biodiesel.

Figure 11-12 was extracted from the *Renewable Energy Atlas* and outlines the biomass resources in Southeast Alaska.

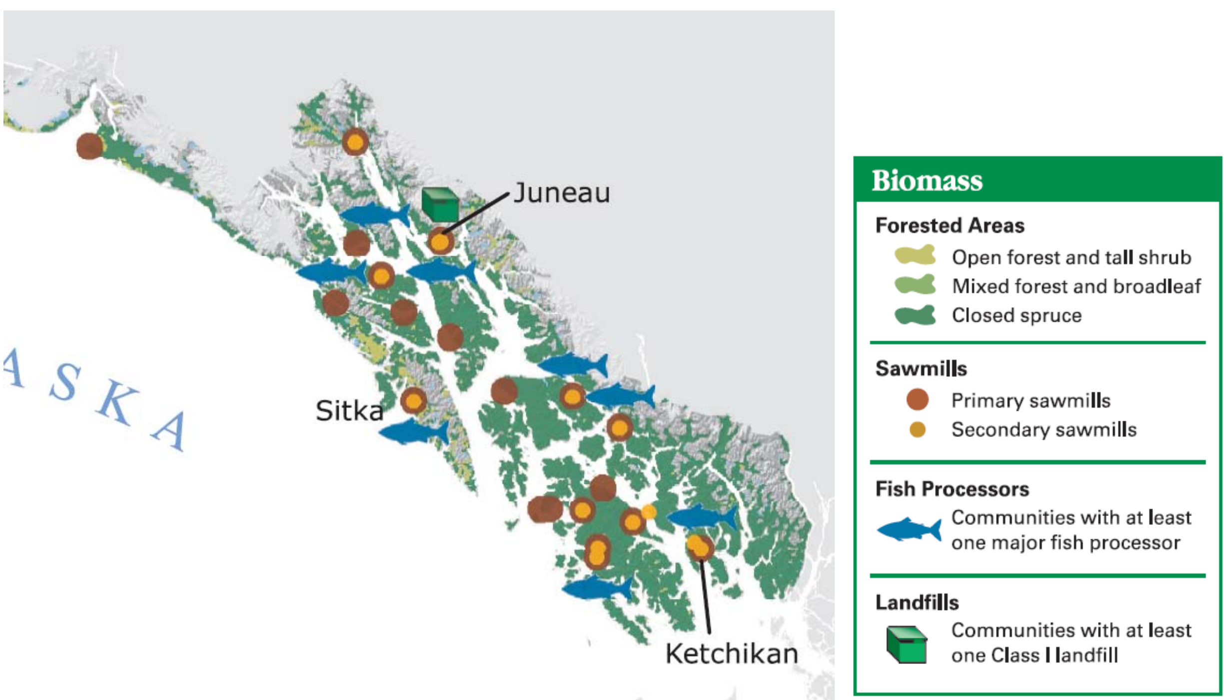


Figure 11-12 Biomass Potential in Southeast Alaska

During Round 1 of the Alaska REGF, an application was submitted for the construction of the Yakutat Biomass Gasification project. A demonstration project was already in place; however, in accordance with AEA's review, while the project showed potential, the reconnaissance and feasibility work was not completed. Given the project's potential and the level of completeness, AEA granted partial funding of $249,600 out of the requested $3.4 million.

In addition, two waste-to-energy projects were proposed, but neither one was successful and did not receive funding. The two applications were for reconnaissance studies, one at the Juneau Landfill and the other at Ward Cove at Ketchikan Pulp Mill.

Round 2 of the Alaska REGF received two applications for the Southeast region. The Kake Biomass Gasifier application was proposed by the Central Council Tlingit and Haida Indian Tribes of Alaska; however, the Tribes withdrew from the project, leaving no Native representation. The project involves the installation of a biomass gasifier combustor system integrated with hot water electrical generating equipment to generate electricity. Funds were not granted for the project.

The Mobile Biodiesel Processing Plant application was to cover first-year operations for a facility converting waste vegetable oil and other feedstock into biodiesel. AEA's conclusions questioned the sustainability of the operation and the assumptions around feedstock supply and savings to consumers. Funds were not granted for the project.

Rounds 3 and 4 did not have applications for the Southeast region for biomass electrical generation projects. As of January 2011, there were no Alaska REGF electric generation projects in the Southeast that were in the construction or pre-construction phase.

Conventional steam biomass units are considered commercially demonstrated, but their small size results in high costs. Costs for conventional steam biomass units are comparable to the coal units discussed in Section 11.7. Costs on a $/MWh basis would increase as the size of the biomass unit decreases. A significant disadvantage of biomass steam units is that they need to be manned during operation. This operation cost quickly adds to the cost on a $/MWh basis for smaller units. Another concern with conventional biomass steam units is the amount of biomass required. A general rule of thumb is that they require about 100,000 tons per year per 10 MW. While the region's forests are certainly capable of sustainably providing these levels of biomass, limitations resulting from the Roadless Rule may preclude the ability to gather and transport the needed biomass in a cost-effective manner. Due to cost considerations and potential issues with fuel supply, these conventional steam biomass units are not included in the expansion plans.

11.7 COAL

A coal fired power plant in the region would need to be appropriately sized to meet the requirements in the region. Black & Veatch has determined that a bubbling fluidized boiler or stoker boiler would be the most appropriate type of firing technology for a coal fired plant in the 10 to 20 MW capacity range.

It is difficult to develop estimated capital costs for a coal plant in Southeast Alaska without some detailed study, but Black & Veatch is of the opinion that the capital costs for a 10 to 20 MW coal fired plant could be between 5,000 and 7,000 $/kW in 2011 dollars. Fixed O&M costs are estimated to be approximately $6 million annually, and variable O&M is estimated at $400,000 to $800,000 per year with an estimated capacity factor of 80 percent. The estimated heat rate is 13,000 to 14,000 Btu/kWh.

Coal would likely be barged to the plant. Detailed evaluation of coal prices has not been conducted, but the relative small amount of coal consumed would result in higher than average prices. For the purpose of estimating the cost of coal generation, the average delivered coal cost for 2011 from the 2011 Annual Energy Outlook of $2.27/MBtu is used.

The estimated 2011 cost of coal generation assuming the larger, more economical 20 MW coal unit is $154/MWh. This compares to the 2011 estimated cost for the same size generic hydroelectric project in Table 10-5 of $95/MWh. The coal unit generation cost will continue to increase with increases in the cost of coal while the cost of hydro generation will remain relatively constant with only escalating O&M costs.

Coal generation offers one of the few dependable sources of baseload energy, but based on its high cost and environmental impacts, it will not be considered as a specific alternative for the Preferred Resource List for the region.

11.8 DIESEL

Although this IRP evaluates several options for reducing diesel demand encountered by the communities in Southeast Alaska, it is important to consider the need to replace retiring diesel generating units with more efficient, reliable machines. Without a robust interconnection grid, diesel generation provides communities with reliable generation when compared to the other alternatives mentioned in this section. Black & Veatch developed criteria for retiring and replacing diesel units while maintaining an appropriate level of diesel capacity for each community. The criteria are discussed in further detail in Section 7.0.

Estimates for capital and O&M costs are presented in Table 11-2. The two types of diesel technologies considered are High-Speed (HS) and Medium-Speed (MS). Fuel costs are community specific and are presented in Section 5.0.

Table 11-2 Diesel Unit Costs (2011 Dollars) and Performance Characteristics

UNIT	SIZE (MW)	HHV HEAT RATE (BTU/KWH)	O&M		CAPITAL COST ($/KW)
			FIXED ($/KW/YR)	VARIABLE ($/MWH)	
HS	0.5	10,715	60	25	600
HS	1	9,880	60	25	550
MS	2	9,100	40	20	1,300
MS	3	8,950	40	20	1,150
MS	5	8,700	40	20	1,050
MS	10	8,550	40	20	1,000

11.9 SOLAR

Specific solar projects have not been identified for the Southeast region, but this section discusses the potential of the resource in the region. Solar technology currently provides the peak of its energy during the summer months, which is non-coincident with the region's winter peak. Hydroelectric projects in the Southeast also currently spill water during the summer months due to the lack of demand. Solar technology would likely increase this spillage. Currently, solar technology is expensive and appears uneconomical in areas where all of its produced energy is not used. Solar is also a non-firm resource, but could be used to displace some diesel and hydroelectric generation. Black & Veatch recommends that solar not be used in meeting the near-term needs of the Southeast, but it should be monitored and considered in the future as costs decrease and efficiencies increase.

11.10 CONSIDERATION OF ALTERNATIVE TECHNOLOGIES BY SUBREGION

Black & Veatch gathered information on the various technologies in this section to evaluate their potential to provide alternative forms of generation to various subregions in the Southeast. In this section, each of the projects and technologies is analyzed within specific subregions, and recommendations about viability are made based on factors such as capital cost, busbar cost, REGF financing, and resource availability. Costs shown are in 2011 dollars.

11.10.1 SEAPA

11.10.1.1 Wind

SEAPA Wind (Phase I and Phase II)

- **Source** – *AEA Renewable Energy Grant Fund – Round 5*.
- **Commercial Status** – Commercial.
- **Project Development Status** – Reconnaissance (Phase I) and Feasibility (Phase II).
- **Capital Costs** – No specific costs are available for this project. Capital costs for a typical wind plant range from $2,100 to 2,400/kW.
- **Annual O&M Costs** – No specific costs are available for this project. Annual O&M costs for a typical wind project range from $20 to 30/MWh.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** - SEAPA has requested grant funding for reconnaissance and feasibility studies in the amount of $287,760. The Round 5 process is still in the reviewing phase and funds have not been granted to date.
- **Resource Availability** – There are some localized areas in the SEAPA subregion that may have the potential for wind resources, but more detailed information is required.
- **Recommendations** – Wind resource activities are increasing in the SEAPA subregion. Currently, there are no detailed feasibility studies that indentify economical projects or resources. Black & Veatch has not modeled this project due to lack of detailed cost and operational information. Black & Veatch recommends that SEAPA continue to pursue reconnaissance and feasibility studies in the region to identify resources and potential project costs.

11.10.1.2 Tidal

Wrangell Narrows (Petersburg)

- **Source** – *AEA Renewable Energy Grant Fund – Round 1*.
- **Commercial Status** – There are some tidal technologies that are commercial, but some are still in the early commercial stages. The funds requested in Round 1 were for reconnaissance and feasibility studies; therefore, a particular technology has not been identified.
- **Project Development Status** – Reconnaissance.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA did not approve this application for funding during the Round 1 process.
- **Resource Availability** – Unknown, more study should be done locally to identify specific areas and resources.
- **Recommendations** – There are no specific costs for this project, and the AEA did not approve this application for funding. Black & Veatch has not modeled this project due to the lack of information and project development. Black & Veatch recommends exploring tidal opportunities throughout the region as they become more commercially economical.

11.10.1.3 Biomass

Ward Cove (Ketchikan Pulp Mill)

- **Source** – *AEA Renewable Energy Grant Fund – Round 1*.
- **Commercial Status** – Commercial.
- **Project Development Status** - Reconnaissance.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA did not grant funding for this project and no other applications have been submitted to date.
- **Resource Availability** - According to the *Renewable Energy Atlas*, there are opportunities to utilize biomass resources in the region, but it is unclear what types of resources would have been needed for this project.
- **Recommendations** - There are no specific costs for this project, and the AEA did not approve any funding. Black & Veatch has not modeled this project due to lack of information and project development. As discussed in Section 11.6, it is difficult for electric generation biomass projects to be cost-effective.

Kake Biomass Gasifier

- **Source** – *AEA Renewable Energy Grant Fund – Round 2*.
- **Commercial Status** – Developmental.
- **Project Development Status** - Reconnaissance.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – The applicants withdrew their application and funding was not granted.
- **Resource Availability** - According to the *Renewable Energy Atlas*, there are opportunities to utilize biomass resources in the region, but it is unclear what types of resources would have been needed for this project.
- **Recommendations** – Black & Veatch did not model this project due to lack of development.

11.10.2 Admiralty Island

11.10.2.1 Wind

Angoon Wind

- **Source** – *AEA Renewable Energy Grant Fund – Round 5*.
- **Commercial Status** – Commercial.
- **Project Development Status** – Reconnaissance.
- **Capital Costs** – No specific costs are available for this project. Capital costs for a typical wind plant range from $2,100 to 2,400/kW for large projects with higher costs for small projects.
- **Annual O&M Costs** – No specific costs are available for this project. Annual O&M costs for a typical wind project range from $20 to 30/MWh.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** - Angoon has requested grant funding for reconnaissance in the amount of $40,000. The Round 5 process is still in the reviewing phase and funds have not been granted to date.
- **Resource Availability** – N/A.
- **Recommendations** – This project is identified to specifically offset the electrical costs at a water treatment facility. Black & Veatch has not modeled this project because detailed costs and operational characteristics are not known, and the project should not be necessary with the installation of the Thayer Creek Hydro project since additional transmission interconnections are not included in the Preferred Resource Expansion Plan.

11.10.2.2 Tidal

Angoon Commercial Demonstration

- **Source** – *AEA Renewable Energy Grant Fund – Round 3*.
- **Commercial Status** – There are some tidal technologies that are commercial, but some are still in the early commercial stages. This technology in particular, sponsored by Blue Energy Canada, Inc., is still in the development phases.
- **Project Development Status -** Reconnaissance.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA found minimal details about the technology during the application process. AEA notes that the local utility, Inside Passage Electric Cooperative, has submitted a letter of support for the project. The reconnaissance phase of the project proposed to develop detailed tidal, bathymetric, and fisheries information that would be useful for siting any project. AEA limited the funding to resources, impacts, and economics because of the proposed development of Thayer Lake. AEA granted $193,200 of the $4 million requested.
- **Resource Availability** – N/A.
- **Recommendations** – The technology proposed for this project is still in the development phases and poses inherent risks with respect to cost and design. Due to lack of design information, cost data, and AEA grant support, Black & Veatch has not modeled this resource. With the installation of the Thayer Creek Hydro project as a Committed Resource and no additional transmission interconnections included in the Preferred Resource Expansion Plan, the need for this project goes away. Black & Veatch recommends continuing support of the technology from a research and development standpoint, in general. Black & Veatch recommends specific support for this project but only for performing reconnaissance and monitoring its progress in the event the technology becomes viable and the project is shown to be feasible.

11.10.3 Baranof Island

There are no projects identified in this section for the Baranof Island subregion.

11.10.4 Chichagof Island

11.10.4.1 Geothermal

Tenakee Springs Geothermal

- **Source** – *AEA Renewable Energy Grant Fund – Round 4*.
- **Commercial Status** – Commercial.
- **Project Development Status** – Reconnaissance.

- **Capital Costs** – The Chena Hot Springs geothermal project was approximately $5,570/kW.[7] With an estimated project cost of $27 million before roads and transmission lines and over $200 million in costs for approximately 30 miles of roads in the area, this project would be in excess of $30,000/kW for a 6 MW project.
- **Annual O&M Costs** – Annual O&M costs for a typical project can range from $20 to 30/MWh. Specific costs for this project are unknown.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA indicated that the project was likely uneconomical based on the costs of roads in the area, but recommended partial funding of approximately $600,000 to support reconnaissance activities.
- **Resource Availability** – This resource appears to be the second hottest resource in Southeast Alaska.
- **Recommendations** – This project has the potential for extremely high capital costs. Black & Veatch has not modeled this project due to high capital costs and lack of operational characteristics. In line with AEA's response, Black & Veatch is of the opinion that this project is uneconomical.

Neka Geothermal (Hoonah)

- **Source** – *Forest Service*.
- **Commercial Status** – Commercial.
- **Project Development Status** – Indentified.
- **Capital Costs** – A typical geothermal project can range from $3,500 to 4,500/kW.[8] The Chena Hot Springs geothermal project was approximately $5,570/kW.[9] Specific costs for this project are unknown.
- **Annual O&M Costs** – Annual O&M costs for a typical project can range from $20 to 30/MWh. Specific costs for this project are unknown.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – N/A.
- **Resource Availability** – N/A.
- **Recommendations** – Black & Veatch did not model this resource due to lack of project information.

Bell Island Geothermal (Hoonah)

- **Source** – *Forest Service*.
- **Commercial Status** – Commercial.
- **Project Development Status** – Indentified.

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[7] Renewable Energy Atlas; http://www.akenergyauthority.org/Reports%20and%20Presentations/EnergyAtlas2009.pdf
[8] *Ibid at 7.*
[9] *Ibid at 8.*

- **Capital Costs** – A typical geothermal project can range from $3,500 to 4,500/kW.[10] The Chena Hot Springs geothermal project was approximately $5,570/kW.[11] Specific costs for this project are unknown.
- **Annual O&M Costs** – Annual O&M costs for a typical project can range from $20 to 30/MWh. Specific costs for this project are unknown.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – N/A.
- **Resource Availability** – N/A.
- **Recommendations** – Black & Veatch did not model this resource due to lack of project information.

11.10.4.2 Tidal

Port Frederick (Hoonah)

- **Source** – *AEA Renewable Energy Grant Fund – Round 3*.
- **Commercial Status** – There are some tidal technologies that are commercial, but some are still in the early commercial stages.
- **Project Development Status** – Reconnaissance.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA's analysis showed the risk for permitting to be high, considering the project's limiting of inflow and outflow of marine basins. AEA also noted that the project had high development costs and relatively low generation, which created project economics that were not compelling. AEA did grant partial funding in the amount of $64,000 for a reconnaissance assessment, but an April 2011 FERC filing reports that the project has requested that its preliminary permit be terminated.
- **Resource Availability** – N/A.
- **Recommendations** – Black & Veatch did not model this resource due to the request for termination of its preliminary FERC permit.

11.10.5 Juneau Area

11.10.5.1 Tidal

Gastineau Channel (Juneau)

- **Source** – *Forest Service*.
- **Commercial Status** – There are some tidal technologies that are commercial, but some are still in the early commercial stages. This project has completed the performance prototype testing and is in the initial stages of the baseline environmental monitoring.
- **Project Development Status** – Baseline monitoring.

[10] *Ibid* at 7
[11] *Ibid* at 8.

- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – N/A.
- **Resource Availability** – The *Renewable Energy Atlas* indicates there is potential for tidal power in the region, but more study should be done locally to identify specific areas and resources.
- **Recommendations** – The project has received a preliminary FERC permit and is in the baseline monitoring phase. Black & Veatch has not modeled this project due to lack of information on costs and resource viability. Black & Veatch recommends continuing development of this project and evaluating its feasibility as more information is collected.

11.10.5.2 Biomass

Juneau Landfill (Waste-to-Energy)

- **Source** – *AEA Renewable Energy Grant Fund – Round 1*.
- **Commercial Status** – Commercial.
- **Project Development Status** – Reconnaissance.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA did not grant funding for this project and no other applications have been submitted to date.
- **Resource Availability** - According to the *Renewable Energy Atlas*, there are opportunities to utilize biomass resources in the region, but it is unclear what types of resources would have been needed for this project.
- **Recommendations** – There are no specific costs for this project, and the AEA did not approve any funding. This particular project is a gasification process. The waste-to-energy gasification projects are in the very early stage of commercialization and have not had a stellar success record. The more conventional steam waste-to-energy projects are considered to be demonstrated commercial technology, but are even more expensive than the conventional coal units discussed in Section 11.7. Furthermore the waste streams associated with the small population in the Southeast region will only support very small projects further decreasing the cost-effectiveness on a $/MWh basis. Other technologies such as plasma arc are even earlier in the development process. Black & Veatch has not modeled this project due to lack of information and project development. Black & Veatch recommends exploring other biomass opportunities throughout the region as they become more commercially economical.

11.10.6 Northern Region

11.10.6.1 Wind

Yakutat Wind

- **Source** - *Wind Data Report for the Yakutat July 2004-2005*.
- **Commercial Status** – Large-scale wind technology is commercial, but small-scale wind needed for Yakutat is still in the early commercial stages.
- **Project Development Status** - Reconnaissance.
- **Capital Costs** – No specific costs are available for this project. Capital costs for a typical wind plant range from 2,100 to 2,400 $/kW for large projects, with higher costs for smaller projects.
- **Transmission Line** – As shown on Figure 11-6, the best wind regimes are located east of Yakutat and will require significant transmission. For purposes of calculating busbar costs, 20 miles of transmission at $250,000 per mile is assumed.
- **Annual O&M Costs** – No specific costs are available for this project. Annual O&M costs for a typical wind project range from 20 to 30 $/MWh.
- **Busbar Price per MWh** - >$1,000.
- **AEA Renewable Energy Grant Fund** – N/A.
- **Resource Availability** – The Yakutat region appears to have one of the better wind resources in the Southeast region with an estimated wind plant capacity factor of approximately 12 percent, but the terrain and remote location of the resource in proximity to Yakutat will likely make construction of turbines and transmission lines prohibitively expensive.
- **Recommendations** – Although specific capital and operating costs are not known for this project, it is likely that the small-scale required by Yakutat, which has a peak in 2012 of approximately 1.3 MW, coupled with the high transmission costs cause generating costs to be prohibitive. The small system load in Yakutat will make integration of a significant percentage of wind difficult. For wind to become cost-effective for Yakutat, the cost, development, and performance of small wind generators will need to develop and improve so that effective wind turbines can be located close to Yakutat's existing transmission system.

11.10.6.2 Wave Energy

Wave Energy Conversion (Yakutat)

- **Source** – *AEA Renewable Energy Grant Fund – Round 3 Applications*.
- **Commercial Status** – Aquamarine's Oyster Wave Energy Conversion technology currently has two demonstration projects in Scotland, with a few other projects in various stages of reconnaissance.
- **Project Development Status** – Reconnaissance.
- **Capital Costs** – The Renewable Energy Fund application lists four different sizes of units and costs, but since Yakutat's peak is approximately 1.3 MW, only costs for the 650 kW and 1,300 kW installations are considered. The application provides estimates for a capital cost range of $11,961 to 14,087/kW.

- **Annual O&M Costs** – Annual operating expenses are estimated to be in the range of $100 to 130/MWh.
- **Busbar Price per MWh** – Aquamarine states the cost of electricity between $391 and 465/MWh.
- **AEA Renewable Energy Grant Fund** – In Round 3 of the Renewable Energy Fund, AEA recommended full funding in the amount of $1.2 million for the final design and permitting phase.
- **Resource Availability** – A feasibility study conducted in late 2009 by EPRI indicated that there were adequate resources off the Yakutat shore for wave energy.
- **Recommendations** – The technology is also still in the demonstration/very early commercial phases. Black & Veatch has not modeled this resource in this IRP due to the uncertainty of the technology and costs, but recommends that this project continue to be explored. Black & Veatch recommends that Yakutat monitor the commercial viability of the technology, continue research and development, and consider the project in the future if the technology demonstrates reliability and the costs become economical.

Wave Energy Sequestration Technology (Yakutat)

- **Source** – *AEA Renewable Energy Grant Fund - Round 5 Application; Atmocean Wave Energy Feasibility Study for Yakutat.*
- **Commercial Status** – This technology currently does not have any demonstrated projects. The Yakutat installation would be the first application of this technology. The technology has been conceptualized, but no design has occurred to date.
- **Project Development Status** – Pre-Design.
- **Capital Costs** – The Renewable Energy Fund application estimates a cost of approximately $3,100 /kW.
- **Annual O&M Costs** – The REGF application estimates an annual O&M cost of $100,000 for 5.94 million kWh, which calculates to approximately $17/MWh.
- **Busbar Price per MWh** – Atmocean states that the cost of electricity will start around $350/MWh and reduce to $150/MWh.
- **AEA Renewable Energy Grant Fund** – Atmocean has requested grant funding for design and construction of the project in the amount of approximately $4.89 million of the total estimated cost of $4.96 million. The Round 5 process is still in the reviewing phase and funds have not been granted to date.
- **Resource Availability** – Atmocean's feasibility study for Yakutat indicated that there are adequate resources to support its Wave Energy Sequestration Technology.
- **Recommendations** – Projected capital costs and O&M cost estimates place the project in an economic range when compared to diesel costs. The technology also involves a carbon sequestration element that claims to reduce carbon dioxide. The project, however, is currently not demonstrated, and there is a level of uncertainty associated with the cost estimates due to the lack of commercial demonstration. Along with the cost uncertainty, there is uncertainty around the application of the design and the ability to deliver and install the project within the projected time frame. Another consideration is the amount of funding that the project may receive from the AEA REGF. Black & Veatch has not modeled this project due to the uncertainties around costs and technology. Black & Veatch

recommends that Yakutat consider more research and development if AEA provides all the funding requested by Atmocean. Yakutat should continue to monitor the progress of the application to decide if the project is economical in the future.

11.10.6.3 Tidal

Icy Passage (Gustavus)

- **Source** – *AEA Renewable Energy Grant Fund – Round 1*.
- **Commercial Status** – There are some tidal technologies that are considered commercial, and some are still in the early commercial stages. There is not a lot of long-term demonstrated commercial performance. The funds requested in Round 1 were for reconnaissance and feasibility studies; therefore, a particular technology has not been identified.
- **Project Development Status** – Reconnaissance.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA did not approve this application for funding during the Round 1 process.
- **Resource Availability** – The *Renewable Energy Atlas* indicates there is potential for tidal power in the region, but more study should be done locally to identify specific areas and resources.
- **Recommendations** – There are no specific costs for this project, and the AEA did not approve this application for funding. Black & Veatch has not modeled this project due to the lack of information and project development. Black & Veatch recommends exploring tidal opportunities throughout the region as they become more commercially economical.

11.10.6.4 Biomass

Yakutat Biomass Gasification

- **Source** – *AEA Renewable Energy Grant Fund – Round 1*.
- **Commercial Status** – Early Commercial.
- **Project Development Status** – Conceptual.
- **Capital Costs** – N/A.
- **Annual O&M Costs** – N/A.
- **Busbar Price per kWh** – N/A.
- **AEA Renewable Energy Grant Fund** – AEA noted that this project showed potential, but the reconnaissance and feasibility work was not completed. A partial grant of $250,000 was rewarded based on the completeness of the project.
- **Resource Availability** – According to the *Renewable Energy Atlas*, there are opportunities to utilize biomass resources in the region.

- **Recommendations** – There are no specific costs for this project, and the AEA only approved partial funding because of lack of reconnaissance and feasibility work. Black & Veatch has not modeled this project due to lack of information and project development. Black & Veatch notes that costs to staff a biomass plant typically create high fixed costs. These costs can be even higher due to the need to have two people on the plant staff at all times for safety reasons. There is some potential for manless operated gasifiers with a large hopper of pellets, but that technology will take some time before it is commercially proven. Manless technology will require greater processing of the biomass fuel which will result in higher fuel costs. Black & Veatch recommends exploring other biomass opportunities throughout the region as they become more commercially economical.

11.10.7 Prince of Wales Region

There are no projects identified in this section for the Prince of Wales subregion.

11.10.8 Upper Lynn Canal

There are no specific projects identified in this section for the Upper Lynn Canal subregion.

11.11 LONG TERM THERMAL STORAGE

The mainstay of the Southeast Region's low-cost electrical supply is from hydro projects. The nature of the hydro resource in the Southeast is such that the hydro projects often run short of water in the late winter and early spring and spill water at times during the summer. One technology that could help this imbalance is long-term thermal storage. This technology uses ground source type heat pumps to utilize excess electric generation in the summer to pump heat into underground geological formations. This heat is then extracted by the heat pumps in the winter to provide space heating. The concept purportedly can be integrated with other industrial processes such as refrigeration for the fish processing industry and can capture the waste heat from the refrigeration process and inject it into the thermal storage media.

The process is supposedly being used in a demonstration project in the northeastern U.S. and elsewhere in the world. Capital and operating costs were not available, but the capital cost is expected to substantial. The process is also going to be very site-specific especially relative to the geological storage conditions. The concept may offer some long-term benefits once it is demonstrated as commercial in Southeast Alaska, but Black & Veatch has not included it as commercial technology for the Southeast at this time. The region should continue to monitor is development.

12.0 Transmission Interconnection Alternatives

12.1 TRANSMISSION DEVELOPMENT PHILOSOPHY

Transmission is often thought of as the electric equivalent of the interstate highway system for several reasons. Without question, the interstate highway system has served as the foundation for economic growth, jobs, business supply chain efficiencies and cost savings, and so forth, producing great public benefit. Despite the level of public benefit, few of the communities that have directly benefited from the interstate highway system could have financed and afforded their full share of the costs incurred to build and maintain the system. A similar situation exists with regard to transmission investments, particularly in Southeast Alaska due to the high capital costs associated with the construction of transmission lines and the relatively small loads served by these transmission lines. While the public benefit of transmission investments is undeniable (such as the lowering of energy costs for those communities connected to the transmission grid resulting in significant cost savings for residents and businesses and providing the foundation of potential economic development, the provision of local construction jobs, etc.), local communities and their utilities are not able to finance and afford the high up-front capital costs associated with potential transmission projects. In this regard, transmission projects are not a traditional utility-type project. This leads to two legitimate questions: 1) what are the proper goals for transmission planning and investment and 2) how should the State and region look at the economics of potential transmission investments?

From a public benefit perspective, transmission investments are not the same as investment in generation resources. Returning to the interstate highway system analogy, public policy decision makers decided to view the highway system as a public benefit investment but left the investment in trucks, cars, and gas stations (investments required to take advantage of the highway system) to private citizens and businesses. From a public policy perspective, transmission investments can be viewed similarly to the investment in the highway system, while investments in generation resources (which produce the electrons whose transfer take advantage of the transmission system) can be viewed similarly to the investment in trucks and cars.

Additionally, potential future transmission segments in Southeast Alaska typically have significantly more transfer capability than required to meet the electric needs of the connected communities, due to the lumpiness (i.e., large increases in transfer capability that cannot be closely matched over time to load requirements) of transmission capacity. Conversely, there are numerous potential hydroelectric generation projects in the region that are small in size and more aligned with the needs of local communities. Stated in another way, it is easier to develop appropriately sized hydroelectric projects in the region than it is to develop transmission.

As a result of these considerations, an argument can be made that the level of State financial assistance for transmission projects should be greater than the level of any assistance provided for generation resources, such as hydroelectric plants. This is a policy decision for the governor's office and the State Legislature to make, and is outside the scope of this study. However, to help inform this policy discussion, the AEA directed Black & Veatch to consider transmission from the perspective of a "public benefit investment" as part of Black & Veatch's evaluation of potential transmission segments. As a result of this directive, Black & Veatch analyzed the economics of potential transmission investments in two ways. First, Black & Veatch, used the best information available (modified where appropriate based upon Black & Veatch's transmission construction and operating experience) regarding the capital and operations and maintenance (O&M) costs of specific transmission segments (including segments that would transfer power within a subregion as well as between subregions). Then an initial economic evaluation was conducted that compared the annual capital carrying costs and O&M expenses of transmission segments to the value of the diesel power displaced. This approach did not include the effect of any State financial assistance.

Additionally, Black & Veatch evaluated the economics of potential transmission segments assuming: 1) that the State provided financial assistance in the form of a grant equal to 100 percent of the construction capital costs and 2) the local utility would be responsible for covering the annual O&M expenses, as well as an annual contribution to a repair and replacement (R&R) fund to ensure adequate monies for future major repairs and replacement investments to keep the transmission system in good shape for decades.

Both of these evaluation approaches, and the resulting economic impacts, are discussed in detail in the following subsections.

Like the interstate highway system, it is one thing to build a transmission network but it is another thing to maintain the network to ensure that it remains a sustainable investment for generations. This leads to the question, "What is a sustainable transmission project?" The following are important elements of sustainability:

- In addition to financing the initial construction costs, annual O&M costs must be covered and the funding of an R&R reserve must be adequate to ensure long-term operations and reliability. Even if the State chose to provide a grant to cover 100 percent of the construction costs, the annual O&M expenses and R&R reserve funding can be a high hurdle for a local Southeast utility as a result of the small loads that would be served by any specific transmission segment.
- The developer and operator of transmission projects needs to have the organizational capabilities required to successfully build the project and operate the transmission line in terms of moving power over the line. This consideration may lead to the conclusion that one regional entity be given the responsibility for expanding the region's transmission network. This entity could be Southeast Alaska Power Agency (SEAPA) or, perhaps, another entity formed to build and operate new transmission facilities.
- Public money should not be invested in new transmission facilities until there are interconnection, power purchase, and business structure agreements in place among all of the affected parties. These agreements should: 1) ensure that adequate program management capabilities are committed to the development of each project, 2) establish the terms, conditions, and wheeling costs for transmission service, 3) establish the terms and conditions for the purchase of power to be transferred over the transmission line, 4) provide for the joint economic dispatch of connected generation facilities and, 5) ensure adequate financing capabilities are present to ensure a long-term sustainable project.
- To protect the public interest, if the State provides financial assistance, sufficient State oversight of transmission projects is required. While this may increase the cost of individual transmission projects, this oversight (if effectively applied) will increase the probability that the project will be successfully built and operated in a sustainable manner, thereby better protecting the public's investment.
- Some economies of scale can be achieved in terms of design and project development costs if more than one transmission project is developed at the same time and built to compatible standards for eventual interconnection. Also regional utilities should consider mutual aid agreements for sharing O&M and R&R needs. These potential costs savings should be evaluated in more detail as part of a regional transmission network expansion program strategy.

12.2 SOUTHEAST TRANSMISSION SYSTEM CONSIDERATIONS

The Southeast region of Alaska consists of numerous islands, evergreen forests, and mountainous regions that make transportation and construction difficult. At the same time, the region is also blessed with significant hydroelectric potential. Electric service in Southeast Alaska is provided by community-based electric utilities that, for the most part, are electrically isolated from each other. Essentially all electric power in the region is supplied by either hydroelectric power plants or diesel engine generators. Hydroelectric facilities provide the majority of the power requirement in Juneau, Ketchikan, Sitka, Petersburg, Wrangell, Skagway, Haines, Metlakatla, and the Alaska Power and Telephone (AP&T) connected communities on Prince of Wales Island. In communities where hydroelectric power is not available, the reliance upon diesel generation has contributed to very high retail electric costs. Diesel power generation also involves a number of issues including dramatic fluctuations in fuel price, concerns with fuel handling, fuel storage and transportation, potential interruption in fuel delivery, air pollution, environmental regulations, and noise.

The power systems in Southeast Alaska have developed to utilize the hydroelectric resources locally or on a subregional basis. The subregions identified for purposes of this study were identified in Section 4.2 and are repeated here as follows:

- Upper Lynn Canal Region -- Existing AP&T System connects Haines and Skagway. Existing Inside Passage Electric Cooperative (IPEC) system serves Klukwan and Chilkat Valley.
- Juneau Area -- Existing Alaska Electric Light and Power (AEL&P) System connects Juneau, Douglas Island, Auke Bay, and Greens Creek.
- Chichagof Island -- Currently isolated communities of Hoonah, Tenakee Springs, Pelican, and Elfin Cove.
- SEAPA Region -- Existing SEAPA system connects Ketchikan/Saxman, Petersburg, and Wrangell; currently isolated communities Kake and Metlakatla will be interconnected with the SEAPA system by interconnections included as Committed Resources.
- Admiralty Island -- Currently isolated community of Angoon.
- Baranof Island -- Currently isolated community of Sitka.
- Prince of Wales Island -- Existing AP&T System Connects Craig, Hollis, Hydaburg, Kasaan, Klawock, Thorne Bay, and Coffman Cove; currently isolated Naukati will be interconnected to the AP&T system in 2012. (Currently isolated community of Whale Pass).
- Northern Region -- Isolated communities of Yakutat and Gustavus.

Currently the electric systems within these regions are generally isolated from each other. Each area has varying levels of grid development locally and may require development of transmission projects to satisfy the local demand and interconnection of the communities. The local demand is met by a mix of existing hydroelectric projects and diesel generation. Each of the subregions is unique and tailored plans must be developed to serve each of them.

In general, the current status of the Southeast Alaska transmission system and associated infrastructure can be characterized as follows:

- No existing transmission grid for the entire Southeast region.[1]
- Populated areas are separated by great distances.
- Low population and consequently small loads.
- Diesel generation has been installed to meet isolated loads.
- Construction of transmission lines is environmentally challenging.
- Significant hydroelectric potential exists.
- Hydroelectric projects are difficult to develop because of their larger size, higher costs, and initial low utilization.
- The high price of diesel makes diesel generation expensive.
- Emissions can be a problem, especially from docked cruise ships.

Objectives for the transmission system include the following:

1. Provide lower cost hydroelectric power to Southeast Alaska communities.
2. Displace the consumption of diesel fuel across Southeast Alaska.
3. Reduce the price of energy to the people of Southeast Alaska.
4. Provide stable energy rates for residents and potential businesses.
5. Encourage economic development based on lower energy costs.
6. Improve the quality of life for Southeast residents.
7. Provide an incentive for population growth.
8. Improve the reliability of energy supply for industrial growth.
9. Reduce environmental impact of burning hydrocarbon fuels.

[1] Transmission systems exist on a sub-region basis for the SEAPA, Prince of Wales Island, and Upper Lynn Canal sub-regions.

12.3 ENVIRONMENTAL AND LAND USE CONSIDERATIONS

In addition to the physical constraints of rugged steep terrain and isolated islands requiring submarine cable for interconnects, Southeast Alaska faces significant environmental and land use constraints to the development of transmission lines. These constraints can be especially restrictive to the development of transmission lines that are not directly associated with hydroelectric projects and included in the Federal Energy Regulatory Commission (FERC) licensing of the project. The vast majority of Southeast Alaska is controlled by the federal government, with 80 percent being in the Tongass National Forest and 15 percent in Glacier National Park. The land in the Tongass National Forest is subject to the 2001 Roadless Area Conservation Rule (the Roadless Rule), which significantly limits and constrains the construction of transmission lines. While the Roadless Rule continues to be entangled in litigation, it may limit transmission line construction to along public roads or require construction and maintenance to be by helicopter, with its attendant higher costs. For a region such as the Southeast that already suffers physical conditions the increase cost of transmission lines, further regulatory costs in many cases make the cost of transmission lines untenable. Most of the other land in the Southeast is under control of Native Corporations or the State with only about 1 percent being controlled by individuals or municipalities. In addition to the direct requirements of the rules associated with US Forest Service control, the intervention and litigation opportunities afforded individuals and organizations in the permitting process add uncertainty and costs to potential transmission projects.

Faced with this uncertainty and possible prohibition of constructing transmission lines in the Southeast as well as the limited scope with respect to this Integrated Resource Plan (IRP) relative to detail route selection and conceptual design, Black & Veatch has relied heavily on previous work done in the Southeast with respect transmission system planning. As such, most of the routes considered follow previously studied routes and corridors with emphasis on following existing or planned roads. While this approach enhances the feasibility of the proposed transmission interconnections, even it does not ensure that the transmission lines will be permitted for construction. Whenever possible transmission lines associated with the addition of hydroelectric projects should be permitted as part of the hydroelectric project so that the direct benefits from the hydroelectric project can be directly associated with the accompanying transmission line. The following section discusses specifics of some of the previous transmission studies of the region.

12.4 PREVIOUS STUDIES

There have been many studies regarding transmission in the Southeast. Many of these studies focused on individual projects. Three studies, however, focused more on the entire transmission system. Those three studies are;

- Southeast Alaska Transmission Intertie Study, Harza Engineering Company, 1987.
- Southeast Alaska Electrical Intertie System Plan, Acres International Corporation, January 1998.
- Southeast Alaska Intertie Study Phases 1 and 2, D. Hittle & Associates, December 2003.

Many of these studies had addenda that updated and focused on specific aspects. Of these studies, the D. Hittle study is the most recent and most well known. The D. Hittle study focused primarily on the transmission system. The Southeast Alaska IRP is significantly different than the D. Hittle transmission study in that the IRP focuses on integrated solutions for communities in the Southeast with equal emphasis on generation, transmission, DSM/EE, as well as space heating. This integrated approach provides more robust solutions to meeting the communities' energy requirements.

The D. Hittle study identified eight specific interconnections plus one alternate which together comprised a fairly complete transmission system for the Southeast. The interconnections considered in the D. Hittle study include the following:

- Juneau – KMC-GC – Hoonah Intertie (SEI-1)
- Kake – Petersburg Intertie (SEI-2)
- Ketchikan – Metlakatla Intertie (SEI-3)
- Ketchikan – Prince of Wales Intertie (SEI-4)
- Kake – Sitka Intertie (SEI-5)
- Hawk Inlet – Angoon – Sitka Intertie (SEI-6)
- Hoonah – Tenakee Springs – Angoon – Sitka (SEI-6 Alternative)
- Hoonah – Gustavus Intertie (SEI-7)
- Juneau – Haines/Skagway Intertie (SEI-8)

Of these interties proposed in 2003, the Juneau – KMC-GC portion of SEI-1 has been constructed and is in operation. Two of the interties, Kake – Petersburg (SEI-2) and Ketchikan – Metlakatla (SEI-3) interties are included in the Committed Resources discussed in Section 4.0. The remaining sections discuss the evaluation of the remaining interconnections, as well as other interconnections proposed and evaluated by Black & Veatch. Figure 12-1 shows the existing transmission system along with the committed hydroelectric projects and transmission interconnections (Committed Resources). Figure 12-2 shows the potential interconnections being evaluated.

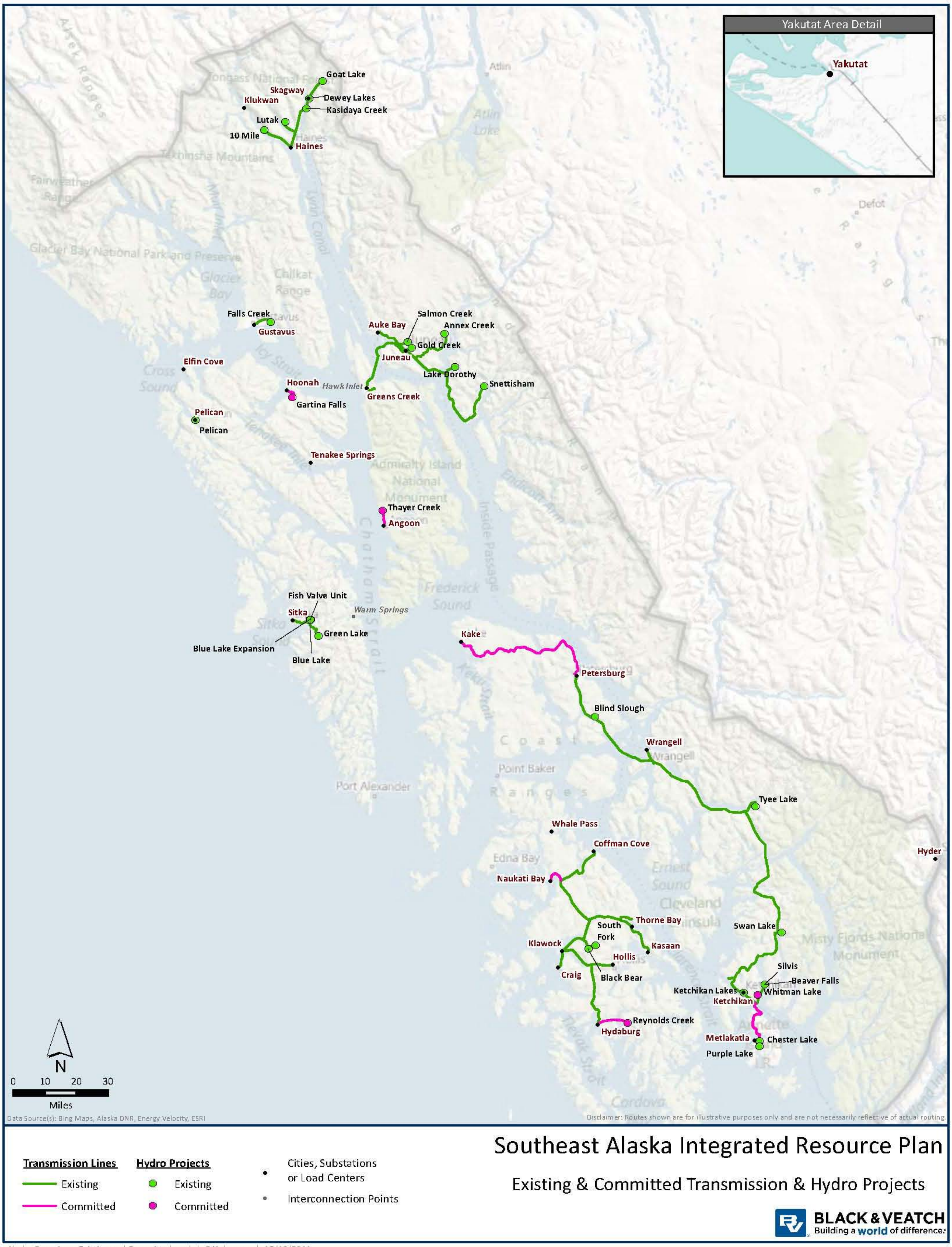
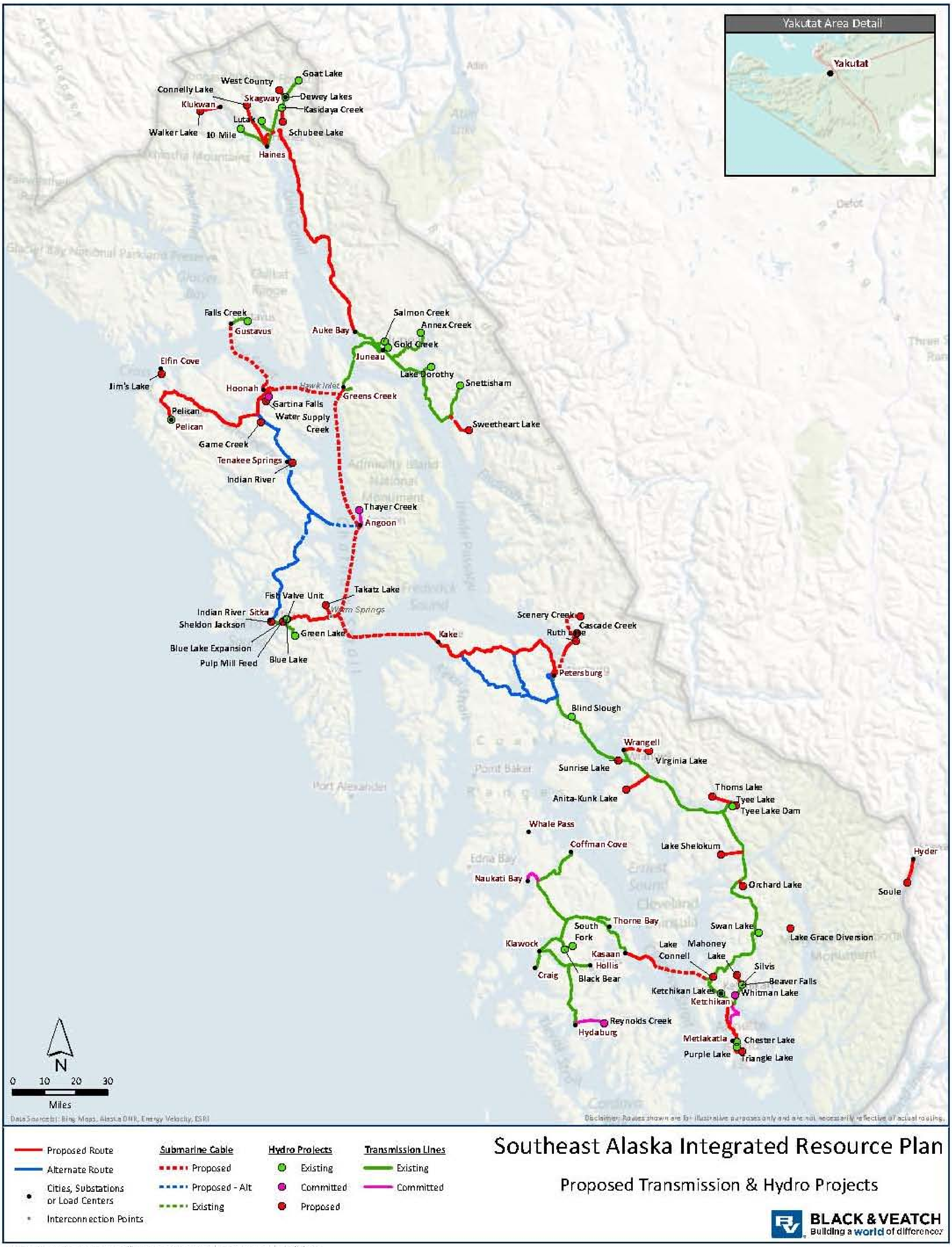


Figure 12-1 Existing and Committed Resources



Alaska Overview - Proposed Different Function.mxd | C.Holmgren | 12/2/2011

Figure 12-2 Proposed Hydroelectric and Transmission

12.5 TRANSMISSION LINE DESCRIPTION AND COSTS

12.5.1 Introduction

Many transmission lines have been evaluated as part of previous intertie studies. Most of the lines involve a combination of overhead and submarine cable components as necessitated by the proposed routes and the topography of Southeast Alaska. The transmission segments identified in this IRP are listed below and are, in large part, routes that have been previously identified. The descriptions of the routes are largely those that have been proposed in previous studies and should be familiar and were developed taking the Roadless Rule and other land use considerations into account. The numbering and nomenclature used is the D. Hittle study is used to maintain continuity with previous studies. The interconnections evaluated are shown again below. SEI-1 is now called SEI-1A Hawks Inlet – Hoonah since part of the original SEI-1 transmission line has been constructed. As stated above SEI-2 and SEI-3 are Committed Resources and discussed in Section 4.0. SEI-9 is an interconnection that was not evaluated in the D. Hittle study.

- SEI-1A: Hawks Inlet – Hoonah
- SEI-2: Kake – Petersburg
- SEI-3: Ketchikan – Metlakatla
- SEI-4: Ketchikan – Prince of Wales
- SEI-5: Kake – Sitka
- SEI-6: Hawks Inlet – Angoon – Sitka
- SEI-6 Alternate: Hoonah – Tenakee Springs – Angoon – Sitka
- SEI -5 and SEI-6: North – South
- SEI-7: Hoonah – Gustavus
- SEI- 8: Juneau – Haines
- SEI-9: Pelican - Hoonah

This section provides a brief description of each of these lines and the estimated cost of construction for each line. Costs are presented in 2011 dollars. It is important to note that the descriptions and costs provided in this report are based primarily on previous studies and should be considered very preliminary in nature. A significant amount of additional study and engineering work will be needed before decisions can be made with regard to the actual routes, characteristics, and costs of each line.

12.5.2 General Technical Considerations

At the present time, a number of alternating current (AC) transmission line voltages are in use throughout Southeast Alaska due in part to the particular use of each line and the isolated nature of the electric utilities. The transmission line from the Snettisham hydroelectric project to Juneau is at 138 kilovolt (kV) whereas the transmission line between the Swan Lake project and Ketchikan is at 115 kV. The Lake Tyee – Wrangell – Petersburg transmission line was constructed at 138 kV but is operated at 69 kV with no plans in place to raise the operating voltage in the foreseeable future. The Swan-Tyee Intertie (STI) is also constructed for 138 kV and operated at 69- kV. AEL&P’s internal transmission system is primarily at 69 kV and AP&T uses 34.5 kV for its transmission system on

Prince of Wales Island and between Haines and Skagway. Higher voltages allow for higher power transfers and lower transmission losses but are more costly to construct.

In the 1987 Harza Study, the Southeast Alaska transmission system was proposed to be constructed primarily at 138 kV. At this voltage, the system would be expected to accommodate significant power transfers between the communities and in many cases, at the loads presently forecasted in Southeast Alaska, could be oversized. The cost of materials and construction is higher for higher voltage systems than it is for lower voltage systems. Consequently, engineering analysis is usually conducted to determine the appropriate voltage for transmission systems to provide proper system performance without paying for unnecessary capacity. An attractive alternative is to design the lines with clearances and possibly some structures to a higher voltage but energize the line at a lower voltage so that upgrades in the event of unexpected increases in loads may be accommodated, especially in areas where access is difficult.

Another factor associated with system voltage includes power losses along the lines. This is a significant issue with AC systems. Power losses are proportional to the square of the current in the line. A 138-kV system would require half the current as a 69-kV system for the same power transfer and would have lower losses than the 69-kV system. The length of the line also contributes to losses. The total "cost" of losses, however, may be insignificant with a lower voltage system if the amount of power being transmitted is relatively small. Again, engineering analysis related to the specific application is needed to evaluate the incremental costs and benefits for each investment decision.

Oversized submarine and underground transmission cables can negatively affect system performance and require additional equipment be installed to compensate for higher system capacitance. Normally, the length of AC submarine cables is considered to be limited to approximately 30 miles because of system performance and loss factors. It would be appropriate to consider direct current (DC) applications for submarine cables that exceed this distance.

For purposes of this study, the system has nominally been sized to operate at 69 kV and 138 kV in some cases operated at 69 kV. This is due in part to AEL&P's use of this voltage for the North Douglas – Greens Creek portion of SEI-1. The 69 kV voltage level should be adequate for the presently anticipated load levels in the region. For example, estimated maximum power flows at Hawk Inlet if transmission lines were extended to Hoonah, Angoon and Sitka are approximately 25 MW, excluding the load at the KMC-GC mine. Previous studies have indicated that 34.5 kV would be adequate for the Kake-Petersburg transmission line, but if this line becomes a component of the larger system, 34.5-kV would be inadequate. With the distances identified for the Southeast transmission system, it is expected that transmission of 60 MW could be routinely accommodated. The system could also transmit higher power flows at certain times. Although the system has been sized at 69 kV for this report, a 138 kV system could be specified later. It is roughly estimated that the costs for a 138 kV system would be about 20 percent higher than for the 69 kV system. Although a final decision on a standardized system voltage is not made in this report, it is felt that by specifying that transmission interties be designed and insulated for 138 kV and operated at various lower voltages to accommodate existing systems, a voltage standard would be easier to adopt in the future.

Many of the longer AC transmission lines are at the upper end of their technical feasibility and could present potential operational difficulty. DC transmission lines are an alternative and are discussed in Subsection 12.5.3.

12.5.3 DC Considerations

An alternative to AC transmission systems that are commonly used to transmit power between generation and load is the growing use of high voltage direct current (HVDC) to transmit power. In HVDC systems energy is transmitted using DC voltages and currents instead of AC.

In a typical HVDC system, the AC voltage and current are connected to a rectifier where it is converted from an alternating source to an unidirectional current and voltage source. This DC power is then transmitted over a DC conducting path. Typically for DC transmission, this path is several miles in length. At the other end of the path (called the inverter) the DC voltages and currents are converted back to AC.

The classical application of HVDC systems is the transmission of bulk power over long distances because the overall cost for the transmission system is less and the losses are lower than AC transmission. A typical HVDC converter station is shown on Figure 12-3. A significant advantage of the DC interconnection is that there is no stability limit related to the amount of power or the transmission distance.

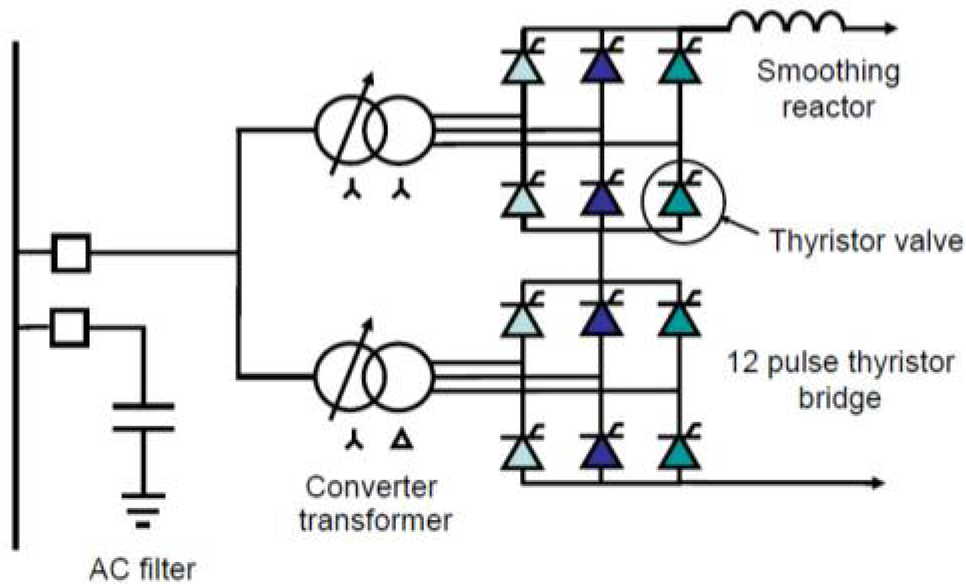


Figure 12-3 Typical HVDC Converter Schematic

Long Distance Bulk Power Transmission

When large amounts of power are to be delivered over long distances, DC transmission is always an alternative to be considered. AC transmission becomes limited by:

- Acceptable variation of voltage over the transmission distance and expected loading levels.
- Need to maintain stability, that is, synchronous operation across the transmission, after a disturbance, both transiently and dynamically.
- Cost of equipment necessary to correct the above limitations.
- The DC line, requiring as few as two conductors (one for submarine with earth return) compared to the AC line's use of three, requires a smaller right-of-way and a less obtrusive tower.

A potential advantage of DC is that, as an AC line reaches either the limit imposed by system stability or its thermal capacity, it may be possible to convert it to DC and increase its capacity by altering the tower head configuration, but not the foundations, tower size nor the right of way.

When two or more independent systems are to be interconnected by a synchronous AC link, the common rules concerning security, reliability, frequency control, voltage control, primary and secondary control of reserve capacity, and so on need to be respected. In most cases, more than one AC link is necessary for reliability. By contrast, interconnecting the systems with DC removes any constraints concerning stability problems or control strategies. The common rules listed above concerning security and so on can largely be left within the jurisdiction of the separate AC systems.

Many of the interties being considered for this study include several miles of submarine cable interconnection. As distance increases, AC cables generate an increasingly amount of reactive power with power flow until the rating of the cable is fully taken up by its charging current. Since intermediate, reactive compensation units cannot be installed, the maximum practical distance for an AC cable is now about 60 miles when modern insulators such as XLPE cable (cross-linked polyethylene) is used. Beyond this distance, DC is the only technically viable solution. An HVDC connection requires only positive and negative (pole and return) conductors, or in some cases a single conductor with sea return, and there is no practical technical limit to length except cost.

12.5.3.1 Comparison of High Voltage Alternating Current (HVAC) and HVDC Transmission

DC transmission lines offer some esthetic and environmental benefits over AC transmission lines although these advantages are more prevalent at higher voltages.

- Visual impact constitutes an environmental advantage for a DC line, since the tower size for the same power is smaller when compared to the tower size of an AC line.
- Right-of-way width of a DC line compared to an AC line is considerably reduced. This facilitates suitable routes in regions with difficult terrain.
- Corona phenomenon has a substantially different nature in DC than in AC transmission. Generally, for a bipolar DC transmission line and an AC transmission line with almost the same roof mean square (rms) conductor voltage to earth and equal transmitting capacity, annual mean corona losses (CL) are more favorable for the DC than the AC case, particularly in poor weather conditions. This, however, is not expected to be an issue with the voltages being considered for Southeast Alaska.

- Radio interference (RI) results from corona discharges, which generate high frequency currents in the conductors producing electromagnetic radiation, in the vicinity of the lines. RI measurements have shown that radio noise from a DC line is considerably lower than from AC lines of similar capacity.
- Audible noise (AN) values resulting from comparable DC and AC lines during fair weather are quite similar. However, during rain which is often prevalent in Southeast Alaska, the better performance and the lower interference levels generated by DC compared to AC lines are considered an advantage.
- Magnetic fields for DC lines are quite different than AC lines. Since a DC line has an unchanging electric field, it exerts effectively no magnetic field on the surroundings. The DC field of a monopolar line is comparable to the strength of the Earth's magnetic field.
- Regarding generation and emission by DC lines of positively charged ions, ozone (O_3), molecular nitrogen (N_2) and free electrons, research studies and investigations of possible consequences have shown, up to now, no evidence of hazard from any operating DC line.

12.5.3.2 HVDC Applied to Alaska

The energy supply problem as outlined throughout this and other reports may be described as many small rural communities with low population density and energy consumption separated by large distances over inhospitable terrain. Despite the existence of rich hydro resources, high energy costs exist because of the use of small diesel generation with high fuel costs. The solution has been to investigate the construction of transmission connections between these communities so that relatively larger hydroelectric plants may become economic, resulting in lower energy costs.

The problem with the traditional solution for some of the Alaskan communities is that the current cost for constructing conventional transmission interconnection ranges from a typical value of $400,000 per mile to the recently experienced value in roadless and difficult terrain of $2,000,000 per mile. Many transmission interties in Alaska will not be cost effective under these conditions.

The HVDC solution is being studied for application in Alaska despite the traditional application to large-scale power transmission of hundreds or thousands of megawatts. Such systems are too large for the transmission needs of Southeast Alaska. No commercially available utility-grade HVDC technology currently exists that is suitable for application in Southeast Alaska.

Conventional HVDC transmission schemes utilize line-commutated, current-source converters (CSC). Such converters require a synchronous voltage source in order to operate. The basic building block used for HVDC conversion is the three-phase, full-wave bridge referred to as a 6-pulse bridge. This conventional technology is applicable to large projects and has several disadvantages when applied to small power application, such as what is being considered in Southeast Alaska. The high reactive power consumption and penchant for commutation failure when applied to "weak" systems all but disqualify this technology for use in Southeast Alaska.

Many if not all of the above shortcomings of the traditional line compensated HVDC system are solved by the voltage source converters (VSC). Construction of the transmission interties using VSCs rather than conventional CSC offers several system advantages. Advanced VSC technology with pulse-width modulation (PWM) permits rapid independent control of active and reactive power in all four quadrants. Control of both active and reactive power is bi-directional and continuous across the entire operating range. Reactive power control capability allows each VSC converter to act as a static synchronous compensator (STATCOM) to regulate the AC voltage at either terminal independently. Converters can be located at points in the network with relatively low short circuit ratios typical of the Southeast Alaska system, minimizing the need for network reinforcements or remedial measures. In fact, the converters can even serve passive load should it become isolated. In such a case, the converters would control the voltage and frequency until the network was restored. The VSC technology is currently being considered by Polarconsult in its demonstration project.

Polarconsult is currently in the process of working with Alaska Village Electric Cooperative, Inc. (AVEC) and the Denali Commission to develop a technology that may be deployed in Southeast Alaska and other rural areas. The effort is outlined in the following phased approach:

- Phase I – Preliminary Design and Feasibility Analysis
- Phase II – Protyping and Field Testing
- Phase III – Demonstration Project

Phase I was recently completed with construction of a demonstration unit shown on Figure 12-4. The demonstrator is capable of bidirectional power conversion between 12 kV DC and 3-phase 480 volts alternating current (VAC) for power delivery up to 250 kW. The demonstrator design is scalable to one MW at 50 kV by "stacking" multiple subassemblies of the demonstrator to increase the DC voltage and the total power throughput. The demonstrator is comprised of four major assemblies, schematically presented on Figure 12-4. The assemblies are:

- High-Voltage Direct Current Bridge Stack.
- Central Transformer/Central Capacitor.
- Low-Voltage Direct Current Bridge Stack.
- Low-Voltage Alternating Current Bridge Stack.

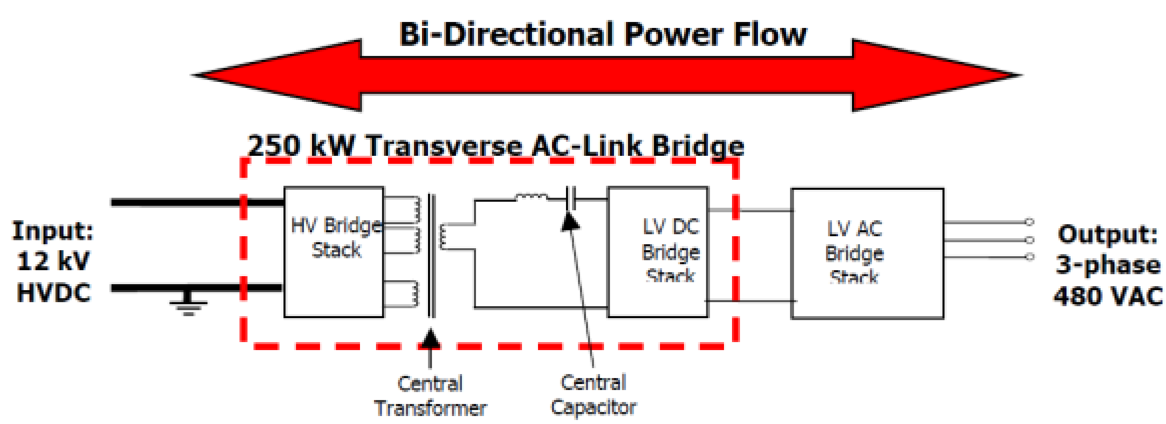


Figure 12-4 Phase I Demonstration Unit

Currently the project is showing promising results; however, the capacities are still small and not yet commercial. Once this technology is demonstrated to be reliable and economic it should provide Southeast Alaska with benefits.

Traditionally, DC has been used for much larger applications than are needed for Southeast Alaska. DC's biggest benefit has been for long transmission lines where the lower line construction costs can offset the higher terminal costs. If this smaller-scale technology is successful, it will be especially beneficial for long submarine cable interconnections. Nevertheless, these long submarine cable interconnections will still be fairly expensive, and that fairly high cost will necessitate that a significant level of confidence be reached with the technology before it can be implemented on a significant utility scale. Figure 12-5 indicates the potential for savings if the technology is successful.

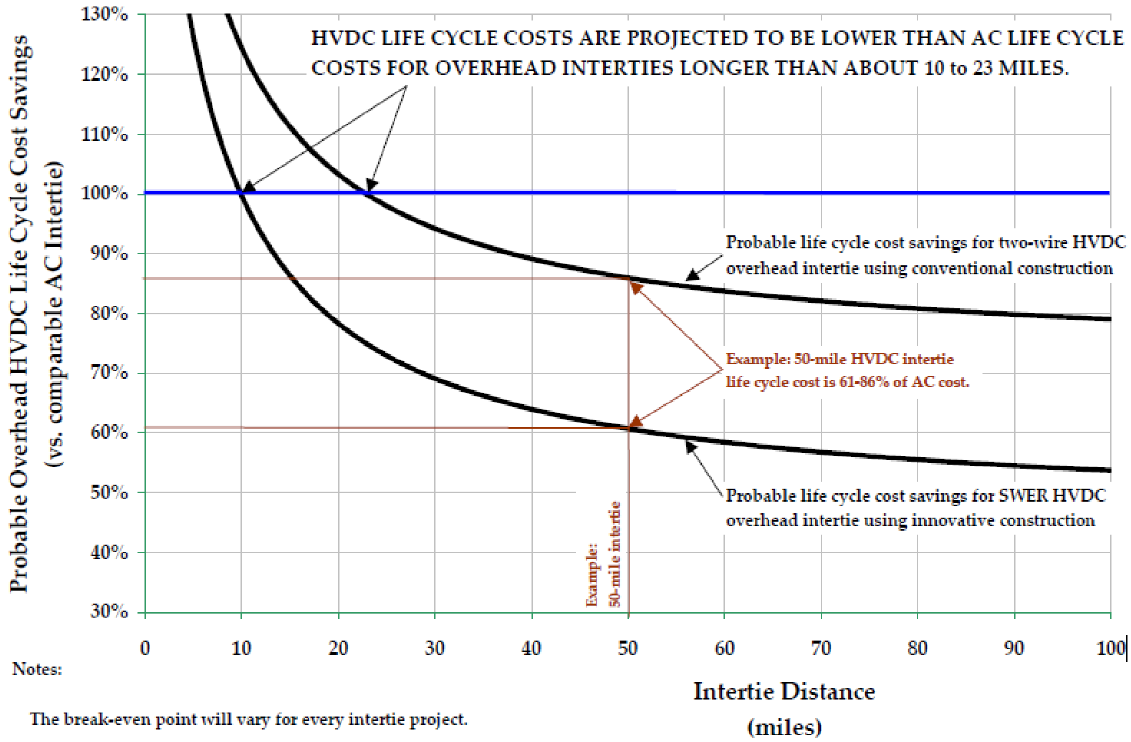


Figure 12-5 Comparative Probable Life-Cycle Costs of HVDC and AC Interties

12.5.4 General Costs

The costs to develop and construct the transmission interconnections are significantly based on estimates for materials and construction contained in previous studies. The material and construction estimates were reviewed by Black & Veatch and adjusted as deemed appropriate based on our recent experience. Special consideration was given to the harsh conditions under which the interconnections will be constructed and operated. Material and construction costs were adjusted to 2011 dollars. Additionally, AEA has requested that Black & Veatch align cost estimates to reflect recent Southeast Alaska experience with the Swan – Tyee Intertie. This cost is reported to be $2,000,000 per mile, where all construction was conducted by helicopter. The estimated costs of the interconnections include all estimated costs of engineering and design, permitting, materials, equipment and construction. Primary components of each line (e.g., overhead lines, submarine cables) are identified separately in the cost estimate.

Since the configuration of the interconnections is still preliminary, a contingency of 20 percent has been applied to all costs. As design proceeds and more precision can be used in estimating the costs, the contingency included in the total cost estimate can possibly be lowered. In any major project of this type, however, the actual cost of construction can vary significantly from the engineer's estimate due to market conditions for the materials and services needed at the time of procurement.

For projects that were not originally estimated in previous studies Black & Veatch has prepared generic estimates for overhead transmission lines on a $/mile basis for 69 kV and 138 kV for relatively simple access. For the more difficult access experienced in much of the Southeast, costs were developed based on recent experience with the Swan – Tyee transmission interconnection. The assumption for construction in roadless areas includes:

- No existing access roads.
- No access roads can be constructed.
- Materials will be transported to the construction site by helicopters.
- Poles will be selfsupporting steel structures.
- Structures will be set exclusively with the aid of helicopters.

With these assumptions for construction in the rugged and inhospitable environment along the routes of many of these proposed lines, the proposed costs for constructing these lines are extremely high. Table 12-1 presents the overland generic transmission costs.

For projects that required submarine cable where existing estimates of material and construction were not available, Black & Veatch developed generic estimates for the submarine cable installations.

Table 12-1 Generic Transmission Estimate

OVERHEAD TRANSMISSION LINES (NORMAL)			
		69 KV ADJACENT TO EXISTING ROADWAY	138 KV ADJACENT TO EXISTING ROADWAY
		WOOD POLES	STEEL POLES
DIRECT COSTS			
Structures		78,938	96,300
Foundations		7,392	11,700
Pole To Assemblies		67,145	56,355
Conductor & Shield Wire		64,469	64,469
Communications		26,136	26,136
ROW Clearing		7,576	12,121
Total Direct Costs		**251,656**	**267,081**
INDIRECT COSTS			
Mobilization		$7,500	$7,500
Craft Subsistence	$120/Day	$15,716	$16,410
Material Logistics	10 percent	$23,669	$24,326
Legal & Right of Way Costs		$0	$0
Engineering	7 percent	$17,616	$18,696
Design Surveying	$5,000/Mi.	$5,000	$5,000
Construction Surveys	$10,000/Mi.	$5,000	$10,000
Geotechnical	$10,000/Mi.	$6,000	$10,000
Permitting	$10,000	$10,000	$10,000
Construction Services	7 percent	$17,616	$18,696
Owner Costs	5 percent	12,583	13,354
Total Subtotal Indirect Costs		**$120,700**	**$133,982**
Contingency	20 percent	$74,471	$80,213
Total Estimated Cost Per Mile		**$446,826**	**$481,275**

Note: For Roadless areas, AEA had directed Black & Veatch to align costs with the STI at $2 million per mile for helicopter constructed self-supported steel poles with micropile foundations.

12.5.5 Transmission Line Segment Descriptions

12.5.5.1 Hawks Inlet – Hoonah Transmission Line (SEI-1A)

This segment represents the remaining portion of the SEI-1 interconnection discussed in the D. Hittle study, and for purposes of this study is designated SEI-1A. AEL&P originally planned the SEI-1 interconnection and construction and owns the line from Juneau to KMC-GC. SEI-1A will interconnect AEL&P's existing transmission system from Hawks Inlet to Hoonah. The existing AEL&P transmission line on Douglas Island is constructed for and operated at 69 kV. AEL&P initially specified that SEI-1A will be operated at 69 kV. The AEL&P plan is based on transmitting a maximum of 30 MW between Hawk Inlet and Hoonah. Previous studies have indicated that the original section of SEI-1 between Hawk Inlet and the KMC-GC mine site is expected to be removed upon closure of the mine. A date for the closure and the subsequent removal of this section of line is currently uncertain. Figure 12-6 shows the SEI-1A interconnection.

Figure 12-6 Proposed Hawk Inlet to Hoonah Interconnection (SEI-1A)

The section of the SEI-1 line from Juneau to KMC-GC is already constructed. The section between Hawks Inlet and Hoonah consists of a 25 mile-long submarine cable between Hawk Inlet and Spasski Bay on Chichagof Island and 3.5 miles of new overhead line between Spasski Bay and the Hoonah powerhouse. This is referred to as SEI-1A in this report.

Interconnection facilities would include submarine cable termination yards at Hawk Inlet and at Spasski Bay on Chichagof Island approximately 3 miles east of Hoonah. The submarine cable termination yards would serve as the interface between overhead sections of the line and submarine cables. They would generally be located near the shoreline but behind existing tree lines to limit visibility from the water. Other facilities include a proposed new substation in Hoonah that would connect to the existing electric system.

The original plan for SEI-1 called for AEL&P's standard single wood pole design to be used for the overhead portion of SEI-1A. The line will generally be placed alongside existing roads, and spans (the distance between poles) will be relatively short. This configuration will provide future maintenance advantages due to ease of access and smaller structures.

The submarine cable crossings between Hawk Inlet on Admiralty Island and Spasski Bay on Chichagof Island is approximately 25 miles long and involves deeper waters than were involved in the constructed section between Juneau and Hawks Inlet. The termination yards will contain 69-kV disconnect switches, lightning arrestors and risers that connect the overhead system to the submarine cable. The disconnect switches allow for the electrical isolation of the cable for maintenance and testing. Other equipment, such as breakers and reactors, may also be needed to assure proper operation and protection of the interconnected electric system. Black & Veatch's estimated cost for SEI-1A in 2011 dollars is presented in Table 12-2. IPEC's and KMC-GC's diesel generating units would be interconnected with the AEL&P system but would not generally be used at the same time that power is being delivered from Juneau. The estimated annual O&M and R&R costs in 2011 dollars are $209,000 and $141,000, respectively.

12.5.5.2 Kake – Petersburg Transmission Line (SEI-2)

The Kake to Petersburg interconnection is a Committed Resource and is described in detail in Section 4.0.

12.5.5.3 Ketchikan - Metlakatla Transmission Line (SEI-3)

The Ketchikan to Metlakatla interconnection is a Committed Resource and is described in detail in Section 4.0.

Table 12-2 Estimated Cost of Project Development and Construction

HAWK INLET - HOONAH TRANSMISSION LINE (SEI-1A)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$3,469,683
69 kV Roadless Areas	$3,000,000
Subtotal	**$6,469,683**
Clearing	$282,502
Submarine Cable	$53,800,000
Cable Termination Facilities	$1,100,000
Substation Improvements and Additions	$1,047,619
Total Direct Costs	**$62,699,805**
INDIRECT COSTS	
Engineering, Permitting, Admin. (30 percent)	$19,035,754
Special Mobilization (Cable Delivery)	$0
Indirect Submarine Cable	$3,000,000
Subtotal - Indirect Costs	**$22,035,754**
Contingency (20 percent)	$16,947,112
Total Project Costs	**$101,682,670**

12.5.5.4 Ketchikan – Prince of Wales Transmission Line (SEI-4)

SEI-4 would provide a connection between AP&T's Prince of Wales Island electric system and the SEAPA system. The 2003 D. Hittle study considered four routes for this interconnection based primary on the work conducted in the 1987 Harza study.

- Ketchikan – Kasaan
- Cleveland Peninsula – Thorne Bay
- Northern Interconnection from Tyee transmission line to Coffman Cove
- Ketchikan – Hollis

The 2003 D. Hittle study eliminated the Cleveland Peninsula – Thorne Bay because the Cleveland Peninsula routing of the Swan-Tyee Interconnection was abandoned. Several additions to the generation and transmission system have been completed since the 2003 D. Hittle study. These additions are shown below.

- The AP&T transmission system was extended to Coffman Cove and will be extended to Naukati Bay in 2012.
- Swan-Tyee Interconnection
- South Fork Hydro Project

The further interconnection of the SEAPA transmission system and the AP&T Prince of Wales transmission system enhances the benefit of interconnecting the two systems. Black & Veatch reviewed the system in light of changes made since the 2003 D. Hittle study for additional transmission routes for consideration and did not find any additional routes that merit consideration at this time.

The Reynolds Creek Project, a Committed Resource, will provide generation into the southern portion of AP&T's transmission system. Other potential hydroelectric projects on Prince of Wales appear to be primarily to support mine development and will likely not be interconnected to AP&T's system. There are several potential hydroelectric projects in both the Wrangle and Ketchikan areas including the Committed Resource Whitman Lake Project. The Ketchikan – Metlakatla interconnection is also a Committed Resource. Without the benefit of detailed load flow analysis that is beyond the scope of this study, consideration of the existing and potential projects in these two subregions does not merit changing the selection of the route to evaluate from that selected in the 2003 D. Hittle study.

The Swan Lake transmission line is at 115 kV and the AP&T transmission system is 34.5 kV. The 2003 D. Hittle study assumed the interconnection should be at 69 kV. Black & Veatch's concurs that 69 kV is appropriate for the interconnection.

The route considered taps the 115-kV Swan Lake transmission line near Ward Cove. A substation will be used to reduce to the voltage from 115 kV to 69 kV. Approximately 5.5 miles of overhead transmission line will run to a submarine cable landing site at Mud Bay northeast of Ward Cove. From the cable termination site, a bundled 3-phase submarine cable will cross Clarence Strait to a point on Prince of Wales Island near Grindall Point. From the submarine cable termination point, an overhead single-pole line will run 5.5 miles north and east along the eastern side of Kasaan Peninsula. The overhead line will continue west, cross the peninsula and follow the shoreline northwest to Kasaan. The total length of overhead line is approximately 12.5 miles. A 69 kV/ 34.5 kV substation will be located in Kasaan.

Overall, the Ketchikan – Kasaan interconnection with be approximately 35.2 miles with 17.2 miles of submarine cable and 18 miles of overhead line. The proposed routes are shown on Figure 12-7, along with the two alternate routes. The cost estimate in 2011 dollars for the proposed route is shown in Table 12-3. Estimated annual O&M and R&R costs in 2011 dollars are $152,000 and $141,000, respectively.

Figure 12-7 Proposed Ketchikan to Kasaan on Prince of Wales Island Interconnection (SEI-4)

Table 12-3 Estimated Cost of Project Development and Construction

KETCHIKAN - PRINCE OF WALES TRANSMISSION LINE (SEI-4)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$1,815,282
69 kV Roadless Areas	$10,000,000
Subtotal	**$11,815,282**
Clearing	$1,741,809
Submarine Cable	$38,800,000
Cable Termination Facilities	$1,100,000
Substation Improvements and Additions	$1,646,801
Total Direct Costs	**$55,103,891**
INDIRECT COSTS	
Engineering, Permitting, Admin (30 percent)	$16,531,000
Special Mobilization (Cable Delivery)	$5,067,080
Other	$0
Subtotal - Indirect Costs	**$21,598,080**
Contingency (30 percent)	$23,010,592
Total Project Costs	**$99,712,563**

12.5.5.5 Kake – Sitka Transmission Line (SEI-5)

A transmission line between Kake and Sitka could interconnect the loads and resources of the City of Sitka Electric with the SEAPA system. The line was evaluated in 2003 D. Hittle study. The total length of this line is estimated at 55 miles, of which 35 miles is a submarine cable and 20 miles is overland across Baranof Island. As discussed in Subsection 12.5.3, longer submarine cables are better candidates for DC.

The 35 mile-long submarine cable is proposed to extend between Kupreanof Island near Point White northwest of Kake to Warm Springs Bay on Baranof Island. The cable would be a 3-phase, bundled cable with double armor because of the length and depth of the crossing of Frederick Sound and Chatham Strait. The submarine cable termination point north in Warm Springs Bay would then interconnect with an overhead line that would continue to the Blue Lake powerhouse and interconnect with the Sitka transmission system, a distance of approximately 20 miles. All overhead route alternatives across Baranof Island are expected to present significant construction and maintenance concerns due to high elevations, roadless terrain, and exposure to avalanche.

The preferred overhead route as determined in the 2003 D. Hittle study proceeds to the west from Warm Springs Bay, follows the south side of Baranof Lake and continues westward into the Baranof River drainage before crossing a high ridge. After the ridge crossing, the route continues north of Medrejia Lake before turning north and paralleling an existing road along Silver Bay to the Blue Lake powerhouse. An existing 69-kV line which connects the Green Lake hydroelectric project to the Sitka electric system parallels the road along Silver Bay. It has been assumed that this section of SEI-5 would be constructed as a double circuit 69-kV line along this portion of the route. The proposed route between Warm Springs Bay and Blue Lake Power house consists of 16 miles of roadless construction and 4 miles of double circuit construction along the existing road adjacent to Silver Bay. The route is shown on Figure 12-8.

The large length of roadless construction presents significant challenges for permitting under the Roadless Rule as well as the high cost of construction and O&M. In addition, the long length of submarine cable installed in deep water presents technical challenges and presents significant risks and expense if it experiences a failure.

A major objective in the Southeast Alaska Transportation Plan is construction of a roadway between Warm Springs Resort and Sitka. The State's proposed road includes a tunnel through the most mountainous section. The estimated SEI-5 capital cost in 2011 dollars is presented in Table 12-4. The estimated overhead line cost in Table 12-4 for SEI-5 does not include the savings if the road were constructed. There still is considerable uncertainty with respect to if and when the road will be constructed. The roadless section of the proposed route would possibly require construction and maintenance with the aid of helicopters. The roadless section would be difficult to construct and maintain due to high elevations, steep slopes and high avalanche potential. If a road is eventually constructed maintenance would be easier, but, reliability is still expected to be lower due to the terrain. The 2003 D. Hittle study proposed that SEI-5 be constructed at 69 kV. Black & Veatch concurs that 69 kV is the appropriate voltage level consistent with the general standardization of 69 kV for the Southeast Alaska system and the potential loads that the line is expected to carry. Approximately 4miles of new transmission line will need to be constructed from the Kake powerhouse to Point White. The submarine cable termination site in Warm Springs Bay will be only about 4 miles south of the proposed Takatz Lake powerhouse. If SEI-5 is constructed, it would facilitate the distribution of energy from the Takatz Lake project if it were to be developed.

The estimated annual O&M and R&R costs in 2011 dollars for SEI-5 are $291,000 and $141,000, respectively.

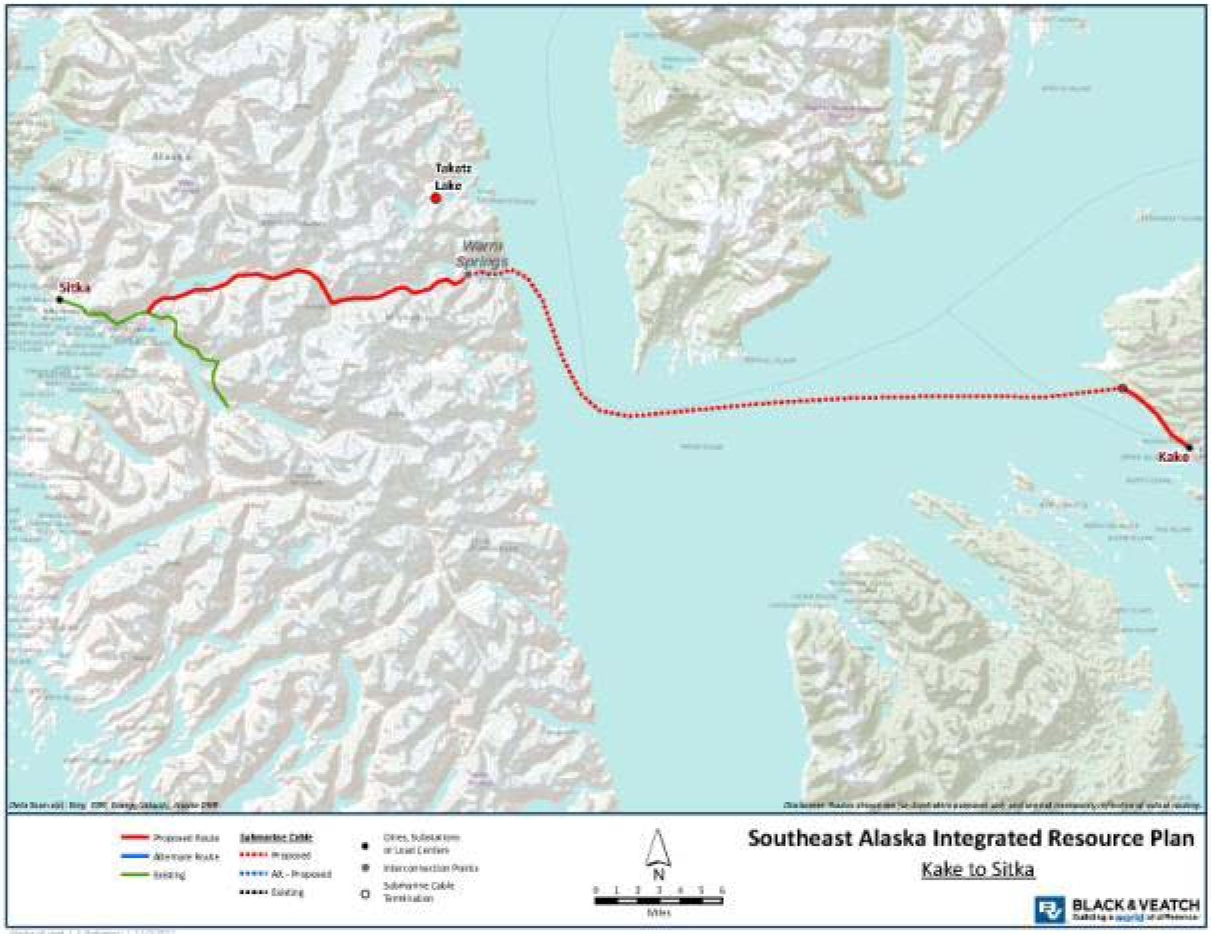


Figure 12-8 Proposed Kake to Sitka Interconnection (SEI-5)

Table 12-4 Estimated Cost of Project Development and Construction

KAKE - SITKA TRANSMISSION LINE (SEI-5)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$2,639,949
69 kV Roadless Areas	$32,000,000
Subtotal	**$34,639,949**
Clearing	$4,560,372
Submarine Cable	$73,000,000
Cable Termination Facilities	$1,100,000
Substation Improvements and Additions	$633,385
Total Direct Costs	**$113,933,706**
Indirect Costs	
Engineering, Permitting, Admin (30 percent)	$34,180,000
Special Mobilization (Cable Delivery)	$5,067,080
Other	$0
Subtotal - Indirect Costs	**$39,247,080**
Contingency (30 percent)	$45,954,236
Total Project Costs	**$199,135,022**

12.5.5.6 Hawk Inlet – Angoon – Sitka Transmission Line (SEI-6)

SEI-6 is proposed to interconnect Angoon and Sitka to the AEL&P electric system through a submarine cable system originating in Hawk Inlet on Admiralty Island. The system could be developed in phases, connecting Angoon to Hawk Inlet first and proceeding to Sitka at a later date. The Hawk Inlet submarine cable termination facility would most likely be adjacent to the submarine cable termination yard to be developed as part of SEI-1.

A 3-phase, bundled, double-armor cable would be used for SEI-6. From the Hawk Inlet cable termination yard, the cable would follow the route of SEI-1A southwest to the entrance of Hawk Inlet. The cable would then proceed south in Chatham Strait along the western shore of Admiralty Island to Angoon, a distance of approximately 48 miles. This distance exceeds the typical length of AC bundled submarine cables and will require further studies and confirmation by vendors that a cable could be supplied for this length. A submarine cable termination yard would be constructed at Angoon. The yard will contain 69-kV disconnect switches, lightning arrestors and risers that connect the overhead system to the submarine cable. The disconnect switches allow for the electrical isolation of the cable for maintenance and testing. Other equipment, such as breakers and reactors, will likely be needed to assure proper operation and protection of the interconnected electric system. Other facilities include a new substation in Angoon to connect SEI-6 to IPEC's existing electric system.

From the submarine cable termination yard in Angoon, another similar cable will proceed south in Chatham Strait, and cross the Strait into Warm Springs Bay on Baranof Island. In Warm Springs Bay, a submarine cable termination yard would connect the submarine cable to the overhead system that would follow the route across Baranof Island described for SEI-5. The length of this submarine cable section of SEI-6 is approximately 34 miles. In total, the length of SEI-6 is 102 miles, of which 20 miles is overhead and 82 miles is submarine. The proposed route of SEI-6 is shown on Figure 12-9.

The proposed voltage level is 69 kV. The estimated cost in 2011 dollars is presented in Table 12-5. The estimated annual O&M and R&R expenses in 2011 dollars are $330,000 and $141,000, respectively.

The mayor of Angoon requested that Black & Veatch consider an overland route on the western side of Admiralty Island from Hawk Inlet to Angoon. Black & Veatch received a proposed route from Kootznoowoo, Inc. for a road along the western side of Admiralty Island. An overhead transmission line section was added as an alternative to the submarine connection between Angoon and Hawk's inlet. The overhead line section is estimated to be about 47.5 miles. This proposed overhead transmission line is included in Figure 12-9. The cost of this alternative would potentially be lower than the submarine cable section provided that the proposed road is permitted and built, and the associated line was constructed adjacent to the road. The vast majority of the western portion of Admiralty Island is classified as Land Use Designation Wilderness and National Monument in the Tongass Land and Resource Management Plan. The Tongass Land and Resource Management Plan does not designate a road or utility corridor on the western side of Admiralty Island. As such, it would appear that it would be very difficult to get an overland route from Hawk Inlet to Angoon permitted. If the route was ultimately permitted without the road, it would be likely that the permit would require roadless construction. The cost of roadless construction based on the Swan-Tyee Interconnection is nearly the same on a per mile basis as Black & Veatch's per mile estimate for submarine cable and, thus, there would be no significant savings from the overland route unless the road is also built.

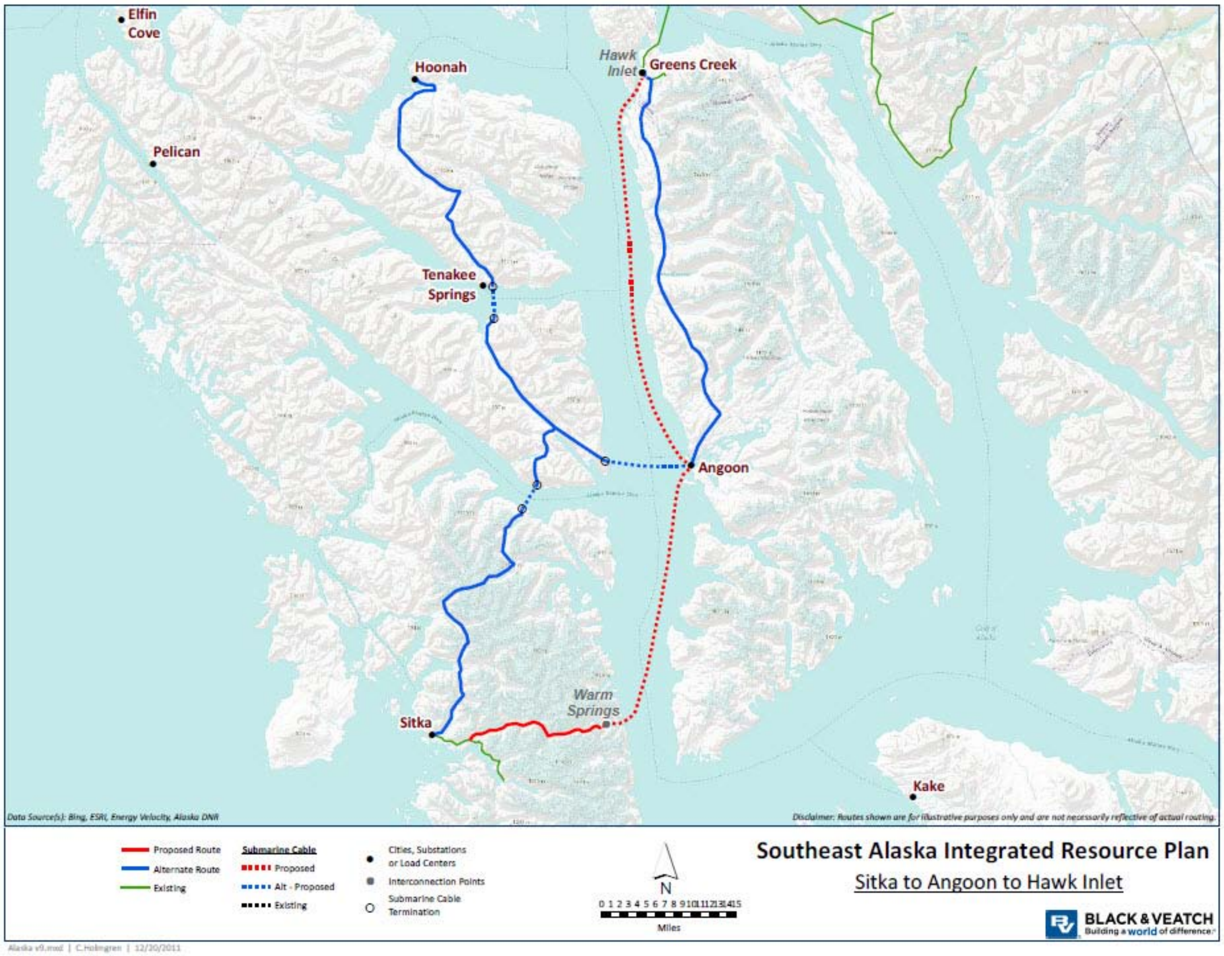


Figure 12-9 Proposed Hawk Inlet to Sitka via Angoon Interconnection (SEI-6)

Table 12-5 Estimated Cost of Project Development and Construction

HAWK INLET - ANGOON - SITKA TRANSMISSION LINE (SEI-6)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$1,979,962
69 kV Roadless Areas	$32,000,000
Subtotal	**$33,979,962**
Clearing	$3,800,310
Submarine Cable	$40,195,121
Cable Termination Facilities	$1,646,801
Substation Improvements and Additions	$1,140,093
Total Direct Costs	**$80,762,287**
INDIRECT COSTS	
Engineering, Permitting, Admin(30 percent)	$24,228,686
Special Mobilization (Cable Delivery)	$5,067,080
Other	$0
Subtotal - Indirect Costs	**$29,295,767**
Contingency (30 percent)	$33,017,416
Total Project Costs	**$143,075,470**

12.5.5.7 Hoonah – Tenakee Springs – Angoon – Sitka Transmission Line (SEI-6 Alternate)

This alternative for connecting Sitka to the North was identified in 2003 D. Hittle study. It is primarily an overland route between Hoonah, Tenakee Springs and Sitka. Angoon would be supplied by a tap from this line over a submarine cable from near Chatham on southern Chicagof Island. The proposed route extended south from a substation located in Hoonah following existing Forest Service logging roads into the Game Creek and North Creek drainages. After crossing a pass into the Freshwater Creek drainage, the route continued to follow Forest Service logging roads to Tenakee Springs with a total distance of 28.6 miles between Hoonah and Tenakee Springs.

At Tenakee Springs, the proposed route would cross Tenakee Inlet (3.0 miles) with an AC underwater cable to a location east of Kadashan Bay and then continue overhead following Forest Service logging roads in the Kadashan River Valley to a point northwest of the head of Sitkoh Bay (12.5 miles). At this point a remote switchyard could be constructed to facilitate a 69-kV spur to Angoon. The proposed route to Sitka would continue south from the Angoon tap point following Forest Service logging roads to Point Lindenburg (9.5 miles).

At Point Lindenburg, the proposed line would cross Peril Strait (3.2 miles) with an AC underwater cable to a location at Point Moses on Baranof Island, and then continue south through rugged terrain without road access to a point west of Middle Arm Kelp Bay. At this point, the line would cross a high elevation pass into an unnamed drainage south of Annahootz Mountain where it would follow existing logging roads through the Indian River Valley, ultimately connecting with the substation at Blue Lake Powerhouse near Sitka (32.2 miles). The total line length is 89 miles, not including the spur and submarine crossing to Angoon. The estimated length of the Angoon spur is approximately 17 miles of which 6 miles is overhead and 11 miles is submarine cable.

The proposed overhead line of SEI-6 is anticipated to be 69-kV single wood pole construction except for the roadless area on the north end of Baranof Island (approximately 16 miles) where self-supporting steel structures would be used. The line routing would create some visual impact to the Alaska Marine Highway system in the area of Peril Strait. Also the shoreline of Chicagof Island has many eagle nests that the line may impact at the underwater crossing locations. The route would also have some visual impact on recreational areas near the Katlian Bay area and the approach to Sitka, particularly at the higher elevations.

The estimated cost for SEI-6 Alternate is presented in Table 12-6. The estimated annual O&M and R&R expenses in 2011 dollars are $342,000 and $155,000, respectively.

The route for SEI-6 Alternate is shown as the alternate route on Figure 12-9.

The submarine cable option for SEI-6 would be significantly easier to construct and would have less impact on the terrestrial environment than the overland option. The route of the overland option is identified as a potential power transmission corridor in the 2005 Tongass Land and Resource Management Plan.

Table 12-6 Estimated Cost of Project Development and Construction

HOONAH -TENAKEE SPRINGS - ANGOON - SITKA TRANSMISSION LINE (SEI-6 ALTERNATE)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$22,703,053
69 kV Roadless Areas	$32,000,000
Subtotal	**$54,703,053**
Clearing	$17,253,409
Submarine Cable	$10,495,190
Cable Termination Facilities	$950,078
Substation Improvements and Additions	$1,710,140
Fiber Optic Systems	$1,978,137
Total Direct Costs	**$87,090,007**
INDIRECT COSTS	
Engineering, Permitting, Admin(30 percent)	$26,127,000
Special Mobilization (Cable Delivery)	$0
Other	$0
Subtotal - Indirect Costs	**$26,127,000**
Contingency (30 percent)	$33,965,102
Total Project Costs	**$147,182,109**

12.5.5.8 North – South Transmission Line (SEI-5 + SEI-6)

The North to South Interconnection includes the construction of both the Kake to Sitka Intertie (SEI-5) and the Hawk Inlet – Angoon – Sitka Intertie (SEI-6). This could be viewed as a single interconnection for connecting the northern areas of the Southeast to the southern areas of the Southeastern Alaska. This could be an attractive alternative if one area is deficient in economic hydroelectric generation and the other has a surplus of low cost hydroelectric energy.

Figure 12-10 shows the North to South Interconnection. The estimated cost for the North to South Interconnection would be the cost for SEI-5 plus the cost for SEI-6 minus the common route from Warm Springs to Sitka. The estimated cost for the North to South Interconnection is $310,210,500 in 2011 dollars.

The estimated O&M and R&R expenses in 2011 dollars are $507,000 and $282,000 respectively.

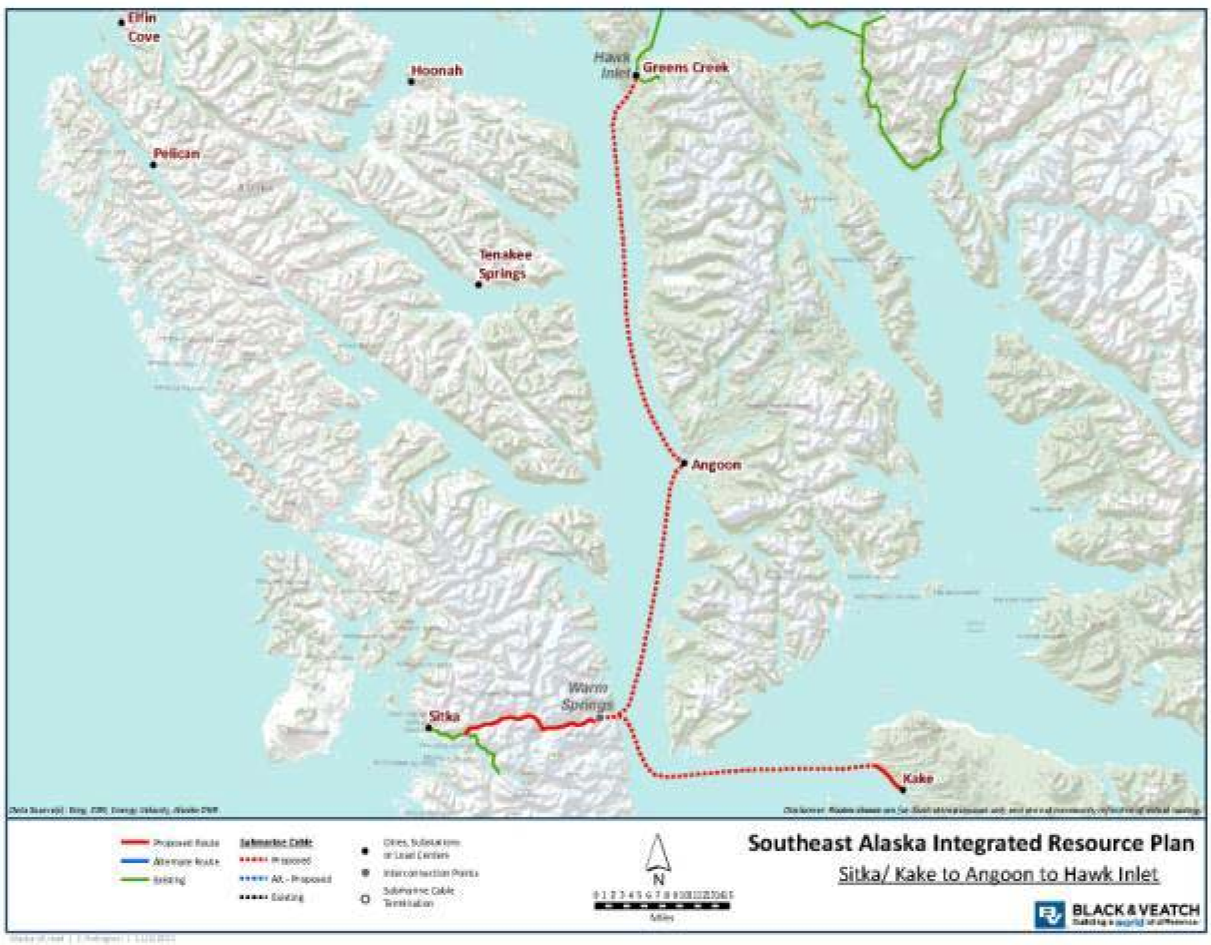


Figure 12-10 Proposed North to South Interconnection (SEI-5 + SEI-6)

12.5.5.9 Hoonah – Gustavus Transmission Line (SEI-7)

A transmission connection between Hoonah and Gustavus could connect the electric loads in Gustavus and the adjacent National Park Service facilities with the North region electric system. The proposed route of SEI-7 would extend from a submarine cable termination facility on Spasski Bay, north and northwest across Icy Strait, north of Pleasant Island and landing at a site near the Gustavus airport. The total length of the submarine cable crossing is estimated to be approximately 29 miles.

The submarine cable termination yard on Spasski Bay would be developed adjacent to the submarine cable termination facility at the same location for SEI-1A. Certain features of the two facilities could potentially be shared. A substation in Gustavus would be needed to convert the voltage from 69 kV to the Gustavus Electric Company primary distribution voltage.

Figure 12-11 presents the proposed route. Table 12-7 presents the estimated cost. The estimated annual O&M and R&R costs in 2011 dollars are $209,000 and $141,000, respectively.

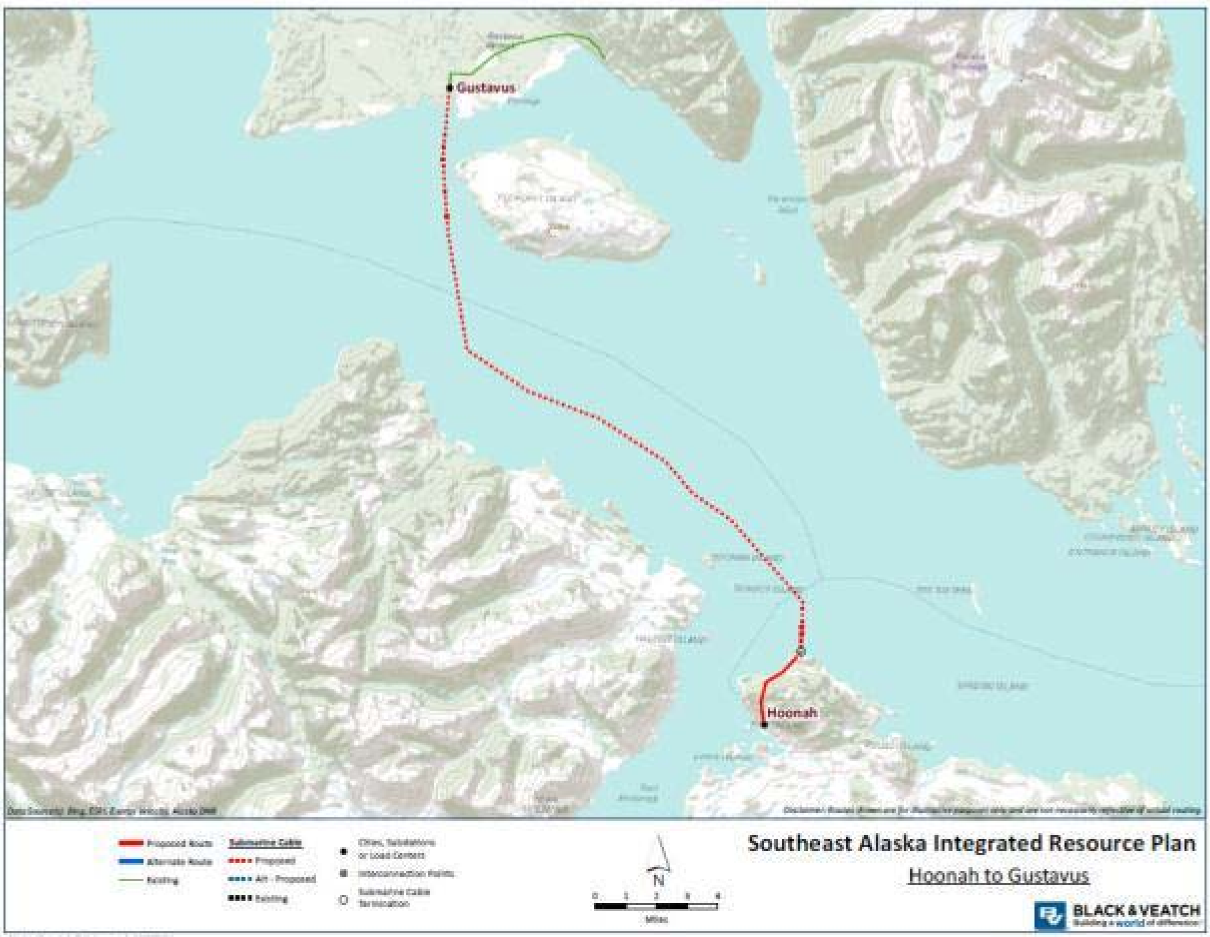


Figure 12-11 Proposed Hoonah to Gustavus Interconnection (SEI-7)

Table 12-7 Estimated Cost of Project Development and Construction

HOONAH - GUSTAVUS TRANSMISSION LINE (SEI-7)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$330,627
69 kV Roadless Areas	$0
Subtotal	**$330,627**
Clearing	$139,345
Submarine Cable	$61,600,000
Cable Termination Facilities	$1,100,000
Substation Improvements and Additions	$1,076,755
Fiber Optic Systems	$791,985
Total Direct Costs	**$65,038,711**
INDIRECT COSTS	
Engineering, Permitting, Admin(30 percent)	$19,512,000
Special Mobilization (Cable Delivery)	$5,067,080
Other	$0
Subtotal - Indirect Costs	**$24,579,080**
Contingency (30 percent)	$26,885,300
Total Project Costs	**$116,503,091**

12.5.5.10 Juneau – Haines Transmission Line (SEI-8)

The proposed route based on the 2003 D. Hittle study extends the existing 69-kV line north from Auke Bay to Bridget Cove following the existing highway. This section is anticipated to be single wood pole construction. North of Bridget Cove the line would continue along the east side of Lynn Canal to a point east of Haines where a remote 69/34.5 kV substation would be constructed and Haines would be interconnected with a new 34.5 kV underwater cable. The section from Bridget Cove to Haines is roadless, and it is anticipated that self-supporting steel structures and helicopter construction would be used. The State has proposed the construction of a highway along the east side of Lynn Canal; however, due to the uncertainty associated with the development of the road, the cost estimate is based on roadless construction north of Bridget Cove. The roadless section would require construction and maintenance with the aid of helicopters. The roadless section would be difficult to construct and maintain due to the extent of steep slopes and high avalanche potential. If a road is eventually constructed, maintenance would be easier, but avalanches will still be a threat to reliability.

Figure 12-12 presents the proposed route. The estimated cost is presented in Table 12-8. Estimated annual O&M and R&R expenses in 2011 dollars are $234,000 and $85,000, respectively.

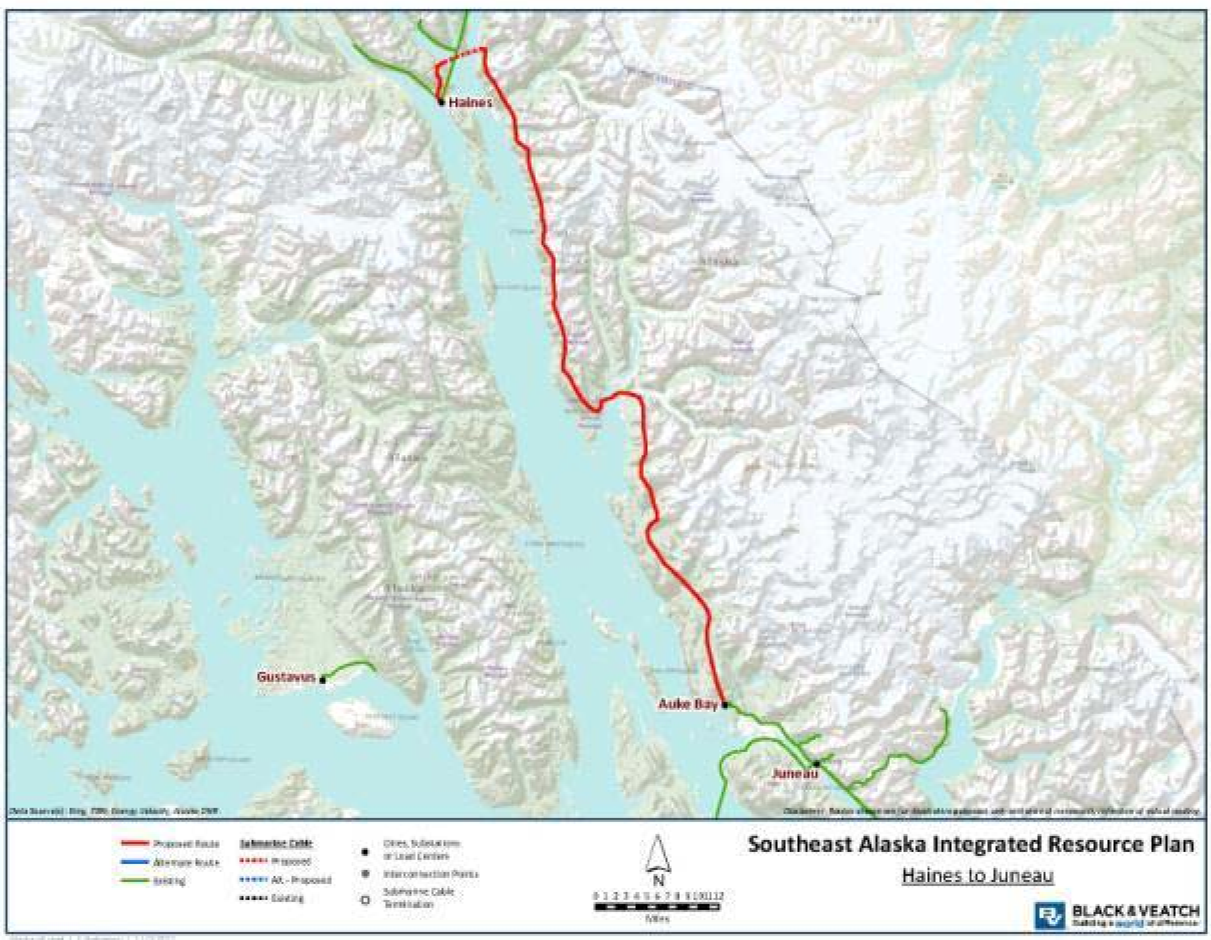


Figure 12-12 Proposed Juneau to Haines Interconnection (SEI-8)

Table 12-8 Estimated Cost of Project Development and Construction

JUNEAU - HAINES TRANSMISSION LINE (SEI-8)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$8,005,639
69 kV Roadless Areas	$114,000,000
Subtotal	**$122,005,639**
Clearing	$15,676,280
Submarine Cable	$2,183,912
Cable Termination Facilities	$633,385
Substation Improvements and Additions	$1,330,109
Fiber Optic Systems	$1,454,252
Total Direct Costs	**$143,283,576**
INDIRECT COSTS	
Engineering, Permitting, Admin (30 percent)	$42,985,000
Special Mobilization (Cable Delivery)	$1,266,770
Other	$0
Subtotal - Indirect Costs	**$44,251,770**
Contingency (30 percent)	$56,260,604
Total Project Costs	**$243,795,950**

12.5.5.11 Pelican – Hoonah Transmission Line (SEI-9)

The Pelican to Hoonah line was not included in the previous Southeast interconnection studies as an alternative but is included in this report and will be screened along with the other lines. The line originates in Hoonah and follows the proposed road to a substation in Pelican. The line is assumed be constructed at 69 kV with single wood poles. Figure 12-13 shows the proposed route.
Table 12-9 presents the estimated costs that are based on roadless construction along the proposed road. If the road were to be constructed, the estimated costs would be reduced. The estimated annual O&M and R&R expenses in 2011 dollars are $203,000 and $85,000, respectively.

Figure 12-13 Proposed Pelican to Hoonah Interconnection (SEI-9)

Table 12-9 Estimated Cost of Project Development and Construction

PELICAN - HOONAH TRANSMISSION LINE (SEI-9)	
	ESTIMATED COSTS
OVERHEAD LINE	
69 kV Along Roads	$11,617,485
69 kV Roadless Areas	$52,000,000
Subtotal	**$63,617,485**
Clearing	$0
Submarine Cable	$0
Cable Termination Facilities	$0
Substation Improvements and Additions	$0
Total Direct Costs	**$63,617,485**
INDIRECT COSTS	
Engineering, Permitting, Admin(30 percent)	$25,447,000
Special Mobilization (Cable Delivery)	$0
Other	$0
Subtotal - Indirect Costs	**$25,447,000**
Contingency (40 percent)	$35,625,794
Total Project Costs	**$124,690,279**

12.5.5.12 Summary

Table 12-10 summarizes the costs for each of the interconnections considered.

Table 12-10 Summary of Capital Cost Estimates

INTERCONNECTION	2011 CAPITAL COST ($ MILLION)
SEI-1A Hawks Inlet - Hoonah	101.7
SEI-4 Ketchikan - Prince of Wales	99.7
SEI-5 Kake - Sitka	199.1
SEI-6 Hawks Inlet - Angoon - Sitka	143.1
SEI-7 Hoonah - Gustavus	116.5
SEI-8 Juneau - Haines	243.8
SEI-9 Pelican - Hoonah	124.7
Total	**1,028.6**

Notes:

1. SEI-6 Alternate instead of SEI-6 will increase cost by $4.1 million.
2. SEI-5 and SEI-6 North - South instead of SEI-5 and SEI-6 individually will reduce costs by $32 million.

12.6 INITIAL TRANSMISSION INTERCONNECTION ECONOMIC EVALUATION

In this section, the results of an economic analysis of the transmission interconnections developed in Subsection 12.5 are provided. This initial analysis simply determines the annual cost in 2011 dollars from the capital, O&M, and R&R costs developed in Subsection 12.5 and divides the annual cost by the average projected flow over the interconnection to determine a $/MWh cost for each transmission interconnection. This analysis does not include any State financial assistance (Note: the resulting impact of State financing of these transmission interconnections (i.e., the Public Benefit Case as discussed in Section 12.1]) in discussed in Section 12.7. To put these annual transmission costs in perspective, they are compared to the 2011 cost of diesel generation.

Table 12-11 presents the potential interconnection flows for each potential transmission interconnection. These estimated interconnection flows are based on the annual average flows determined by the Strategist® modeling in Section 12.7.

Table 12-11 Basis for Estimated Transmission Interconnection Flows

	SUBREGION NEEDS	AVERAGE ANNUAL FLOW ON INTERCONNECTION (MWH)
SEI-1A Hawks Inlet – Hoonah	Hoonah	2,8002
SEI-4 Ketchikan – Prince of Wales	Prince of Wales	9,094
SEI-5 Kake – Sitka	SEAPA	31,520
SEI-6 Hawks Inlet – Angoon – Sitka	Juneau	11,204
SEI-6 Alternate Hoonah – Tenakee Springs – Angoon – Sitka	Hoonah, Tenakee Springs, Angoon, and Sitka	6,270
SEI-5 and SEI-6 North – South	Juneau, Angoon, Sitka, and SEAPA	93,180
SEI-7 Hoonah – Gustavus	Gustavus	0
SEI-8 Juneau – Haines	Juneau	4,844
SEI-9 Pelican – Hoonah	Pelican	632

Table 12-12 presents the results of the initial evaluation of potential transmission interconnections. It is important to note that the 2011 transmission interconnection costs do not include any cost for generating the electricity that would be transmitted over each interconnection. In other words, the costs shown are only for the annual costs of the transmission interconnection.

Figures 12-14 through 12-22 show schematically the annual average transfer over the interconnection for each of the interconnections evaluated in Table 12-1 based on the transmission regions presented on Figure 4-3.

Table 12-12 Results of Initial Transmission Interconnection Economic Evaluation

INTERCONNECTION		MILES	2011 CAPITAL COST ($ MILLION)	2011 ANNUAL O&M AND R&R COSTS	ANNUAL AVERAGE TRANSFER OVER INTERCONNECTION (NOTE 1) (MWH)	2011 TRANSMISSION INTERCONNECTION COST (NOTE 2) ($/MWH)
SEI-1A	Hawks Inlet - Hoonah	28.5	101.7	350,000	2,802	2,891
SEI-4	Ketchikan - Prince of Wales	35.2	99.7	293,000	9,094	797
SEI-5	Kake - Sitka	55	199.1	432,000	31,521	495
SEI-6	Hawks Inlet - Angoon - Sitka	102	143.1	471,000	11,104	1,025
SEI-6 Alternate	Hoonah - Tenakee Springs - Angoon - Sitka	106	147.2	497,000	7,290	1,607
SEI-5 and SEI-6	North - South	137	310.2	789,000	93,180	262
SEI-7	Hoonah - Gustavus	29	116.5	350,000	0	--
SEI-8	Juneau - Haines	85.3	243.8	319,000	4,844	3,902
SEI-9	Pelican - Hoonah	55	63.6	288,000	632	8,125
2011 Diesel Generation Cost						255

Note 1: The annual average transfer over the interconnection is determined by taking the sum of the annual flows for each segment of each interconnection as modeled in Strategist® for the 50-year planning period and dividing the sum by 50.

Note 2: The annual transmission interconnection cost does not include any cost for the generating the electricity that would be transmitted over each transmission interconnection.

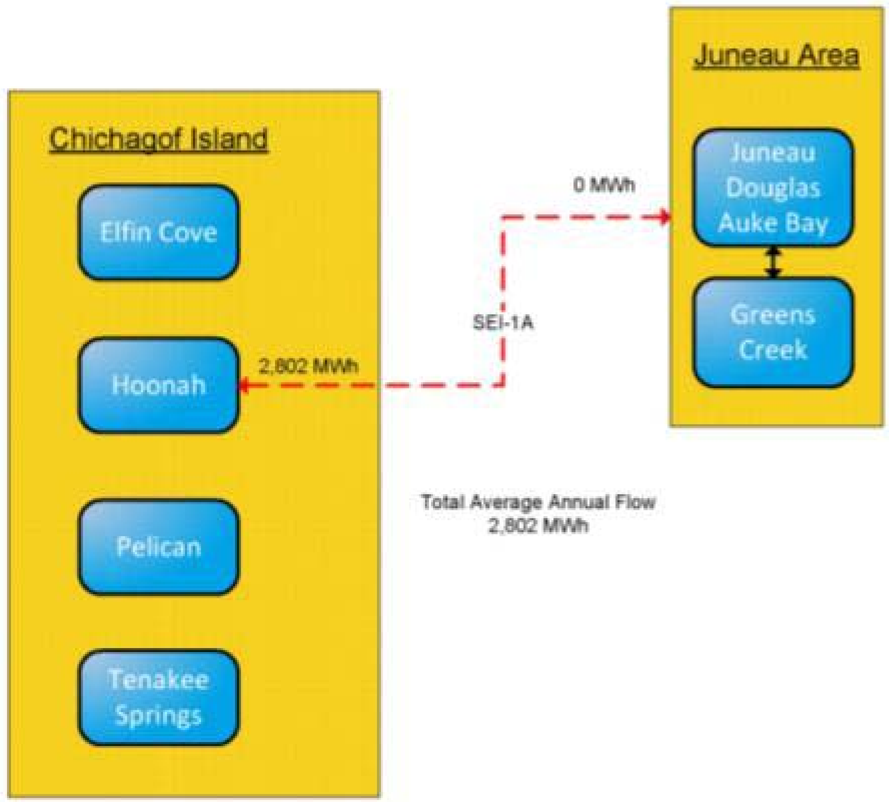


Figure 12-14 SEI-1A Hawk's Inlet - Hoonah Average Annual Flow

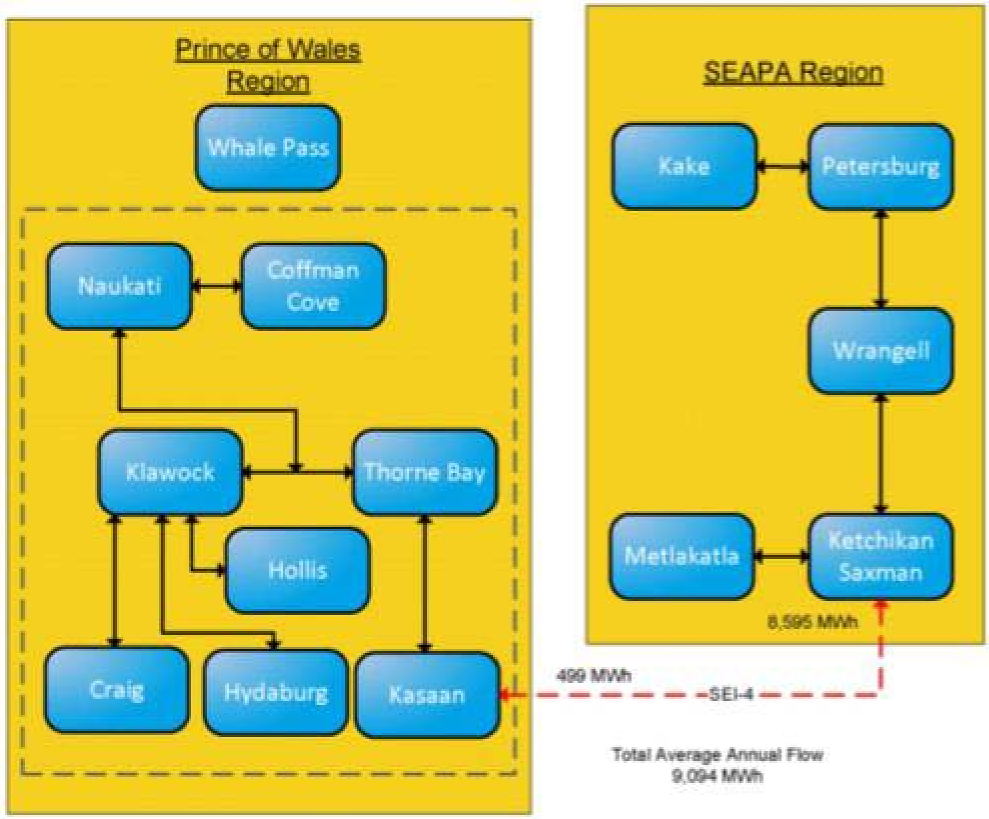


Figure 12-15 SEI-4 Ketchikan - Prince of Wales Average Annual Flow

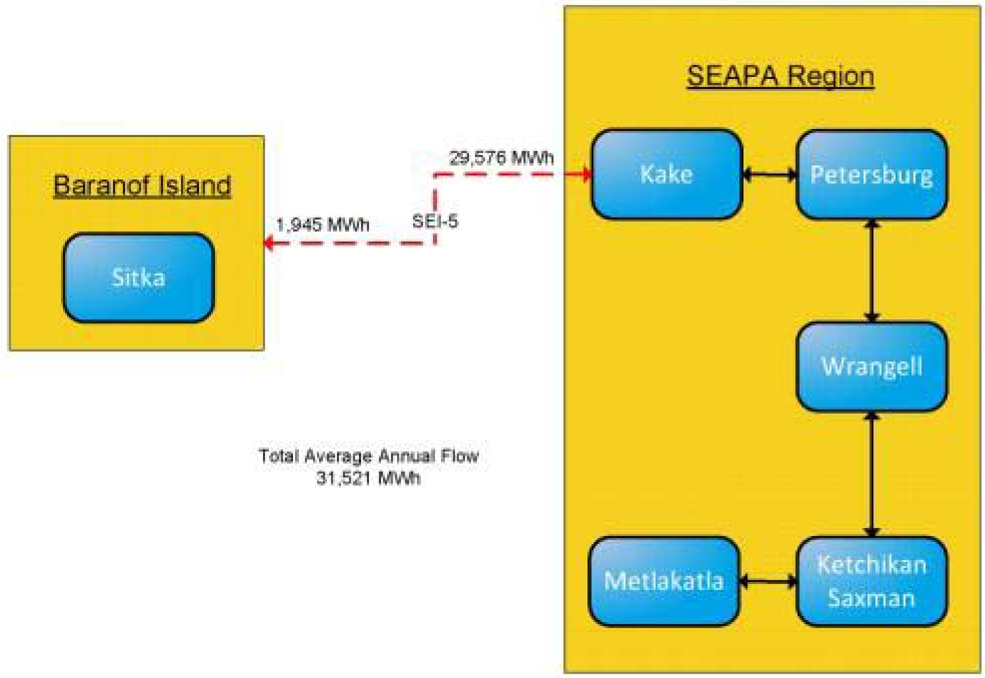


Figure 12-16 SEI-5 Kake - Sitka Average Annual Flow

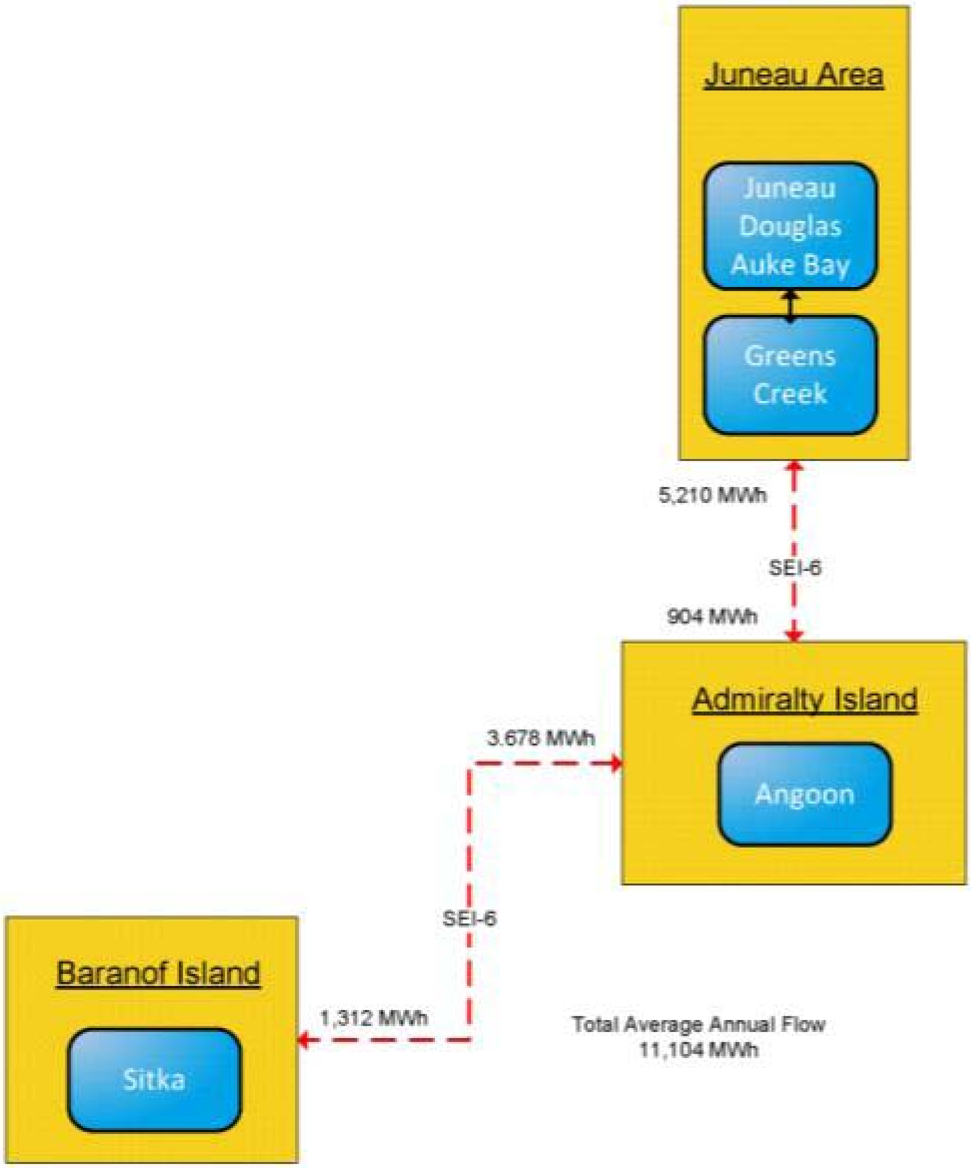


Figure 12-17 SEI-6 Hawk's Inlet - Angoon - Sitka Average Annual Flow

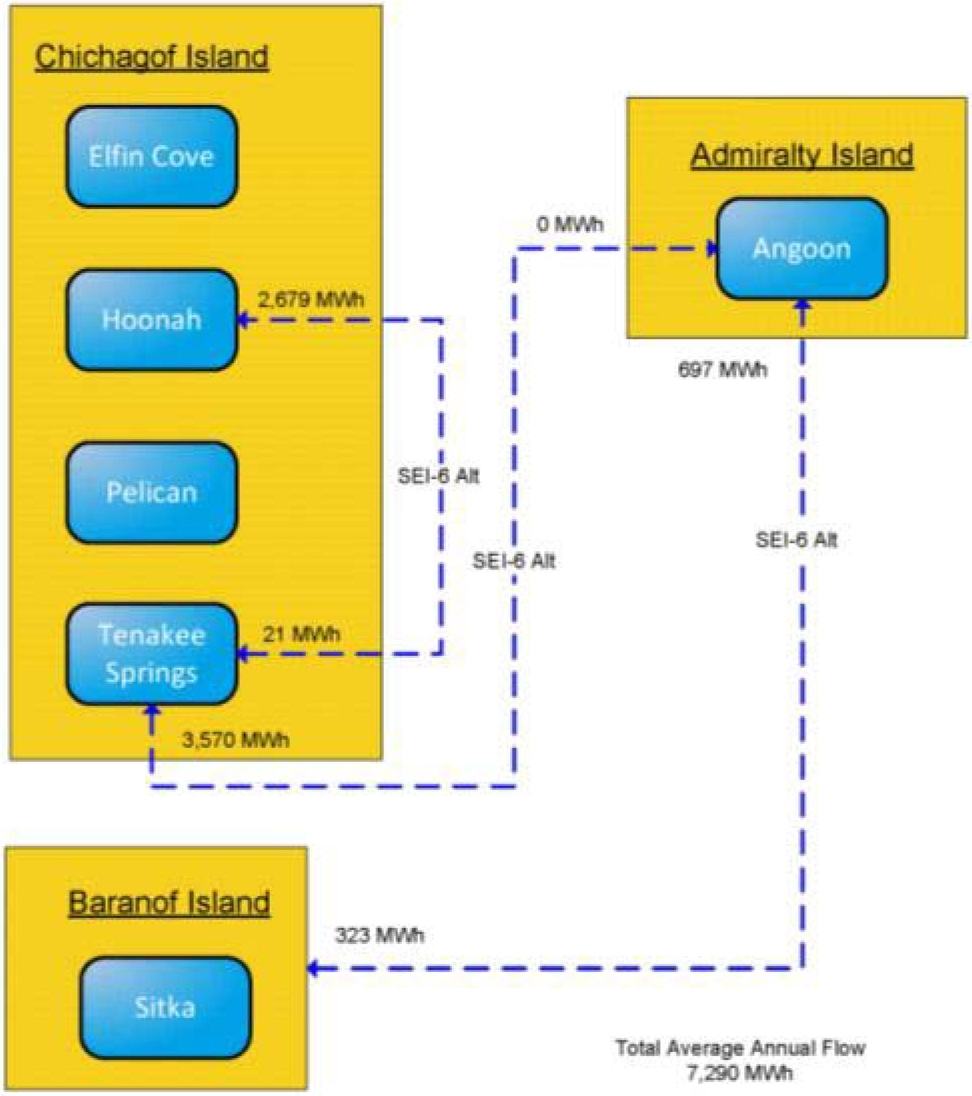


Figure 12-18 SEI-6 Alternate Hoonah - Tenakee Springs - Angoon - Sitka Average Annual Flow

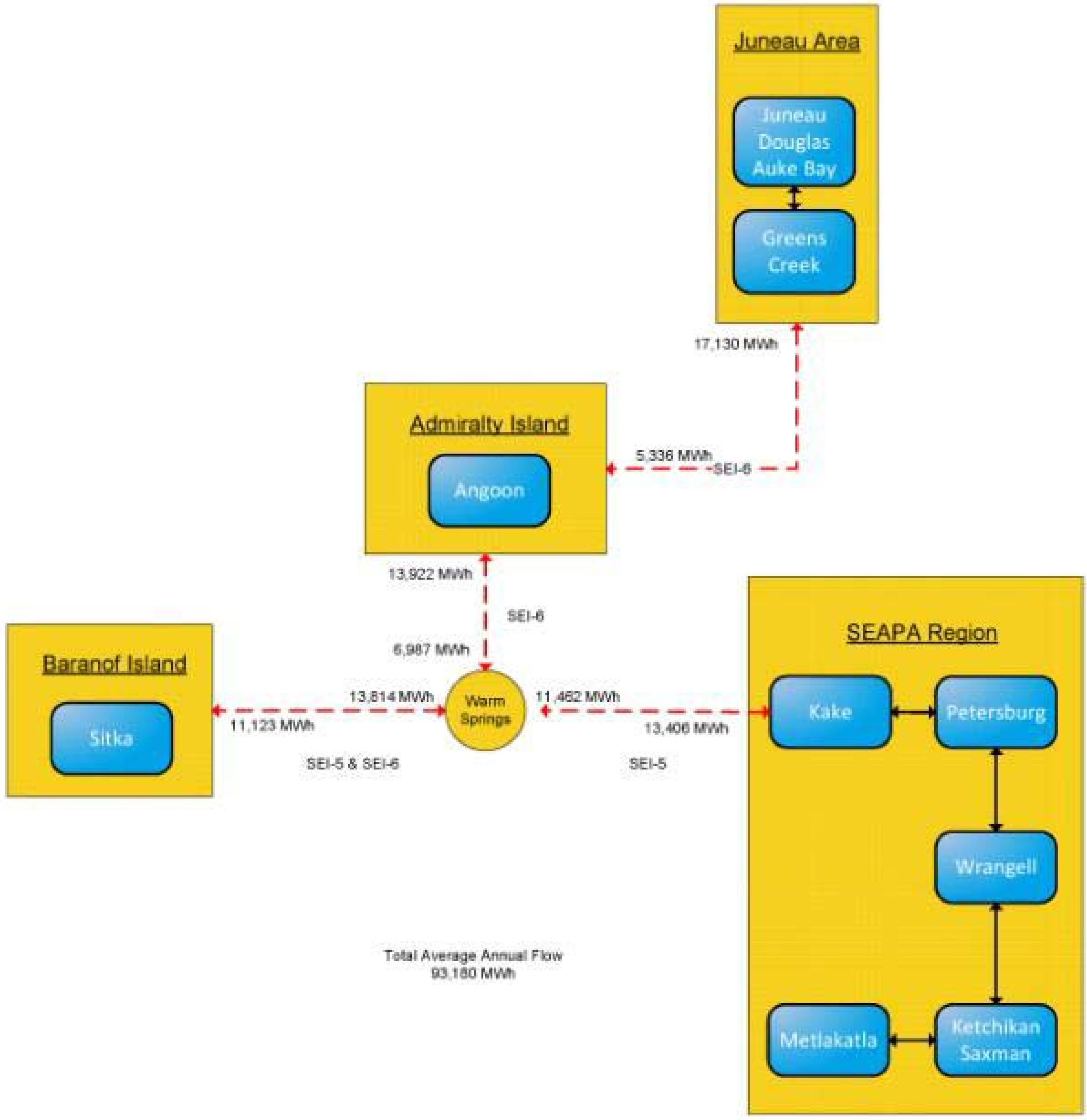


Figure 12-19 SEI-5 and SEI-6 North and South Average Annual Flow

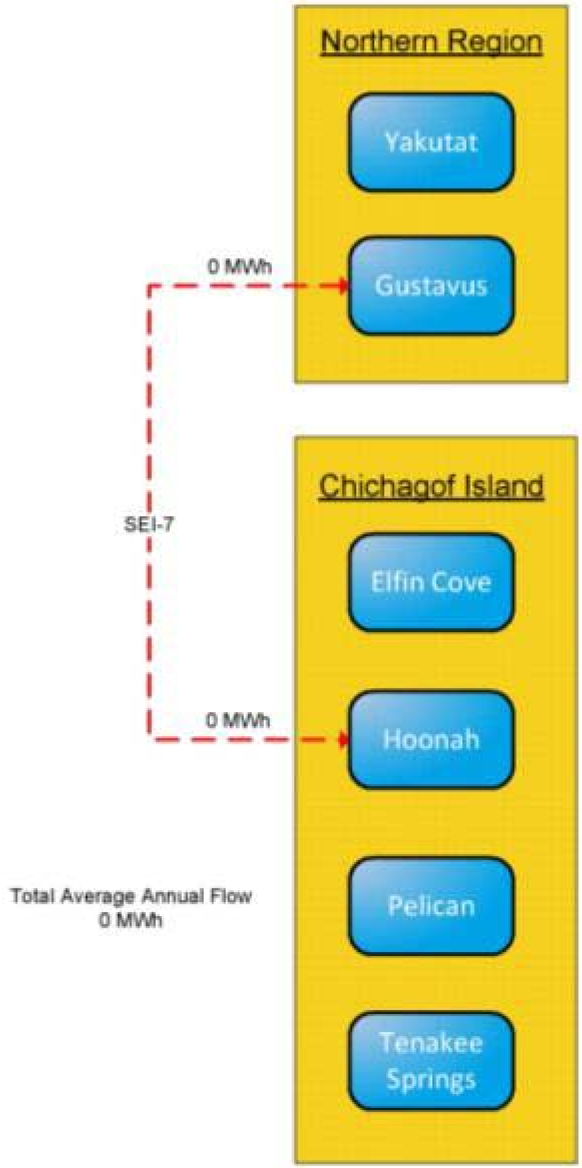


Figure 12-20 SEI-7 Hoonah - Gustavus Average Annual Flow

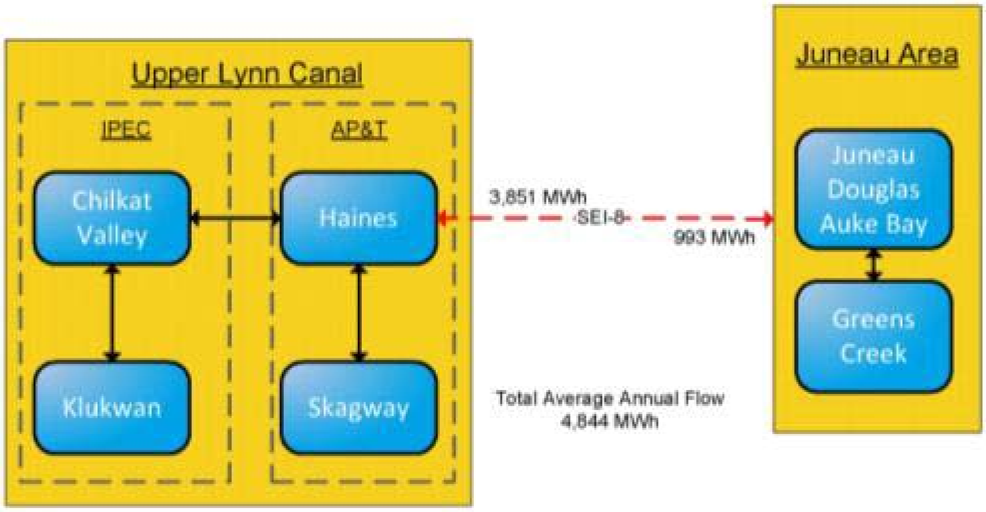


Figure 12-21 SEI-8 Juneau - Haines Average Annual Flow

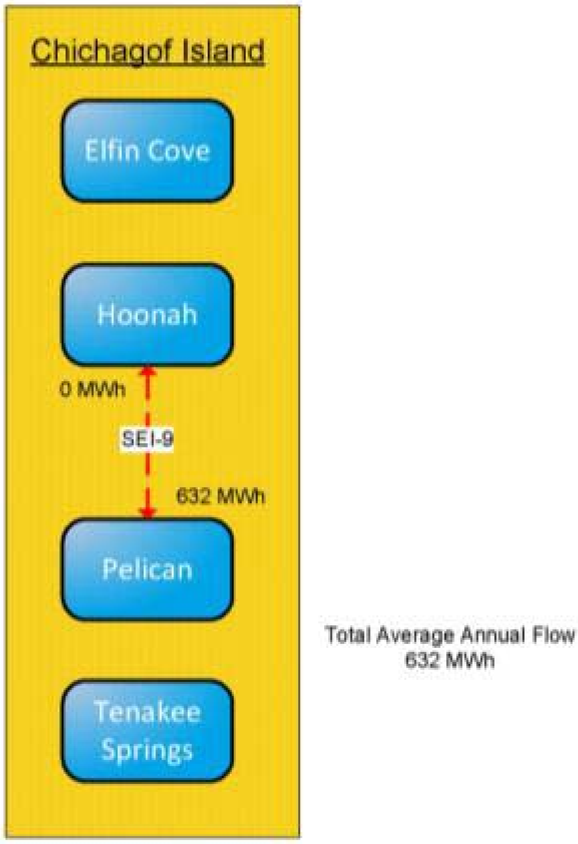


Figure 12-22 SEI-9 Pelican - Hoonah Average Annual Flow

The transmission interconnection costs in Table 12-12 are based on applying the 30-year fixed charge rate in Table 6-1 along with the annual O&M and R&R costs and dividing by the transfer MWh. The annual average transfer over interconnection is the average of the total flows modeled in Section 12.7. The diesel generation costs are based on the average of the diesel costs in Section 11.7 with the 15-year fixed charge rate for the high-speed diesels and the 20-year fixed charge rate for the medium-speed diesels applied to the diesel capital costs and the 2012 medium diesel price for Ketchikan from Table 5-4. The diesel costs assume a 55 percent capacity factor.

Table 12-12 indicates that none of the interconnections evaluated have estimated transmission costs that are lower than the projected diesel costs.

12.7 TRANSMISSION INTERCONNECTION PUBLIC BENEFIT EVALUATION

This section presents the results of the evaluation of the transmission interconnection alternatives presented in Section 12.5 from the perspective of the transmission interconnections being constructed using State grant funds and only the transmission O&M and R&R costs included in the system costs. In order to evaluate the relative benefits of each interconnection, the benefit-cost ratio for each interconnection is calculated by comparing the cumulative present worth cost savings associated with each interconnection to the estimated capital cost of each interconnection presented in Section 12.5.

Table 12-13 presents the results of the public benefit screening. The cumulative present worth costs are determined by modeling the subregions with Strategist® using the generic hydroelectric projects, as described in Section 10.0, with and without the subject interconnection. The cumulative present worth savings from the interconnected operation, minus the O&M and R&R costs for the interconnection, are compared to the estimated capital cost of the proposed interconnections to determine the estimated benefit-cost ratio for each interconnection. As indicated in Table 12-13, the benefit-cost ratios are low, indicating that there are not enough savings from the interconnection to offset the capital cost of the interconnection.

Table 12-13 Transmission Interconnection Public Benefit Screening Evaluation

INTERCONNECTION		MILES	2011 CAPITAL COST ($ MILLION) (A)	2011 CUMULATIVE PRESENT WORTH COST FOR ISOLATED SUBREGIONS ($ MILLION) (B)	2011 CUMULATIVE PRESENT WORTH COST FOR INTERCONNECTED SUBREGIONS ($ MILLION) (C)	2011 CUMULATIVE PRESENT WORTH COST SAVINGS DUE TO INTERCONNECTION ($ MILLION) (D) = (B) – (C)	2011 CUMULATIVE PRESENT WORTH COST FOR INTERCONNECTION O&M AND R&R ($ MILLION) (E)	2011 NET CUMULATIVE PRESENT WORTH SAVINGS ($ MILLION) (F) = (D) – (E)	BENEFIT-COST RATIO (G) = (F)/(A)
SEI-1A	Hawks Inlet - Hoonah	28.5	101.7	286.1	277.9	8.2	13.1	-4.9	--
SEI-4	Ketchikan - Prince of Wales	35.2	99.7	307.6	282.5	25.1	11.4	13.7	0.14
SEI-5	Kake - Sitka	55	199.1	386.1	341.6	44.5	15.5	29.0	0.15
SEI-6	Hawks Inlet - Angoon - Sitka	102	143.1	339.8	290.1	49.7	16.5	33.2	0.23
SEI-6 Alternate	Hoonah - Tenakee Springs - Angoon - Sitka	106	147.2	182.8	128.2	54.6	17.6	37.0	0.25
SEI-5 and SEI-6	North - South	137	310.2	654.0	522.9	131.1	32.0	99.1	0.32
SEI-7	Hoonah - Gustavus	29	116.5	115.1	110.5	4.6	13.1	-8.5	--
SEI-8	Juneau - Haines	85.3	243.8	278.8	239.5	39.3	13.8	25.5	0.10
SEI-9	Pelican - Hoonah	55	63.6	51.9	46.7	5.2	10.1	-4.9	--

12.8 AK-BC INTERTIE

12.8.1 Scope of Assessment

As part of the Southeast Alaska IRP scope of work, Black & Veatch was tasked to develop a new region-wide transmission plan for interconnecting Southeast Alaska communities. The high-level feasibility of constructing an export intertie was to be considered as part of this planning. To complete this assessment of the AK-BC Intertie, consistent with the scope of work under the contract with the AEA, Black & Veatch reviewed previous studies and considered additional information related to the Intertie that was provided during the course of the project.

12.8.2 Review of Previous Studies

Black & Veatch reviewed numerous reports and other documents (many of which were provided by the Alaska Canada Energy, or ACE, Coalition), including the following three reports which represent the most comprehensive assessments of the AK-BC Intertie:

- AK-BC Intertie Feasibility Study SE Alaska; Hatch Acres Corporation, September 2007. (Hatch Acres Study).
- Southeast Alaska Energy Export Study, D. Hittle & Associates, Inc., May 2006.
- Bradfield Power – Integrated Hydroelectric and Power Line Development Proposal, WH Pacific, Inc., May 2010.

12.8.3 Results of Current Assessment

Black & Veatch conducted a high-level screening assessment of the AK-BC Intertie based upon information available at the time of this study, including the results of previous studies for both export and import scenarios.

12.8.3.1 Export Scenario

For the **export scenario**, the screening was based upon California wholesale renewable power market prices, and the results are shown in Table 12-14.

Table 12-14 Export Scenario

ELEMENT	PRICE ($/MWH)	SOURCES AND NOTES
California Wholesale Market Price	104	California Public Utilities Commission, 2009 Market Price Referent Values for 2009 Renewables Portfolio Standard (RPS) Solicitations, assuming a 25-year power purchase contract with a contract start date of 2011. See following paragraph for additional discussion regarding this price point.
Wheeling Cost and Losses From AK-BC Intertie Terminus to California	15 - 25	Black & Veatch analysis based upon transmission tariffs for BC Hydro, and Bonneville Power Administration (BPA). Additional details are provided in discussion that follows this table. Note: California Independent System Operator (CAISO) transmission wheeling charges are paid by the load serving utility. The actual total wheeling charge (on a $/MWh basis) would be a function of the transmission capacity reserved, on a firm or nonfirm basis, and the amount of power that is wheeled.
Annual AK-BC Intertie Costs	12 - 58	Black & Veatch analysis, based upon an estimated capital cost of $41.7 million in 2011 dollars. The high end of this range assumes 65,000 MWh of power is exported annually (per the Hatch Acres Study) and includes annualized capital-related costs (using 30-year fixed charge rate), equal to $49.9/MWh, and annual O&M costs, equal to $8.2/MWh). The low end of this range assumes 325,000 MWh of power is exported annually and includes annualized capital-related costs (using 30-year fixed charge rate), equal to $10.0/MWh, and annual O&M costs, equal to $1.6/MWh). Hatch Acres did not include annualized capital-related costs in its analysis because it assumed that the State would provide a grant to cover all capital costs.
Net Back Price	21 - 77	

With regard to market prices, we used the California Renewables Market Price Referent Value as the basis for establishing a market price for this analysis because it represents a benchmark for long-term, firm, renewable power sold in a high-cost market that has an aggressive RPS; as a result the Referent Value is significantly higher than average California spot market prices in recent years. To qualify for this price, the supplier must demonstrate a firm transmission path to California, which has not been independently verified as part of this screening analysis. Furthermore, this type of energy sale is typically as a heavy and light load split, or as a flat volume. If the supplier fails to deliver, then: 1) a backing transfer must support the failed delivery, or 2) the price has a reduction clause based on the volume of missed deliveries. Costs associated with conditions 1) and 2) have not been included in our analysis.

Spot market prices, especially in markets dominated by hydroelectric resources, are different from long-term contract prices and they can vary significantly over time (for example, off-peak spot market prices at the Mid-Columbia hub averaged about $26/MWh in 2010, although the average off-peak price in 2011 has been slightly below $11/MWh). This compares to an average off-peak price of $65/MWh in 2005. Peak spot prices are typically higher (for example around $35/MWh on average in 2010 and $27/MWh in 2011, again for the Mid-Columbia hub). (Source: Energy Velocity). Furthermore, spot market prices can vary significantly between regions, within regions, and by season. Actual MWh sales in the spot market are uncertain, is the price that the power can be sold, at and consequently total revenues could be less, perhaps significantly, than under a long-term sales contract.

Table 12-15 provides additional detail regarding our estimated wheeling charges and transmission losses from Alaska to California.

Table 12-15 Estimated Wheeling Charges and Transmission Losses from Alaska to California

			TOTAL WHEELING CHARGES AND COST OF LOSSES AT COST OF GENERATION @ $50/MWH		TOTAL WHEELING CHARGES AND COST OF LOSSES AT COST OF GENERATION @ $100/MWH	
	WHEELING CHARGE ($/MWH)	% LOSSES	COST OF LOSSES ($/MWH)	TOTAL WHEELING AND LOSSES ($/MWH)	COST OF LOSSES ($/MWH)	TOTAL WHEELING AND LOSSES ($/MWH)
BC Hydro (at 100% load factor)	5.36	6.28	3.14	8.50	6.28	11.64
BPA – Main System	3.74	1.90	0.95	4.69	1.90	5.64
BPA – Southern Intertie	3.72	3.00	1.50	5.22	3.00	6.72
Total	**12.82**	**11.18**	**5.59**	**18.41**	**11.18**	**24.00**

Sources: BC Hydro and BPA transmission tariffs.

It is impossible to conclude that there is a better market price to use for this screening evaluation than the California Renewables Market Price Referent Value without a more detailed prediction of future market prices, and without a detailed assessment of both term and spot price marketing mechanics for imports into the Western Electricity Coordinating Council (WECC) control area, to determine the most appropriate export strategy to maximize revenues.

It should be noted that all of the candidate hydroelectric projects considered in the Hatch Acres Study (page 179) had generation costs higher than $21/MWh, with the lowest cost project (Whitman Lake) estimated at $55/MWh in 2007 dollars, or $60/MWh in 2011 dollars. Only three other potential hydroelectric projects (Scenery Lake, Cascade Creek, and Connell Lake) had generation costs less than $71/MWh in 2007 dollars, or $77/MWh in 2011 dollars. (Note: While the Hatch Acres Study had the above estimated costs, Whitman Lake is now projected at around $110/MWh and Cascade Creek showed a 50-year levelized energy cost of $103/MWh in Exhibit D of its Draft License Application.)

It should also be noted that the above analysis does not include: 1) any costs associated with the interconnection of hydroelectric projects to the AK-BC Intertie, 2) the costs associated with any required SEAPA system improvements, 3) any costs related to the Canadian transmission segment between the Canadian border and BC Hydro's transmission system, some of which may need to borne by the AK-BC Intertie developer, or 4) any costs associated with the marketing and dynamic scheduling of power for export. **The additional costs associated with these unknowns could be significant; in fact, the combined cost impact of these three unknowns could be greater than the annual AK-BC Intertie costs.**

Based on these screening results and, more specifically, because of the potential significant cost impacts of the unknowns discussed above, the export scenario for the AK-BC Intertie will not be considered further in the detailed Strategist® modeling.

12.8.3.2 Import Scenario

For the **import scenario**, the screening was based upon the power purchase cost and transmission-related costs associated with buying power in the PNW and moving that power to the AK-BC Intertie terminus with the SEAPA system (PNW purchase power cost, plus annual AK-BC Intertie costs, plus wheeling charges from the PNW to the AK-BC Intertie), relative to the cost of potential Southeast Alaska hydroelectric generation. Table 12-16 shows the calculation of the estimated cost of power from the PNW delivered to the SEAPA transmission system.

It should be noted that the above analysis does not include: 1) any costs related to the Canadian transmission segment between the Canadian border and BC Hydro's transmission system, some of which may need to be borne by the AK-BC Intertie developer, 2) the costs associated with any required SEAPA transmission system improvements, or 3) the costs associated with additional transmission segments that would need to be constructed to move power from the SEAPA system to a local load center. The first and second of these unknowns also apply to the export scenario, as discussed above. **Similar to the export scenario, the potential cost impact of these unknowns could be significant.** Additionally, this screening analysis does not include consideration of the energy security and transmission reliability-related issues associated with the AK-BC Intertie.

Table 12-16 Import Scenario

ELEMENT	PRICE ($/MWH)	SOURCES AND NOTES
Delivered PNW Market Price	70	Hatch Acres Study.
Wheeling Cost From PNW to AK-BC Intertie Terminus	9 - 13	Black and Veatch analysis. Low end of the range includes only wheeling charges for transmission of power over the BC Hydro and BPA-Main transmission systems. The high end of the range includes transmission losses assuming the cost of purchased power in $50/MWh. See table above for additional details.
Annual AK-BC Intertie Costs	58	See comments for export scenario. For the import scenario, we used the high end of the range of Annual AK-BC Intertie Costs due to the lower unmet energy requirements relative to the BC, PNW, and California markets, which will significantly limit the amount of power transmitted over the AK-BC Intertie.
Price of Power Delivered to the SEAPA System	137 - 141	

Based on the Hatch Acres Study, there are several potential local hydroelectric generation facilities (e.g., Mahoney Lake, Scenery Lake, Delta Creek [Ruth Lake], and Cascade Creek to name a few) with estimated generation costs below $137/MWh. Black & Veatch is currently reviewing the generation costs of potential Southeast Alaska hydroelectric facilities, but it believes that the Hatch Acres Study estimates are adequate for this screening analysis.

Based on these screening results, the import scenario for the AK-BC Intertie will not be considered further in the detailed Strategist® modeling since the total delivered price of PNW power to a local load center (PNW purchase power cost, plus wheeling charges, plus AK-BC Intertie costs, plus transmission interconnection cost from SEAPA to the load center) would need to be lower than the cost of local hydroelectric generation delivered to the load center. Furthermore, as noted above, the costs associated with any required improvements, if any, to the SEAPA system (either to move power from the PNW or from a local hydroelectric facility that requires use of the SEAPA system to move power to the load center) has not been included in this screening analysis and it is likely that the SEAPA system-related improvements related to the AK-BC Intertie would be equal to or greater than any required improvements related to a Southeast Alaska hydroelectric facility.

12.8.4 Future Consideration

Given the 50-year time horizon of the Southeast Alaska IRP, it is appropriate to ask the question whether the AK-BC Intertie might become a preferred resource option during this period, should conditions change. Our directional Southeast Alaska IRP is the first step in the iterative process for defining future Southeast Alaska energy needs and solutions. Typically, large projects of this scope, which are not defined sufficiently to be considered for inclusion in the first integrated resource plan, can be considered for inclusion in subsequent plans if they become adequately defined and shown to be economically viable. This methodology ensures that short-term transient market developments, such as one state instigating an environmental policy, are not used as the basis for a large investment that in the end could sit stranded should the short-term policy expire.

Given the volatility that exists related to North American power market dynamics and other factors that affect the economic viability of the AK-BC Intertie, it is impossible to conclude with absolute certainty that the AK-BC Intertie would not, under any set of conditions, become a viable project.

Therefore, it is appropriate to consider the various set of conditions under which the AK-BC Intertie might become economical. The following is a list of such conditions:

- The expected monthly profile of electric sales (or purchases) and whether those sales (or purchases) would be under the terms of a long-term firm contract or on the spot market is clearly defined.
- Prices in potential export markets in North America (principally BC, PNW, and/or the Southwestern region of the United States) increase significantly due to capacity and energy shortages, continued increases in applicable RPSs, and/or increased environmental regulations that cause existing generation facilities to be retired or prohibit planned facilities from being built.
- For potential import, costs for new generation will have to increase substantially over the costs for potential hydroelectric projects capable of meeting Southeast Alaska's energy requirements. This could be the result of large project cost increases or significant load increases that exceed the availability of lower cost regional hydroelectric projects.
- State energy policy decisions lead to the consideration of the Intertie as a "public good" investment, whereby justification of the project is made on public good grounds, as opposed to fundamental economics.

12.8.5 Required Actions

A detailed business plan needs to be developed in order for the AK-BC Intertie to be considered a viable project in the future. In order to develop this business plan in sufficient detail to justify public or attract private financing, the following actions are required:

- **Technical Studies:** The following studies need to be completed to address important technical issues:
  - Detailed engineering studies of potential development alternatives for the AK-BC Intertie, including: 1) detailed transmission system load flow and stability analyses, 2) detailed capital and operating cost estimates, and 3) a more defined route option selection assessment.

- Detailed engineering studies of a defined set of potentially viable hydroelectric projects in Southeast Alaska, and related transmission interconnections to the SEAPA transmission system, including: 1) detailed capital and operating cost estimates for the hydroelectric facilities, and 2) detailed interconnection-related capital and operating costs.
- Detailed engineering studies to identify the improvements that will need to be made to the existing SEAPA transmission system to move AK-BC Intertie-related power throughout the interconnected region of Southeast Alaska, including: 1) detailed transmission system load flow and stability analyses, 2) detailed capital and operating cost estimates, and 3) associated cost allocation protocols (Note: FERC has established procedures for the allocation of capital and operating costs incurred to improve existing transmission systems as a result of the impact of other projects that impact the existing transmission system; subject to a more definitive legal opinion, these FERC cost allocation procedures should be assumed to apply here).

- **Market Assessment**: The following should be completed to address market issues:
  - Detailed electric market price projections for all areas where power may be sold (or bought) over a sufficiently long enough period (at least 30 years).
  - Alternative scenarios need to be considered given the likely variability of electric market prices over this extended period of time.
  - Clear understanding on evolving Canadian policies regarding the import of power.
  - Detailed assessment of the available capacity on all transmission lines from the AK-BC Intertie connection point in Canada to the ultimate market(s) for the sale (or purchase) of power, and associated transmission wheeling costs.
  - Clear understanding of which states consider hydroelectric power to be "renewable" under the provisions of their renewable portfolio standards, where applicable (e.g., the State of Washington does not include hydroelectric power as a renewable resource).
  - Understanding of standard power purchase agreement terms and conditions as they will largely determine the terms and conditions under which power will be sold (or bought) over the Intertie.
- **Risk Assessment:** A thorough project risk assessment needs to be completed to evaluate potential risks, identify any "fatal flaws," and include a risk mitigation or avoidance plan (with associated capital and operating costs). This risk assessment needs to consider, at a minimum, the following risks:
  - Transmission reliability risks given the lack of redundant transmission lines (this directly impacts whether the power moved over the AK-BC Intertie could be sold or bought as firm power or would have to be considered nonfirm).
  - Resource potential risks associated with related hydroelectric facilities, including the total energy and capacity that could be economically developed for each resource option.
  - Impact of potential developments regarding the Roadless Rule in terms of the ability to construct the AK-BC Intertie and related hydroelectric plants.
  - Variability of electric market conditions and prices and the resulting impact on the underlying economics of the intertie and associated hydroelectric projects.

- Project development and operational risks associated with the development of the Intertie and related hydroelectric facilities, including regulatory and permitting issues, the potential for construction costs overruns, actual operational performance relative to planned performance, and so forth. This also includes noncompletion risks once a project gets started, the risk that adverse operating conditions will severely damage the facilities resulting in a shorter useful life than expected, and project delay risks.
- The risks of environmental-related operational concerns and the potential for future changes in environmental regulations.
- The risk that the intertie and hydroelectric facility developers will not be able to obtain the required financing under reasonable and affordable terms and conditions.
- The risk that regulatory and legislative issues could affect the economic feasibility of specific resource options.

- **Organizational Assessment:** A number of organizational issues need to be considered, including:
  - Scope of responsibilities (e.g., independent operation of the Intertie, regional planning, and project development).
  - Formation issues, such as legal structure (e.g., public or private), location, transfer of existing assets (if any), and so forth.
  - Operational issues, such as O&M responsibility and associated staffing or outsourcing plans, creation of control center capability, development of operational rules and procedures, required supervisory control and data acquisition (SCADA)/ telecommunications investments, and so forth.
  - Staffing plan to ensure adequate staffing and skill sets, including the development of a power trading and scheduling capability (Note: it is important to understand that the utilities "on the other end of the line" are sophisticated utilities and have been trading in competitive wholesale power markets for years; consequently, a similar level of trading capability needs to be developed or outsourced to protect regional interests).
  - Tax and legal issues, such as the ability to issue tax-exempt debt, transfer of existing assets (if any), and governance structure.
  - Regulatory oversight issues and required legislative actions, potentially including the development of a FERC-compliant Open Access Transmission Tariff (OATT).
  - Rules, regulations and rate schedules for transmission service over the intertie.
  - Detailed organizational start-up plan with estimates of associated one-time and annual costs.

12.9 YUKON ENERGY TRANSMISSION INTERCONNECTION

One of the interconnections that has been discussed for the region is an interconnection from Skagway, Alaska to Whitehorse, Yukon. The purpose of the interconnection is to exchange power between Skagway and AP&T in the Haines/Skagway area with Yukon Energy. The interconnection would run along the Skagway road to the Canadian border and then continue to Whitehorse. One of the main drivers for the interconnection is the potential development of West Creek Hydro Project. The West County Hydro project would be located about 7 miles west of Skagway adjacent to the small community of Dyea. The primary purpose of the West County Hydro Project would be to offset the diesel generation from the cruise ships docked in Skagway. The diesel generation from the cruise ships causes air pollution in the area. The West Creek Hydro project would also provide winter energy to the AP&T system serving Haines/Skagway and if the interconnection were constructed would provide winter energy to Yukon Energy. The West Creek project is being developed by the municipality of Skagway.

There are also some potential hydroelectric projects along the Carcross to Skagway Road that Yukon Energy is reviewing. These projects potentially could supply additional energy to Skagway during the summer to serve the cruise ships.

The municipality of Skagway has applied for $236,000 grant from AEA's Round 5 Renewable Energy Grant Fund, which along with a $59,000 match by the municipality, would be used to conduct feasibility/conceptual design study for the West Creek Hydro project. The current estimated costs of constructing the West Creek Hydro Project, based on the Round 5 Application, range between $127 million and $140 million, depending on whether the project is constructed as a run-of-river project or a storage project. These costs will obviously be refined as part of the feasibility/conceptual design study. The study is scheduled for completion in October 2013 if it is successful in receiving full funding under the Round 5 grant. The municipality and AP&T do not believe that FERC licensing will be required since the project will not be on federal lands, affect interstate commerce, or be on a navigable stream. The municipality plans to apply for a jurisdictional determination from FERC during the feasibility study. The West Creek Hydro Project is estimated to provide 25 MW of capacity and an average of 27,000 MWh of annual energy. Black & Veatch's independent estimate of cruise ship load in Skagway is 45,000 MWh annual, as presented in Subsection 8.1.2.3.

A feasibility study was conducted for West Creek in 1981-82. While this work has been conducted and a detailed feasibility study has proposed for the West Creek Hydro Project, relatively little work has been directed to the development of the proposed interconnection. The interconnection may have some merit, but at this stage in the development process, the interconnection does not merit detailed evaluation. The economics of the interconnection will be highly dependent upon the amount of power transmitted over it. Power would need to flow to the Yukon in the winter and Skagway in the summer to increase the economics of the interconnection. The potential generation to supply these flows is in the very early stages of development and is far from assured sources of supply. Thus the interconnection has not been evaluated in detail for this study.

13.0 Demand-Side Options

13.1 INTRODUCTION

The purpose of this section is to summarize Black & Veatch's approach to the assessment of demand-side options as part of the overall Southeast Alaska IRP project. A very important element of any comprehensive IRP is the development of a portfolio of proposed energy efficiency and demand reduction programs that can contribute energy savings and peak load reductions, and then evaluate these potential programs relative to alternative supply-side electric generation options. These resources are particularly important given the 15 percent energy efficiency by 2020 target established by the State Legislature. Those demand-side resources that prove to be more cost effective than supply alternatives are then typically included in integrated resource planning model or models (in this case, Strategist®) as a reduction to the load forecast. The resulting lower forecast then serves, in a typical IRP, as the basis from which the alternative supply-side options are considered for adding generation resources when and as needed.

Black & Veatch considered the following four types of demand-side options as part of this study:

- **Weatherization Measures**--As used in this study, weatherization involves the modification of a building to reduce energy consumption and optimize energy efficiency. The savings result from a reduction in space conditioning costs, which in Southeast Alaska is primarily space heating. Thus, savings to electric loads only occurs if electric space heating is used. Weatherization commonly includes insulation (wall, ceiling, and floor), building envelope sealing, windows and doors, caulking, roof treatments, ventilation, duct sealing, and similar measures. Since weatherization provides savings for all types of space heating, it is discussed separately in Section 14.0.
- **DSM/EE Measures**--As used in this report, DSM/EE measures include those that lead to a reduction in the amount of electrical energy required to provide products and services. For example, installing compact fluorescent lights or natural skylights reduces the amount of energy required to attain the same level of illumination compared to using traditional incandescent light bulbs. In addition to efficient lighting, other types of DSM/EE measures considered in this study included the following:
  - High-efficiency appliances (e.g., refrigerators, freezers, electric water and space heaters).
  - Heat pump water heaters.
  - Set-back thermostats.
  - Low-flow showerheads.
  - High-efficiency pumps and motors.
- **Conversions of Space Heating Equipment**--This involves the conversion of existing diesel space heating equipment to biomass (e.g., wood pellets), as opposed to the recent trend of converting to electric space heating. This demand-side option was considered separately due to: 1) the significance of the recent trend, in communities with access to low-cost hydroelectric generation, of residential and commercial customers converting from diesel to electric space heating, with the resulting impact of the availability of hydroelectric generation for other needs, and 2) the impact of the high cost of diesel space heating in

those communities without access to low-cost hydroelectric generation. Conversion of space heating equipment is discussed in Section 15.0.

- **Demand Response (DR)**--DR is aimed at managing consumption of electricity in response to supply conditions; typically DR is used to refer to mechanisms used to encourage consumers to reduce demand, thereby reducing the peak demand for electricity. For example, many utilities have implemented programs that provide incentives to residential customers and business customers to reduce their consumption at critical times or in response to market prices, which are structured to reflect the higher costs of supplying electricity during periods of high demand (e.g., in communities in Southeast Alaska with access to low-cost hydroelectric power sufficient to meet the majority of their annual demand, peak demands may be met through high-cost diesel generation during periods of the year, either because their total installed hydroelectric capacity, on a MW basis, is less than peak demands, or their storage capabilities are insufficient to enable them to produce sufficient hydroelectric power throughout the year). Since electrical generation and transmission systems are generally sized to correspond to peak demand (plus margin for forecasting error and unforeseen events), lowering peak demand reduces overall plant and capital cost requirements.

  DR can be achieved through either active measures (e.g., installation of dedicated control systems to shed loads in response to a request by a utility or market price conditions), or passive measures (e.g., the use of real-time rate structures and related communications technologies so that customers know the actual cost of power they are consuming at any given time, thereby providing them with the incentive to curtail usage during high cost periods).

  There are three types of DR - emergency DR, economic DR, and ancillary services DR. Emergency DR is employed to avoid involuntary service interruptions during times of supply scarcity. Economic DR is employed to allow electricity customers to curtail their consumption when the productive or convenience of consuming that electricity is worth less to them than paying for the electricity. Ancillary services DR consists of a number of specialty services that are needed to ensure the secure operation of the transmission grid and that have traditionally been provided by generators.

  The implementation of DR programs require: 1) sophisticated generation and transmission system monitoring systems, 2) sophisticated communications systems to provide real-time (or near real-time) pricing signals to residential and commercial customers and/or to activate control equipment within homes or at commercial facilities, and 3) utility rate structures that provide real-time (or near real-time) pricing signals to residential and commercial customers.

Data for demand-side options for the Southeast is very limited making detailed definitive analysis impossible; however, estimates can be developed as long as the appropriate levels of uncertainty are realized that can at a minimum give appropriate direction to implementing DSM options in the Southeast while accurate detailed data is developed. Weatherization and conversion of space heating equipment are most affected by the lack of quality data due to the widely varying housing and commercial building stock and usage patterns. DSM/EE measures, while still very much affected by lack of quality data are relatively more transferable from other areas. The ongoing AEA Energy End Use Data Collection Project is expected to be completed in the first quarter of 2012, and it will provide much of the data necessary to conduct more definitive analysis of the savings and costs associated with DSM options.

13.2 DEMAND-SIDE OPTION EVALUATION METHODOLOGY

This section summarizes Black & Veatch's approach to the evaluation of the four types of demand-side options discussed above.

- **Weatherization Measures**--From an evaluation perspective, it is much more difficult to appropriately evaluate weatherization measures due to their site-specific nature. For instance, the cost, savings, and therefore cost effectiveness of retrofitting with energy efficient windows varies widely by size of the house, the orientation of the windows, and the quality and condition of the windows being replaced. Often many weatherization measures such as window replacement are not cost effective on an average basis, but may be highly cost effective for a specific installation where the condition of the existing windows is very poor. Thus, it is more appropriate to have weatherization measures evaluated as part of a weatherization or energy audit program such as that offered by the AHFC for residential buildings or by the AEA for commercial and industrial buildings where all the measures appropriate for a specific residence or commercial building are evaluated and implemented specifically for each residence or building. Furthermore, weatherization results in savings for all types of space heating technologies, not just electricity. For these reasons and the lack of availability of quality data, Black & Veatch has addressed weatherization separately in Section 14.0.
- **DSM/EE Measures**--To evaluate a wide variety of DSM/EE measures, Black & Veatch accomplished the following:
  - Conducted a review of the existing DSM/EE programs, including weatherization, available in the region.
  - Conducted an economic screening of these measures, using utility industry-standard cost-effectiveness tests.
  - Packaged those measures that passed the cost-effectiveness screening into logical DSM/EE programs, as described in Section 17.
  - Forecasted the level of residential and commercial customer participation in these DSM/EE programs, using market adoption experience of utilities in other parts of the country with years of experience in the implementation of DSM/EE programs.
  - Estimated the peak and annual load impacts of DSM/EE programs in each subregion, based upon the per customer impacts of each program and the adoption of these programs. These estimated load impacts were used in the development of the Low Case Load Forecasts for each subregion. The resulting Low Case Load Forecasts are discussed in detail in Section 8.0.
  - Estimated the total capital costs associated with the implementation of these DSM/EE programs.
- **Conversions of Space Heating Equipment**--The detailed approach used by Black & Veatch to: 1) estimate the amount of oil space heating on a subregion basis, 2) develop a regional biomass space heating conversion program, 3) estimate the potential penetration of that program in each subregion, 4) estimate the potential impact of this program on diesel consumption, and 5) estimate the total capital costs associated with the implementation of this program, as discussed in detail in Section 14.0.

- **Demand Response (DR)**--As stated above, the implementation of DR programs require: 1) sophisticated generation and transmission system monitoring systems, 2) sophisticated communications systems to provide real-time (or near real-time) pricing signals to residential and commercial customers and/or to activate control equipment within homes or at commercial facilities, and 3) utility rate structures that provide real-time (or near real-time) pricing signals to residential and commercial customers. Generally speaking, these conditions do not exist within the Southeast region. The capital costs associated with providing the infrastructure required to implement DR programs in the Southeast region would be significant given current circumstances; additionally, the adoption of the types of rate structures required for the effective implementation of DR programs requires considerable evaluation and consideration by the region's utilities (e.g., the adoption of DR programs requires utilities to conduct seasonal- and time-differentiated cost-of-service studies, and develop residential and commercial rate structures that reflect their seasonal- and time-differentiated cost-of-service). As a result of these constraints and the lack of required cost information, Black & Veatch did not conduct an economic evaluation of potential DR programs as part of this study.

With regard to the evaluation of DSM/EE measures and programs (including weatherization), Black & Veatch has conducted a review of the weatherization and other demand-side programs currently offered in the region by the AHFC, AEA and RurAL CAP. Black & Veatch then developed a portfolio of potential DSM/EE measures (including weatherization) for evaluation. The costs and benefits associated with the DSM/EE measures were taken from existing data sources as described later in this section. Data on non-weather sensitive measures (e.g., lighting, appliances) are directly transferred from existing nationally-known sources, and data on weather-sensitive measures are transferred from existing sources using a regression model that considers both heating and cooling degree days as an adjustment factor. This approach has been used successfully in various other jurisdictions, including the Railbelt Regional IRP.

The short time frame, budget, and limited data availability for this study precluded a rigorous analysis of electric and heating DSM/EE potential (i.e., technical potential and maximum achievable potential) in the Southeast region. However, Black & Veatch has made maximum use of existing data, augmented by discussions with a number of individuals, and employed industry-accepted data sources and analytical tools to produce a preliminary estimate of the cost-effective DSM/EE resources that exist within the Southeast region.

In the next section, some background information is presented on current DSM/EE/ weatherization programs available within the region. An estimate of DSM/EE potential is presented in the next section, followed by a discussion of the DSM/EE technologies or measures considered, screened, and included in the Southeast Alaska IRP modeling. These are some conclusion comments regarding the effective delivery of DSM/EE programs.

13.3 CURRENT DSM/EE PROGRAMS IN THE SOUTHEAST REGION

Currently, there are a number of demand-side programs offered within the Southeast region by the AHFC, AEA and Rural CAP. These programs are briefly summarized below; more detailed information of these programs is provided in Section 16.0.

- **AHFC**--The AHFC is a self-supporting public corporation with the mission to provide Alaskans access to safe, quality, affordable housing. It offers the following programs:
    - **Energy Improvements Through Weatherization**--The AHFC Weatherization Program offers free energy efficiency improvements to low-income houses State-wide. Under the program, Alaskans with low-to-moderate incomes (up to 100 percent of the median), living in owner-occupied homes, condos, rentals and mobile homes qualify for free weatherization upgrades. The program is operated by several program providers located throughout the State. Residents interested in the program contact the provider nearest to them to participate.
    - **The Home Energy Rebate Program**--The Home Energy Rebate Program (HERP) reimburses homeowners for up to $10,000 of energy efficiency improvements that move the home at least one step higher on the agency's energy rating system.
    - **Appliance Rebates for Qualified Alaskans with Disabilities**--Alaskans with qualified disabilities can apply for the appliance rebate program funded by a $658,000 grant from the federal Department of Energy that is administered by AHFC. The program's goal is to encourage the use of energy-efficient appliances.
    - **5-Star Plus New Construction Energy Rebate**--AHFC offers rebates on newly built, highly efficient homes labeled as 5-Star Plus homes. To qualify for the rebate, the home must be owner-occupied, a primary residence, and must be completed and not occupied for more than 12 months from the date of completion on or after April 5, 2008. In 2010, more than 760 newly constructed homes received a 5-Star Plus rebate of $7,500.
    - **Heating Assistance Program**--This program provides grants to qualifying low income Alaskan residents to help pay a portion of home heating expenses. The grant amount is based on the area of Alaska where the home is located and the type of dwelling, and point values are assigned for heating costs. Fuel or electric companies receive the funds directly for qualified applicants' bills, and grants are not transferable if an applicant moves to another area.
    - **Energy Efficiency Education and Workshops**--The AHFC offers a variety of public education and workshop efforts to assist weatherization assessors, crews, contractors, do-it-yourself homeowners, and the general public with installation techniques, building science, building auditing, energy modeling, combustion safety, moisture control and ventilation, and more.

- **Loan Programs**--AHFC also offers a number of loan programs to encourage energy efficiency, including the following:
  - **Second Mortgage for Energy Conservation**--Homeowners may obtain financing to make energy efficiency improvements in their homes through AHFC's Second Mortgage for Energy Conservation Program. Loans are limited to a maximum of $30,000 and a term of 15 years. For borrowers simultaneously participating in the Home Energy Rebate Program; the rebate received is applied toward the outstanding balance of the mortgage program. In 2010, AHFC reported that the average loan through the program was $19,400.
  - **Energy Efficiency Interest Rate Reduction Program (EEIRR)**--AHFC offers interest rate reductions when financing new or existing energy efficient homes, or when borrowers purchase and make energy improvements to an existing home. Any property that can be energy rated and is otherwise eligible for AHFC financing may qualify for this program. Interest rate reductions apply to the first $200,000 of the loan amount. A loan amount exceeding $200,000 receives a blended interest rate, rounded up to the next one-eighth of one percent (0.125%). The percentage rate reduction depends on whether or not the property has access to natural gas.
  - **Association Loan Program**--Under this program targeting homeowners' associations, the homeowners' association representative submits a proposal directly to AHFC to obtain preliminary approval for common-area improvements. Some examples are roof or siding replacement, window replacement, or driveway improvements. Repayment of the loan is typically made through a pro-rata increase in the monthly dues in order to avoid a special assessment.
  - **Small Building Material Loan**--In this program, borrowers with residential property located in small communities may obtain financing to renovate or complete their property. The project may include repair or renovations that improve the livability of the home, energy efficient upgrades or the addition of living space. Loan funds may be used to purchase building materials (exclusive of luxury items), or pay for freight or third party labor costs. Borrowers must complete renovations within six months (180 days) of loan closing.
  - **Alaska Energy Efficiency Revolving Loan Fund Program**--The Alaska Energy Efficiency Revolving Loan Fund Program provides financing for permanent energy efficient improvements to buildings owned by regional educational attendance areas, by the University of Alaska, by the State, or by municipalities in the State. Borrowers obtain an Investment Grade Audit as the basis for making cost-effective energy improvements, selecting from the list of energy efficiency measures identified. All of the improvements must be completed within 365 days of loan closing.

- **Alaska Energy Authority (AEA)**--The AEA has several programs targeting improvements in energy efficiency at the end user level. Programs include the following:
  - **Commercial Energy Efficiency Audits**--The AEA offers an energy efficiency audit program to assess electrical load, equipment, lighting, thermal, HVAC and other conservation methods in privately owned commercial buildings. AEA will reimburse the cost of a qualifying energy audit up to a limit that is based upon the square footage of the building and the complexity of its heating, ventilation and air conditioning system (between $1,400 and $6,500 per building), plus a $300 auditor travel stipend if applicable.
  - **Commercial Alternative Energy and Energy Efficiency Loans**—The AEA and the Alaska Department of Commerce, Community and Economic Development are currently writing regulations for a new loan fund to support privately owned commercial buildings energy efficiency improvements and alternative energy installations. Loans will be available in 2012.
  - **Village Energy Efficiency Program (VEEP)**--The AEA provides energy efficiency upgrades to public buildings in rural Alaska through the VEEP program. Communities with high cost of energy and colder climates receive services from selected service providers to audit and retrofit cost-effective energy efficiency measures in public buildings. Measures typically include lighting, boiler upgrades, controls (lighting and HVAC), insulation, weather sealing, community efficiency education, and occasionally street lighting and water/wastewater plant improvements. Typically, all measures implemented average a three to four year simple payback, despite the expensive rural delivery and installation costs associated with working in Alaska villages and rural communities. Community annual electricity reductions typically range from 1 to 4 percent with relatively little ($25,000 to $125,000) investment. Heat energy savings are typically greater than the electrical savings.
  - **Whole Village Retrofit Program**--Very similar to VEEP, Whole Village Retrofits are more extensive energy efficiency services provided to communities where deep community measures are needed for a variety of reasons, such as to match community energy load to the power plant's capabilities, to avert either expensive mid-winter fuel deliveries by airplane or the building of a larger fuel storage tanks, to make energy improvements at the same time alternative energy or interties are installed, or simply to demonstrate the power of efficiency when implemented across all public buildings and residences. This program attempts to match timing with weatherization crews or RurAL CAP efforts in communities in order to garner the greatest impact.
  - **Industrial Energy Efficiency Audits for Seafood Processing Plants**--The Alaska seafood industry has not traditionally focused on energy efficiency, yet this industry is energy intensive and employs a large number of residents. The AEA offers a targeted energy audit program for the seafood industry to help identify the potential for savings.
  - **Public Education and Outreach**--The AEA built and continues to develop an interactive web site that serves as a one stop shopping clearinghouse of information about energy efficiency and energy conservation. Alaska Energy Authority leads the coordinated outreach efforts of the Alaska Energy Efficiency Partnership, most notably the Alaska Energy Awareness Month initiatives of 2010 and 2011. AEA is

currently working with a local marketing firm to develop a broad, sustained, comprehensive energy efficiency and energy conservation public awareness marketing campaign.

- **Heat Recovery**--AEA provides grants and/or services to install heat recovery systems for rural diesel power plants in order to capture and utilize the otherwise wasted heat to heat nearby community buildings. In many cases this heat transfer is measured and monetized in order to compensate the utility for the value of the heat, while at the same time offering a reduced cost source of heat for nearby buildings or facilities.
- **Tool Loan Kits**--The AEA offers watt meters, light meters, and ballast checkers, for check-out by Alaskans seeking to assess opportunities for improved efficiency in their homes or workplaces. Additionally, AEA offers full industrial grade self-audit kits, complete with a laptop, analysis software, electrical analysis tools, an infrared camera and other tools and instructions. These are intended for use by electricians at industrial plants, with a current focus on seafood processing plants.
- **Alaska Small Cities Energy Efficiency and Conservation Block Grants**--AEA manages grants with 97 small Alaskan cities and boroughs to identify and install energy efficient equipment in city facilities. While this program is currently funded through the American Recovery and Reinvestment Act (ARRA), AEA is considering continuing the program, and/or blending it with the VEEP program discussed above. The program is successfully installing cost-effective energy efficiency measures across the State through either a service provider model (similar to VEEP), or through cities self-managing their energy audits and retrofits. While the long-term nature of this program is uncertain due to the linkage with ARRA funding, the program is of interest in that it targets whole communities and can be economical for relatively isolated communities. This type of program could be effective to target specific communities in Southeast Alaska.
- **Other Programs and Research**

  End Use Study—WH Pacific is conducting an Energy End Use Study for the AEA. The results of this study will add significantly to the quality and comprehensiveness of information available on how Southeast residential and commercial customers use energy. This information will greatly improve the ability of regional utilities and other entities to develop DSM/EE programs tailored to the specific circumstances of the Southeast region. The study is due to be published at the end of February 2012.

  Needs Assessment: Another current project managed by the AEA is Information Insights' conducting of a State-wide Needs Assessment to determine more effective public education and outreach methods. This project is a largely qualitative data collection effort that will complement the End Use Study data and will shed light on State-wide end user behavior. The forthcoming final report ("Recommendations for Alaska Energy Efficiency and Conservation Public Education and Outreach")will include recommendations on how best to communicate energy efficiency and energy conservation information to various Alaskan audiences in order to most effectively encourage behavior changes that lead to improved energy efficiency and conservation practices. These recommendations may have more relevance in all regions of the State, including the Southeast, than case studies or research from outside. The report will be completed in January 2012.

Policy Report--The AEA is also reassessing State-wide policies, programs, and regulations related to energy efficiency. This project, an update to the 2008 *Energy Efficiency Program and Policy Recommendations Report*, is being written by the Cold Climate Housing Research Center and is expected to be completed by the end of January 2012. Though not specific to the Southeast region, recommendations in this report could potentially lead to State policy changes that will positively affect every region, including Southeast.

Alaska Energy Efficiency Map--AEA is creating a database and geographic information system (GIS) visualization of energy efficiency projects State-wide. This map allows users to view a State-wide map image, a community image, or zoom in to a building aerial view to identify energy efficiency measures that have taken place or that have been identified in that building or buildings. The site will also allow public users to tell their energy efficiency story, successes and failures via text, photographs and YouTube videos. A metrics box calculates the energy and dollar savings and money invested (by source) for the selected geographic area, efficiency programs and timeframe selected by the user. The map was publicly demonstrated in the September 2011, and is expected to become publicly available in the first quarter 2012.

- **RurAL CAP**--Another organization providing selective energy efficiency measures is RurAL CAP. This organization was founded in 1965 and is a private, State-wide, nonprofit organization working to improve the quality of life for low-income Alaskans. Governed by a 24-member Board of Directors representing every region of the State, RurAL CAP is one of the largest and most diversified nonprofit organizations in Alaska. In fiscal year 2010, RurAL CAP employed 1,048 Alaskans in 91 communities State-wide and expended more than $40 million in conjunction with its for-profit subsidiary, Rural Energy Enterprises.

  RurAL CAP's weatherization and rehabilitation programs refurbish older homes to make them warmer and more energy efficient. The program serves one community at a time, rather than many houses in scattered communities. Each community project takes one to three years to complete; the 2009 weatherization communities were Alakanuk, Emmonak, Juneau, Kipnuk, Kivalina, Kwethluk, Nome, Nunam Iqua, St. Michael, and Tununak.

13.4 DSM/EE POTENTIAL IN THE SOUTHEAST REGION

The purpose of this section is to provide an overview of Black & Veatch's estimate of the potential for DSM/EE measures in the Southeast region.

13.4.1 Methodology for Determining Potential

The general approach for developing an estimate of the DSM/EE technical potential consisted primarily of the following three steps:

1. Black & Veatch reviewed the universe of measures that are available in the marketplace to increase energy efficiency. This review included not only the limited DSM/EE program experience in Alaska but also a review of the DSM/EE program experience of other utilities throughout the United States.

2. Black & Veatch eliminated nonelectric energy savings measures since this portion of the study is focused on meeting the demand and energy requirements of the electric utilities within the Southeast region. The nonelectric energy savings resulting from the

implementation of a biomass space heating conversion program is discussed in Section 15.0. At the time of final consideration of energy programming, State and regional energy planners will likely want to re-assess which energy efficiency programs to implement to include efficiency programs that address non-electric (primarily heating/building envelope) measures, as heating costs are typically higher and there is demonstrated substantial non-electric energy efficiency potential.

3. Black & Veatch conducted a cost-effective screening of potential DSM/EE measures, which is discussed below.

13.4.2 DSM/EE Measure Cost-Effectiveness Screening Methodology

A universe of DSM/EE measures exists that provide energy savings over standard products that serve the same end-uses. The majority of these measures are well proven in terms of their impact on electric demand and energy requirements based upon the experience of utilities in other regions of the country. To cull this list, Black & Veatch used a cost-effectiveness screening process to screen measures to identify those that are most appropriate for the Southeast region. The primary objective of this effort was to select the most appropriate measures for further analysis.

There is a considerable range of new products and technology options that are available for energy efficiency and demand reduction applications. Many of these are available today to consumers in the Southeast region, while others are less prevalent or readily available. Black & Veatch examined a broad array of the most relevant technologies and measures for residential and commercial (non-residential) applications, and considered the extent to which each technology and measure makes sense for the Southeast region.

For those measures that are relevant to the Southeast region, Black & Veatch completed a cost-effectiveness screening, using the following three industry-standard DSM/EE cost-effectiveness tests:

- **Total Resource Cost (TRC) Test**--The TRC test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.
- **Ratepayer Impact Measure (RIM) Test**--The RIM test measures what happens to rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. For example, rates would go down if utility costs went down more than revenues did; or conversely, if revenues increased more than utility costs increased. Conversely, rates will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer rates. This test is sometimes referred to as the "No Losers Test." If a measure passes the RIM test, all customers benefit even if they do not participate in the program. If a measure fails the RIM test, a customer must participate in the program to benefit. The ability to participate in a program may be beyond the control of the customer (e.g., renters may not be able to participate since they do not own the property).
- **Participant Test**--The Participant test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer; however, it is difficult to get participation in programs that do not benefit the customer.

Furthermore, Black & Veatch conducted the standard cost-effectiveness tests for three categories of communities, as follows:

- **High Cost Utilities**--This category includes those communities who are dependent upon high cost diesel generation in 2010 and includes the communities of Angoon, Chilkat Valley, Coffman Cove, Elfin Cove, Hoonah, Kake, Klukwan, Pelican, Tenakee Springs, Whale Pass, and Yakutat.
- **Mid Cost Utilities**--This category includes those communities who have access to some low cost hydroelectric generation but have higher costs due to economies of scale and includes the communities of Craig, Gustavus, Haines, Hollis, Hydaburg, Kasaan, Klawock, Naukati Bay, Skagway, and Thorne Bay.
- **Low Cost Utilities**--This category includes those communities who have sufficient low cost hydroelectric generation to meet almost all of their electric demand and includes the communities of Juneau, Ketchikan, Metlakatla, Petersburg, Sitka, and Wrangell.

Black & Veatch did not use the Societal Test, which is similar to the TRC Test but also includes additional societal benefits.

For purposes of the cost-effectiveness screening, Black & Veatch established the criterion that a DSM/EE measure had to pass all three of the standard DSM/EE cost-effectiveness tests. This is both a conservative and restrictive criterion – conservative in that this requirement helps ensure that the specific DSM/EE measures will prove to be cost-effective, and restrictive in that more measures would have passed the cost-effectiveness screen if we had not required a measure to pass all three cost-effectiveness tests. Black & Veatch believes that this is the most appropriate approach given the limited end-use and vendor DSM/EE-related information available at this time, and the region's limited experience with these types of programs. However, it should be noted that additional measures could be implemented if utility decision-makers and regional policy-makers chose to apply a less conservative standard. One point of note is that many measures did not pass the RIM test for the High Cost Utilities. This is because those utilities also have high nonfuel costs and therefore will suffer significant lost revenue due to DSM/EE programs. This issue will need addressing if utility decision-makers and regional policy-makers choose to apply a less conservative standard.

Finally, these cost-effectiveness tests are screening tools and, for the Southeast Alaska IRP, are conducted for a single point in time. As a result, the dynamic inclusion of DSM/EE programs into the Strategist® modeling over time may yield different results relative to cost effectiveness.

13.4.3 DSM/EE Measures Evaluated

This subsection discusses the DSM/EE measures that were subjected to the standard DSM/EE cost-effectiveness tests discussed above. Consistent with standard industry practice, Black & Veatch screened a wide variety of residential and commercial DSM/EE measures as shown in Tables 13-1 and 13-2, respectively. These tables also show the following information for each DSM/EE measure:

- Measure life.
- Estimated kWh savings per customer.
- Estimated kW savings per customer.
- Incremental cost per installation (e.g., the incremental cost incurred to purchase appliance or equipment with higher that standard energy efficiency levels).

Table 13-1 Residential DSM/EE Measures Evaluated

MEASURES				LIFE (YEARS)	ESTIMATED KWH PER CUSTOMER PER YEAR	ESTIMATED KW SAVINGS PER CUSTOMER	COST PER INSTALLATION (2011$)
Residential	Weather	Cooling/ Heating	ASHP - SEER 16	15	41.7	0.633	210.8
			Setback Thermostat - Moderate Setback	9	152.1	0.000	48.4
		Shell	Duct Sealing 20 Leakage Base	18	41.7	0.017	161.5
			Roof Insulation	20	41.7	0.025	503.8
			Ceiling Fans	15	47.8	0.034	173.9
	Non-Weather	Water Heater	Heat Pump Water Heaters	15	2,885.0	0.325	271.4
			Low Flow Showerheads	12	518.0	0.058	52.0
			Pipe Wrap	6	257.0	0.029	2.4
		Appliance	Freezers Energy Star-Chest Freezer	12	46.0	0.008	58.5
			Clothes Dryers	14	144.0	0.035	94.9
			Refrigerators-Freezers Energy Star - Top Freezer	12	79.0	0.013	58.5
			Refrigerators-Freezers Energy Star - Side by Side	12	109.0	0.019	58.5
			Pump and Motor Single Speed	10	694.0	0.357	26.9
			Smart Strip Plug Outlet	5	184.0	0.013	12.7
			Freezer Recycling	6	1,551.0	0.177	375.0
			Refrigerator Recycling	6	1,672.0	0.191	430.0
		Lighting	Holiday Lights	10	10.6	0.000	16.2
			Torchiere Floor Lamps	12	164.0	0.000	10.0
			CFL Fixtures	12	78.0	0.000	28.5
			LED Night Light	12	22.0	0.000	17.3
			CFL Bulbs Regular - Outside	9	191.6	0.000	0.9
			CFL Bulbs Regular	9	44.1	0.000	2.9

Table 13-2 Commercial DSM/EE Measures Evaluated

MEASURES				LIFE	ESTIMATED KWH PER CUSTOMER	ESTIMATED KW PER CUSTOMER	COST PER INSTALLATION ($2011)
Commercial	Weather	Cooling/ Heating	Window Film	10	256.0	0.147	97.3
			Refrigerant Charging Correction	10	712.4	1.014	24.3
			VFD Fan	10	1,185.6	0.008	49.3
			VFD Pump	10	3,959.2	0.345	47.2
	Non-Weather	Water Heater	ENERGY STAR Steam Cookers 3 Pan	12	11,188.0	2.550	1,312.4
			HP Water Heater 10 to 50 MBH	15	21,156.0	4.200	1,265.0
			Pre Rinse Sprayers	5	1,396.0	0.116	11.1
		Office Load	Plug Load Occupancy Sensors Document Stations	5	803.0	0.055	58.5
		Motor	Motors 1 to 5 HP	15	113.3	0.024	108.5
			Motors 7.5 to 20 HP	15	408.4	0.087	168.6
			Motors 25 to 100 HP	15	1,056.0	0.224	377.9
			VFD HP 1.5 Process Pumping	15	1,623.4	0.343	1,370.9
			VFD HP 10 Process Pumping	15	10,713.4	2.286	929.5
			VFD HP 20 Process Pumping	15	21,643.1	4.571	1,452.9
			Pumps HP 1.5	15	302.0	0.064	357.1
			Pumps HP 10	15	2,014.0	0.427	130.0
		Refrigeration	Vending Equipment Controller	5	800.0	0.210	86.8
			Efficient Refrigeration Condenser	15	120.0	0.118	11.1
			ENERGY STAR Commercial Solid Door Freezers (less than 20 ft^3)	12	520.0	0.059	47.4
			ENERGY STAR Commercial Solid Door Freezers (20 to 48 ft^3)	12	507.0	0.058	379.5
			ENERGY STAR Commercial Solid Door Refrigerators (less than 20 ft^3)	12	905.0	0.103	79.1
			ENERGY STAR Commercial Solid Door Refrigerators (20 to 48 ft^3)	12	1,069.0	0.122	316.3
			ENERGY STAR Ice Machines (less than 500 lbs.)	12	1,652.0	0.189	379.5
			ENERGY STAR Ice Machines (500 to 1000 lbs.)	12	2,695.0	0.308	948.8
			ENERGY STAR Ice Machines (more than 1,000 lbs.)	12	6,048.0	0.690	632.5
			Refrigeration Commissioning	3	375.0	0.043	42.9
			Strip Curtains for Walk-ins - Freezer	4	613.0	0.070	88.6

MEASURES				LIFE	ESTIMATED KWH PER CUSTOMER	ESTIMATED KW PER CUSTOMER	COST PER INSTALLATION ($2011)
Commercial	Non-Weather	Lighting	Exterior HID Replacement Above 250W to 400W HID Retrofit	12	706.0	0.000	673.0
			High Bay 3L T5HO Replacing 250W HID	12	449.0	0.103	256.3
			High Bay 4L T5HO Replacing 400W HID	12	882.0	0.200	183.2
			High Bay 6L T5HO Replacing 400W HID	12	374.0	0.086	424.7
			High Bay Fluorescent 6LF32T8 Replacing 400W HID	12	961.0	0.219	81.5
			High Bay Fluorescent 8LF32T8 Double Fixture Replace 1,000W HID	12	2,005.0	0.458	157.4
			CFL Fixture	12	342.0	0.084	25.0
			CFL Screw-in	2	202.0	0.049	9.5
			Daylight Sensor Controls	12	14,800.0	3.819	1,265.0
			Central Lighting Control	12	11,500.0	2.808	2,340.3
			Occupancy Sensors Under 500 W	10	397.0	0.099	91.1
			Low Watt T8 Lamps	12	15.0	0.004	3.9
			3 Lamp T5 Replacing T12	12	99.4	0.024	126.6
			4 Lamp T5HO Replacing T12	12	191.0	0.047	193.6
			HPT8 4ft 3 Lamp, T12 to HPT8	12	145.2	0.036	87.4
			HPT8 4ft 4 Lamp, T12 to HPT8	12	169.7	0.041	93.0
			T12HO 8ft 1 Lamp Retrofit to HPT8 T8 4ft 2 Lamp	12	174.0	0.042	71.7
			T12HO 8ft 2 Lamp Retrofit to HPT8 T8 4ft 4 Lamp	12	293.0	0.072	93.0
			T8 4ft 3 Lamp	12	128.8	0.032	123.5
			T8 4ft 4 Lamp	12	139.8	0.034	131.0
			T8 HO 8 ft 2 Lamp	12	184.0	0.045	143.7
			LED Exit Signs Electronic Fixtures (Retrofit Only)	15	201.0	0.023	38.0

Tables 13-3 and 13-4 provide additional information regarding the input assumptions used in the evaluation of the residential and commercial DSM/EE measures, respectively. This information includes the following:

- Incremental equipment cost.
- Rebate as a percentage of incremental equipment cost.
- Rebate amount.
- Administrative costs.
- Vendor or other costs.
- Total per unit costs.

In addition to the input assumptions shown in Tables 13-2 and 13-3, Black & Veatch estimated how many customers would adopt each technology each year in order to arrive at potential energy savings to be used in the Southeast Alaska IRP modeling. Even though technologies are grouped into one or more program(s) for going to market, the application of a participation rate is done at the measure level. The number of customers available to adopt the technology was based upon the customer counts in each community. From this starting point, a set of technology adoption curves were applied that characterize the pattern of acceptance (or purchase) typical of products at different levels of marketing. For example, a high rebate amount for a product might be expected to achieve a high penetration in the early years, translating into a "steep" curve. On the other hand, a program that merely provides consumers with information about changing their behavior, but offers no monetary incentive, may result in an increase in related participation over time, but at a lower level and slower pace. To estimate maximum penetration rates for purposes of the Southeast Alaska IRP modeling, Black & Veatch used a series of technology adoption curves for DSM/EE studies from the Bass diffusion model. These curves are built from the original "S" shaped curve of product adoption and are a generally-accepted tool for characterizing consumer adoption patterns. Since Alaska is fairly new territory for DSM/EE programs, Black & Veatch assumed that the level of incentives required to move the market to adopt DSM/EE measures would average approximately 45 percent of incremental equipment costs.

Table 13-3 Input Assumptions - Residential DSM/EE Measures

MEASURES				INCREMENTAL EQUIPMENT COST (IEC) ($)*	REBATE AS % OF IEC	REBATE AMOUNT ($)*	ADMINISTRATION COSTS (10%) ($)*	VENDOR OR OTHER COSTS ($)*	TOTAL PER UNIT PROGRAM COSTS ($)*
Residential	Weather	Cooling/Heating	ASHP - SEER 16	337.9	50%	168.9	16.9	25	210.8
Residential	Weather	Cooling/Heating	Setback thermostat - moderate setback	21.2	100%	21.2	2.1	25	48.4
Residential	Weather	Cooling/Heating	Duct sealing 20 leakage base	248.2	50%	124.1	12.4	25	161.5
Residential	Weather	Cooling/Heating	Roof Insulation	870.5	50%	435.2	43.5	25	503.8
Residential	Weather	Cooling/Heating	Furnace-AC - SEER 16	319.5	50%	159.8	16.0	25	200.7
Residential	Non-Weather	Cooling/ Heating	Ceiling Fans	316.3	50%	158.1	15.8		173.9
Residential	Non-Weather	Water Heater	Heat Pump Water Heaters	805.0	25%	201.3	20.1	50	271.4
Residential	Non-Weather	Water Heater	Low Flow Showerheads	36.3	100%	36.3	3.6	12	52.0
Residential	Non-Weather	Water Heater	Pipe Wrap	8.7	25%	2.2	0.2	0	2.4
Residential	Non-Weather	Appliance	Freezers ENERGY STAR-Chest Freezer	106.4	50%	53.2	5.3	0	58.5
Residential	Non-Weather	Appliance	Clothes Dryers	172.5	50%	86.3	8.6	0	94.9
Residential	Non-Weather	Appliance	Clothes Washer ENERGY STAR, Electric Water Heater, Electric Dryer	276.0	50%	138.0	13.8	0	151.8
Residential	Non-Weather	Appliance	Refrigerators-Freezers ENERGY STAR - Top Freezer	106.4	50%	53.2	5.3	0	58.5
Residential	Non-Weather	Appliance	Refrigerators-Freezers ENERGY STAR - Side by Side	106.4	50%	53.2	5.3	0	58.5
Residential	Non-Weather	Appliance	Pump and Motor Single Speed	97.8	25%	24.4	2.4	0	26.9
Residential	Non-Weather	Appliance	Smart Strip Plug Outlet	46.0	25%	11.5	1.2	0	12.7
Residential	Non-Weather	Appliance Turn In	Freezer Recycling	107.0	0%	0.0	0.0	375	375.0
Residential	Non-Weather	Appliance Turn In	Refrigerator Recycling	107.0	0%	0.0	0.0	430	430.0
Residential	Non-Weather	Lighting	Holiday Lights	13.8	100%	13.8	1.4	1	16.2
Residential	Non-Weather	Lighting	Torchiere Floor Lamps	57.5	0%	0.0	0.0	10	10.0
Residential	Non-Weather	Lighting	CFL Fixtures	51.8	50%	25.9	2.6	0	28.5
Residential	Non-Weather	Lighting	LED Night Light	5.8	100%	5.8	0.6	11	17.3
Residential	Non-Weather	Lighting	CFL Bulbs Regular - Outside	3.5	25%	0.9	0.1		0.9
Residential	Non-Weather	Lighting	CFL Bulbs Regular	3.5	25%	0.9	0.1	2	2.9

* All amounts in 2011 dollars

Table 13-4 Input Assumptions - Commercial DSM/EE Measures

MEASURES				INCREMENTAL EQUIPMENT COST (IEC) ($) *	REBATE AS % OF IEC	REBATE AMOUNT ($) *	ADMINISTRATION. COSTS (10%) ($)*	VENDOR OR OTHER COSTS ($)*	TOTAL PER UNIT PROGRAM COSTS ($)*
Residential	Weather	Cooling/Heating	Window Film	176.9	50%	88.4	8.8	0	97.3
			Refrigerant Charging Correction	44.1	50%	22.1	2.2	0	24.3
			VFD Fan	179.3	25%	44.8	4.5	0	49.3
			VFD Pump	171.5	25%	42.9	4.3	0	47.2
			Water-Cooled Centrifugal Chiller<150ton 0.56 kW/ton w/0.53 kW/ton IPLV	191.0	50%	95.5	9.6	0	105.1
			Setback/Setup	163.3	25%	40.8	4.1	0	44.9
	Non-Weather	Water Heater	ENERGY STAR Steam Cookers 3 Pan	4,772.5	25%	1,193	119.3	0	1,312
			HP Water Heater 10 to 50 MBH	4,600.0	25%	1,150	115.0	0	1,265
			Pre Rinse Sprayers	40.3	25%	10.1	1.0	0	11.1
			Clothes Washer CEE Tier1, Electric Water Heater, Electric Dryer	399.1	50%	199.5	20.0	0	219.5
		Office Load	Plug Load Occupancy Sensors Document Stations	212.8	25%	53.2	5.3	0	58.5
		Motor	Motors 1 to 5 HP	101.2	75%	75.9	7.6	25	108.5
			Motors 7.5 to 20 HP	261.1	50%	130.5	13.1	25	168.6
			Motors 25 to 100 HP	641.7	50%	320.9	32.1	25	377.9
			VFD HP 1.5 Process Pumping	1,661.8	75%	1,246	124.6	0	1,371
			VFD HP 10 Process Pumping	3,289.0	25%	822.3	82.2	25	929.5
			VFD HP 20 Process Pumping	5,192.3	25%	1,298	129.8	25	1,453
			Pumps HP 1.5	402.5	75%	301.9	30.2	25	357.1
			Pumps HP 10	381.8	25%	95.5	9.5	25	130.0

MEASURES				INCREMENTAL EQUIPMENT COST (IEC) ($) *	REBATE AS % OF IEC	REBATE AMOUNT ($) *	ADMINISTRATION. COSTS (10%) ($)*	VENDOR OR OTHER COSTS ($)*	TOTAL PER UNIT PROGRAM COSTS ($)*
Residential	Non-Weather	Refrigeration	Vending Equipment Controller	224.8	25%	56.2	5.6	25	86.8
			Efficient Refrigeration Condenser	40.3	25%	10.1	1.0	0	11.1
			ENERGY STAR Commercial Solid Door Freezers (less than 20 ft³)	172.5	25%	43.1	4.3	0	47.4
			ENERGY STAR Commercial Solid Door Freezers (20 to 48 ft³)	460.0	75%	345.0	34.5	0	379.5
			ENERGY STAR Commercial Solid Door Refrigerators (less than 20 ft³)	287.5	25%	71.9	7.2	0	79.1
			ENERGY STAR Commercial Solid Door Refrigerators (20 to 48 ft³)	575.0	50%	287.5	28.8	0	316.3
			ENERGY STAR Ice Machines (less than 500 lbs.)	690.0	50%	345.0	34.5	0	379.5
			ENERGY STAR Ice Machines (500 to 1,000 lbs.)	1,725.0	50%	862.5	86.3	0	948.8
			ENERGY STAR Ice Machines (more than 1000 lbs.)	2,300.0	25%	575.0	57.5	0	632.5
			Refrigeration Commissioning	130.0	30%	39.0	3.9	0	42.9
			Strip Curtains for Walk-ins - Freezer	230.0	35%	80.5	8.1	0	88.6

MEASURES				INCREMENTAL EQUIPMENT COST (IEC) ($) *	REBATE AS % OF IEC	REBATE AMOUNT ($) *	ADMINISTRATION. COSTS (10%) ($)*	VENDOR OR OTHER COSTS ($)*	TOTAL PER UNIT PROGRAM COSTS ($)*
Residential	Non-Weather	Lighting	Exterior HID Replacement Above 250W to 400W HID Retrofit	1,223.6	50%	611.8	61.2	0	673.0
			High Bay 3L T5HO Replacing 250W HID	319.2	73%	233.0	23.3	0	256.3
			High Bay 4L T5HO Replacing 400W HID	333.0	50%	166.5	16.7	0	183.2
			High Bay 6L T5HO Replacing 400W HID	514.7	75%	386.1	38.6	0	424.7
			High Bay Fluorescent 6LF32T8 Replacing 400W HID	296.2	25%	74.1	7.4	0	81.5
			High Bay Fluorescent 8LF32T8 Double Fixture Replace 1,000W HID	572.2	25%	143.1	14.3	0	157.4
			CFL Fixture	90.8	25%	22.7	2.3	0	25.0
			CFL Screw in	34.7	25%	8.7	0.9	0	9.5
			Daylight Sensor Controls	4,600.0	25%	1,150	115.0	0	1,265
			Central Lighting Control	4,255.0	50%	2,128	212.8	0	2,340
			Occupancy Sensors Under 500 W	165.6	50%	82.8	8.3	0	91.1
			Low Watt T8 Lamps	7.2	50%	3.6	0.4	0	3.9
			3 Lamp T5 Replacing T12	230.2	50%	115.1	11.5	0	126.6
			4 Lamp T5HO Replacing T12	352.0	50%	176.0	17.6	0	193.6
			HPT8 4ft 3 Lamp, T12 to HPT8	158.9	50%	79.4	7.9	0	87.4
			HPT8 4ft 4 Lamp, T12 to HPT8	169.1	50%	84.6	8.5	0	93.0
			T12HO 8ft 1 Lamp Retrofit to HPT8 T8 4ft 2 Lamp	130.4	50%	65.2	6.5	0	71.7
			T12HO 8ft 2 Lamp Retrofit to HPT8 T8 4ft 4 Lamp	169.1	50%	84.6	8.5	0	93.0
			T8 4ft 3 Lamp	149.7	75%	112.3	11.2	0	123.5
			T8 4ft 4 Lamp	158.8	75%	119.1	11.9	0	131.0
			T8 HO 8 ft 2 Lamp	174.1	75%	130.6	13.1	0	143.7
			LED Exit Signs Electronic Fixtures (Retrofit Only)	69.0	50%	34.5	3.5	0	38.0

* All amounts in 2011 dollars

13.4.4 Results of DSM/EE Measures Cost-Effectiveness Screening

Figures 13-1 through 13-3 graphically show the results of the cost-effectiveness screening, as follows:

- Figure 13-1 – High Cost Utilities
- Figure 13-2 – Mid Cost Utilities
- Figure 13-3 – Low Cost Utilities

Each graphic shows the results of the three cost-effectiveness tests for each residential and commercial DSM/EE measure considered. The circled DSM/EE measures are those that pass all three of the cost-effectiveness tests.

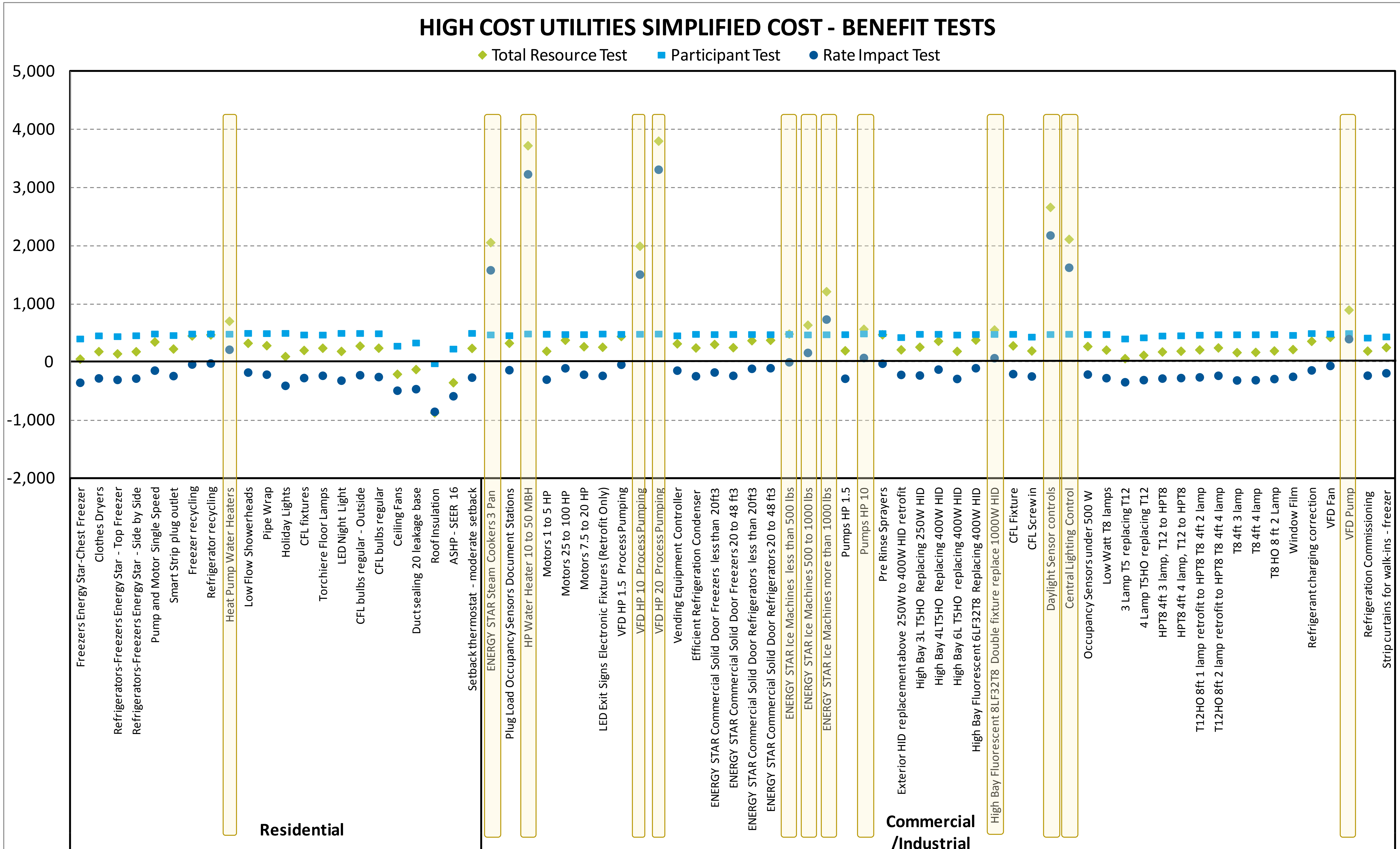


Figure 13-1 **DSM/EE Cost-Effectiveness Screening Results – High Cost Utilities**

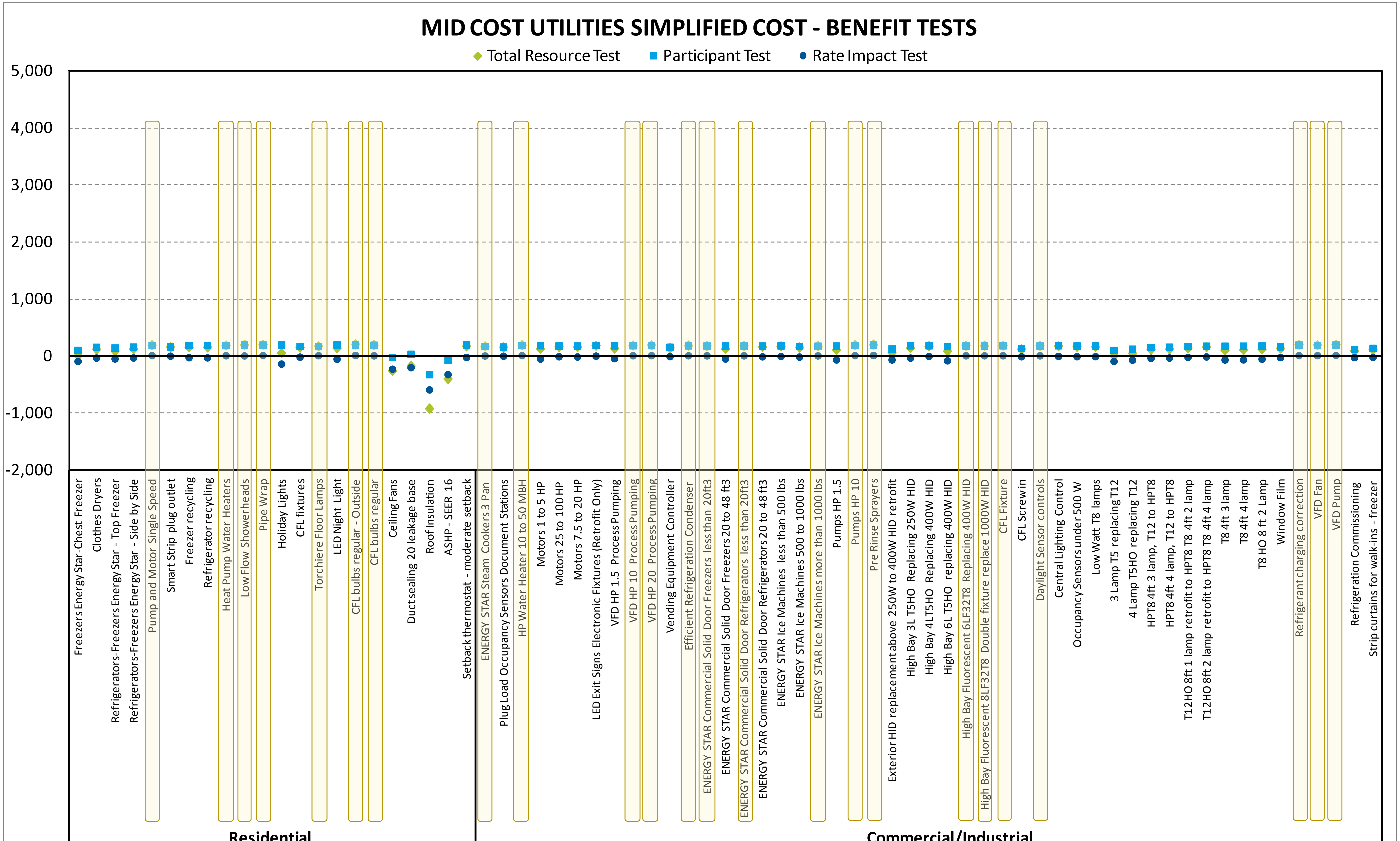


Figure 13-2 DSM/EE Cost-Effectiveness Screening Results – Mid Cost Utilities

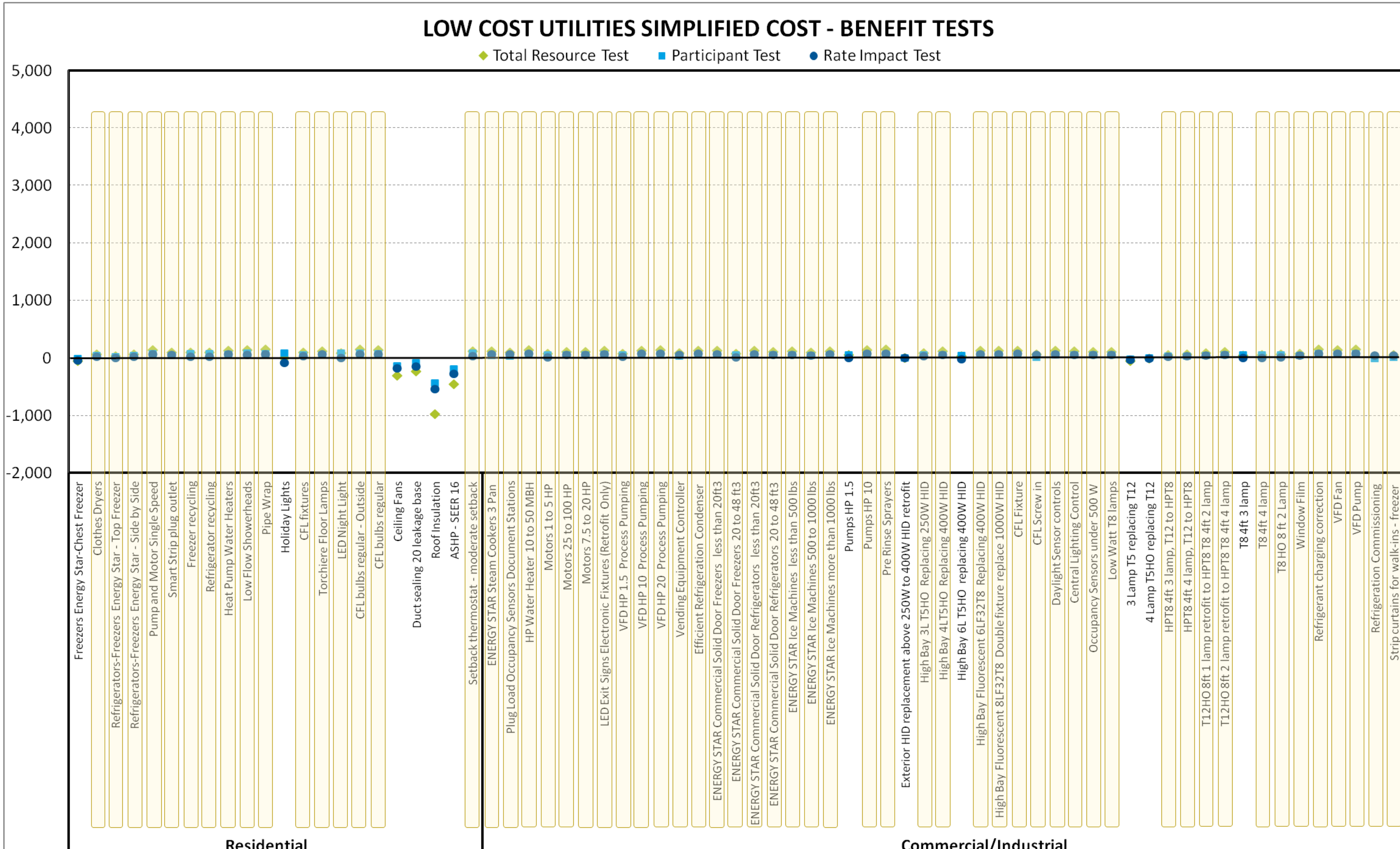


Figure 13-3 DSM/EE Cost-Effectiveness Screening Results – Low Cost Utilities

13.4.5 Program Design Process

Once this initial cost-effectiveness screening was completed, Black & Veatch then grouped similar, or related, DSM/EE measures that passed the cost-effectiveness screening into potential DSM/EE programs that were further evaluated within the Southeast Alaska IRP models. The programs are presented in Table 13-5. This approach is consistent with the approach typically used by utilities to develop DSM/EE programs, as shown on Figure 13-4.

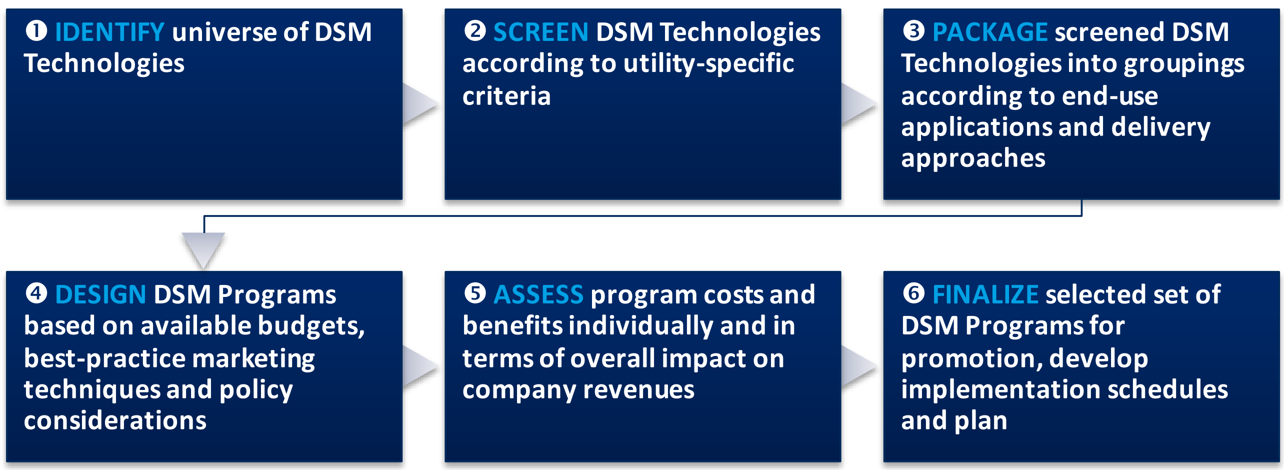


Figure 13-4 Common DSM/EE Program Development Process

Table 13-5 DSM/EE Programs

CATEGORY	SECTOR	PROGRAM	MEASURES
High Cost Utilities	Residential	Water Heater	Heat Pump Water Heaters
	Commercial/ Industrial	Water Heater	ENERGY STAR Steam Cookers 3 Pan HP Water Heater 10 to 50 MBH
		Motor	VFD HP 10 Process Pumping VFD HP20 Process Pumping Pump HP 10
		Refrigeration	ENERGY STAR Ice Machines (less than 500 lbs.) ENERGY STAR Ice Machines (500 to 1000 lbs.) ENERGY STAR Ice Machines (more than 1000 lbs.)
		Lighting	High Bay Fluorescent 8LF32T8 Double Fixture Replace 1000W HID Daylight Sensor Controls Central Lighting Control
		Cooling/ Heating	VFD Pump
Medium Cost Utilities	Residential	Appliance	Pump and Motor Single Speed
		Water Heater	Heat Pump Water Heaters Low Flow Showerheads Pipe Wrap
		Lighting	Torchiere Floor Lamps CFL Bulbs Regular - Outside CFL Bulbs Regular
	Commercial/ Industrial	Water Heater	ENERGY STAR Steam Cookers 3 Pan HP Water Heater 10 to 50 MBH Pre Rinse Sprayers
		Motor	VFD HP 10 Process Pumping VFD HP 20 Process Pumping Pumps HP 10
		Refrigeration	Efficient Refrigeration Condenser ENERGY STAR Commercial Solid Door Freezers (less than 20 ft^3) ENERGY STAR Commercial Solid Door Refrigerators (less than 20 ft^3) ENERGY STAR Ice Machines (more than 1000 lbs.)

CATEGORY	SECTOR	PROGRAM	MEASURES
		Lighting	High Bay Fluorescent 6LF32T8 Replacing 400 W HID High Bay Fluorescent 8LF32T8 Double Fixture Replace 1000W HID CFL Fixture Daylight Sensor Controls
		Cooling/Heating	Refrigerant Charging Correction VFD Fan VFD Pump
Low Cost Utilities	Residential	Appliance	Clothes Dryers Refrigerators-Freezers Energy Star Top Freezer Refrigerators-Freezers Energy Star Side by Side Pump and Motor Single Speed Smart Strip Plug Outlet Freezer Recycling Refrigerator Recycling
		Water Heater	Heat Pump Water Heaters Low Flow Showerheads Pipe Wrap
		Lighting	CFL Fixtures Torchiere Floor Lamps LED Night Light CFL Bulbs Regular - Outside CFL Bulbs Regular
		Cooling/Heating	Setback Thermostat - Moderate Setback
	Commercial/ Industrial	Water Heater	ENERGY STAR Steam Cookers 3 Pan HP Water Heater 10 to 50 MBH Pre Rinse Sprayers
		Office Load	Plug Load Occupancy Sensors Document Stations
		Motor	Motors 1 to 5 HP Motors 25 to 100 HP Motors 7.5 to 20 HP VFD HP 1.5 Process Pumping VFD HP 10 Process Pumping VFD HP 20 Process Pumping Pumps HP 10

CATEGORY	SECTOR	PROGRAM	MEASURES
		Lighting	LED Exit Signs Electronic Fixtures (Retrofit Only) High Bay 3L T5HO Replacing 250 W HID High Bay 4L T5HO Replacing 400W HID High Bay Fluorescent 6LF32T8 Replacing 400 W HID High Bay Fluorescent 8LF32T8 Double Fixture Replace 1000W HID CFL Fixture CFL Screw in Daylight Sensor Controls Central Lighting Control Occupancy Sensors Under 500 W Low Watt T8 Lamps HPT8 4 ft 3 Lamp, T12 to HPT8 HPT8 4 ft 4 Lamp, T12 to HPT8 T12HO 8ft 1 Lamp Retrofit to HPt8 T8 4ft 2 Lamp T12HO 8ft 2 Lamp Retrofit to HPT8 T8 4 ft 4 Lamp T8 4ft 4 Lamp T8 HO 8 ft 2 Lamp
		Refrigeration	Vending Equipment Controller Efficient Refrigeration Condenser ENERGY STAR Commercial Solid Door Freezers (less than 20 ft^3) ENERGY STAR Commercial Solid Door Freezers (20 to 48 ft^3) ENERGY STAR Ice Machines (less than 500 lbs.) ENERGY STAR Ice Machines (500 to 1000 lbs.) ENERGY STAR Ice Machines (more than 1000 lbs.) Refrigeration Commissioning Strip Curtains for Walk-ins - Freezer
		Cooling/Heating	Window Film Refrigeration Charging Correction VFD Fan VFD Pump

Typically, utilities develop detailed DSM/EE program plans for each program selected for implementation. These DSM/EE program plans commonly include the following elements:

- **Detailed description of the program**--Derived from best practices from various sources.
- **Reasons why the program would be successful in the utility's service territory**--Derived from a comprehensive market assessment and background research.
- **Number of customers within the customer class/segment that are likely to adopt/use the proposed program**--Derived from market assessments and surveys, with a percent or modeled participation estimate based on experience from other utilities with similar programs; informed by actual results from other utilities offering similar programs.
- **Achievable energy savings**--From a variety of sources, consistent with a utility-specific technology assessment and published reports.
- **Marketing plans that should include incentives, rebates, and preferred distribution channels and how each reduces existing barriers to proposed program adoption/acceptance**--Based on best practices from a variety of sources; incentive amounts based on examples from other companies.
- **Detailed budget plans complete with explanations of anticipated increases/decreases in financial and human resources during the expected life of the program**--Based on best practices from a variety of sources, over a designated time period for the program life.
- **Recommended methodology or tracking tools for recording actual performance to budget**--Based on current standard practice using simple commercially available software.
- **Proposed program evaluations and reports**--Based on current standard monitoring and evaluation practices using a logic-based model approach.

The resulting impacts of the DSM/EE programs were used to modify the Reference Case Load Forecast, and are reflected in the Low Case Load Forecast for each subregion. This process and the resulting load impacts are described in Section 8.0.

13.4.6 Achievable DSM Potential from Other Studies

There are several organizations that have estimated the potential for energy savings on a regional and State-wide basis in recent years; most notably Electric Power Research Institute (EPRI) and the Edison Electric Institute (EPRI/EEI), and the American Council for an Energy Efficient Economy (ACEEE). None of these studies, however, specifically examined Alaska. However, one study by the Energy Efficiency Task Force of the Western Governor's Association (WGA) was conducted under the Clean and Diversified Energy Initiative and published in January 2006. The states included in the study were Alaska, Arizona, California, Colorado, Hawaii, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming. The study estimates achievable potential for three years (2010, 2015, and 2020) at 7, 14, and 20 percent, respectively.

The EPRI/EEI Assessment looked at the amount of energy savings deemed to be achievable in each of three time periods by sector and end use. The top 10 end uses did not vary considerably by region, and are shown on Figure 13-5 for the Western Census Region, which includes Alaska.

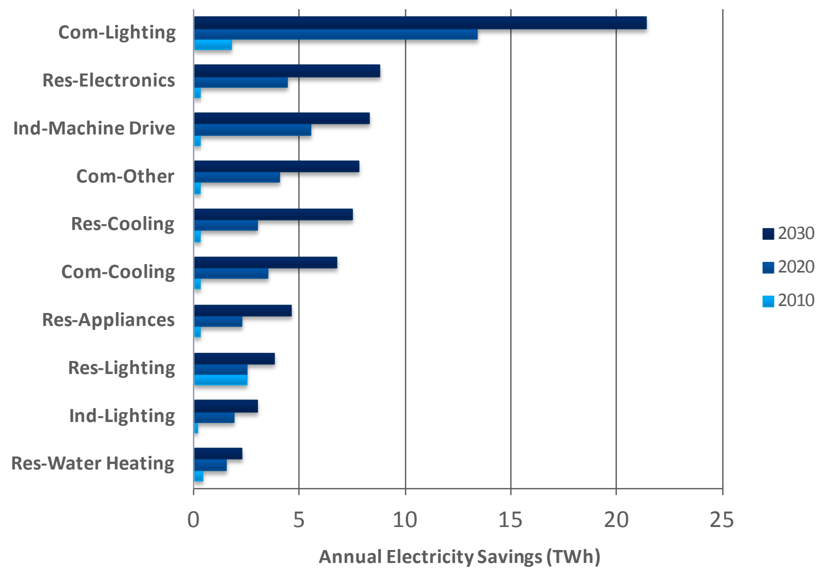


Figure 13-5 EPRI/EEI Assessment: West Census Region Results

These studies all provide comparative "top down" estimates from which to gauge the reasonableness of the estimates that Black & Veatch has derived from a "bottom up" assessment of DSM/EE potential in the Southeast region.

13.5 DSM/EE PROGRAM DELIVERY

As will be discussed in Sections 17.0, 20.0 and 21.0, the Preferred Resource Lists for each subregion includes an aggressive expansion of DSM/EE programs as part of the future energy solution. The successful implementation of these resources, however, is dependent on several factors. In addition to developing detailed DSM/EE program plans, the following actions should be taken:

- Leverage the AEA's State-wide residential and commercial end-use saturation survey that is currently underway. The purpose of this survey is to gather more detailed SE Alaska-specific information on how residential and commercial customers use energy, which will greatly enhance efforts to develop targeted DSM/EE programs that will be successful.
- Add staff with the required DSM/EE-related skills and experience, either within a regional entity or at individual utilities.
- Conduct residential and commercial customer attitudinal surveys. The information gathered from these surveys will help: 1) identify the elements of DSM/EE programs (e.g., level of rebates offered for weatherization and the purchase of high efficient appliances/equipment) necessary to incent residential and commercial customers to make these types of investments, and 2) help regional utilities develop targeted educational and marketing campaigns.

- Complete a market and economic potential study, based upon the results of the AEA State-wide residential and commercial end-use saturation survey, which will result in a more definitive estimate of the economic market potential for DSM/EE programs in the region.
- Conduct trade ally surveys and training/certification programs, to identify willing vendors and ensure that they are adequately trained and certified to install weatherization measures and high-efficiency equipment. The region will not be successful without the active involvement of trained trade allies.
- Develop a regional DSM/EE program measurement and evaluation (M&E) protocol.
- Develop a start-up advertising program.
- Aggressively pursue available Federal funding for DSM/EE programs and renewable projects.

It should be noted that the Southeast region can learn from the lessons of others with regard to the development and execution of a comprehensive DSM/EE program. Many regions of the country, as well as other countries, have been delivering DSM/EE programs for a number of years; some utilities have been implementing DSM/EE programs for 30 years. Consequently, there are many “lessons learned” and the region should do everything it can to take advantage of this experience.

14.0 Weatherization

14.1 COST-EFFECTIVENESS

Weatherization activities offer the region the opportunity to significantly reduce heating costs. These activities include numerous items such as the following:

- Wall, ceiling, and floor insulation.
- Moisture barriers for walls and ceiling.
- Caulking and weatherproofing.
- Energy efficient doors and windows.
- Wall switch and electric socket insulation.
- Roofing material and coloring.
- Duct leakage and insulation.
- Ventilation.

Many of these items are directly related to the quality and integrity of the building and, in essence, go beyond mere energy reduction to actual structure improvements. As such, it is difficult to isolate the costs associated with energy reduction from the costs associated with building improvement.

The region has several existing weatherization and weatherization-related programs in place. Most of these programs are discussed in Sections 13.3 and 16.7, and those discussions are not repeated here. Of these programs, the Alaska Housing Finance Corporation (AHFC) Weatherization Program is probably the most substantial and comprehensive. In 2010, the AHFC Weatherization Program incurred costs per residence that ranged from $11,000 for homes in communities on the road system to $30,000 in remote areas. While these costs are supposed to be just for weatherization, as stated above, there is a thin line between weatherization and general home improvement. There are many variables determining the percent age of savings due to weatherization. For example, the worse the shell of building, the percentage of savings is higher, and the more measures included, the percentage of savings is higher. While it is difficult to determine an average or consensus percentage of savings, many sources indicate the percentage of savings for space heating from weatherization is approximately 30 percent. Another variable is the annual space heating load. As stated elsewhere in this study, the quality of end-use data available for this study is poor. For electric space heating, information developed in conducting the load forecasts indicates that space heating loads are likely between 7.5 and 15 MWh annually for an average weather year per residential customer. With the weatherization costs ranging from $11,000 to $30,000 and the space heating load ranging from 7.5 MWh to 15 MWh annually, the cost of the energy saved ranges from $186/MWh to $1,016/MWh using the 30-year fixed charge rate presented in Section 6.0.

For comparison, the costs for the 10 MW generic hydro project are $135/MWh and the cost for diesel generation is $255 as presented in Section 11.0. Thus, in general, it can be concluded that weatherization is not always cost effective in the Southeast. Weatherization is more cost effective for the communities with high costs. For instance, the highest cost retail rate in Table 16-8 before the application of the PCE is $640/MWh. One advantage of weatherization is that once the weatherization measures are conducted, the savings by and large continue, with some continuing for the entire life of the structure. This is especially cost effective compared to diesel generation, which will continue to increase as the price of oil escalates, but is less so compared to hydro, which also does not escalate appreciably.

While savings from weatherization are certainly achievable, they are not as easy to obtain as the savings from other alternatives addressed in the Integrated Resource Plan (IRP) such as biomass space heating, other demand-side management/energy efficiency (DSM/EE) measures, and hydro generation. To increase the cost effectiveness of weatherization, the weatherization program needs to be applied on a case-by-case basis. The program needs to have experienced weatherization experts evaluate each residence and determine which weatherization measures are cost effective to apply. In this manner, weatherization is ensured to be cost effective, although the percentage of savings will decrease.

14.2 OTHER FORMS OF SPACE HEATING

One advantage of weatherization is that space heating savings occur regardless of the fuel used. The same percentage of savings will occur whether the space heating fuel is electricity, oil, or biomass. While the percentage of energy saved will be the same, the cost effectiveness of weatherization will generally decrease with oil or biomass. Resistance space heating with oil is more expensive than with electricity generated by hydro, but is less expensive than electricity generated by diesel. Biomass space heating is lower in cost than either electric resistance space heating with hydro (obviously including the capital cost for new hydro units) and with oil. Nevertheless as with electric space heating, there are opportunities for specific measures to be cost-effective when applied to specific structures.

14.3 COMMERCIAL AND INDUSTRIAL FACILITIES

The vast majority of the existing program effort on weatherization is applied to residential buildings. The opportunities for weatherization savings are generally less for commercial and industrial facilities than for residential. This stems from the generally greater ratio of volume to shell area for commercial and industrial facilities than residential facilities. In general, the heating load per square foot is less for commercial and industrial facilities partly due to above ratio and partly due to other heat loads in the commercial and industrial facilities. Of course there can be and are exceptions to these generalities, such as commercial facilities that have a high level of door openings. Commercial and industrial facilities do offer advantages relative to economies of scale in the implementation of weatherization measures. Like residential facilities, specific analysis of individual commercial and industrial facilities will ensure that weatherization measures are applied in a cost-effective manner.

14.4 PROGRAM IMPLEMENTATION

Historically, weatherization programs in the Southeast have not made a major impact in reducing costs for the region as a whole. When the economics of weatherization are closely examined, it becomes apparent that while weatherization can be cost effective, there are other initiatives that are more cost-effective for the region. Nevertheless, it is Black & Veatch's observation in visiting many of the communities in the Southeast that additional weatherization can reduce energy requirements in a cost-effective manner.

While weatherization is not the most cost-effective method of reducing energy costs for the region, weatherization is by far the most organized initiative in the Southeast for reducing energy costs. For this reason, Black & Veatch is not proposing the development of entirely new initiatives, but recommends that the existing programs be improved and utilized to reduce energy consumption for space heating. Black & Veatch is not proposing that new funds be provided at this time, but upon completion of AEA's Energy End Use Data Collection Project when quality data becomes available, the issue should be reevaluated. Black & Veatch is assuming that the current funding for the programs will be adequate. Black & Veatch recommends that the following be addressed:

- Most of the weatherization programs are tailored for low income households. These income thresholds limit the availability and consideration should be given to increasing the thresholds.
- Black & Veatch has observed that there are shortages in many of the subregions of qualified auditors and contractors. The programs should increase emphasis on staffing these areas.
- The same shortage of auditors and contractors affects the customers that are not eligible for the programs, but may have the economic means to pay for weatherization measures. The programs should make auditors and contractors available to customers that are not eligible for the programs.
- The programs are primarily directed towards residential customers. The programs should also address commercial and industrial customers. This is the one area that may require additional funding because it is generally beyond the scope of the existing programs.
- Finally, the marketing efforts for the programs should be increased to make customers aware of the programs and the benefits that can be obtained by them.

15.0 Space Heating Conversion

15.1 INTRODUCTION

Space heating costs represent a major portion of residential, commercial, and industrial energy expenditures in Southeast Alaska. Historically most of the space heating has used fuel oil. When oil prices increased significantly in 2008 and again in 2010 and 2011, many customers in areas with low-cost hydroelectric generation converted to electric heat. This conversion significantly increased electric loads consuming excess hydroelectric generation resources and, in some cases, resulted in the operation of diesel generation when water levels of the hydroelectric projects dropped to unacceptable levels. The significant increase in electric loads also often strains other parts of the utility system, including transformer capacity. In most instances the increase in electric loads occurred very rapidly.

Southeast Alaska lacks adequate data on electric loads and end-uses, as well as on space heating using other sources, to accurately forecast electric loads and consumption of other fuels for space heating. This lack of data also limits the ability to forecast conversion between different means of space heating. However, within these limitations, Black & Veatch has endeavored to forecast space heating loads and evaluate conversion alternatives to reduce space heating costs in Southeast Alaska. This section presents the results of the forecasts and evaluations, consistent with the directional nature of this IRP relative to space heating issues considering the high level of uncertainty in the forecasts and evaluations while the Southeast develops better data for such forecasts and evaluations. One initiative to improve the quality of data is AEA's Energy End Use Data Collection Project which is currently underway and scheduled to be completed in the first quarter of 2012.

15.2 ELECTRIC SPACE HEATING

15.2.1 Existing Electric Space Heating Loads

Black & Veatch estimated the existing electric space heating loads as part of the load forecasts presented in Section 8.0. Black & Veatch's considerations relative to those estimates are discussed in that section. Most of the utilities with hydroelectric generation have either a flat rate structure or a declining block rate structure which has contributed to their customers' decisions to convert to electric heat. Some utilities have special rates or incentives, such as interruptible rates or special heat rates, to encourage electric heat. Only the City of Sitka Electric Department has a requirement that customers converting to electric heat must maintain an alternate source of heat.

The most common methods of electric heat used by customers are electric boilers and electric baseboard heating. The electric boilers can generally directly replace oil fueled boilers and are more expensive in general than the electric baseboard heaters, which are relatively inexpensive to install. Relatively few homes have duct systems, and thus, there are few electric resistance forced-air systems and air source heat pump systems. Typical air source heat pump systems lose efficiency rapidly at temperatures below 30˚ F. Heat pump systems that operate in a heating only mode are now being developed that can operate efficiently down to 0˚ F. Ground source heat pumps are relatively unaffected by air temperature, but are extremely expensive resulting in very few being installed. The heat pump systems operate much more efficiently than the resistance heating systems. The increase in efficiency is generally in the range of a factor of three corresponding to a Coefficient of Performance (COP) of around 3. On the other end of the scale, portable space heaters are very inexpensive and used by many customers. The portable space heaters are often used in a supplemental role with oil heat. For existing commercial customers with electric heat, electric boilers represent the most common type of heat. The penetration of commercial customers with electric heat is generally quite a bit lower than for residential customers.

In addition to the broad variance in the size and type of housing, the type of electric heat installed also varies and the resulting heating load per customer varies widely. This variance is even more pronounced for commercial customers. Variance in weather conditions also causes a tremendous variance in loads and makes determining loads for normal weather conditions very difficult. The significant use of portable space heaters and the use of baseboard heaters in residences that maintain their existing oil boilers subject the electric system to the potential of significant loss of load if oil prices decline.

15.2.2 Forecast Electric Space Heating Loads

Black & Veatch projected future electric space heating loads as presented in Section 8.0. The price of oil drives the amount of space heating load converted from oil to electric. Customer response is difficult to determine without detailed attitudinal surveys and studies which are beyond the scope of this IRP. After the surveys and studies have been completed, there may still be considerable uncertainty. Customer options have a significant range of customer costs associated with them from the minor costs of portable space heaters to the significant costs of electric boilers. The perceived future price of oil will need not only to offset the electric energy price, but will also overcome the customer cost for conversion with an acceptable payback period. The depressed economic situation for many of the customers in the Southeast also has a detrimental effect on conversion. It may be economical for a customer to convert to electricity, but they simply may not have the money for the conversion. These issues make accurate forecasting of conversion to electrical space heating very difficult and uncertain. The thresholds of oil price that result in conversion based on the experience of the utilities are discussed in the load forecasts in Section 8.0, but even these thresholds will change through time and with greater electric space heat conversion.

Nevertheless, in spite of the uncertainty, Black & Veatch has projected electric loads for the utilities incorporating electric heat conversion recognizing the attendant uncertainty in the forecasts. This IRP uses the fuel price projections based on Institute of Social and Economic Research (ISER) projections presented in Section 5.0. Fuel costs in 2010 and 2011 have generally exceeded the 2012 medium projections resulting in significant electric heat conversion for utilities with low rates. In general, Black & Veatch has assumed that these higher costs will decrease back to the medium projections generally in the 2012 and 2013 time frame. As a result, the Reference Scenario Load Forecast projections included significant electric heat conversion in the 2010 to 2012 time frame, after which continued electric heat conversions will be nominal. Section 15.4 further addresses comparisons between oil and electric heating costs. While the return to lower oil prices appears to be a reasonable assumption, events that could lead to higher oil prices and greater electric heat conversion are certainly possible.

To provide some additional insight to the upper end of this exposure to greater electric heat conversion, Black & Veatch has estimated the additional electric load if all oil space heating converts to electric. These estimates are based on the projections of oil space heat presented in Section 15.5 and, therefore, have a very high level of uncertainty as discussed in Section 15.3. Figures 15-1 through 15-8 present the Reference Scenario Load Forecast including these estimates of all oil space heating converted to electric for each of the subregions along with the High Scenario Load Forecast. Figures 15-1 through 15-8 indicate that, in general, the Southeast still has significant potential exposure for conversion of oil space heating to electric space heating if the price of electricity is low enough to make the conversion economical for the customers. Figures 15-1 through 15-8 generally show that the potential exposure to electric space heating conversion is covered by the High Scenario Load Forecast at some point during the planning period for the utilities that have low cost hydroelectric generation and have already had significant conversions to electric space heating. However, for the subregions that do not have low cost hydroelectric generation and, therefore, have not already had conversions to electric space heating, the potential conversion generally significantly exceeds the High Scenario Load Forecast and remains an issue to be considered if low cost hydroelectric generation is brought to the region either by transmission interconnection or through the construction of low cost hydroelectric generation.

15.3 OIL SPACE HEATING

Oil has traditionally been the main source of space heating in the Southeast. Generally two forms of oil space heating are used. The first is oil fired boilers, and the second is monitor oil stoves. There is relatively little data available in the Southeast for the amount of oil used for space heating. Black & Veatch attempted to obtain data directly from the fuel oil suppliers, but in general this effort was not successful because most of the fuel oil suppliers view the data as confidential. The *Alaska Energy Pathway* estimates the amount of oil used for space heating for each community. The timing of the *Alaska Energy Pathway*, which was published in July 2010, results in the oil space heating estimates being made before the significant conversions to electric heat that occurred in 2010 and 2011.

Black & Veatch has used the information obtained in developing the load forecasts presented in Section 8.0 to forecast the volume of oil used for space heating for each subregion. Graphs of these projections are presented in Section 15.5. Table 15-1 presents the 2012 estimated volume of oil used for space heating in each community and the estimated 2012 cost based on the medium heating oil price projections in Section 5.0. These projections are generally lower than those in the *Alaska Energy Pathway*, reflecting the recent conversions to electric space heating. The uncertainty associated with these forecasts is large due to the lack of data associated with heating oil usage. Usage by sector contains even greater uncertainty due to the lack of data, especially relative to the number and sizes of commercial customers. The estimated total cost for oil for space heating in 2012 for the Southeast is over $72 million, or equivalent to over a $1,000 annually per person. Even if that estimate is significantly overstated, the cost for oil for space heating in the Southeast is huge.

Figure 15-1 Potential Electric Space Heating Loads - SEAPA

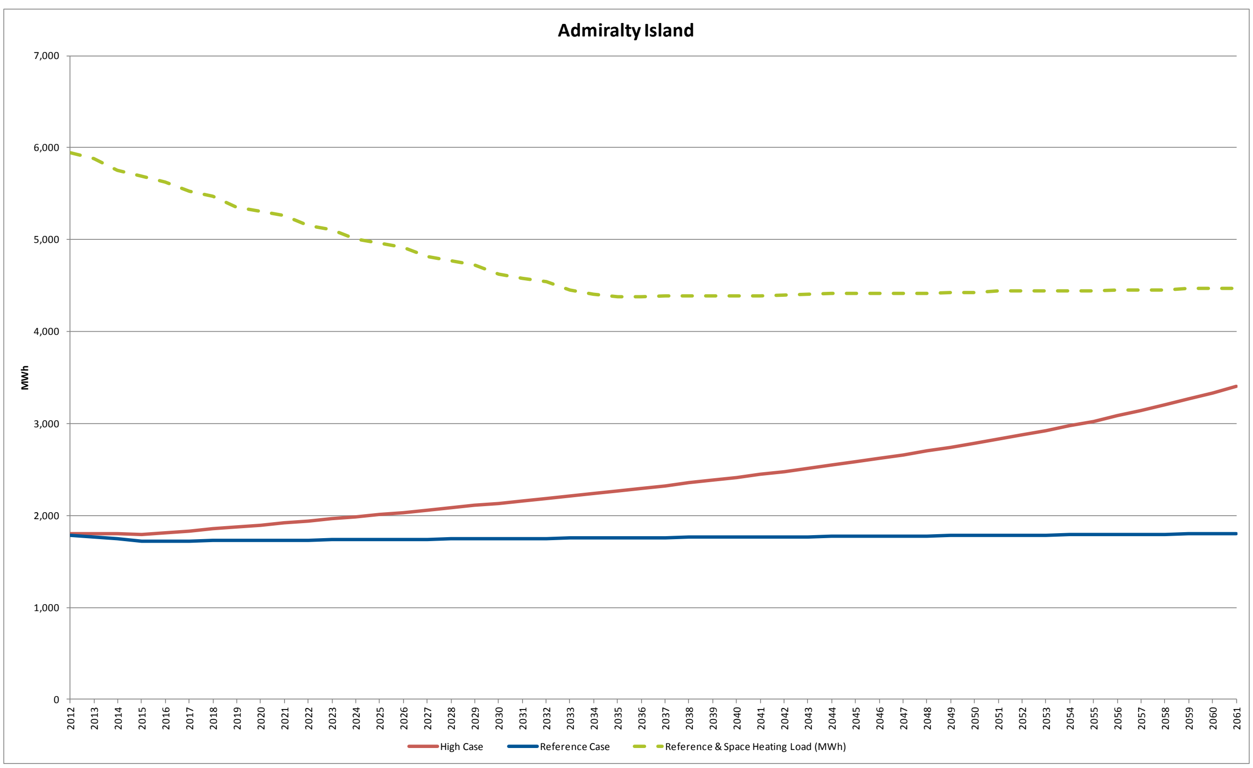


Figure 15-2 Potential Electric Space Heating Loads - Admiralty Island

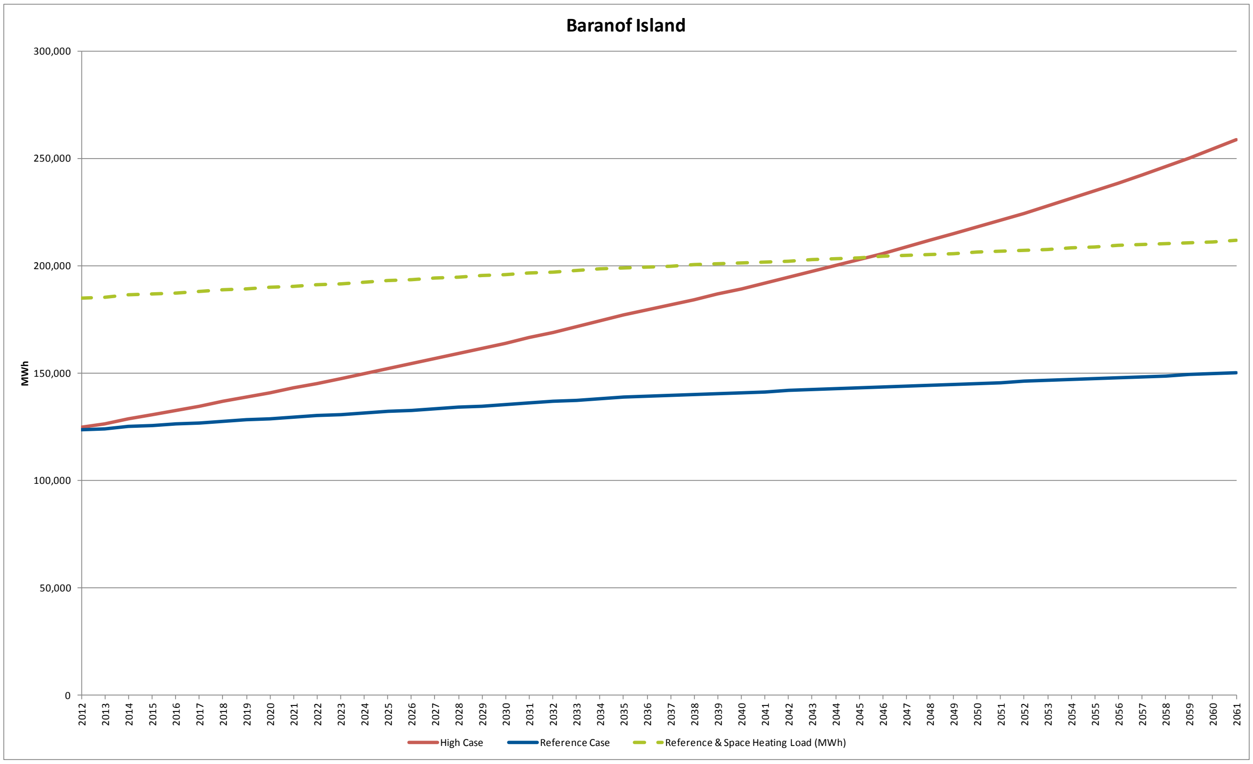


Figure 15-3 Potential Electric Space Heating Loads - Baranof Island

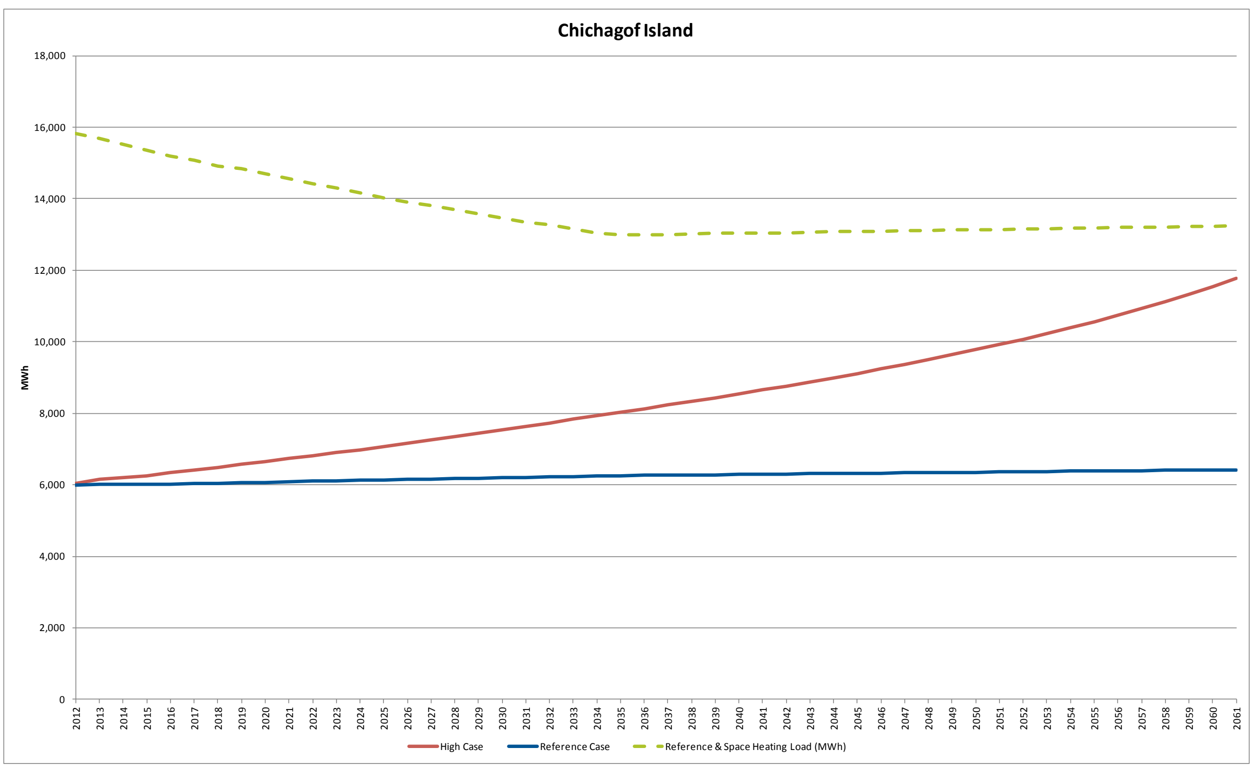


Figure 15-4 Potential Electric Space Heating Loads - Chichagof Island

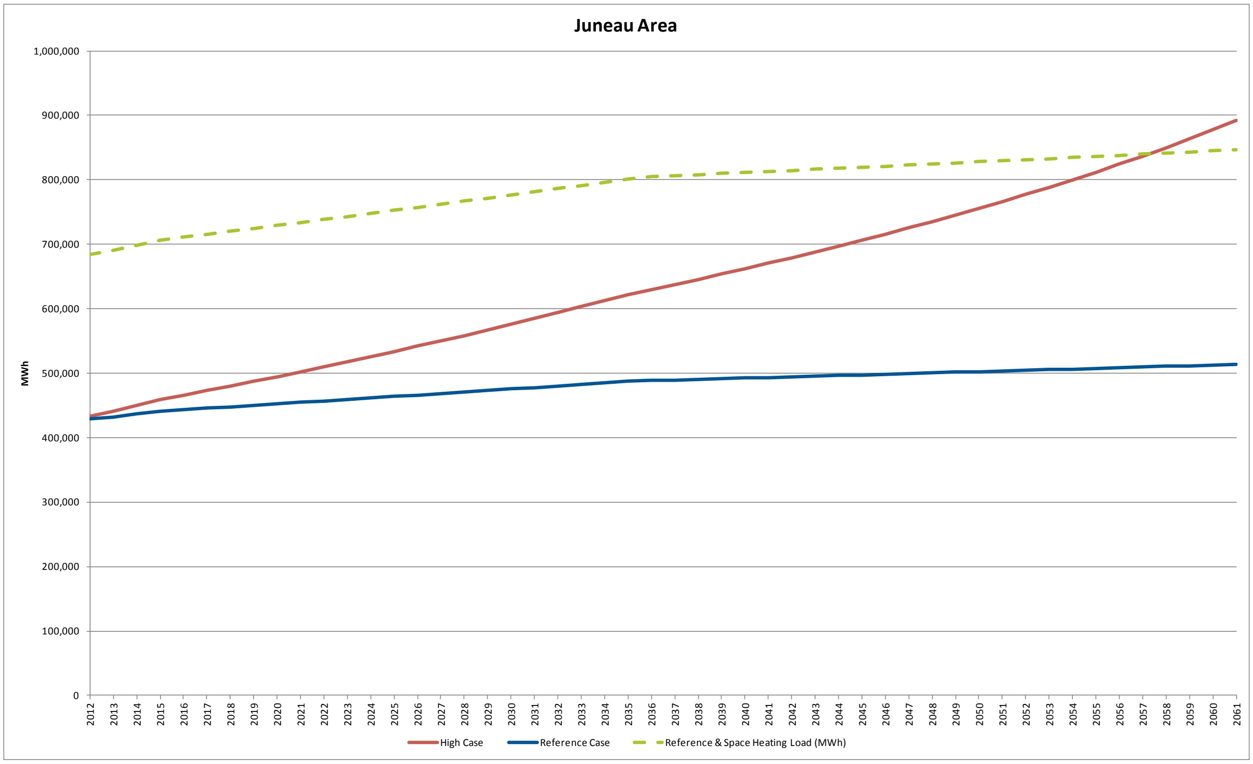


Figure 15-5 Potential Electric Space Heating Loads - Juneau Area

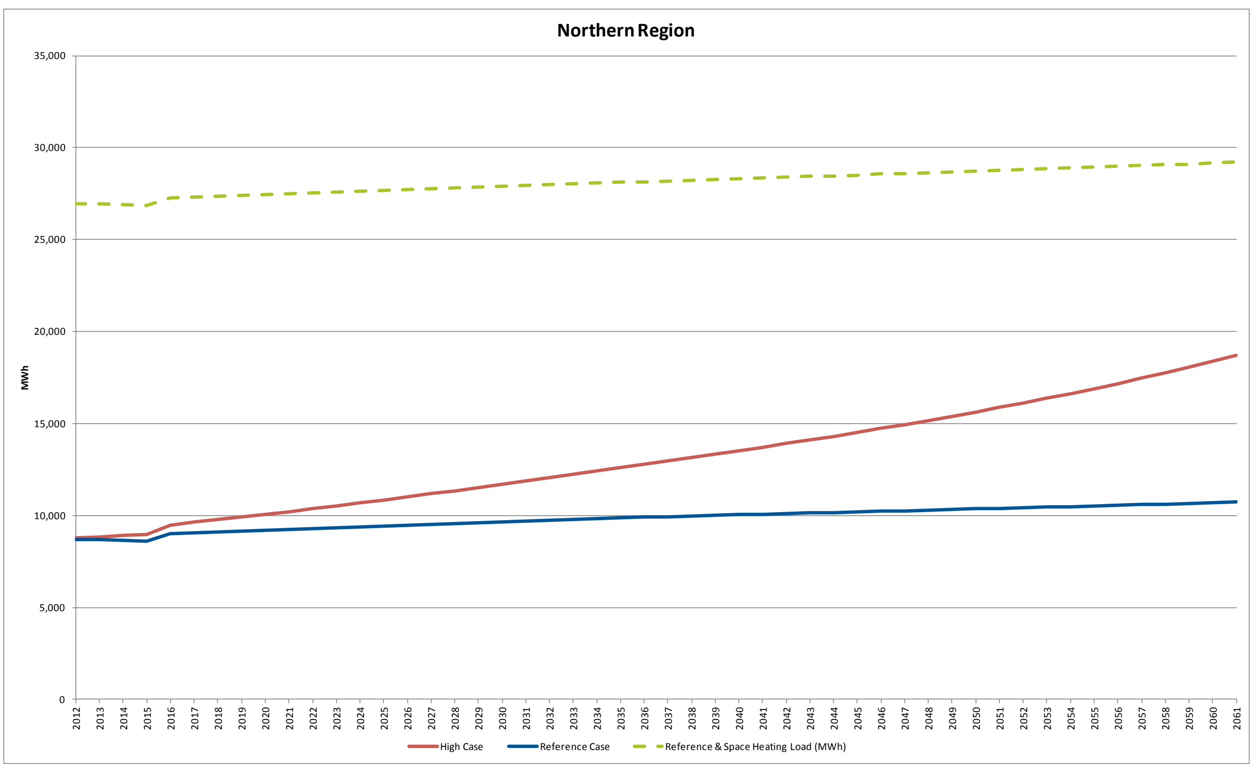


Figure 15-6 Potential Electric Space Heating Loads - Northern Region

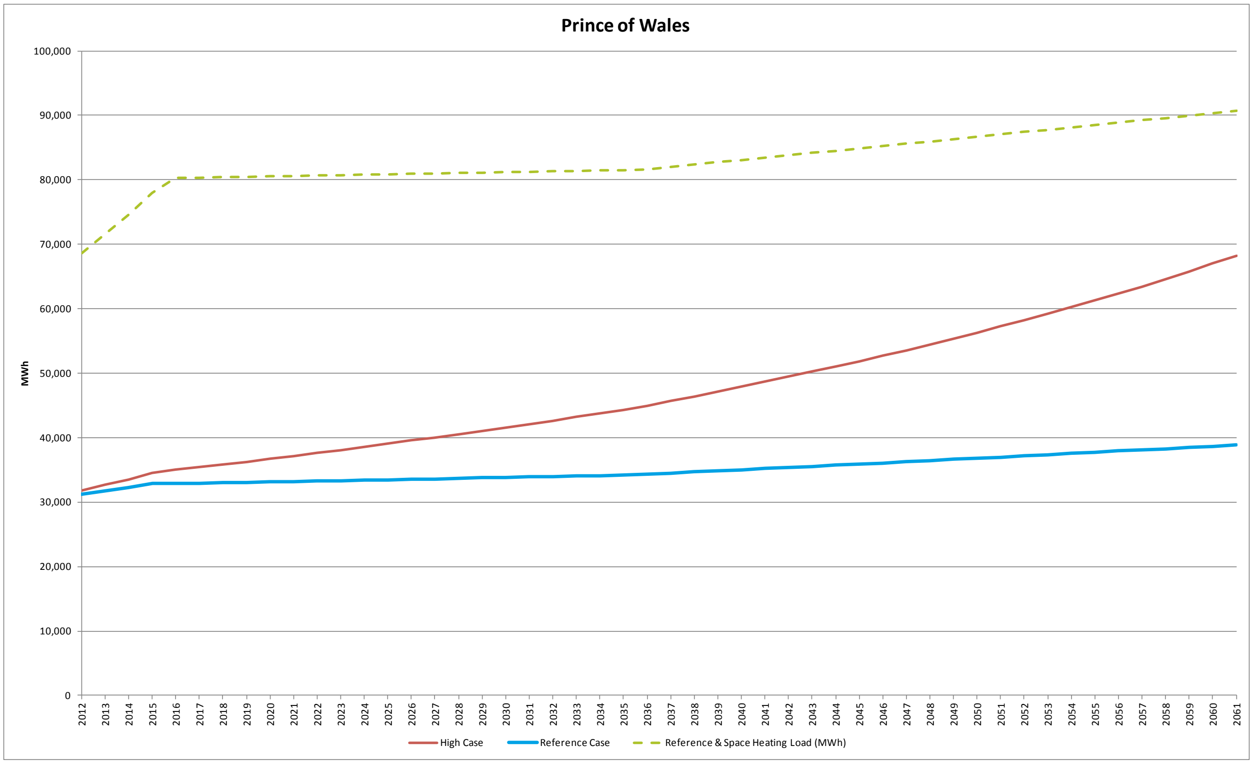


Figure 15-7 Potential Electric Space Heating Loads - Prince of Wales

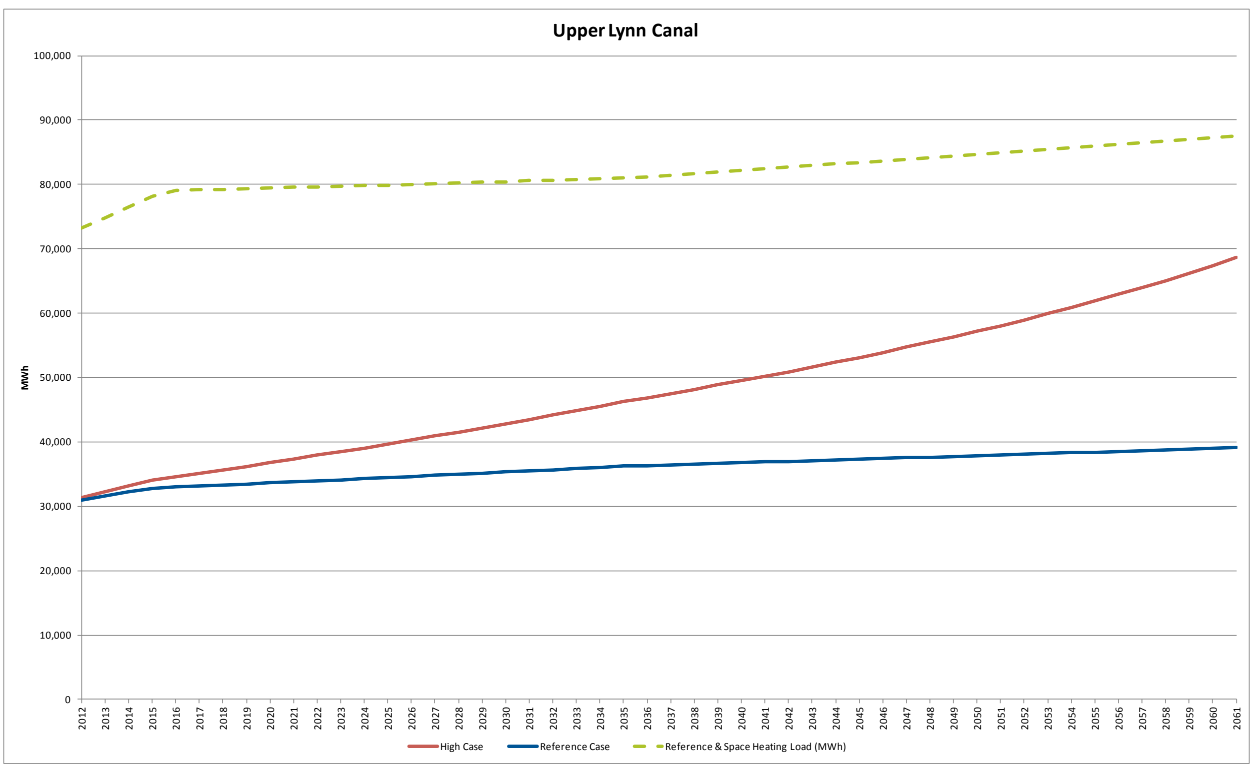


Figure 15-8 Potential Electric Space Heating Loads - Upper Lynn Canal

Table 15-1 2012 Oil Space Heating Estimates

SUBREGION	2012 GALLONS	2012 COST
SEAPA		
Kake	286,552	1,271,506
Petersburg	225,961	914,492
Wrangell	784,572	3,175,260
Ketchikan	2,903,831	10,683,780
Metlakatla	328,117	1,327,930
Total Gallons	**4,529,034**	**17,372,968**
ADMIRALTY ISLAND		
Angoon	125,356	556,333
Total Gallons	**125,356**	**556,333**
BARANOF ISLAND		
Sitka	1,844,742	8,144,044
Total Gallons	**1,844,742**	**8,144,044**
CHICHAGOF ISLAND		
Elfin Cove	2,754	14,761
Hoonah	238,235	1,093,805
Pelican	23,247	124,597
Tenakee Springs	32,423	168,654
Total Gallons	**296,658**	**1,401,817**
JUNEAU AREA		
AEL&P	7,700,523	31,452,518
Total Gallons	**7,700,523**	**31,452,518**
NORTHERN REGION		
Yakutat	295,094	1,393,902
Gustavus	254,931	1,297,638
Total Gallons	**550,025**	**2,691,540**
PRINCE OF WALES		
AP&T (POW)	1,110,191	4,926,292
Whale Pass	17,687	80,503
Total Gallons	**1,127,879**	**5,006,795**
UPPER LYNN CANAL		
Chilkat Valley	129,671	582,540
Kluwan	34,238	151,922
Haines	675,533	2,982,297
Skagway	433,960	1,880,302
Total Gallons	**1,273,402**	**5,597,061**
SE Alaska Total	**17,447,619**	**72,223,076**

15.4 EVALUATION OF SPACE HEATING CONVERSION ALTERNATIVES FOR SOUTHEAST ALASKA

This section analyzes the alternatives available to move the Southeast away from a dependence upon fuel oil for space heating.

15.4.1 Requirements for Technological Change

For a technology to displace another technology, the new technology must have favorable characteristics compared to the existing technology as presented in the Triangle of Change shown on Figure 15-9. The stronger that all of the legs of the Triangle of Change for the new technology are compared to the existing technology, the faster the change to the new technology can be. The following briefly describes the characteristics of the Triangle of Change.

- **Technology**--The technology has to serve its intended purpose. It has to be reliable. It has to function easily in its environment.
- **Social/Political**--The technology must comply with laws and regulations. It must be viewed by the public as desirable. The effort associated with its use cannot be undue. These social/political characteristics are often the target of advertising by technology providers.
- **Economics**--The foundation of the Triangle of Change. The technology's cost must be commensurate with the function it provides and the Social/Political effort associated with its use. Economics must consider all costs including initial capital costs, operating costs, and replacement costs or lifetime. Technologies with high initial costs and lower operating costs have additional hurdles to overcome for rapid acceptance.

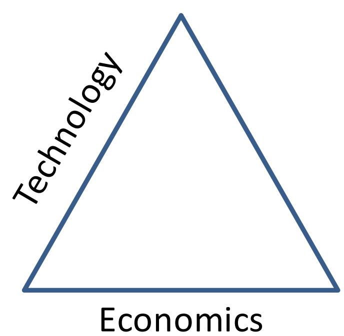


Figure 15-9 Triangle of Change

Traditionally, oil space heating has been strong relative to these characteristics except when high oil prices make operating costs unacceptable.

Section 16.0 analyzes several alternatives to oil for space heating each of which is discussed below relative to them being readily applied to the Southeast region.

15.4.2 Conversion to Electric

Electric space heating using resistance space heating fares very well relative to the Triangle of Change characteristics where low cost electric energy is available. This is evidenced by the significant penetration of electric space heating in the communities with low cost hydroelectric generation. The economic leg of the triangle also reflects consumer's expectations that future operating costs remain low. Historically this has been the case for the communities with low cost hydroelectric generation, but as the excess hydroelectric generation diminishes, and higher cost resources are required, consumer's expectations of long-term low cost operation will also diminish.

Electric space heating using heat pump technology compares somewhat differently in the Triangle of Change characteristics. While Section 16.0 demonstrates that heat pump technology has lower long-term cost than electric resistance heating and oil heating, it has the hurdle of much higher initial costs to overcome. The initial cost of ground source heat pumps is very site dependent, but is easily four or five times the cost of installation of resistance heating and many times the cost of portable space heaters. While the technology of ground source heat pumps is proven, the consumer's perception is one of more complexity. From a social/political standpoint, besides the higher cost, the actual installation of a ground source heat pump is much more disruptive due to well drilling or other heat exchanger installation and viewed less favorably by consumers. The use of air source heat pumps for Southeast Alaska temperatures is much less proven and presents, at least from the consumer's perspective, a technical challenge.

While conversion to resistance electric space heating has been occurring without any incentives because the price of oil in 2010 and 2011 has been very high, significant conversion to heat pumps will require incentives to overcome the high initial costs. The heat pumps also still consume electricity, although only about one third of that of resistance heating.

15.4.3 Conversion to Propane

Propane space heating is analyzed in Section 16.0. Propane space heating technology is very similar to oil and well established. While some communities have propane service, the infrastructure for providing propane is not heavily established in the Southeast, and the propane delivery infrastructure is a challenge for the technology.

The economics of propane conversion hinge on the comparative cost of propane and oil. While, historically, the comparative actual market costs have generally favored propane, the consumer's long-term perception has not resulted in a significant differential resulting in a strong move to conversion. While these comparative market costs are likely to continue, it is unlikely that they will drive significant conversions.

While market prices may not result in a significant movement to conversion, there is considerable propane produced but not used on the North Slope. There have been ongoing initiatives in various forms to bring this propane to the coastal markets in Alaska. Because of its current lack of value on the North Slope, it is possible and even likely that the cost of bringing propane to Alaska's coastal market will be such that propane could be provided significantly below the world market price. The question to be answered is whether the North Slope propane would be provided to the Southeast space heating market at below market price or whether the propane will be sold at market price. Even if North Slope propane sells at market price at the Alaska coast, there is opportunity for some savings in transportation cost to the Southeast Alaska space heating market. Nevertheless based on past experience in the Southeast, if North Slope propane is provided to the Southeast space heating market at market prices, it would not be expected that there would be significant conversion to propane for space heating in the Southeast. In addition, significant investment in the required propane delivery infrastructure would be required. The North Slope propane issue is one that should continue to be monitored by the Southeast, but it should not be a technology that the Southeast counts on for space heating conversion until a policy is in place that provides a significant savings of propane over oil.

15.4.4 Conversion to Biomass

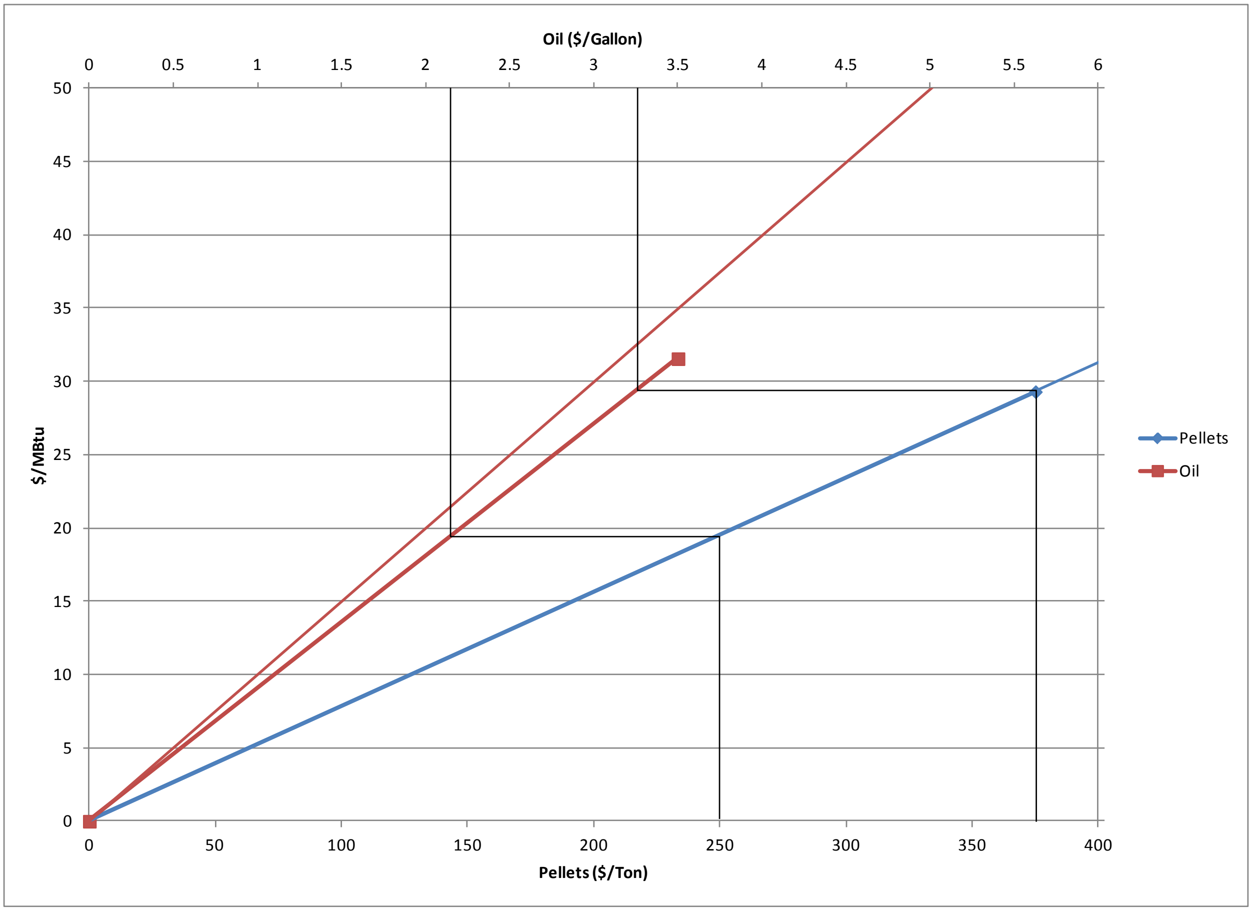
Biomass space heating can take place in three major forms:

- Pellets
- Chips
- Cord Wood

Biomass space heating is analyzed in Section 16.0. The technology for all three forms of biomass is well established although the infrastructure for production and delivery for pellets and chips needs to be developed in the Southeast. There are a number of favorable aspects relative to the social/political characteristics of biomass. The concept of using a local renewable resource that creates local jobs is well received. The ease and convenience of use varies considerably with the form of biomass. One of the big social/political benefits of oil and electric space heating is the convenience of use. Pellet space heating can provide a similar level of convenience via continuous feed from a hopper and minimal operating maintenance. On the other hand, cord wood space heating requires much more effort and attention for burning the wood and for removing ash. Wood chip systems have the highest requirements for maintenance due to their complexity.

The economic characteristic is the major determinant relative to technology change. Biomass is significantly lower in cost than oil. The cost of the different forms of biomass is inversely proportional to their ease of use with pellets being the most expensive and cord wood being cheapest. Cord wood is generally better suited for commercial applications where the economic benefits can better offset the additional effort associated with its use. Chips are generally better suited for larger commercial applications where manual stoking with cord wood becomes infeasible. For purposes of estimating the conversion potential, in Section 15.5, Black & Veatch has estimated the economic benefits assuming conversion would be to pellets. Specific commercial customer applications using chips or cord wood may result in greater savings.

Figure 15-10 shows the relationship between the cost of pellets and the break-even cost of oil for space heating. As discussed in Section 16.0, currently the average cost of pellets in the lower 48 states is approximately $250 per ton with costs as low as $190 per ton. Currently Sealaska is promoting conversion to pellets in the Southeast and is providing pellets from the State of Washington delivered to space heating installations in the Southeast for approximately $300 per ton, while pellets are selling in 40 pound bags in Juneau for an equivalent of $375 per ton. As shown on Figure 15-10, for pellets at $300 per ton, the break-even price of oil is approximately $2.70 per gallon. The 2012 medium heating oil price projections presented in Section 5.0 for communities in the Southeast range from $3.38 per gallon to $5.36 per gallon with actual prices in 2010 and 2011 being even higher. At $300 per ton with pellets delivered from Washington, there appear to be significant savings from the use of pellets, and, if the Southeast can develop their own pellet mills at prices approaching the prices in the lower 48 states, savings would be even greater.



Note: Assumes 80 percent efficiency for both pellets and oil. Assumes 8,000 Btu/lb for pellets and 138,690 Btu/gal for oil.

Figure 15-10 Comparative Costs of Pellet and Oil Space Heating

Another aspect to consider in the conversion to biomass from oil for space heating is the emission increases from biomass. Table 15-2 presents the comparative emissions from residential oil space heating and from residential pellet space heating based on the EPA's AP-42 emission factors. There is significant inconsistency relative to air emissions from spacing in large part due to the inconsistencies with the vintage of stove or furnace and the composition of the sample (all versus new; certified versus exempt; fuel quality). The use of the AP-42 emission factors provides some level of consistency, but they are also somewhat dated. Table 15-2 indicates that space heating emissions from pellets are generally higher than oil for residential space heating. While the emissions are higher, they are low on an absolute basis. For CO_2 emissions, while not unanimous, the general consensus is that biomass is considered CO_2 neutral or nearly so. The CO_2 emissions in Table 15-2 do not reflect this neutrality and represent the actual CO_2 from combustion only.

Table 15-2 Emission Comparison Between Oil and Pellet Space Heating (lb/MBtu)

EMISSION	OIL	PELLETS
PM_{10}	0.0029(1)	0.26-0.55(2)
CO	0.036	2.46 - 3.26(2)
CO_2	160.8	184.5 - 229.4(2)
SO_x	0.0016	0.025(3)
NO_x	0.13	0.86(3)

(1)Filterable.
(2)Certified - Exempt.
(3)Certified.
Note: Pellets 8,000 Btu/lb, Ultra Low Sulfur No. 2 Oil 0.138690 MBtu/gal.
Source: EPA AP-42.

The cost, however, for equipment to convert to biomass space heating using pellets is significant. For estimating purposes, Black & Veatch has used $5,000 in 2011 as the average cost of conversion to pellets for residential customers. For commercial customers, Black & Veatch has used costs that vary by estimated customer size, but are equivalent to residential customer conversion costs on an MBtu basis. The lack of quality end-use data in the Southeast causes there to be considerable uncertainty relative to cost, customer size, number of customers, and heating load per customer. The estimated savings for conversion to pellets is presented in Section 15.5. While the savings are significant, the high initial cost of conversion will likely require some level of financial assistance to obtain high levels of conversion. This conclusion is supported by Sealaska's experience in promoting conversion to pellets. Sealaska has obtained slow and somewhat limited conversion by commercial customers with most of the commercial customers receiving some form of financial assistance. Most of the commercial customer conversions to other forms of biomass space heating in the Southeast have also received financial assistance, and the number of customers converting can be characterized as limited.

15.5 PELLET CONVERSION EVALUATION

Based on the analysis of the use of pellets for space heating in the Southeast, Black & Veatch has conducted an evaluation of the cost and impact of a proposed plan for a major conversion to pellets for space heating in the Southeast.

For the first step of the evaluation, Black & Veatch estimated the oil space heating load for each of the subregions in the Southeast through the 50 year evaluation period. The oil space heating load was developed based on information used for the electric load forecasts described in Section 8.0 and the space heating requirements contained in the *Alaska Energy Pathway*. Figures 15-11 through 15-18 present the estimated oil space heating load in annual gallons per year of fuel oil for each region.

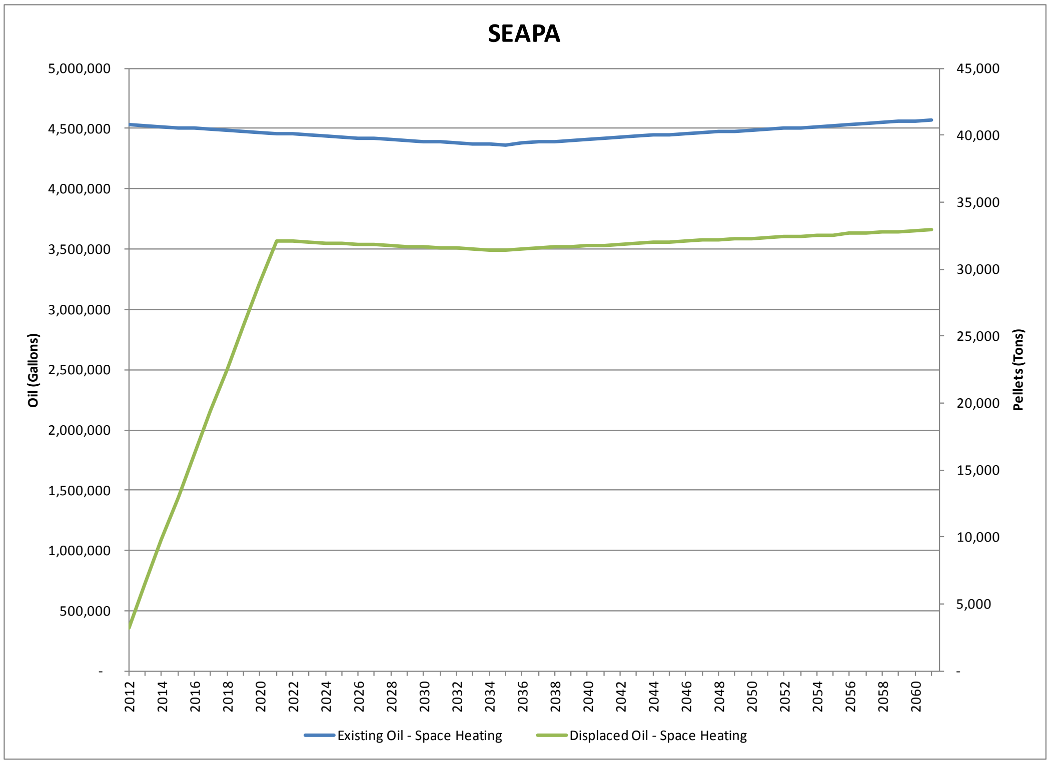


Figure 15-11 Estimated Oil Space Heating Load - SEAPA

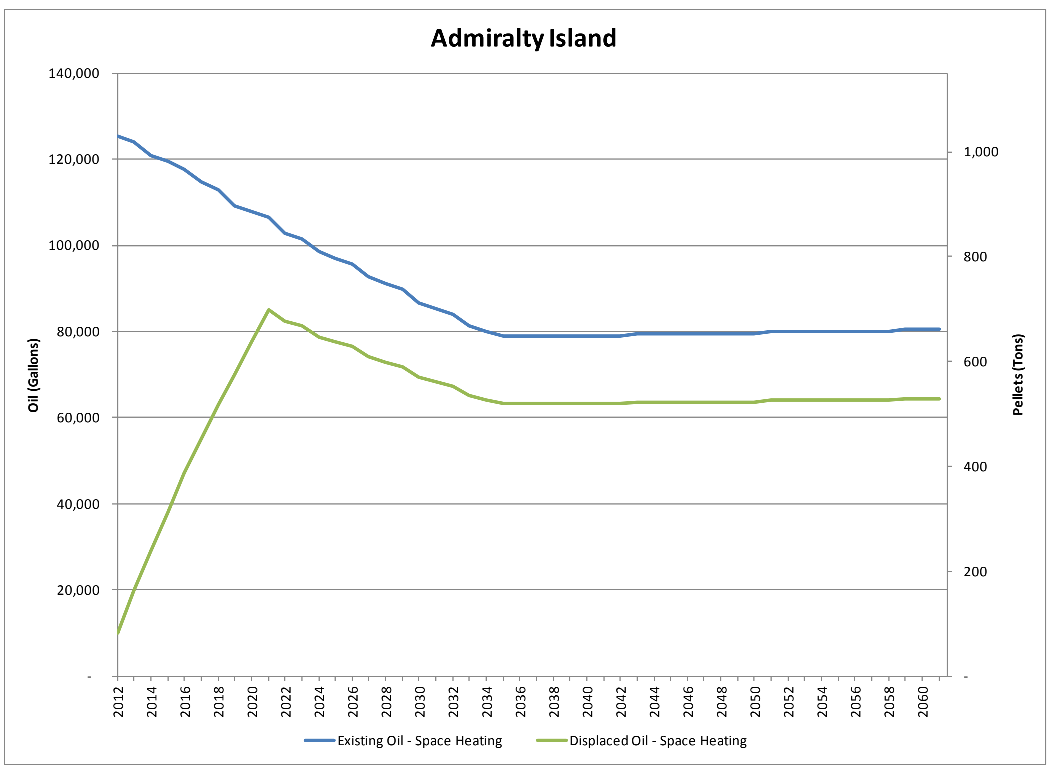


Figure 15-12 Estimated Oil Space Heating Load - Admiralty Island

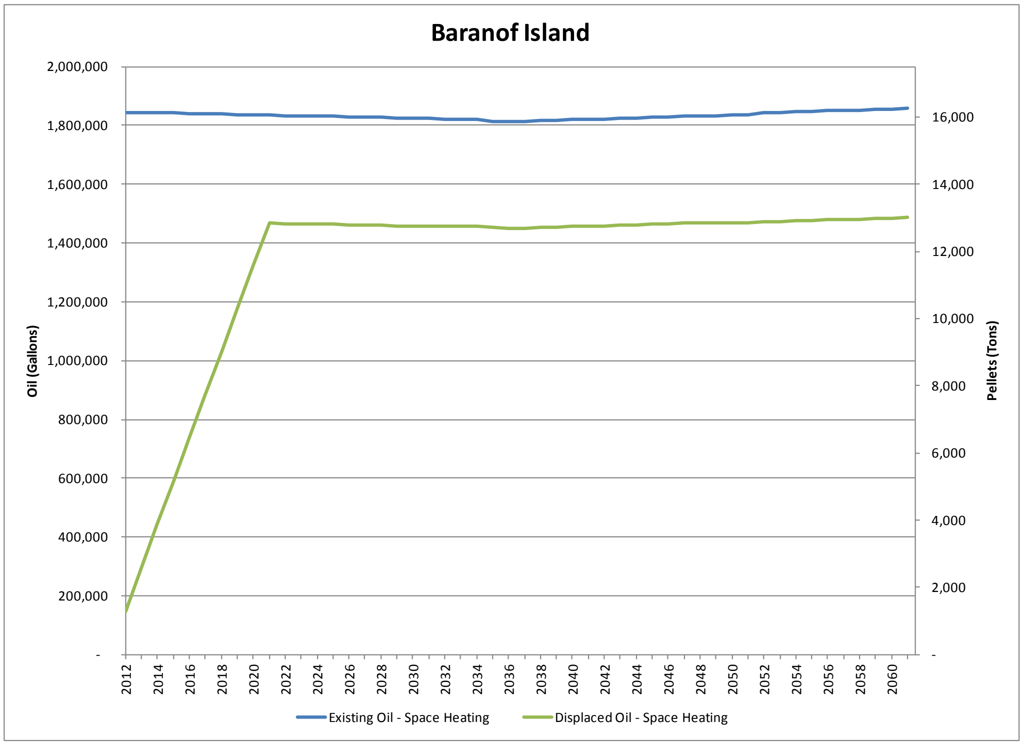


Figure 15-13 Estimated Oil Space Heating Load - Baranof Island

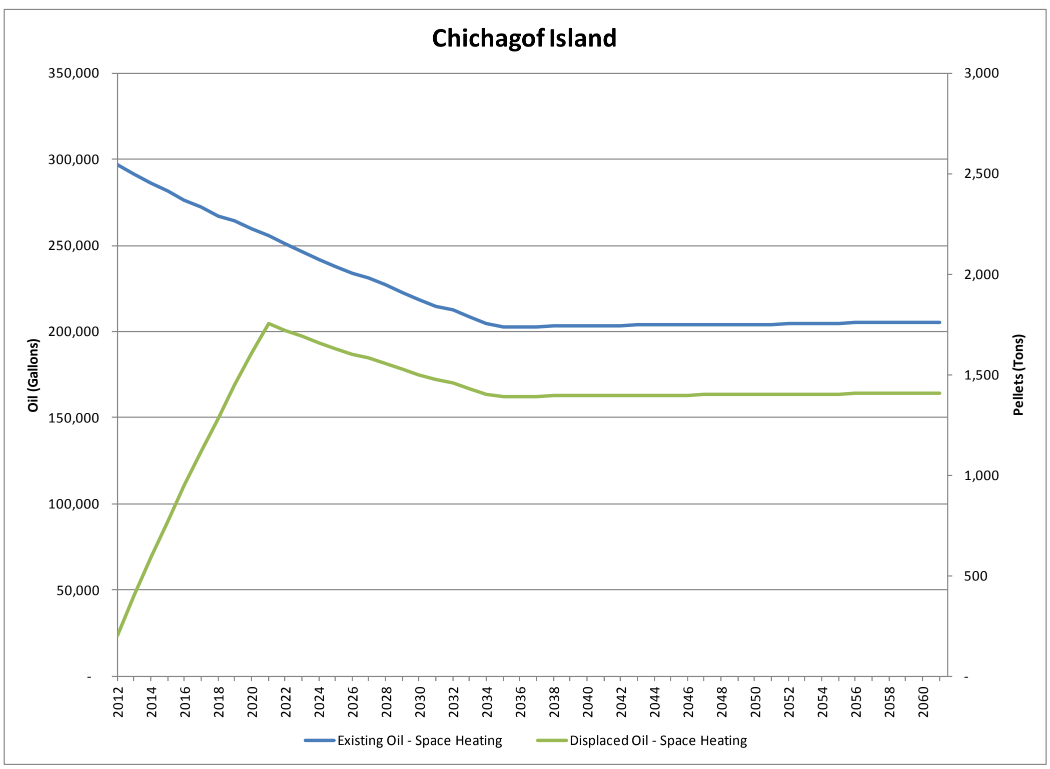


Figure 15-14 Estimated Oil Space Heating Load - Chichagof Island

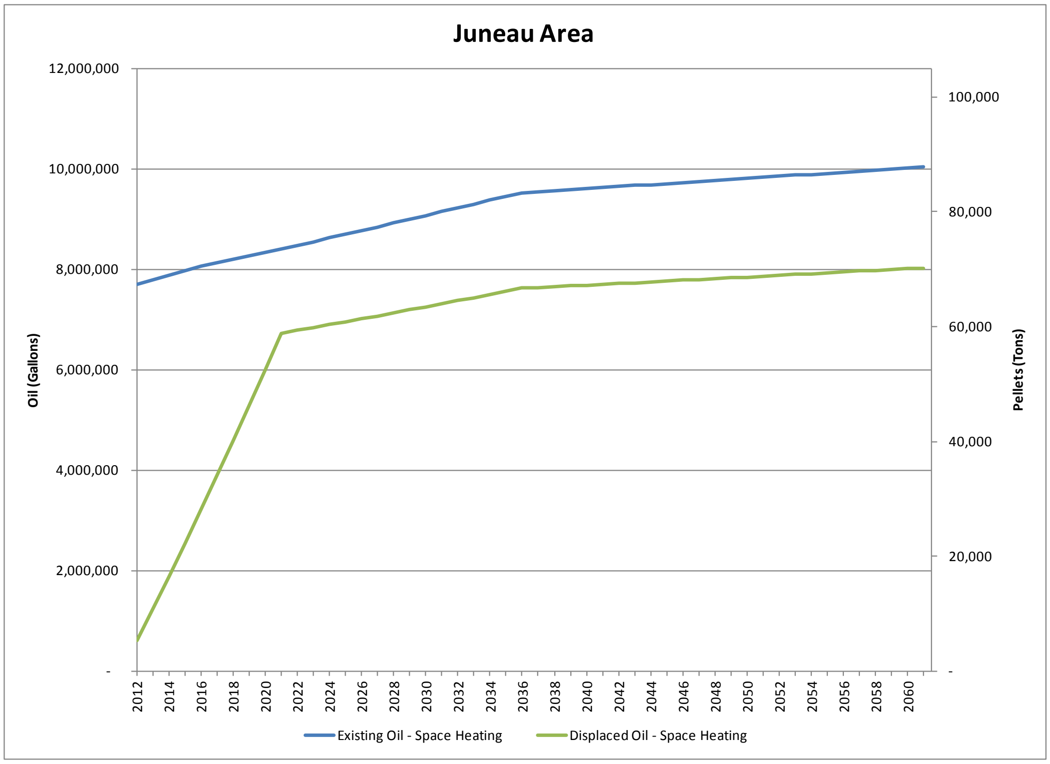


Figure 15-15 Estimated Oil Space Heating Load - Juneau Area

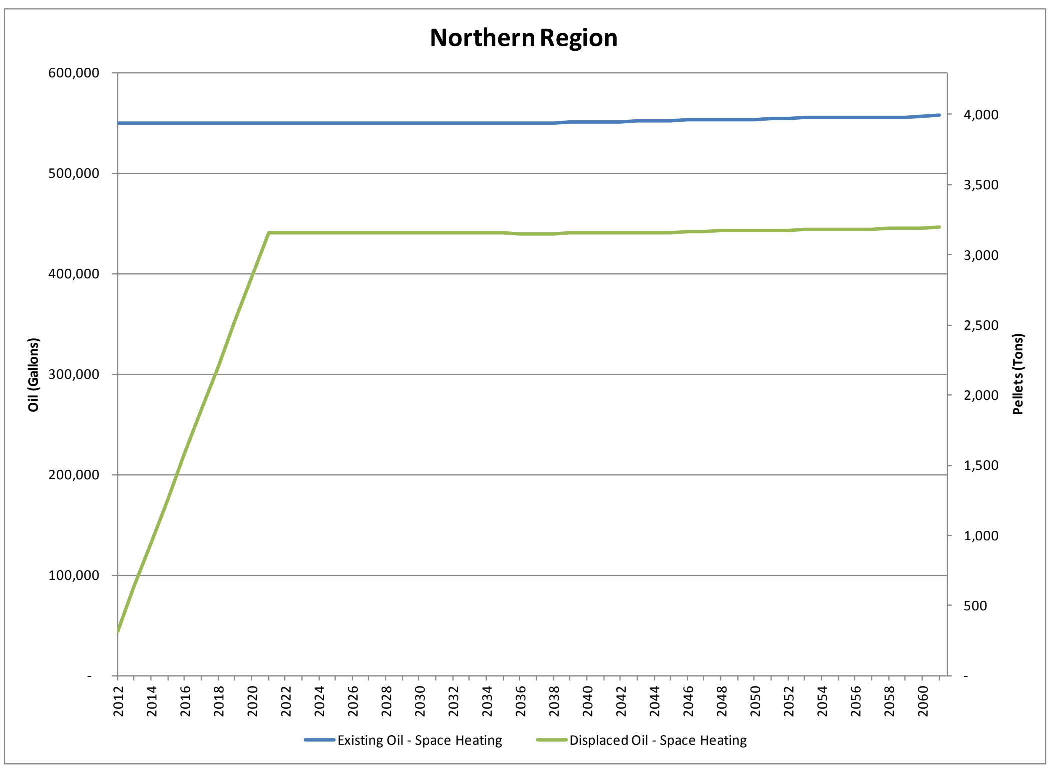


Figure 15-16 Estimated Oil Space Heating Load - Northern Region

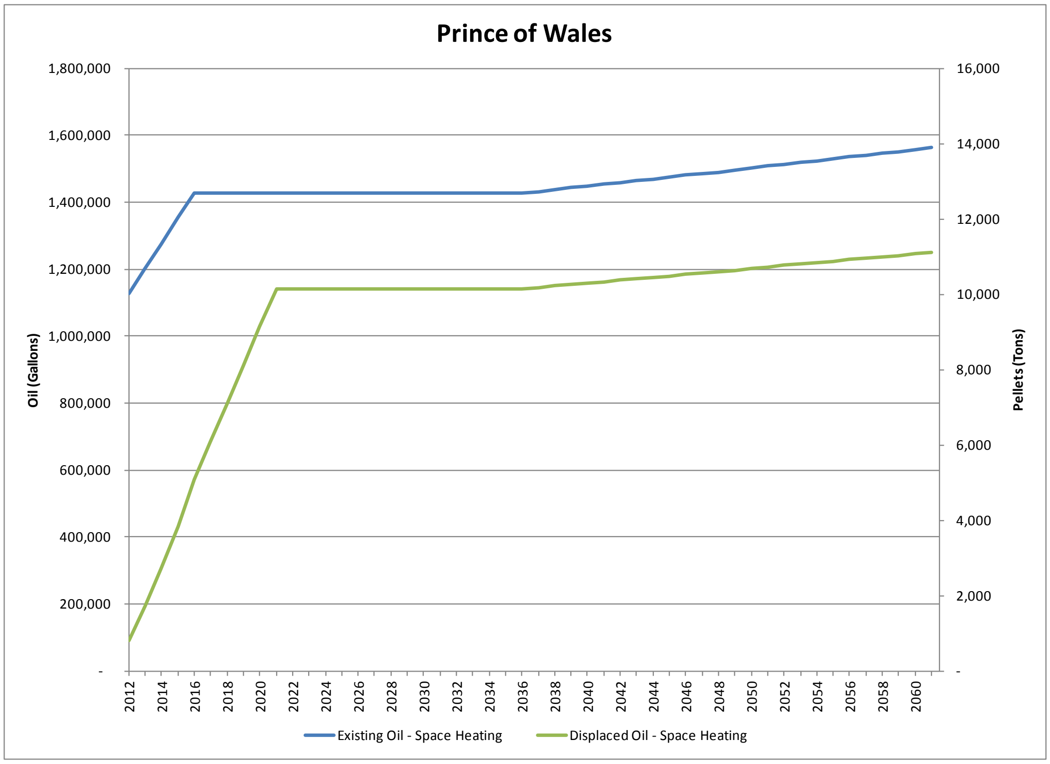


Figure 15-17 Estimated Oil Space Heating Load - Prince of Wales

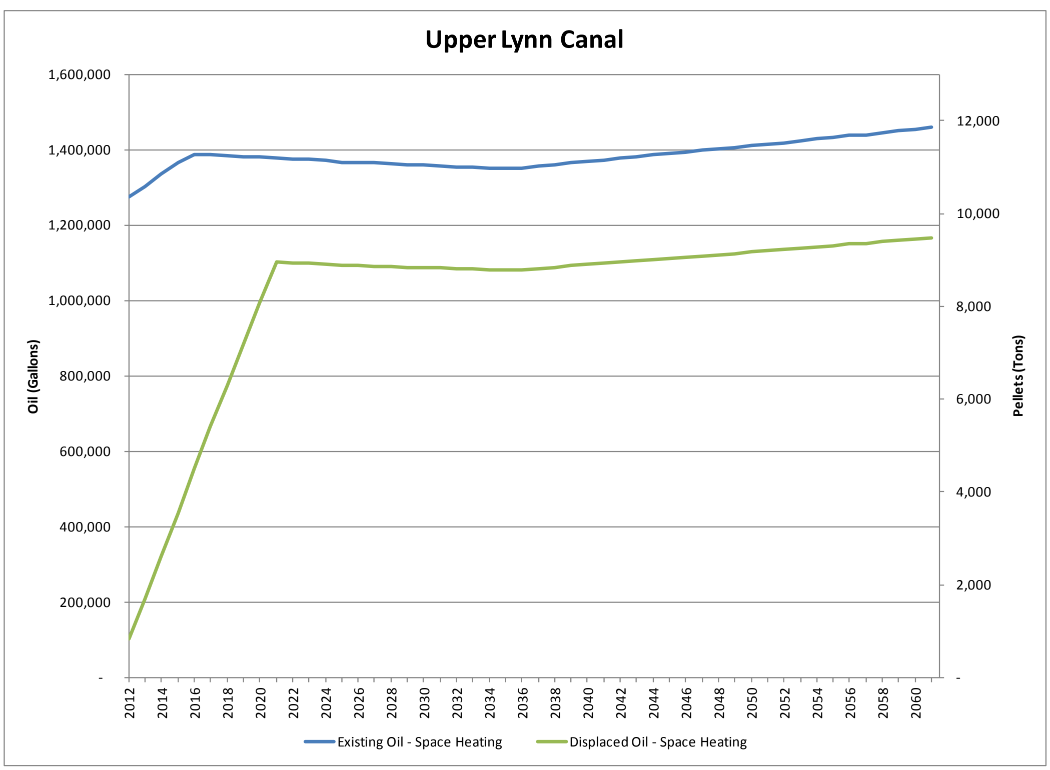


Figure 15-18 Estimated Oil Space Heating Load - Upper Lynn Canal

Figures 15-11 through 15-18 also show the projected conversion to pellets assuming that 80 percent of the space heating load is converted to pellets within 10 years, with the conversions occurring evenly starting in 2012. Figures 15-11 through 15-18 also show the annual amount of pellets consumed in tons. The lower graph on Figures 15-11 through 15-18 shows both the annual number of gallons of oil displaced due to conversion to pellets on the left hand scale and the annual number of tons of pellets consumed on the right hand scale. Consistent with previous comments, there is considerable uncertainty in Figures 15-11 through 15-18 because of the lack of data on space heating loads in the Southeast. The conversion program is very aggressive and may well be limited by a number of factors, such as the ability of a distribution system to be developed to deliver the required amount of pellets. The 80 percent ultimate penetration is very aggressive, but the economic analysis includes the entire estimated cost of conversion, which would be provided as an incentive as part of the program. If the entire cost of conversion is paid with the projected savings in operating costs, a high penetration level is reasonable. The economic evaluation of the savings from the pellet conversion program is presented in Table 15-3. Table 15-3 is based on the medium heating oil projections in Section 5.0 and assumes a pellet cost of $300 per ton escalating at the general escalation rate of 3 percent as presented in Section 6.0. The costs for the pellet space heating equipment are those presented in Subsection 15.4.4 and are escalated at 3 percent annually. Table 15-3 does not include any consideration for any differences in O&M costs between pellets and oil. Specific costs for pellet mill development or transportation or distribution system infrastructure are not included since the $300 pellet price used is the delivered price for pellets by Sealaska, and those production and infrastructure costs are captured in the delivered costs. The actual program may want to provide assistance in these areas to hasten the local development of the industry. Table 15-4 presents the estimate capital cost for the pellet space heating equipment. The proposed pellet conversion program would save an estimated $2.1 billion in cumulative present worth costs for space heating for the region over the 50 year period and would require a total capital investment of $532 million for the pellet space heating equipment. While there is substantial uncertainty in the magnitude of these savings and costs, the magnitude of savings is sufficiently large that it can be concluded that the region would incur significant savings for space heating with a significant program for conversion to biomass for space heating.

Table 15-3 Savings from Pellet Conversion Program (Cumulative Present Worth Costs $1,000)

REGION	EXISTING OIL SPACE HEATING COSTS	OIL COSTS	PELLET COSTS	COST OF PELLET SPACE HEATING EQUIPMENT	TOTAL PELLET PROGRAM COSTS	SAVINGS
SEAPA	977,320	258,011	238,441	61,875	558,327	418,993
Admiralty Island	22,334	6,830	4,717	1,195	12,742	9,592
Baranof Island	460,426	121,745	98,280	23,655	243,680	216,746
Chichagof Island	58,459	13,753	11,950	2,806	28,509	29,950
Juneau	2,120,883	541,759	490,307	111,314	1,143,380	977,503
Northern	147,786	39,089	23,925	6,849	69,863	77,923
Prince of Whales	366,725	94,304	77,469	14,916	186,689	180,036
Upper Lynn Canal	347,271	90,274	67,919	16,287	174,480	172,791
Total Southeast Region	**4,501,204**	**1,165,765**	**1,013,008**	**238,897**	**2,417,670**	**2,083,534**

Table 15-4 Southeast Alaska Annual Capital Costs - Heating Conversion to Pellets

YEAR	SEAPA	ADMIRALTY ISLAND	BARANOF ISLAND	CHICHAGOF ISLAND	JUNEAU AREA	NORTHERN REGION	PRINCE OF WALES	WHALE PASS	UPPER LYNN CANAL	TOTAL
2012	25,201,783	143,994	2,663,683	313,738	11,379,543	780,689	1,329,524	10,300	1,624,722	**43,447,975**
2013	26,393,070	108,636	2,644,399	417,040	12,016,390	749,208	1,504,568	44,982	1,828,249	**45,706,543**
2014	27,875,739	249,470	2,825,901	327,381	12,675,742	828,232	1,746,178	10,927	1,839,606	**48,379,177**
2015	29,442,860	146,091	2,916,306	320,320	13,315,782	800,462	2,048,651	47,722	2,290,523	**51,328,717**
2016	30,490,589	107,117	3,019,677	503,357	13,953,371	894,554	2,104,778	17,389	2,152,772	**53,243,603**
2017	30,749,354	149,018	2,976,295	327,887	14,495,078	849,210	1,881,349	56,598	2,048,874	**53,533,663**
2018	31,923,774	222,484	3,180,577	285,577	15,136,673	926,034	1,983,787	6,149	2,087,342	**55,752,396**
2019	33,054,972	104,382	3,157,551	418,921	15,930,901	900,927	1,995,923	12,668	2,143,628	**57,719,872**
2020	34,360,615	156,312	3,252,278	296,444	16,578,970	988,953	2,098,075	61,846	2,243,688	**60,037,181**
2021	35,869,061	104,019	3,482,222	298,618	17,373,076	1,011,902	2,117,475	13,439	2,543,899	**62,813,711**

15.6 PELLET SPACE HEATING PROGRAM ISSUES

As a result of the limited scope of this IRP and the lack of quality data on space heating in the Southeast region, additional studies and program development activities should be conducted for the Regional Biomass Conversion Program. Table 15-5 provides an estimate of the costs associated with those activities. In addition to specific program development activities, the AEA's Energy End Use Data Collection Project currently under way and scheduled for completion in the first quarter of 2012 will provide needed details on end-use space heating in the Southeast region.

Table 15-5 Regional Biomass Conversion Program Startup Costs

ACTIVITY	COST
Regional Entity Startup Costs (e.g., organizational strategy, legal, etc.)	$500,000
Initial Staff Related Costs (e.g., salaries, benefits, space)	$1,000,000
Customer Attitudinal Survey	$75,000
Market and Economic Potential Studies	$250,000
Detailed Program Design Costs	$500,000
Vendor Training/Certification Program	$150,000
Program Startup Advertising Program	$250,000
Total	**$2,725,000**

The results of these studies and program development activities will provide insight and specific program direction in many areas, including the following:

- Besides reducing the costs for space heating for the Southeast region, the program is necessary to control the conversion to electric space heating caused by high oil prices. With the program in place, the region may be able to react to spikes in the price of oil by motivating customers to convert to biomass instead of electric space heating. Likewise, if oil prices dip, the program may be able to reduce costs by reducing incentives to convert to biomass without increasing the conversion rate to electric space heating.
- The program estimates are based on conversion using pellets. It may be more cost-effective for small commercial customers to use cord wood and larger commercial customers to use chips.
- Weatherization will decrease the space heating loads for whatever the source of fuel. The biomass conversion program can work with the weatherization program to coordinate actions.
- The program can refine the level of incentives required to achieve the desired conversion. The cost estimates are based on paying all costs of conversion. It is likely that as a result of market studies, it will be determined that significantly less incentives will be required.
- Various subregions can be targeted by the program. For instance, customers in areas where low-cost hydroelectric generation is available pay a much smaller amount of their disposable income for electricity and heat than customers in areas where low-cost hydroelectric is not available. Those subregions without low-cost hydroelectric generation could be targeted for the conversion program, which at least would reduce heating costs.

15.7 REGION'S ABILITY TO SUPPORT BIOMASS CONVERSION PROGRAM

One of the major benefits of a biomass space heating conversion program is the ability to develop a local biomass industry, resulting in the creation of local jobs. Key to the development of a biomass industry is the ability of the region to supply the necessary biomass on a sustainable basis. Black & Veatch's research on the availability of biomass supply concluded that there is currently still significant uncertainty regarding the management of the Tongass National Forest to enable accurate and detailed determinations of the sustainable availability of biomass for space heating. The management policies of the Tongass are also dynamic, and even if determinations could be made today, the policies will change in the future and will likely change in accordance with the biomass needs of the region. There are also concerns that Tongass management policies may adversely affect the economics of supplying pellets from the region. Even if this were to occur, imported pellets should still be economical since the evaluations are based on the cost of imported pellets.

Table 15-6 presents the estimated pellet usage in 2021, which represents the target year for the 80 percent penetration of conversion to pellets. Table 15-6 indicates that by 2021, 129,000 tons of pellets would be required annually, which may be difficult to achieve under today's conditions, but may not be unreasonable to achieve in 10 years. Table 15-7 presents the projected annual pellet consumption for 2012 through 2021 for the proposed program. Potential sources of supply identified by Sealaska are as follows:

- 53,000 tons per year of manufacturing residues.
- 18,000 tons per year silvaculture residues.
- Harvest residuals currently going to pulp market.

While pellet mills vary in size, the minimum amount of pellets necessary to initially support a mill is approximately 10,000 tons annually. Mills can increase their production by increasing their operation. Depending on the size of the mill, an individual mill can produce up to about 30,000 tons per year. Some mills in British Columbia and the lower 48 produce over 100,000 tons annually. Based on the tonnage requirements for the proposed program about four 30,000 ton per year mills would be required fot the region. Actual size and location of mills in the region will be a function of the source of wood for the pellets and a balance of wood transportation costs and economies of scale with pellet mill size. Sealaska has estimated that residues at the Viking Mill are sufficient to support a 10,000 to 25,000 ton per year pellet mill.

One benefit of the use of pellets is that if there are periods of time that an Alaskan supply of pellets is insufficient to meet the regions needs pellets can be imported into the Southeast to meet the region's needs.

Table 15-6 Estimated Pellet Consumption by Subregion (Tons)

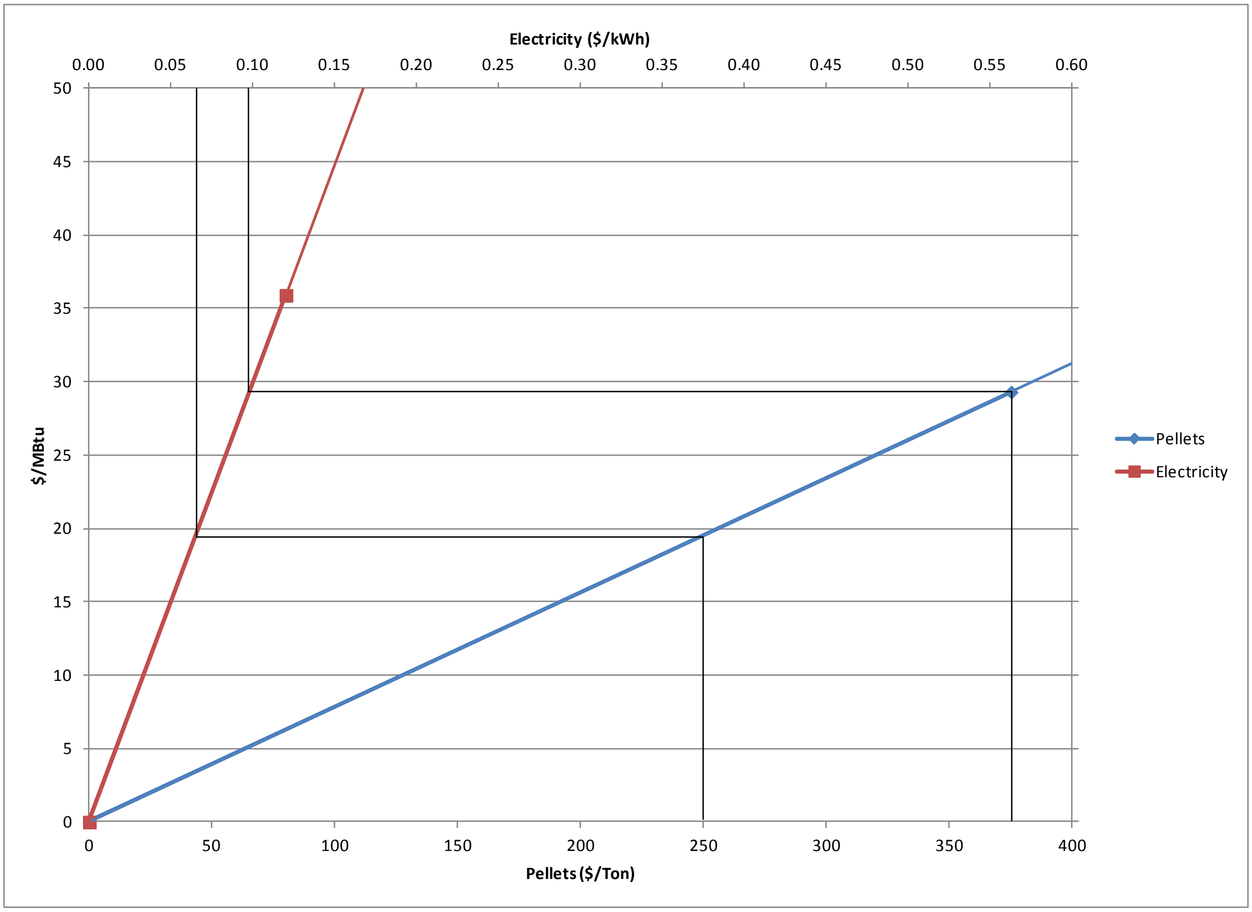
SUBREGION	TONS
SEAPA	
Kake	1,717
Petersburg	1,611
Wrangell	5,362
Ketchikan	20,558
Metlakatla	2,327
Total	**31,574**
ADMIRALTY ISLAND	
Angoon	733
Total	**733**
BARANOF ISLAND	
Sitka	13,010
Total	**13,010**
CHICHAGOF ISLAND	
Elfin Cove	74
Hoonah	1,390
Pelican	157
Tenakee Springs	227
Total	**1,848**
JUNEAU AREA	
AEL&P	59,495
Total	**59,495**
NORTHERN REGION	
Yakutat	1,352
Gustavus	1,797
Total	**3,149**
PRINCE OF WALES	
AP&T	9,945
Whale Pass	134
Total	**10,078**
UPPER LYNN CANAL	
Chilkat Valley	821
Klukwan	235
Haines	4,179
Skagway	3,729
Total	**8,964**
Southeast Region	**128,852**

Table 15-7 Annual Pellet Consumption Southeast Region (Tons)

YEAR	TONS
2012	12,162
2013	24,556
2014	37,279
2015	50,335
2016	63,575
2017	76,448
2018	89,396
2019	102,440
2020	115,567
2021	128,852

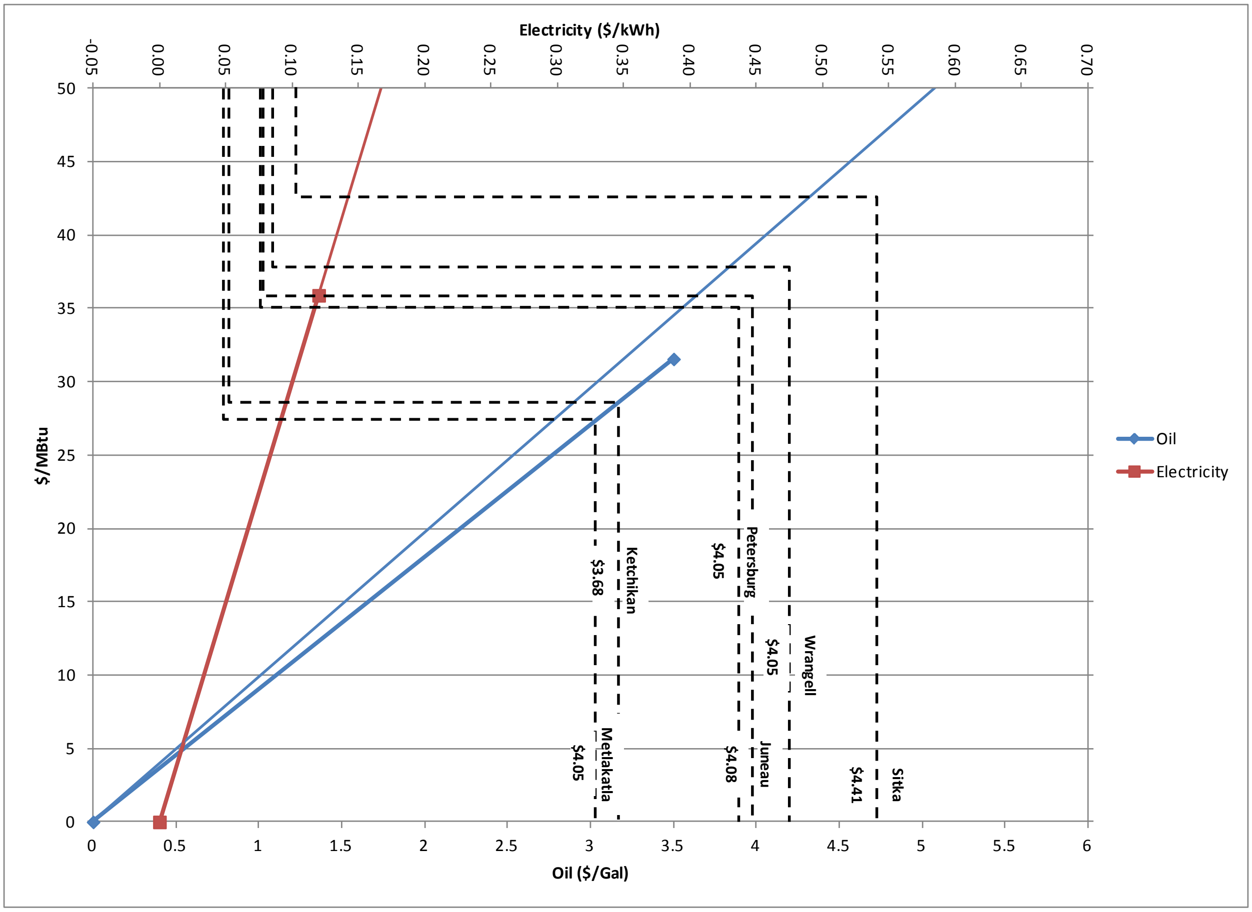
15.8 COMPETITION FROM ELECTRIC SPACE HEATING CONVERSIONS

Historically, there have been significant numbers residential and commercial customers who have converted to electric space heating with no incentives other than the price of electricity. Figure 15-19 shows the relationship of the breakeven cost of pellets and the cost of electricity considering their respective efficiencies as discussed in Section 16.0. Figure 15-20 shows the 2010 cost of electricity for the communities with low-cost hydroelectric generation and the projected 2012 medium price of heating oil from Section 5.0. While the Figure 15-20 presents supposedly the average electric rates, many communities have declining block or other rates, which incentivize conversion to electric space heating. For example, while Petersburg shows an 11.8 cent rate that applies to the first 325 kWh each month, Petersburg's rate for over 650 kWh per month is 7.0 cents. Because, in general, there are no incentives to pay the capital cost of conversion to electric space heating, the energy cost for conversion will need to be somewhat lower in order to provide the customer with an incentive to convert. Section 8.0 presents discussions by utility managers as to what they believe the threshold of oil price is to stimulate conversions on their system. This threshold of oil prices is difficult to predict and will continue to change with customer perceptions of the comparative costs of oil and electricity. Figure 15-20 shows that there can still be potential to convert to electric space heating and Figure 15-19 shows that the conversion could potentially be more competitive than pellets, depending on the special electric rates that incentivize electric heat.



Note: Assumes 80 percent efficiency for pellets and 98 percent efficiency for electricity. Assumes 8,000 Btu/lb for pellets.

Figure 15-19 Comparison of Breakeven Costs for Pellet Versus Electric Space Heating



Note: Assumes 80 percent efficiency for oil and 98 percent efficiency for electricity. Assumes 138,690 Btu/gal for oil.

Figure 15-20 Comparison of Breakeven Oil Prices for Conversion to Electric Space Heating

The question becomes whether it is in the best interest overall for the region to have declining block rates or other incentives for electric space heating. If there is excess hydroelectric generation, or if the cost of new hydroelectric generation is low enough, such incentives could be justified. In general, however, it appears that the cost of new hydroelectric generation will be above that of existing generation, which would tend to make block tariffs that decrease less appropriate. The issue is further clouded by the fact that much of the existing hydroelectric generation has been subsidized in some manner or another, and those subsidies are included in the rates. While future hydroelectric generation may also be subsidized to some extent, the question is whether incentive rates should reflect these subsidies or be based on actual costs. Conventional economic theory dictates that it is important to send appropriate price signals to obtain rational decision making.

If the region's energy policy is to adopt the cost based approach, declining block tariffs should be adjusted to reflect the cost of future generation. Unfortunately, many customers have made investments in electric space heating equipment based on these lower tariffs. Increasing these tariffs to reflect the cost of new generation will cause unrest among the customers who have made these investments. Thus, adjusting tariffs will not be an easy task, but remains as a low-cost method to stem the number of conversions to electric space heating.

Interruptible rates for space heating offer an additional alternative. The benefit of interruptible rates is that the can help better optimize the use of hydro. They can provide additional load for hydro projects that are initially unable to have their energy fully utilized upon initial operation. Interruptible rates can also make use of water that might otherwise be spilled, although most spillage occurs during periods of no or low space heating load. The disadvantage of interruptible rates is that it requires the customer to have back up space heating. This increases the capital cost for the customer and can be a barrier to implementation.

Another issue to consider is value of electricity to the economies of the Southeast. Electricity has a higher value than space heating due to the many end uses that it can perform. This fact contributes to decisions to reserve electricity for these uses rather than expend it for space heating when other energy forms are available.

Black & Veatch has estimated a cost of $50,000 for conducting a workshop to address these issues with the utilities in the Southeast and has estimated a cost of $1.5 million for conducting utility-specific cost of service studies to determine the appropriate tariffs for the last block of residential and commercial customer tariffs. Special attention will be given to tariffs for large community heating loads.

16.0 Initial Analysis of Issues

Section 3.0 listed several economic and socioeconomic issues and challenges affecting Southeast Alaska. Since these issues include fundamental indicators of economic well being, such as the continued loss of population and jobs, it is not an exaggeration to state that the long-term viability of the Southeast Region depends on developing an effective plan to address these issues and challenges. An initial analysis of these issues is provided in this section.

At the outset, it is important to identify whether the issues and challenges facing Southeast Alaska can be addressed by the local populations and governments, or whether State and Federal decision involvement will be required as well.

Southeast Alaska is unique from many perspectives. Covering a vast area, it is nevertheless sparsely populated and has very limited private sector and local government resources to coordinate and fund an economic stabilization plan. While the government sector does have a high percentage of employees compared to other regions, this is driven by State workers in Juneau who provide services for the entire State. Due to the small population size, it is apparent that State involvement will be required from a number of perspectives.

The situation is further impacted and complicated due to the control of approximately 95 percent of the land in Southeast Alaska by the Federal government. Much of this land is in the Tongass National Forest (80 percent, 16.8 million acres) or in Glacier Bay National Park (15 percent, 3.3 million acres). Less than 1 percent of the land is in private or municipal land holdings.[1] Since these lands are under Federal government control and are impacted by Federal regulations and laws such as the 2001 Roadless Area Conservation Rule (the Roadless Rule), it is apparent that an adequate, viable, long-term solution will require involvement at the Federal level as well as at the State and local level.

[1] *Southeast Alaska Action Initiatives for Key Economic Clusters*, presentation by the Juneau Economic Development Council (JEDC) presented in Juneau, May 24, 2011, slide 4. Available at http://jedc.org/forms/PowerPoint%20Presentation%20May%2024,%202011.pdf, accessed July 15, 2011.

Coordination at three levels is difficult to manage and requires the balancing of many different and sometimes competing interests. Fortunately, the need for cooperation in the development of a long-term stabilization plan has been previously recognized by Federal and State entities and efforts to develop a plan are underway. At the Federal level, the effort is being led by the U.S. Department of Agriculture (USDA) and the U.S. Forestry Service, where a Transition Framework is currently being developed. This framework will be referenced in this section as it addresses many of the regional issues and challenges identified in Section 3.0 of this report. The following excerpt from a U.S. Forest Service Issue Paper (June 2011) summarizes its perceived role in helping to stabilize the region:

> Secretary of Agriculture Tom Vilsack has directed USDA agencies, Forest Service (FS), Rural Development (RD), and Farm Services Agency (FSA) to develop a strategy known as the Transition Framework to help Southeast Alaska diversify and strengthen its economy…The focus of the transition is on supporting job growth and healthy communities through partnerships and alignment of USDA and USDOC resources. Growth opportunities in natural resource based sectors were identified through a series of community listening sessions and a contract with Juneau Economic Development Council (JEDC). The JEDC contract resulted in a report on assets important to economic growth and over 30 action initiatives to create jobs in SE Alaska. The action initiatives were developed by economic cluster work groups…[that] consisted of leaders from business, government, and non-government organizations. The charge of these collaborative groups was to produce a set of actions that would create jobs and give SE Alaska a competitive advantage in four natural resource based sectors: Ocean Products, Visitor Services, Forest Products and Renewable Energy.
>
> A USDA-USDOC Implementation Team has been meeting to oversee the development and implementation of this effort. State, tribal, and local government leaders have met with the Implementation team and partners to help formulate follow-up efforts.[2]

Another collaborative effort of the U.S. Forest Service involving local, State, and Federal planning efforts is the Tongass Futures Roundtable that includes various stakeholders in the region who explore ways to balance economic, cultural, and ecological interests through public policy decisions. The goal is to "achieve a long-term balance of healthy and diverse communities, vibrant economies, responsible use of resources, including timber, while maintaining the natural values and ecological integrity of the forest."[3]

The following sections provide a description and initial analysis of the key issues and challenges affecting Southeast Alaska.

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[2] U.S. Forest Service Issue Paper (June 2011) available at http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb5299766.pdf accessed July 14, 2011.

[3] http://www.fs.fed.us/r10/tongass/Tongass_Futures_Roundtable/Tongass_Futures_Roundtable.shtml, accessed July 19, 2011.

16.1 DECLINING POPULATION IN COMMUNITIES

Table 16-1 lists the change in resident population for Alaska and the Census areas and boroughs in Southeast Alaska from 2001 through 2008. While the State population increased by approximately 53,000 or 8.4 percent during this period, six of the eight Census areas and boroughs in Southeast Alaska decreased in population. In total, the Southeast Alaska Region experienced a decrease in resident population from 71,949 to 70,456. This is a loss of 2.1 percent.

The downward population trend for Southeast Alaska began in 1998 due primarily to forest industry declines. According to the Alaska Department of Labor and Workforce Development, this downward trend is expected to continue and represents a serious threat to long-term social and economic stability. Table 16-2 shows that between 2009 and 2034, the State of Alaska is projected to experience a population growth of 24.6 percent. In addition, five of the six State regions are expected to experience population growth; only the Southeast Region is expected to experience a population decline. The population decline forecasted for the Southeast Region is 14.2 percent over the period. Driving this projection of further losses of population is the demographic makeup of the Southeast Region, which includes a median age that is nearly 6 years older than the State-wide average (39.3 versus 33.5) and the low birth rates associated with an older population. According to the Alaska Department of Labor and Workforce Development:

> The only regional population expected to decline over the projection period is Southeast. Due to particularly low birth rates and the highest median age in the state (39.3), growth would require a sharp rise in net-migration. Southeast's projected loss is about 9,866 people (a 14.2 percent drop) between 2009 and 2034. The future of Southeast is uncertain because of its dependence on future social and economic developments.[4]

In general, such trends are very difficult to stabilize or reverse. Primarily, this is because demographic trends are usually linked to economic opportunities and the general business environment of a region. Section 16.2 discusses the declining economies in the Southeast Region in more detail, but it seems clear that a reversal of population trends in the Southeast Region will be linked to the ability to attract new, relocating populations and this will require the establishment of a business environment that is seen as being stable for the long term. Adequate infrastructure including a low and reliable cost of power is a key component of such a strategy to stabilize any region and is important from both a business investment and resident population perspective. While a low cost and reliable power supply is not, in and of itself, sufficient to reverse population trends, it is highly probable that the recent population and economic trends will not be reversed unless adequate and economic power supplies are secured for the region.

[4] From the Alaska Department of Labor and Workforce Development.

Table 16-1 Annual Resident Population Estimates for Alaska and Southeast Alaska Census Areas and Boroughs, 2001 and 2008

GEOGRAPHIC AREA	2001 RESIDENT POPULATION	2008 RESIDENT POPULATION	CHANGE	PERCENT CHANGE
Alaska	633,160	686,293	53,133	8.4%
Haines Borough	2,318	2,271	(47)	-2.0%
Juneau City and Borough	30,475	30,988	513	1.7%
Ketchikan Gateway Borough	13,762	13,142	(620)	-4.5%
Prince of Wales-Outer Ketchikan Census Area	5,896	5,533	(363)	-6.2%
Sitka City and Borough	8,726	8,889	163	1.9%
Skagway-Hoonah-Angoon Census Area	3,385	3,066	(319)	-9.4%
Wrangell-Petersburg Census Area	6,588	5,910	(678)	-10.3%
Yakutat City and Borough	799	657	(142)	-17.8%
Total for Southeast Alaska	**71,949**	**70,456**	**(1,493)**	**-2.1%**

Source: U.S. Census Bureau, Table 1: Annual Estimates of the Resident Population for Counties of Alaska: April 1, 2000 to July 1, 2008 (CO_EST2008-01-02).

Table 16-2 Annual Resident Population Forecast for Alaska, State Regions, and Southeast Alaska Census Areas and Boroughs, 2009 and 2034

GEOGRAPHIC AREA	2009	2034	CHANGE	PERCENT CHANGE
Alaska	692,314	862,750	170,436	24.6%
Haines Borough	2,286	1,422	(864)	-37.8%
Juneau City and Borough	30,661	30,191	(470)	-1.5%
Ketchikan Gateway Borough	12,984	9,878	(3,106)	-23.9%
Prince of Wales-Outer Ketchikan Census Area	5,392	3,566	(1,826)	-33.9%
Sitka City and Borough	8,627	8,000	(627)	-7.3%
Skagway-Hoonah-Angoon Census Area	2,908	2,100	(808)	-27.8%
Wrangell-Petersburg Census Area	5,852	3,828	(2,024)	-34.6%
Yakutat City and Borough	628	487	(141)	-22.5%
Total for Southeast Region	**69,338**	**59,472**	**(9,866)**	**-14.2%**
OTHER REGIONS				
Anchorage/Mat-Su Region	374,902	517,429	142,527	38.0%
Gulf Coast Region	76,686	81,925	5,239	6.8%
Interior Region	108,463	124,658	16,195	14.9%
Northern Region	23,664	29,572	5,908	25.0%
Southwest Region	39,261	49,694	10,433	26.6%

Source: Alaska Dept. of Labor and Workforce Development, Research and Analysis Section: December 2010, *Alaska Economic Trends*, p. 10, Table 9.

16.2 DECLINING ECONOMIES IN COMMUNITIES

Southeast Alaska is a sparsely populated, geographically dispersed region that includes many small island communities dependent on industries linked to the area's natural resources. Employment is largely connected with the industries of fishing, tourism, timber, and mining. Juneau, as the State capital, also has a large number of government workers and differs from the remainder of Southeast Alaska in terms of population density, transportation access, and dependency on resource-related industry. Consequently, while most communities in the Southeast have been suffering population loss and economic challenges over the past decade, Juneau has remained relatively stable.

Southeast Alaska had an average of 36,200 jobs in 2010. The division of these jobs into major employment sectors is shown in Table 16-3. One of the characteristics of the Southeast Region is that, while a small population and employment region, there is a large amount of economic and employment diversity. The largest employment sector is the government sector (13,500 workers), with State (5,550 workers) and local (6,200) government workers the largest categories. Retail trade (4,350 workers) is the second largest sector and is part of the trade, transportation, and utilities sector that had 7,150 workers. Other sectors of note are the manufacturing sector (1,800 workers), which is dominated by the seafood processing industry (1,300 workers), the mining and logging sector (700 workers), education and health services sector (3,800 workers), and the leisure and hospitality sector (3,500 workers).

The total number of workers in 2010 grew by 0.4 percent compared to the average 2009 workers in the region (36,050). This slight growth was encouraging given the 2.2 percent loss in the 2008 to 2009 period and given the sluggish national economy. However, regional jobs were lost in the trade, transportation, manufacturing, information, construction, and leisure and hospitality sectors.

Table 16-4 indicates the unemployment rate for the United States, Alaska, the Southeast Region and the cities and boroughs in the region. The figures are not seasonally adjusted. The Statewide unemployment rate of 7.7 percent is a percentage below the national rate, and the Southeast Region rate of 7.4 percent is slightly below the Statewide rate. Within the region, unemployment rates vary widely, from a low of 5.3 percent in Juneau to a high of 19.5 percent in the Hoonah-Angoon Census area.

The Alaska Department of Labor and Workforce Development projects that the 2011 average employment level in the Southeast Region will decrease by 1.1 percent in 2011. This projection is based on the expectation that "structural demographic changes and hesitant tourists will continue to erode employment in the trade, transportation, leisure, and accommodation sectors. However, government, mining, and health care will provide enough ballast to keep overall losses small."[5] The Southeast Region's projection of 2011 employment is shown in Table 16-3.

[5] Alaska Department of Labor and Workforce Development, *Alaska Economic Trends*, January 2011, p. 16.

Table 16-3 Wage and Salary Employment for Southeast Alaska, 2010 Average and 2011 Forecast

GEOGRAPHIC AREA	2010 EMPLOYMENT AVERAGE	2011 EMPLOYMENT PROJECTION	CHANGE	PERCENT CHANGE
Total Nonfarm Wage and Salary	36,200	35,800	(400)	-1.1%
Mining and Logging	700	700	-	0.0%
Construction	1,400	1,400	-	0.0%
Manufacturing	1,800	1,800	-	0.0%
Seafood Processing	1,300	1,300	-	0.0%
Trade, Transportation, and Utilities	7,050	6,850	(200)	-2.8%
Retail Trade	4,350	4,300	(50)	-1.1%
Information	450	450	-	0.0%
Financial Activities	1,300	1,300	-	0.0%
Professional and Business Services	1,450	1,450	-	0.0%
Educational and Health Services	3,800	3,800	-	0.0%
Leisure and Hospitality	3,500	3,400	(100)	-2.9%
Other Services	1,200	1,200	-	0.0%
Government	13,550	13,450	(100)	-0.7%
Federal	1,800	1,750	(50)	-2.8%
State	5,550	5,550	-	0.0%
Local	6,200	6,150	(50)	-0.8%

Source: Alaska Department of Labor and Workforce Development, *Alaska Economic Trends*, January 2011, page 16, Table 14. Southeast Alaska Wage and Salary Employment Forecast for 2011.

Table 16-4 Unemployment Rates for the United States, Alaska, the Southeast Region and Cities and Boroughs in the Region, May, 2011

AREA	MAY, 2011 RATE, UNADJUSTED
United States	8.7
Alaska	7.7
Southeast Region	7.4
Haines Borough	9.6
Hoonah-Angoon Census Area	19.5
Juneau, City and Borough	5.3
Ketchikan Gateway Borough	7.6
Petersburg Census Area	10.5
Prince of Wales-Hydrer Census Area	14.7
Sitka, City and Borough	5.9
Skagway	16.2
Wrangell, City and Borough	8.2
Yakutat, City and Borough	12.4

Source: Alaska Department of Labor and Workforce Development, *Alaska Economic Trends*, June 2011, p. 18, Table 4.

16.2.1 Primary Industries

In addition to government, there are a number of sectors that drive the Southeast Alaskan economy. A brief profile of these industries is provided below.

The **tourism (visitor products) industry** in Southeast Alaska is of primary importance, with the majority of visitors coming to the area aboard cruise ships. Visitors to Southeast Alaska from cruise ships increased from approximately 569,000 in 1998 to 1,018,700 in 2008 before being impacted by the national recession. Still, however, there were more than 1 million cruise ship passengers visiting the Southeast in 2009 and 875,000 in 2010.[6]

There were also approximately 230,000 independent travelers that were not associated with the cruise ship industry. Of this number, approximately 200,000 came during the summer months and 30,000 came in the winter. Further development of independent (noncruise ship) tourism would appear to be an important focus as it would involve longer stays and increased opportunities for expenditures and support businesses in the Southeast.

In 2009, the transportation and tourism industry employed 3,225 workers, up slightly from 3,175 in 2003. The average wage in 2009 for this industry was $33,953. Sectors in this grouping plus their respective employment and average salary levels included air transportation (716; $37,295), water transportation (268; $59,124), scenic and sightseeing transportation (727, $34,639) accommodations (1,094; $21,005). The economically linked food services and drinking places sector employed 1,614 workers at an average wage of $15,833 in 2009.[7]

The **fishing and ocean products industry** is another key sector for Southeast Alaska. The fishing industry's main fish product is salmon, but a variety of other fish are also harvested and processed each year. There is also a mariculture industry made up of approximately a dozen farms in Yakutat, Kake, and Naukati Bay that primarily raise oysters and clams. There are approximately 60 fisheries in the Southeast with most utilizing small fishing boats. In 2009, the industry generated $234 million in wages earned by fishermen, and 18 percent of employment in the Southeast was related to this industry, which produced 178 million pounds of processed seafood that year.[8]

The average sector employment in 2009 was 3,845 in the region, up from 3,680 in 2003. The average wage for the fishing and ocean products industry was $51,989. Sectors within the industry plus their respective employment and wage information for 2009 included seafood product preparation and packaging (1,390; $31,487), animal aquaculture (131; $36,968); fishing (2,281; $65,338) and fish and seafood merchant wholesalers (43; $52,052).[9]

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[6] *Southeast Alaska Action Initiatives for Key Economic Clusters*, presentation by the Juneau Economic Development Council (JEDC) presented in Juneau, May 24, 2011, slide 10. Available at http://jedc.org/forms/PowerPoint%20Presentation%20May%2024,%202011.pdf, accessed July 15, 2011.

[7] Ibid, slide 11.

[8] Ibid, slide 13, 14.

[9] Ibid, slide 21.

The **forest products industry** has been a very important industry for the region historically, but has been in steep decline for years, with employment decreasing from 3,463 in 1990 to only 238 in 2009. The total timber harvest has decreased from 495 million board feet (mmbf) in 1997 to 115 mmbf in 2009. Of the 238 workers in 2009, 158 were directly involved in logging activities, 24 in support activities for forestry, and 56 were involved in wood product manufacturing. The average wage for the industry was $49,375 and subsector wages averaged from a low of $38,214 in wood products to $52,149 in logging and $56,858 in forestry support activities.[10]

A study by the Juneau Economic Development Council and funded by the USDA reported that the timber industry has been hurt by changing forest management practices, declining timber harvests on private land, and general market conditions. There were processing mills closed in Ketchikan, Sitka, and Wrangell in the 1990s, and the loss of jobs in this industry has cost more than $100 million in annual payroll. Today, there is only one large sawmill in the Southeast.[11] Clearly, if the industry is to survive in the Southeast to any meaningful degree, the challenges facing the industry must be addressed to the degree possible. It must be recognized, however, that the industry is part of a global market and its remote location places it at a competitive disadvantage versus other participants in the global timber industry. When additional issues such as high power costs and limited access to timber resulting from the Roadless Rule (see below) are factored in, it is apparent that saving the industry will be challenging. Key issues will be the provision of a reliable and low cost power supply to the industry and its workers, the resolution of issues related to the Roadless Rule, and the development of a local (Southeast and Alaskan) market for industry products. This final issue (a local market for product) and the cost of power are related, and they are further discussed in Section 16.3.

The **mining industry** has historically been a volatile employment sector but it has shown strong growth recently due to a rapid increase in global prices for minerals and ores. Products mined locally include gold and silver, and there are also rare earth elements on Prince of Wales Island. The primary mines include the Kensington Gold Mine in Juneau, which is expected to reach 600 employees by the end of 2011; the Hecla Greens Mine on Admiralty Island, which is the second largest silver producer in North America, and a mine for rare earth elements is currently being developed on Bokan Mountain on Prince of Wales Island. This mine could begin production in 2012.[12] As with the timber industry, the mining sector is subject to competition in a global market, but that market has been very favorable in the recent past and could help stabilize the overall economy in the Southeast. Specific local issues related to the health of this industry include the access to low cost power and the resolution of issues related to the Roadless Rule.

[10] Ibid, slide 40
[11] Ibid, slide 17.
[12] Ibid, slide 17, 18.

16.2.2 Additional Analysis

In theory, the economic diversity in the Southeast Region is a benefit that can help buffer the impact of a downturn in a single industry. Much of the diversity is the result of the natural resources in the region that lead to employment opportunities. On the other hand, there are several major issues and challenges to overcome for the Southeast Region to stabilize and recover. These issues and challenges were touched on previously and are more fully developed in this section.

As part of the USDA's Transition Framework, the JEDC conducted a survey of business leaders to identify the strengths and challenges of doing business in Southeast Alaska. Reflecting the link to the natural resources found in the Southeast, 57 percent of business leaders indicated that the location in Southeast Alaska was good, very good, or excellent.[13]

The survey also identified several barriers present in the region. A full 75 percent of business leaders indicated that freight costs were a moderate or significant barrier, and 61 percent of the business leaders located outside of Juneau indicated that the price of electricity was a barrier. A majority indicated that the costs of business real estate (59 percent) and residential real estate (56 percent) were moderate or significant barriers, while Federal regulations (33 percent) and State regulations (25 percent) were identified as barriers. [14] Of these barriers, some are simply inherent in the remote location and geographical characteristics of the Southeast and will be difficult to address with any policy change or through a stabilization plan. However, the price of electricity and certain issues related to regulations are matters that could be addressed through the Transition Framework or through other stabilization initiatives and will be further discussed below.

The survey asked about regional issues that needed to be resolved. The top issues were to stabilize the economy and to improve the transportation network (16 percent each), to improve attitudes towards industry and collaboration between industries (15 percent), to reduce government regulations and controls (13 percent), and to create more affordable housing (8 percent).[15]

The JEDC studies identified specific objectives for each of the key economic cluster areas (ocean products, visitor services, forest products and renewable energy). Key recommendations for these areas included the following:

Tourism

- Develop multi-purpose, multi-community land and water trails and support facilities.
- Increase guided access to land.
- Promote multi-community and regional visitor packages.
- Strengthen accountability for Tongass access fees.
- Integrate tourism course with UAS existing degree program.

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[13] *Southeast Alaska Economic Asset Map: Summary*, Juneau Economic Development Council, (JEDC), http://jedc.org/forms/Southeast%20Alaska%20Economic%20Asset%20Map%20Summary.pdf, slide 3, accessed July 18, 2011.
[14] Ibid, slide 4 and 5.
[15] Ibid, slide 6.

Ocean Products Industry

- Enhance salmon production.
- Increase wild salmon production through habitat restoration.
- Ensure the fishing industry's future through targeted education and training.
- Establish a marine industry technology and workforce improvement consortium.
- Include the seafood industry in the USDA programs.
- Study the conversion of fish byproduct to biogas and fertilizer through anaerobic digestion.
- Further develop renewable energy.
- Protect long term assured access to fisher resources (including marine spatial planning, research, etc.).
- Establish region-wide mariculture zoning.
- Develop a sea otter management program.

Forest Products Industry

- Use young growth wood for cabin and recreational structures on Prince of Wales Island.
- Simplify small timber sale process to allow small mills on Prince of Wales Island to operate more efficiently, economically, and with supply certainty.
- Increase knowledge about building with Alaskan wood and influence attitudes about Southeast Alaska woodworking industries.
- Improve selected USFS processes.
- Establish the "Tongass National Forest – Congressionally Designated Timberlands" to provide a secure and perpetual working forest land base managed under forest regulations and guidelines that streamline process and improve predictable delivery of supply.
- Substitute biomass for diesel to meet energy needs of Southeast Alaska.

Southeast Alaska Renewable Energy Resources

- Establish a renewable energy revolving loan fund for residences and small businesses to promote local installation and fueling industries.
- Biomass energy demand development.
- Streamline permitting and schedule acceleration.
- Renewable energy education for Southeast Alaska residents, students, businesses.
- Study best practices to overcome barriers, provide incentives to pursue renewables and energy efficiency.
- Propose net metering legislation.

- Marketing Southeast Alaska to the renewable energy industry.
- Conduct renewable energy economic modeling for Southeast Alaska.
- Explore opportunities for connecting with North American Grid.[16]

16.2.3 Electricity and Land Use: Key Issues Impacting Long-Term Employment Growth

Many issues will impact the ability to achieve long-term employment growth objectives in the Southeast Region, but it is apparent that two key issues will heavily influence the overall results of stabilization efforts as well as the success of stabilization efforts in specific communities and industries. The first is the ability to balance the competing interests surrounding land use of Federal lands in the Tongass National Forest. The second key issue is the ability to provide affordable and stable electricity to businesses and residents in the Southeast communities. The first of these will also directly impact the second issue, since the ability to provide low cost power options to the dispersed communities will, in some degree, depend on the ability to install hydroelectric facilities and transmission lines in new areas that may be located or otherwise utilize National Forest lands (see Section 16.5).

Perhaps the largest consideration related to use of Federal lands is the Forest Service 2001 Roadless Area Conservation Rule (the Roadless Rule) that limits road construction on designated areas of public land, called "inventoried roadless areas." The rule was passed in 1991 to help prevent erosion, pollution, and species loss in National Forest areas.

According to the U.S. Forest Service, the inventoried roadless areas in Southeast Alaska include 9.5 million acres (57 percent) of the Tongass National Forest. In addition, congressionally designated wilderness areas make up 5.9 million acres (35 percent) of the Tongass National Forest. The majority of the inventoried roadless areas in the Tongass National Forest (7.4 million acres) are allocated to nondevelopment land use designations. A total of 13.3 million acres (80 percent of the Tongass) is generally off limits to road construction and timber harvest activities.

The restricted access to the Tongass National Forest has impacted the lumber industry and, to an extent, the mining and other industries. As the U.S. Forest Service stated in its briefing paper "10-Year Sale Contracts" (April 2011):

> The previous administration made a commitment to the forest products industry in Alaska for four, 10-year timber sale contracts to aid in stabilizing the existing industry infrastructure and provide a basis from an integrated forest product industry. Current administration policies with respect to activities within inventoried roadless areas have greatly reduced the land base from which these contracts could be planned. In an effort to sustain the remaining forest products industries, timber industry stakeholders, including the State of Alaska, continue to press for contracts that are not possible under current roadless policies.

[16] Southeast Alaska Action Initiatives for Key Economic Clusters, http://jedc.org/forms/PowerPoint%20Presentation%20May%2024,%202011.pdf, presented May 24, 2011, Juneau., slides 14 – 64, accessed July 18, 2011.

> Given Departmental direction, the recent court decision, and consideration of goals and objectives of the Transition Framework for Southeast Alaska, all long-term contracts (e.g., stewardship and timber sale) will consider timber harvest in the roaded base only, thereby reducing overall project volumes and making commitments for larger scale, 10-year contracts more difficult to obtain.[17]

The Roadless Rule has been subject to several court actions since 2001. While the administration of President George W. Bush modified the regulations to allow more State control to designated roadless areas, in 2006, a U.S. District Judge ruled against the Bush Administration's approach. In 2003, through a settlement among the State of Alaska and six other parties, the USDA temporarily exempted the Tongass National Forest from application of the Roadless Rule until completion of a rulemaking process to make permanent amendments to the Roadless Rule. On March 4, 2011, however, the Alaska District Court vacated the Tongass Exemption and reinstated the Roadless Rule on the Tongass National Forest.[18] The March decision that reinstated the Roadless Rule had the impact of placing off limits, approximately 300,000 acres of inventoried roadless areas that could have otherwise been logged.

On July 13, 2011, an Alaskan Congressional Delegation led by United States Senator Mark Begich and Congressman Don Young introduced legislation to repeal the 2001 Roadless Rule in Alaska's National Forests. Senator Lisa Murkowski was a co-sponsor of the Senate legislation. A story in SitNews (Ketchikan), partially reproduced below, shows the opinions on each side of the issue and the challenges involved in arriving at a solution that satisfies all sides:

> Referring to the Roadless Rule, "This cookie-cutter rule is a bad fit for Alaska," U.S. Senator Begich said. "With high unemployment and high energy costs in Southeast Alaska, the Forest Service needs greater flexibility to address these issues. Repealing the rule will help keep the few existing mills alive and allow for the development of hydro projects throughout the region as well as two promising mining projects on Prince of Wales Island. Instead of adding options, the Roadless Rule takes them away."
>
> Conservationist groups say the Roadless Rule currently protects 9.3 million acres in the Tongass and 5.6 million acres in the Chugach – areas that include vital watersheds, critical salmon habitat, and old-growth trees – from logging and other road-building activities. This legislation is a departure from the March 2011 Federal court decision that called the past exemption of the Tongass from the Roadless Rule "arbitrary and capricious."
>
> "This bill makes absolutely no sense for Americans. It threatens vital habitat for salmon, bears, and other wildlife, which Southeast Alaskans rely upon for their living," said Carol Cairnes, President of the Tongass Conservation Society. "These are our public lands and we should have a say in how they are managed. The American taxpayer will not only lose a national treasure, but will have to foot the bill for timber subsidies. It's ridiculous."

[17] U.S. Forest Service, Issue Paper: *10-Year Timber Sales Contracts*, April, 2011, http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb5299777.pdf, accessed July 15, 2011.
[18] U.S. Forest Service, Briefing Paper, *Roadless Area Conservation*, http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb5299802.pdf, accessed July 15, 2011.

> Cindy Shogan, Executive Director of the Alaska Wilderness League, said, "The Roadless Rule is one of the most important public lands policies that protects vital watersheds, critical habitat for salmon and wildlife, and supports the top economic drivers of the region – tourism and commercial fishing industries. The Tongass and Chugach National Forests in Alaska represents our largest remaining temperate rainforest in the world."
>
> Shogan said, "We call upon Congress to stop this attack on one of America's greatest national treasures."
>
> Congressman Don Young said, "The Roadless Rule was ill-conceived and based on a one-size-fits-all theory." He said, "As we have seen time and time again, the one-size-fits-all approach rarely ever applies to Alaska. The economic well-being and way of life for many Alaskans relies on responsible resource development and this legislation will ensure that this rule doesn't harm Alaska more than it already has. Over the last few decades I have watched the timber industry go from thousands of jobs to nothing; we cannot allow the government to decimate this area more than they already have. This legislation is an economic necessity so that Alaskans may start to responsibly develop our resources in these areas again."
>
> "The roadless rule never made sense for Alaska since 96 percent of the Tongass and 99 percent of the Chugach are already protected by ANILCA and forest management plans," said U.S. Senator Lisa Murkowski. "Exempting the Tongass from the Roadless Rule will help make certain that what little remains of the timber industry in Southeast can survive long enough for the Forest Service to implement its second-growth harvest policy. The exemption will also ensure that hydropower and other affordable energy projects in Southeast can move forward."[19]

The future of the proposed legislation is difficult to anticipate at the present time. However, it seems apparent that due to the isolated nature of the Southeast Alaskan communities and the high cost of interconnecting these communities, even if the Roadless Rule were relaxed or eliminated for Alaska National Forests, project economics will favor the development of small hydroelectric projects located near the communities that have favorable characteristics or that are able to access transmission lines cost effectively to allow the transmission of hydroelectric power. Other communities not located near such hydroelectric opportunities, near existing transmission lines, or with the ability to interconnect with existing transmission at a reasonable cost may need to focus on other options for cost-effective alternatives to diesel generation such as wood pellets or propane. These options are addressed in the following sections.

[19] http://www.sitnews.us/0711News/071411/071411_roadless.html, accessed July 20, 2011.

16.3 HIGH COST OF SPACE HEATING

As indicated in Table 16-5, space heating in Southeast Alaska is provided primarily by fuel oil. While only 34 percent of homes in the entire State are heated by fuel oil and 23 percent of homes in the Railbelt used fuel oil, 70 percent of homes in Southeast Alaska used fuel oil in the 2005 through 2009 period. Electric heating was a distant second in the Southeast, at 16 percent, but this was higher than the 10 percent figure for the State as a whole, since the Railbelt region currently has access to natural gas supplies. Only four percent of the homes in the Southeast used natural gas or propane for heating, while 50 percent of homes at the State level and 63 percent of Railbelt homes used natural gas or propane for heating. Combined, 86 percent of homes in Southeast Alaska use either fuel oil or electricity for heating.

Another form of providing residential space heating includes heating by wood, which can include log-burning wood stoves or pellet burning systems. In the Southeast, 9 percent of homes utilized wood heating.

Table 16-5 Housing Unit Fuel Type by Region in Alaska, 2005 – 2009 Averages

AREA	NG/PROPANE	FUEL OIL	ELECTRICITY	WOOD	OTHER
Alaska	50%	34%	10%	4%	1%
Railbelt	63%	23%	10%	3%	2%
Southeast	4%	70%	16%	9%	1%
Rest of State	8%	79%	3%	10%	1%

Source: *Alaska Energy Statistics*, May, 2011, Fay, Ginny, Alejandra Villalobos Melendez, Ben Saylor & Sarah Gerd, Institute of Social and Economic Research, prepared for Alaska Energy Authority, May 2011, Page 158.

The cost of fuel oil is very volatile and depends on many factors. A study by the Institute of Social and Economic Research (University of Alaska, Anchorage), ISER, studied the price of delivered fuel oil to ten Alaska communities, including Yakutat and Angoon in Southeast Alaska, and found that prices varied by more than 100 percent.[20] The largest driver of delivered prices was the cost of crude oil, but significant drivers of the delivered price depended on factors such as how the fuel is transported to the community, the distance transported, quantity of fuel delivery and amount of storage capability, the number of times fuel is transported in route to the final delivery point, unloading equipment, and competition among transporters. The cost of transporting fuel oil is itself dependent on the cost of crude oil and fuel prices, so it is not surprising that the cost of fuel oil is highly volatile and costly to use for heating purposes. Crowley, a long-time distributor of fuel oil to Alaska communities reports that 62 percent of delivered heating oil costs are driven by the cost of crude oil, 29 percent is distribution cost related, and 9 percent are overhead costs.[21] These

[20] Research Summary: *Dollars of Difference: What Affects Fuel Prices Around Alaska?* By Meghan Wilson, Ben Saylor, Nick Szymoniak, Steve Colt, and Ginny Fay, Institute of Social and Economic Research, University of Alaska Anchorage, May 2008, R.S. No. 68, page 1.

[21] *Getting Fuel From There to Here, The challenges. The costs*. Phamplet accessible on the Crowley website: www.crowley.com; accessed on July 8, 2011.

figures are generally consistent with figures provided by the U.S. Energy Information Administration that estimate 62 percent of heating oil prices are accounted for by crude oil prices, 22 percent by distribution marketing and profits, and 16 percent for refinery processing and profits.[22]

Since the delivered cost of fuel oil is largely driven by volatile crude prices, the cost of home heating utilizing fuel oil or even electricity produced by diesel generating units will likely remain volatile and costly based on historical price fluctuations. This means that a long-term stabilization plan for Southeast Alaska communities must focus on more cost-effective and stable options to provide space heating for homes, commercial spaces, and industry.

Because natural gas is not available to communities in the Southeast, options to replace space heating reliant on fuel oil consist of additional hydroelectric power supplies, wood heating, and perhaps increased propane supplies. For those communities having nearby hydroelectric resources or the ability to interconnect with such projects at a reasonable cost, hydroelectric power will generally be a preferred option. For other communities not having access to hydroelectric power supplies, space heating for residential, commercial, and industrial uses could utilize wood heating in the form of wood pellets. This would be especially attractive if there was a regional effort to develop a viable wood pellet industry using local feedstock. Given this possibility, an overview of the wood pellet industry is provided below and comparative prices are provided with other fuels. This is followed by a discussion of recent studies that have evaluated the economics of increased propane supplies to coastal Alaskan communities.

16.3.1 Wood Pellet Space Heating

Wood pellets are small pieces of wood fuel made from timber, sawdust, or wood waste generated from lumber milling or other wood working processes. The pellets are formed by passing the material through a hammer mill and press where it is turned into a dough-like material and then forced through holes usually 6 mm or 8 mm in diameter. The resulting wood pellet product usually has a water content of less than 10 percent, which makes the product efficient to burn and transport. A typical heat content of wood pellets is approximately 8,000 Btu/lb.

A large advantage of heating with pellets over more traditional wood logs is that pellet feed systems are available and can automatically feed a stove for long periods of time. Pellet feed systems can be installed on wood burning stoves and are available for use with central heating furnace systems. Existing heating systems can also be retrofitted to accommodate wood pellet systems. The ability to automatically feed pellets and to utilize pellets in central heating systems makes this source of heating a realistic option for homes and commercial uses.

The wood industry and wood pellets generally have very attractive environmental qualities. This includes very low emission rates of NO_x, SO_x and volatile organic compounds (VOCs). It is estimated that, when compared to an equivalent amount of fossil fuel, wood pellets have up to 98 percent lower net lifecycle CO_2 emissions provided best practices are used.

[22] Heating Oil Prices and Outlook, U.S. EIA, available on-line at www.eia.gov/energyexplained/index.cfm?page=heating_oil_prices, accessed 7/11/2011.

Table 16- 5 presents a comparison of the emissions for residential oil and pellet space heating based on the EPA AP-42 emission factors. While there is considerable variance between sources of emission rates, the AP-42 emission factors represent a relatively consistent basis for comparison even though they are somewhat dated. The variance in emission rates stems from many factors such as vintage of furnace and fuel quality. While the emissions for pellets are low, they are in general somewhat higher than for oil. The CO_2 emissions for pellets in Table 16-5 are based on actual combustion and not the lifecycle rates discussed above.

Table 16-6 Emission Comparison Between Oil and Pellet Space Heating (lb/MBtu)

EMISSION	OIL	PELLETS
PM_{10}	0.0029[(1)]	0.26-0.55[(2)]
CO	0.036	2.46 - 3.26[(2)]
CO_2	160.8	184.5 - 229.4[(2)]
SO_x	0.0016	0.025[(3)]
NO_x	0.13	0.86[(3)]

[(1)]Filterable
[(2)]Certified - Exempt
[(3)]Certified
Note: Pellets 8,000 Btu/lb, Ultra Low Sulfur No. 2 Oil 0.138690 MBtu/gal.
Source: EPA AP-42.

The price of wood pellets has varied over the past decade with changing supply and demand conditions. Even so, the volatility of wood pellets has been less than crude oil and could become more stable as more production facilities come online to meet rising demands.

Pellets can be purchased in 40 pound bags or can be shipped and stored in large quantities. Prices per ton of wood pellets can currently range from $190 to $260 per ton in the lower 48 states with an average of around $250 per ton. Currently in Alaska, the price for a 40 pound bag of pellets in Juneau is a per ton equivalent of approximately $375. If a wood pellet industry emerged in Southeast Alaska, the retail price would decrease and could approach the price range seen in the lower 48 states.

At the current average price of approximately $250/ton, the cost of wood pellet heat is competitive with other options available in Southeast Alaska. Stated on a cost per MBtu basis, a price of $250 per ton equates to a cost of $19.53/MBtu (based on an appliance efficiency of 80 percent and assuming 16 million Btu/ton of wood pellets). Table 16-7 compares this cost with other heating options for Southeast Alaska. At a heating oil price of $3.50/gallon, this option has a cost of $31.55/MBtu (based on an appliance efficiency of 80 percent). To break even with wood pellets costing $250/ton, heating oil prices would need to decrease to $2.11/gallon.

Table 16-7 Wood Pellet Heating Option Cost Comparison on a $/MBtu Equivalent Basis

FUEL	UNIT COST	$/MBTU	BREAKEVEN UNIT COST WITH WOOD PELLETS AT $250/TON
Wood Pellets (average lower 48 price, proxy for SE Alaska price with local pellet production)	$250/ton	$19.53	NA
Wood Pellets (current price per ton based on cost of 40 pound bags in Juneau)	$375/ton	$29.30	$250/ton
Heating Oil	$3.50/gallon	$31.55	$2.09/gallon
Propane	$3.70/gallon	$50.644	$1.43/gallon
Electric (Juneau 2010 average)	12 cents/kWh	$35.89	6.5 cents/kWh
Electric (Metlakatla, 2010 average, lowest Southeast Alaska community)	9.2 cents/kWh	$27.51	6.5 cents/kWh
Electric (Tenakee Springs, 2010 average, highest Southeast Alaska community after PCE)	31.51 cents/kWh	$94.24	6.5 cents/kWh
Note: Assumes 80 percent appliance efficiency for wood pellets, fuel oil, and propane calculations, 98 percent efficiency for electricity.			

Table 16-7 also compares the cost of electricity at three price levels with wood pellets. The table indicates that at a cost of 12 cents/kWh, which was the average residential price in Juneau in 2010, the cost of electricity would be $35.89/MBtu (assuming 98 percent efficiency for a furnace or boiler). The break even price of electricity versus wood pellets at $250/ton is approximately $6.5 cents/kWh. Based on the high (30.5 cents/kWh) and low (9.2 cents/kWh) residential electricity costs of Southeast communities in 2010, the cost of electricity ranges from a high of $91.21/MBtu to a low of $27.51/MBtu. These break even costs are for fuel only and do not include the cost of new or retrofit stoves and furnaces needed to burn wood pellets.

A recent study by Haa Aaní, LLC evaluated the total program costs and benefits of converting seven schools in the Ketchikan School District from electric power to wood pellets. The study estimated that it would cost $2.5 million to convert the seven schools, but this would create a 20 percent savings on fuel costs each year (assuming a pellet cost of $300/ton) and the program would have a payback of less than 12 years if no State grant funds were put into the program. The volume of wood pellet fuel required for the program would account for one-fourth of the volume needed to support a local wood pellet production mill and could be a catalyst for creating a local production industry. The study concluded that there were ample opportunities for the conversion of additional commercial buildings to fully utilize the capacity of a wood pellet production mill. The study noted that conversion of the seven schools alone would reduce electric power requirements by 5 MW, thereby allowing other end-users the ability to utilize existing power supplies.[23]

[23] See *Ketchikan School District Pellet Boiler Systems: The Business Case*, a Power Point presentation by Nathan Soboleff, Renewable Energy Program Manager, Haa Aani, LLC and Peter Brand: PBrand BioEnergy Consulting.

The wood pellet industry has become firmly established in the United States and also in Europe, where wood pellets are being used to reduce reliance on oil imports and to control emissions. In fact, European investment in wood pellet production facilities in the United States has been on the rise in the past few years. Leading European countries using wood pellets include Sweden, Italy, Germany, Austria, and Denmark.

It is possible that a wood pellet industry could be established in Southeast Alaska to provide for local wood pellet demand if increased conversion to pellet systems materialized. When evaluating this possibility, there are both opportunities and obstacles to consider. The number of existing mills has been sharply reduced in recent years but remaining mills in the Southeast have an opportunity to expand their product base and sell into a relatively isolated market by adding pellet production operations that could utilize some waste from current operations or utilize harvesting equipment to secure the optimal supply of wood for pellets. It is also possible for specialized wood pellet production facilities that are not linked to existing mills to be established. One of the key issues impacting the perceived risk and long-term viability of such an industry in the Southeast Region is the resolution of the Roadless Rule and other policy decisions that could help ensure the long-term supply of basic wood product. If these issues can be resolved then from a supply perspective, the basic requirements for the emergence of a wood pellet industry would seem to exist in Southeast Alaska.

The largest uncertainties of establishing a viable wood pellet industry in Southeast Alaska surround product demand. Specific issues and challenges include the lack of current demand large enough to support a local production industry and the cost of installing wood burning systems that, while competitive with other heating systems, nevertheless requires an initial investment that many may not be willing or able to make. Given the small population of the communities that are the most likely candidates for wood pellet systems, the long-term viability of wood pellet manufacturing would depend on a significant percentage of candidate households and even businesses going to wood pellet systems. Conversion of large heating loads can provide anchor tenants for pellet production. In addition to the retrofit or installation of wood pellet systems in homes or businesses, there could be additional investments needed to allow for cost-effective transportation and distribution of wood pellets from manufacturing plants to communities where end-user programs have been implemented. This again could require funding assistance in the form of State grants or low interest loans to businesses entering the wood pellet business.

It is recommended that additional studies of the potential for a viable investment in the wood pellet industry in Southeast Alaska be undertaken. The study should evaluate production (supply) opportunities and discuss the potential for production at existing lumber operations. Transportation infrastructure and distribution possibilities should also be assessed along with the estimate of potential demand for wood pellets in Southeast Alaska and in other regions to which the economical transport of pellets can occur. The study should identify market barriers and the degree to which State funding may be required to help start the industry. The cost of such incentives should be compared to the potential savings in heating costs.

16.3.2 Propane Options

Another potential heating option for communities in Southeast Alaska is the utilization of propane from the North Slope of Alaska. Approximately 50,000 barrels of propane are produced each day on the North Slope, with about one-third pumped back into the ground due to the lack of a sufficient market for the product.[24] The potential for developing a larger propane market in Alaska has generated much attention in the past several years with evaluations conducted to understand the economics of expanding the use of propane in Alaska as a transportation fuel and as a heating fuel. Thus, while propane prices are not especially attractive at the present time, recent studies project that there could be a long-term downward shift in local propane prices if North Slope supplies are utilized.

In 2010 and 2011, tests involving the powering automobile fleets with propane were performed and the results appeared promising, even in the harsh Alaskan climate. It is estimated that propane used on the North Slope would only cost approximately $1 per gallon at the source (North Slope). In Anchorage, the cost has been estimated to be on the order of $2 per gallon if the North Slope source is developed, versus about $3.50 per gallon for propane currently brought in from Canada.[25] Although the cost to fit a vehicle for propane can add $9,000 to $11,000 to the vehicle cost, the payback can be attractive when oil prices are high, and the emissions associated with propane are much lower than for gasoline.[26]

The option of most interest for this study is the possibility of using North Slope propane supplies for home heating in other parts of the State. This could especially be cost effective for remote communities that can pay from $4 to $8 per gallon currently for diesel delivery, although the lower heat content of propane per gallon versus heating oil (91,333 Btu/gallon versus 138,690 Btu/gallon, respectively) must be factored in and requires a comparison on a MBtu basis instead of a cost per gallon basis. Table 16-7 shows that the cost of propane would need to be to $1.43/gallon in order to compete with wood pellets costing $250/ton on a fuel cost per MBtu basis ($19.53/MBtu for wood pellets from the table). This break even figure is for the fuel only and does not account for differentials in fuel delivery and handling infrastructure that may be needed for each option.

There have been multiple studies evaluating the feasibility of a more developed delivery system of propane to the coastal and river communities in Alaska in the past 6 years.[27] A 2005 study by PND Consulting Engineers conducted for the Alaska Natural Gas Development Authority (ANGDA) indicated that if a 24-inch natural gas pipeline from the North Slope of Alaska to the Cook Inlet were constructed, propane would be available for loading at the Cook Inlet at a cost of $3.35/MBtu (2005 price) and could be distributed by barge to coastal communities. The total delivered cost to the communities would vary significantly depending on whether propane delivery utilized large (30,000 barrel), dedicated propane barges, or barges utilizing ISO containers holding 6,500 gallons of propane. The study estimated that, including transport costs and storage costs at the communities, the cost of propane to Juneau would be $6.53/MBtu and the cost to Yakutat would be

[24] From the article "Propane has the potential to power state, drive down energy costs" by Andrew Jensen, Alaska Journal of Commerce, September 4, 2011, available on-line at http://peninsulaclarion.com/news/2011-09-04/propane-has-potential-to-power-state-drive-down-energy-costs, accessed on September 23, 2011.
[25] Ibid
[26] Ibid
[27] See http://www.angda.state.ak.us/default.asp and click on Propane Distribution in the menu.

$6.79/MBtu in 2005 dollars using large, dedicated barges.[28] If these costs are escalated at 3 percent to 2011, the cost would be $7.80/MBtu for Juneau and $8.11/MBtu for Yakutat. If ISO containers are utilized, the study estimated that the delivery cost would be $12.65/MBtu for Juneau and for Yakutat in 2005 dollars. This equates to $15.10/MBtu in 2011 dollars when a 3 percent escalation is applied. This is a cost-based estimate that is competitive with wood pellets ($19.53/MBtu) but it should be recognized that there will be incentive to price the fuel up to the break even point with next best alternative in the absence of a long-term supply agreement.

More recent studies involve the development of a North Slope propane project that would distribute propane produced on the North Slope to coastal areas of Alaska, including Southeast Alaska communities by barge or ISO container. One study has estimated that the project could deliver propane to Fairbanks for $12.68/MBtu (2009 estimate), or $13.45/MBtu in 2011 dollars using a 3 percent escalation rate.[29] Deliveries to Southeast Alaska would involve longer distances and would presumably be somewhat higher in delivered cost.

In summary, there is much activity regarding the near-term development of markets for propane being produced on the North Slope and there is the potential that North Slope propane supplies could be provided at a substantially lower cost than the current cost of propane supplies from Canada. Depending on the developments surrounding the development of additional propane supplies and transportation networks based from the North Slope or the Cook Inlet, an increased role for propane could be cost effective for Southeast Alaska and these developments should be monitored. At the same time, the development of a wood pellet industry is largely under the local control of Southeast Alaska and is cost effective versus other options currently available. This option could also have the benefit of helping to stabilize the lumber industry in Southeast Alaska. Therefore, the recommended study of wood pellet industry development in Southeast Alaska should go forward while possible developments related to increased propane supplies should be monitored and considered in a final policy and investment decision.

16.3.3 Heat Pump Options (Air-source and Ground-source)

Another option for the provision of residential space heating instead of traditional electric furnace heating is the use of a heat pump system. A brief discussion of heat pump options is provided below, including the recently released results of a 15-year study evaluating the feasibility of heat pumps operating in Alaska.

The heat pump technology transfers energy from the outside air, ground, or water into a home and can also reverse the transfer. A heat pump brings warm air into the home during heating season and can take heat out of the home during cooling periods. To perform work, heat pumps use an intermediate fluid called a refrigerant that absorbs heat as it vaporizes and releases the heat when it is condensed. The two most common types of heat pumps are air-source and ground-source heat pumps (GSHPs).

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[28] *Feasibility Study of Propane Distribution throughout Coastal Alaska*, prepared for Alaska Natural Gas Development Authority by PND Incorporated, Consulting Engineers, August 2005, Table 12. Estimated Total Cost of Energy, p. 18.

[29] *Preliminary Economic Analysis of North Slope Propane and Review of June Alaska Propane Opportunities Conference*, by Nick Szymoniak, Scott Goldsmith of the Institute of Social and Economic Research, presented at The North Slope Propane Opportunity Consortium Meetings, September 24, 2009.

The air-source heat pump is the most common type of unit installed in the United States due to its low cost relative to the ground-source system, its reliability, and its economy compared to the traditional alternative of heating a home with an electric or gas fired furnace and cooling with an air conditioning unit. Figure 16-1 illustrates the conceptual operation of the air-source heat pump. When in cooling mode, the heat pump evaporates a refrigerant in the indoor coil; as the liquid evaporates it pulls heat from the air in the house. After the gas is compressed, it passes into the outdoor coil and condenses, releasing heat to the outside air. The pressure changes caused by the compressor and the expansion valve allow the gas to condense at a high temperature outside and evaporate at a lower temperature indoors.

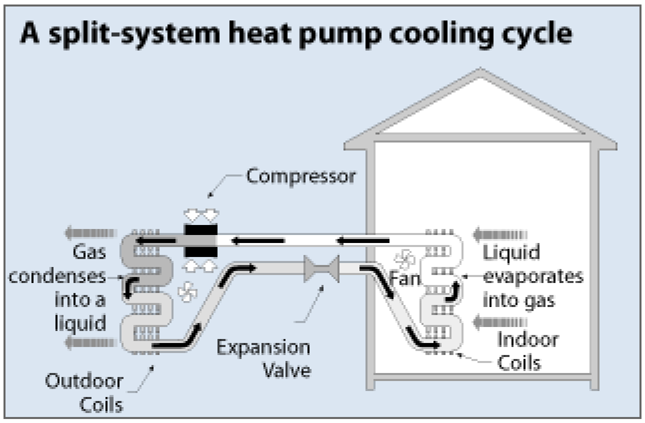

Figure 16-1 Air-Source Heat Pump Cooling Cycle[30]

A typical savings in electricity of 30 to 40 percent is achievable for most U.S. locations using air-source heat pump technology.[31] However, the efficiency of air-source heat pumps in the heating mode decreases significantly at low temperatures, making them uneconomical or marginal for colder climates. (There are newer systems and systems in development that aim to overcome the problems associated with heat pump operation in colder climates, but these will likely require a higher upfront cost than common air-source heat pumps). According to the U.S. government, "although air-source heat pumps can be used in nearly all parts of the United States, they do not generally perform well over extended periods of sub-freezing temperatures." In regions with subfreezing winter temperatures, it may not be cost effective to meet all your heating needs with a standard air-source heat pump."[32]

[30] From http://www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12620, accessed September 28, 2011.
[31] From http://www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12610, accessed September 27, 2011.
[32] From http://www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12620, accessed September 27, 2011.

The GSHP is more costly to install than an air-source heat pump but it achieves a higher efficiency and is more suitable for application in colder climates such as Alaska. In Sweden, for example, 30 percent of the homes have GSHP systems.[33]

GSHPs collect the natural heat of the ground through a "loop" or series of hard plastic (usually polyethylene) tubes that are installed below the ground or, sometimes, submerged in a pond, lake, or seawater. The tubes are filled with a moving fluid that carries the transferred heat into the home where the heat pump's compressor and heat exchangers convert the heat to a higher temperature (when in heating mode) and release the heat into the home, usually through a blower and duct system. It is the near-constant temperature of the ground around the loop system (depending on location, the ground temperature at a depth of 6 feet in the U.S. is between 45° and 75° F) that allows the GSHP to operate more efficiently than an air-source heat pump in the winter and other heating periods.[34]

Depending on location and other factors, a GSHP can use 25 to 60 percent less electricity than conventional alternatives according to the U.S. government and, depending on location, is usually able to recover the higher initial investment cost over a 2 to 10 year period through lower utility bills.[35] Ground-source systems also have the benefit of being very reliable and a typical loop system will be guaranteed 25 to 50 years by the manufacturer. Currently, about 50,000 GSHPs are installed in the U.S. each year.

Geothermal systems can also provide hot water if the system includes a desuperheater. This component allows the capture of excess heat that would otherwise be transferred into the loop system and can provide hot water for little or no cost in the summer period. In the winter, a conventional water heater may be needed as a supplement, however.

In 2011, a 15-year study of the economics of GSHPs in Alaska was completed by the Cold Climate Housing Research Center and the Alaska Center for Energy and Power. The locations studied were Fairbanks, Anchorage, Juneau, Bethel, and Seward. The study - "Ground-Source Heat Pumps in Cold Climates" - determined the net present value (NPV) cost of heating with various options in the five cities evaluated. The NPV at each location was the discounted value of capital, fuel, electric, and other operating costs over a 15-year period, using a 3 percent discount rate. The results are summarized in Table 16-8 and indicate that the relative economics of heat pumps in Alaska are highly dependent upon the cost of the primary heating alternatives of electric resistance heating, oil-fired boilers, oil-fired laser vented heaters and, in Anchorage, natural gas heating.

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[33] From "Ground-Source Heat Pumps in Cold Climates: The Current State of the Alaska Industry, a Review of the Literature, a Preliminary Economical Assessment, and Recommendations for Research", May 31, 2011, page iii. The report was prepared for the Denali Commission by the Alaska Center for Energy and Power and by the Cold Climate Housing Research Center. The report can be found on-line at http://www.cchrc.org/.

[34] From http://www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12640, accessed September 27, 2011.

[35] Ibid, and http://www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12670.

Table 16-8 NPV Cost of Ground-source Heat Pump Options in Five Alaskan Cities

CITY	GROUND HEAT PUMP	ELECTRIC RESISTANCE	OIL-FIRED BOILER OR HEATER	NATURAL GAS
Juneau	$56,300 to $61,500	$82,500	$68,000 to $74,800	NA
Anchorage	$79,100 to $86,400	$114,100	NA	$37,900 to $44,600
Fairbanks	$76,900 to $87,300	$161,800	$85,300 to $90,500	NA
Bethel	$158,100 to $185,700	$414,900	$65,500	NA
Seward	$50,500 to $55,000	$71,100	$57,000 to $62,200	NA

Source: *Ground-Source Heat Pumps in Cold Climates: The Current State of the Alaska Industry, a Review of the Literature, a Preliminary Economical Assessment, and Recommendations for Research*, May 31, 2011, by the Alaska Center for Energy and Power and by the Cold Climate Housing Research Center, p. 29.

In Bethel, the high cost of electricity ($0.54/kWh after the first 500 kWh each month) caused the cost of electric resistance heating to be most costly, followed by GSHPs and then by oil-fired heaters.[36] Thus, even though the ground-source heating option was economical compared to full reliance on resistance heating, the partial reliance of the ground-source heating option for supplemental heat from electric sources harmed the overall economics relative to the oil-fired heater option.

In Anchorage, natural gas heating was the least-cost option evaluated, followed by ground-source heating and electric resistance heating. In Juneau and Seward, GSHPs were lowest in overall cost, compared with electric resistance heating and oil-fired boilers. Finally, in Fairbanks, heat pumps were slightly lower in NPV cost than an oil-fired alternative while electric resistance heating was significantly higher than these two options.

The implication for Southeast Alaska is that, while GSHPs seem to be a viable option for Juneau and for communities with moderate electricity costs, many of the smaller communities having a high cost of electricity may be more comparable to the study economics for Bethel, and heat pumps may be marginal or uneconomic in such locations. Related specifically to Southeast Alaska, the study concluded the following about GSHPs:

> GSHP systems are more viable where electricity costs are relatively low and heating costs are relatively high. Juneau, included in the economic analysis, displayed this relationship. These results can be roughly extrapolated to many other communities in Southeast Alaska that utilize hydropower.[37]

[36] From "Ground-Source Heat Pumps in Cold Climates: The Current State of the Alaska Industry, a Review of the Literature, a Preliminary Economical Assessment, and Recommendations for Research", May 31, 2011, p. 23.
[37] Ibid, p. viii

When evaluating these conclusions, it should also be kept in mind that the heat pump study did not evaluate heat pumps against all possible heating alternatives. Wood pellets and perhaps propane options from the North Slope would appear to be preferred options for the smaller communities in Southeast Alaska. Table 16-9 presents a comparison of the pellet costs and the electricity costs from Table 6-6 for heat pumps with a COP of 3.0. These alternatives are dependent, however, on the development of a local wood pellet industry and, in the case of propane, the development of an Alaskan market and transport system capable of delivering propane from the North Slope to Southeast Alaska.

Table 16-9 Wood Pellet Heating Option Cost Comparison on a $/MBtu Equivalent Basis

FUEL	UNIT COST	$/MBTU	BREAKEVEN UNIT COST WITH WOOD PELLETS AT $250/TON
Wood Pellets (average lower 48 price, proxy for Southeast Alaska price with local pellet production)	$250/ton	$19.53	NA
Wood Pellets (current price per ton based on cost of 40 pound bags in Juneau)	$375/ton	$29.30	$250/ton
Electric (Juneau 2010 average)(1)	4 cents/kWh	$11.72	6.5 cents/kWh
Electric (Metlakatla, 2010 average, lowest Southeast Alaska community)(1)	3.07 cents/kWh	$8.99	6.5 cents/kWh
Electric (Tenakee Springs, 2010 average, highest Southeast Alaska community after PCE)(1)	10.50 cents/kWh	$30.79	6.5 cents/kWh
Note: Assumes 80 percent appliance efficiency for wood pellets with a COP of 3.0 for heat pumps. (1)Adjusted for a COP of 3.0.			

16.4 RAPIDLY DECLINING EXCESS HYDRO

As discussed in Section 3.0, in communities where hydroelectric power is available, rapid conversion from heating oil to electricity for space heating has been common in recent years due to the lower cost of hydroelectric electricity for home heating and other uses. While a benefit to users who convert to electricity, this has had the effect of reducing the availability of excess hydroelectric generation and increasing the reliance on diesel generation for communities having limited hydroelectric capacity. As a result, the average cost of electricity generation has gone up in many communities that have hydroelectric power.

The reason for the cost impact is seen on Figure 16-2, which shows a hypothetical load duration curve plotting kW demand from highest to lowest during the 8,760 hours in a year. The dashed load duration curve above the initial curve represents the increased energy demand due to additional customers who switch to electric power for home heating. The amount of energy that can be produced from the hydroelectric facility is indicated by a horizontal line in the graph. Above this line, energy requirements are met by costly diesel generation. As the load duration curve rotates upward on the vertical axis due to more customers converting to electric heat and utilizing electric resources during heating days, the added energy requirements must be met by diesel generation as the hydroelectric facility has no excess energy to provide. If a new hydroelectric facility were added to the system, the horizontal line representing the hydroelectric production would shift upward, reducing the reliance on diesel generation. Alternatively, if wood pellet or propane applications were installed, the dashed load duration curve would shift down and would also reduce the overall reliance on diesel generation.

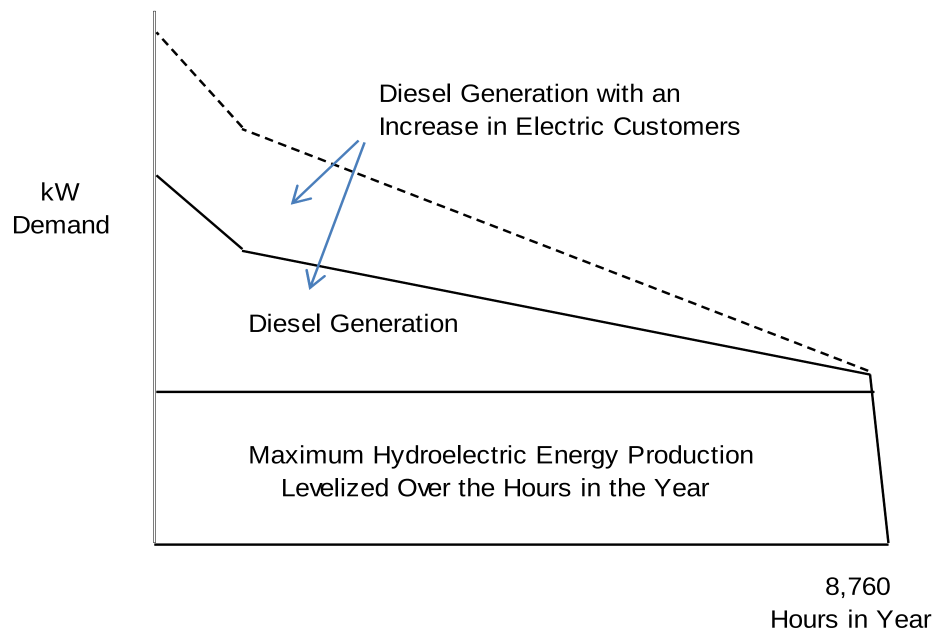

Figure 16-2 Sample Load Duration Curve Illustrating Greater Reliance on Diesel Generation as More Residents Switch to Electric Power

The most cost-effective way to address the declining excess hydroelectric power depends on the specific circumstances of the municipality. Some municipalities will be able to utilize new hydroelectric facilities cost effectively (causing an upward shift in the hydroelectric production line on Figure 16-2). Other communities that may not be candidates for new hydroelectric facilities may benefit from converting to alternative sources for home heating (causing a downward shift in the load duration curve). As discussed above, these alternative sources of heating could include wood pellet systems or propane if a Statewide investment is made in further developing propane systems.

Again, however, it is likely that conversion to an alternative system may require grant funding or, at a minimum, low interest loans to those willing to convert to an alternative source of home heating. More important, funding assistance may be needed to assist with the cost of certain infrastructure installed to allow delivery and distribution of propane and, to a lesser extent, the delivery and distribution of wood pellets.

16.5 DIFFICULTY IN DEVELOPING NEW HYDROELECTRIC AND TRANSMISSION INTERCONNECTION PROJECTS

Hydroelectric and transmission interconnection projects generally face a long, difficult, expensive, and uncertain licensing process in Southeast Alaska. The Federal Power Act requires anyone building or operating a hydroelectric project to obtain a Federal Energy Regulatory Commission (FERC) license if the project;

(1) is located on navigable water,

(2) is located on public land or a Federal reservation,

(3) uses surplus water or power from a Federal dam, or

(4) is located on a body of water over which Congress has jurisdiction under the Commerce Clause, was built after 1935, and affects interstate or foreign commerce.

With 95 percent of Southeast Alaska being in the Tongass National Forest and Glacier Bay National Park, most projects will require a FERC license. The National Environmental Policy Act process required by FERC requires extensive studies including an Environment Assessment and possibly an Environmental Impact Statement. The process is open to public comment and involvement and is subject to appeal by intervening organizations. The licensing process can thus be lengthy with the schedule and cost beyond the control of the applicant. The process can also require significant mitigation costs and potential design changes for the project increasing costs.

One specific significant obstacle to FERC licensing in the Southeast is the 2001 Roadless Area Conservation Rule. The Roadless Rule has been under litigation in one form or another since its issuance and currently continues to be under litigation. The manner of its application also remains uncertain and is subject to varying interpretations by affected parties. The Roadless Rule has the potential to significantly limit the licensing of hydroelectric and transmission projects. The uncertainty associated with its application and the outcome of the legal challenges to it casts significant uncertainty over the entire licensing process. As a result, the licensing process is slow and many projects are hesitant to expend the significant sums to move projects through the licensing process.

Some resolution to the issue may occur with the results of the ongoing litigation. However, with the long history of litigation associated with the Roadless Rule it would appear unlikely that resolution will occur anytime soon. Projects need to work closely with the Forest Service on the permitting process. Currently, the Secretary of Agriculture has reserved the authority to approve all permitting issues for hydroelectric and transmission lines in the Roadless areas. This approval removes an element of local control by the Forest Service and represents another required step in the approval process. The relinquishment of this authority would return local control back to the Forest Service.

16.6 HIGH COST OF ELECTRICITY

The availability and low cost of energy, including electricity, is a significant factor influencing the viability of businesses and communities. As stated in the May 2011 issue of *Alaska Economic Trends*:

> The cost of energy is a significant component of the cost of doing business for business and consumers, and it remains a major issue of concern for Alaskans. From the price at the pump to the cost of staying warm, the cost of energy continues to be a challenge for Alaska. Energy is closely tied to our economy, jobs, and national security. Recent global events reinforce how critical it is for Alaska to have energy options, especially in a cold climate like ours where power shortages pose a real threat.

The cost of electricity in Alaska is significantly higher, on average, than in the lower United States. In the power sector, the average price for electricity in the United States was 9.82 cents/kWh in 2009 compared to an average of 15.09 cents/kWh in Alaska. Only five other states had a higher cost of electricity than Alaska in 2009.[38]

Section 4.0 listed available power cost data for the municipalities in the study. The simple average of these rates was 16.97 cents in 2010, but the range was from a low of 9.2 cents/kWh (where hydroelectric power was available) to 31.51 cents/kWh after the PCE adjustment. Prior to the PCE adjustment, the cost of electricity for some municipalities exceeded 60 cents/kWh in 2010. The cost of power and information on the population of municipalities and study participants is shown in Table 16-10.

According to a cost of living index published in the May 2011 publication *Alaska Economic Trends*, the cost of utilities for Juneau is 35.4 percent higher than the average U.S. city. Since Section 4.0 indicated that the more remote municipalities in the region face much higher power costs than the 12 cents/kWh residential price in Juneau (2010 price), it is apparent just how much higher the cost of electricity is for most communities in Southeast Alaska. Clearly, the high cost of electricity in the Southeast Region places businesses at a disadvantage compared to competing firms located elsewhere in the United States. The high cost of power also indicates that residents must allocate a considerably higher portion of their income to utilities than other U.S. citizens, on average.

[38] US Energy Information Administration, State Electricity Profiles, 2009 edition, accessed online at www.eia.gov/cneaf/electricity/st_profiles/e_profiles_sum.html.

Table 16-10 Electric Power Costs and Population Size for Municipalities and Participants in the Study

CITY	POPULATION	HOUSEHOLDS	POWER COST BEFORE PCE (C/KWH)	POWER COST AFTER PCE (C/KWH)
Angoon	459	167	56.1	19.8
Coffman Cove	176	89	49.5	18.6
Craig	1,201	470	21.3	14.5
Edna Bay	42	18		
Elfin Cove	20	13	52.3	19.8
Excursion Inlet	12	6		
Gustavus	442	212	39.2	25.5
Haines	1,713	782	21.9	14.7
Hollis	112	44	21.3	
Hoonah	760	305	56.1	19.8
Hydaburg	376	128	21.3	14.5
Hyder	87	48		
Juneau	31,275	12,187	12.0	
Kake	557	213	56.1	19.8
Kasaan	49	23	21.3	14.5
Ketchikan	8,050	3,259	9.6	
Klawock	755	297	21.3	14.5
Klukwan/Chilkat Valley	95	41	56.1	19.8
Kupreanof	27	15		
Metlakatla	1,405	493	9.2	
Meyers Chuck	21	9		
Naukiti	113	49	49.3	18.5
Pelican	88	41	41.7	18.0
Petersburg	2,948	1,252	11.8	
Saxman	411	120	9.6	
Sitka	8,881		14.2	
Skagway	920	410	21.9	14.7
Tenakee Springs	131	72	64.0	31.5
Thorne Bay	471	214	21.3	14.5
Whale Pass	31	20	52.2	22.7
Wrangell	2,369	1,053	12.6	
Yakutat	662	275	46.7	18.0

Source:

1. 2010 Census Data Table "Race, Hispanic or Latino, Age, and Housing Occupancy 2010: 2010 Census Redistricting Data (Public Law 94-171) Summary File" http://factfinder2.census.gov/faces/nav/jsf/pages/index.xhtml
2. Statistical Report of the Power Cost Equalization Program, Fiscal Year 2010 (July 1, 2009-June 30, 2010, Twenty Second Edition, March 2011, Alaska Energy Authority. http://www.akenergyauthority.org/PDF%20files/FY10PCEreport.pdf.

In Sections 16.1 and 16.2, the interrelationship between economic well being, population, and power supplies that are reliable and affordable was discussed. In the Southeast region, populations are dwindling in many communities and are projected to continue their decline by the State of Alaska. Employment is also expected to decline along with population. Given that the region has the highest median age in the State (39.3 years), the Southeast is not likely to self-generate sufficient new population to reverse or even stabilize the downward trend. This means that the long-term viability of the region is dependent on the ability to attract new populations into the region, and this will depend on the ability to attract new business investment. On the surface, this seems to be a surmountable issue, given the abundance of resources and scenic beauty in the Southeast that have produced a diverse, though small, economy. At closer look, however, it is apparent that businesses may well be reluctant to locate or to expand given the uncertainty surrounding the availability of adequate, reliable, and affordable energy, especially with regards to electricity. This includes energy intensive industries such as mining and timber-related firms, as well as small, family-owned businesses aimed at accommodating tourists.

If the region is to stabilize and rebound, there will need to be a concerted effort to develop a more accommodating business and community environment. This will need to focus on more than power costs, yet it is clear that having a low cost and reliable supply of electricity will be one component of an overall strategy to stabilize the local economy and population level. Key issues about land use on Federal lands will also need to be addressed. Thus, the IRP recommendations should be pursued and should be part of a larger stabilization strategy developed for the region. Whatever additional strategies may be developed to help stabilize the region's population and employment picture, it is essential to lower electricity costs and to reduce the volatility inherent in a power sector that is currently heavily dependent on diesel generation.

16.7 LOW LEVELS OF WEATHERIZATION AND ENERGY EFFICIENCY

As discussed in Section 3.0, Southeast Alaska utilities have limited direct experience with the planning, developing, and delivering of energy efficiency programs and the general belief is that there are additional opportunities to reduce energy consumption through weatherization and energy efficiency measures. There has been discussion as to whether such measures and programs should be implemented by the individual utilities or whether a regional approach would be more effective. Given some of the specialized training involved in administering the measures, it seems clear that either approach, or a combined effort, would benefit by utilizing State experts, programs, and resources that are available.

The State of Alaska administers multiple weatherization and energy efficiency programs primarily through two agencies. These agencies are the Alaska Housing Finance Corporation (AHFC) and the Alaska Energy Authority (AEA). A third organization, RurAL CAP, also provides some energy efficiency services to small communities. The primary State programs that could benefit Southeast Alaska are summarized below. The State has generously funded energy efficiency programs, especially since 2008, although the funding for some of the larger programs is being consumed and the availability of ongoing State funding at comparable levels in the long-term is uncertain.

16.7.1 The Alaska Housing Finance Corporation

The AHFC is a self-supporting public corporation with the mission to provide Alaskans access to safe, quality, affordable housing. AHRC provides a wide array of services to help achieve this mission, ranging from special loans for certain types of home buyers to energy and weatherization programs. Since 1986, AHFC has contributed more than $1.9 billion to Alaska's State budget revenues through cash transfers, capital projects, and debt-service payments. In 2010, AHFC's total assets were $4.8 billion.[39]

The AHFC involvement in energy efficiency and weatherization efforts increased dramatically in 2008 when the Alaskan legislature allocated $360 million in subsidies toward home improvement programs. More than half the funds were targeted to weatherization work for lower-income residents and since 2008, AHFC has provided weatherization upgrades or rebates for energy improvements for more than 15,600 homes. AHFC estimates that the resulting energy savings from its programs is approximately 30 percent.[40] In 2010, homes in more than 100 communities were served and an estimated 2,000 jobs were created. The cost per home ranged from an average of $11,000 for homes in communities on the road system to approximately $30,000 in remote areas. It is anticipated that funds for weatherization will have been expended by 2013.[41] The most widely used programs are described below.

Energy Improvements Through Weatherization

The AHFC Weatherization Program offers free energy efficiency improvements to low-income houses Statewide. Under the program, Alaskans with low-to-moderate incomes (up to 100 percent of the median), living in owner-occupied homes, condos, rentals, and mobile homes qualify for free weatherization upgrades. The program is operated by several program providers located throughout the State. Residents interested in the program contact the provider nearest to them to participate.

The Weatherization Program is more than 30 years old. The program was expanded by $200 million in 2008 and allowed for a much greater cumulative impact. Prior to the increased funding in 2008, an average of 600 homes were modified each year. In 2008 and 2009, more than 5,000 home were weatherized. Eighty-five percent of the homes are owner-occupied; more than 70 percent consist of a senior citizen or a person with disabilities; 51 percent included children under the age of 6.[42]

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[39] Alaska Housing Finance Corporation 2010 Annual Report, page ii, available online at http://www.ahfc.state.ak.us/iceimages/about/2010_annual_report.pdf

[40] Ibid, p. 3

[41] Ibid, p. 3

[42] Ibid, p. 6

The Home Energy Rebate Program

The Home Energy Rebate Grant Program (HERP) reimburses homeowners for up to $10,000 of energy efficiency improvements that move the home at least one step higher on the agency's energy rating system. Rebates are funded by the Alaska Legislature, which put a total of $160 million into the program in 2008.[43] The steps to participate include requesting an initial energy rating, receiving an improvement report and submitting paperwork to AHFC to establish funds available for 18 months. Next, homeowners or contractors complete the improvements chosen from the list, and then request another energy rating when the work is done. The amount of rebate is related to the number of steps the home moves up on the five-step energy rating system.

Appliance Rebates for Qualified Alaskans with Disabilities

Alaskans with qualified disabilities can apply for the appliance rebate program funded by a $658,000 grant from the Federal Department of Energy that is administered by AHFC.[44] The program's goal is to encourage the use of energy-efficient appliances.

5-Star Plus New Construction Energy Rebate

AHFC offers rebates on newly built, highly efficient homes labeled as 5-Star Plus homes. To qualify for the rebate, the home must be owner-occupied, a primary residence, and must be completed and not occupied for more than 12 months from the date of completion on or after April 5, 2008. In 2010, more than 760 newly constructed homes received a 5-Star Plus rebate of $7,500.[45]

Heating Assistance Program

This program provides grants to qualifying low income Alaskan residents to help pay a portion of home heating expenses. Applications are accepted October 1 through April 30 of each year, or earlier for legally disabled and senior residents. The grant amount is based on the area of Alaska where the home is located and the type of dwelling, and point values are assigned for heating costs. Fuel or electric companies receive the funds directly for qualified applicants' bills, and grants are not transferable if an applicant moves to another area.

Energy Efficiency Education and Workshops

The AHFC offers a variety of public education and workshop efforts to assist weatherization assessors, crews, contractors, do-it-yourself homeowners, and the general public with installation techniques, building science, building auditing, energy modeling, combustion safety, moisture control and ventilation, and more.

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[43] Ibid, p. 8
[44] Ibid, p. 9
[45] Ibid, p. 10

Loan Programs

AHFC offers a number of loan programs to encourage energy efficiency. The primary programs are summarized below.

Second Mortgage for Energy Conservation. Homeowners may obtain financing to make energy efficiency improvements in their homes through AHFC's Second Mortgage for Energy Conservation Program. Loans are limited to a maximum of $30,000 and a term of 15 years. For borrowers simultaneously participating in the Home Energy Rebate Program; the rebate received is applied toward the outstanding balance of the mortgage program. In 2010, AHFC reported that the average loan through the program was $19,400.[46]

Energy Efficiency Interest Rate Reduction Program (EEIRR). AHFC offers interest rate reductions when financing new or existing energy efficient homes, or when borrowers purchase and make energy improvements to an existing home. Any property that can be energy rated and is otherwise eligible for AHFC financing may qualify for this program. Interest rate reductions apply to the first $200,000 of the loan amount. A loan amount exceeding $200,000 receives a blended interest rate, rounded up to the next one-eighth of one percent (.125%). The percentage rate reduction depends on whether or not the property has access to natural gas.[47]

Association Loan Program. Under this program targeting homeowners' associations, the homeowners' association representative submits a proposal directly to AHFC to obtain preliminary approval for common-area improvements. Some examples are roof or siding replacement, window replacement, or driveway improvements. Repayment of the loan is typically made through a pro-rata increase in the monthly dues in order to avoid a special assessment.[48]

Small Building Material Loan. In this program, borrowers with residential property located in small communities may obtain financing to renovate or complete their property. The project may include repair or renovations that improve the livability of the home, energy efficient upgrades or the addition of living space. Loan funds may be used to purchase building materials (exclusive of luxury items), or pay for freight or third party labor costs. Borrowers must complete renovations within 6 months (180 days) of loan closing.[49]

Alaska Energy Efficiency Revolving Loan Fund Program. The Alaska Energy Efficiency Revolving Loan Fund Program provides financing for permanent energy efficient improvements to buildings owned by regional educational attendance areas, by the University of Alaska, by the State, or by municipalities in the State. Borrowers obtain an Investment Grade Audit as the basis for making cost-effective energy improvements, selecting from the list of energy efficiency measures identified. All of the improvements must be completed within 365 days of loan closing.[50]

[46] Ibid, p. 9
[47] http://www.ahfc.state.ak.us/loans/eeirr.cfm, accessed July 27, 2011
[48] http://www.ahfc.state.ak.us/loans/association.cfm, accessed July 27, 2011
[49] http://www.ahfc.state.ak.us/loans/small_building_material.cfm, accessed July 27, 2011
[50] http://www.ahfc.state.ak.us/loans/akeerlf_loan.cfm

16.7.2 RurAL CAP

Another organization providing selective energy efficiency measures is RurAL CAP. This organization was founded in 1965 and is a private, Statewide, nonprofit organization working to improve the quality of life for low-income Alaskans. Governed by a 24-member Board of Directors representing every region of the State, RurAL CAP is one of the largest and most diversified nonprofit organizations in Alaska. In fiscal year 2010, RurAL CAP employed 1,048 Alaskans in 91 communities Statewide and expended more than $40 million in conjunction with its for-profit subsidiary, Rural Energy Enterprises.[51]

RurAL CAP's weatherization and rehabilitation programs refurbish older homes to make them warmer and more energy efficient. The program serves one community at a time, rather than many houses in scattered communities. Each community project takes one to three years to complete; the 2009 weatherization communities were Alakanuk, Emmonak, Juneau, Kipnuk, Kivalina, Kwethluk, Nome, Nunam Iqua, St. Michael, and Tununak.

16.7.3 Alaska Energy Authority (AEA) Programs

The mission of the AEA is to reduce the cost of energy in Alaska. To achieve this aim, the AEA is involved in power supply and demand-side studies and programs. In the areas of energy efficiency and conservation, the AEA has several programs targeting improvements in energy efficiency at the end-user level. Programs include the following.

- **Commercial Energy Efficiency Audits**--The AEA offers an energy efficiency audit program to assess electrical load, equipment, lighting, thermal, HVAC and other conservation methods in privately owned commercial buildings. AEA will reimburse the cost of a qualifying energy audit up to a limit that is based upon the square footage of the building and the complexity of its heating, ventilation and air conditioning system (between $1,400 and $6,500 per building), plus a $300 auditor travel stipend if applicable.
- **Commercial Alternative Energy and Energy Efficiency Loans**—The AEA and the Alaska Department of Commerce, Community and Economic Development are currently writing regulations for a new loan fund to support privately owned commercial buildings energy efficiency improvements and alternative energy installations. Loans will be available in 2012.
- **Village Energy Efficiency Program (VEEP)**--The AEA provides energy efficiency upgrades to public buildings in rural Alaska through the VEEP program. Communities with high cost of energy and colder climates receive services from selected service providers to audit and retrofit cost-effective energy efficiency measures in public buildings. Measures typically include lighting, boiler upgrades, controls (lighting and HVAC), insulation, weather sealing, community efficiency education, and occasionally street lighting and water/wastewater plant improvements. Typically, all measures implemented average a three to four year simple payback, despite the expensive rural delivery and installation costs associated with working in Alaska villages and rural communities. Community annual electricity reductions typically range from 1 to 4 percent with relatively little ($25,000 to $125,000) investment. Heat energy savings are typically greater than the electrical savings.

[51] http://www.ruralcap.com/, accessed July 29, 2011

- **Whole Village Retrofit Program**--Very similar to VEEP, Whole Village Retrofits are more extensive energy efficiency services provided to communities where deep community measures are needed for a variety of reasons, such as to match community energy load to the power plant's capabilities, to avert either expensive mid-winter fuel deliveries by airplane or the building of a larger fuel storage tanks, to make energy improvements at the same time alternative energy or interties are installed, or simply to demonstrate the power of efficiency when implemented across all public buildings and residences. This program attempts to match timing with weatherization crews or RurAL CAP efforts in communities in order to garner the greatest impact.
- **Industrial Energy Efficiency Audits for Seafood Processing Plants**--The Alaska seafood industry has not traditionally focused on energy efficiency, yet this industry is energy intensive and employs a large number of residents. The AEA offers a targeted energy audit program for the seafood industry to help identify the potential for savings.
- **Public Education and Outreach**--The AEA built and continues to develop an interactive web site that serves as a one stop shopping clearinghouse of information about energy efficiency and energy conservation. Alaska Energy Authority leads the coordinated outreach efforts of the Alaska Energy Efficiency Partnership, most notably the Alaska Energy Awareness Month initiatives of 2010 and 2011. AEA is currently working with a local marketing firm to develop a broad, sustained, comprehensive energy efficiency and energy conservation public awareness marketing campaign.
- **Heat Recovery**--AEA provides grants and/or services to install heat recovery systems for rural diesel power plants in order to capture and utilize the otherwise wasted heat to heat nearby community buildings. In many cases this heat transfer is measured and monetized in order to compensate the utility for the value of the heat, while at the same time offering a reduced cost source of heat for nearby buildings or facilities.
- **Tool Loan Kits**--The AEA offers watt meters, light meters, and ballast checkers, for check-out by Alaskans seeking to assess opportunities for improved efficiency in their homes or workplaces. Additionally, AEA offers full industrial grade self-audit kits, complete with a laptop, analysis software, electrical analysis tools, an infrared camera and other tools and instructions. These are intended for use by electricians at industrial plants, with a current focus on seafood processing plants.
- **Alaska Small Cities Energy Efficiency and Conservation Block Grants**--AEA manages grants with 97 small Alaskan cities and boroughs to identify and install energy efficient equipment in city facilities. While this program is currently funded through the American Recovery and Reinvestment Act (ARRA), AEA is considering continuing the program, and/or blending it with the VEEP program discussed above. The program is successfully installing cost-effective energy efficiency measures across the State through either a service provider model (similar to VEEP), or through cities self-managing their energy audits and retrofits. While the long-term nature of this program is uncertain due to the linkage with ARRA funding, the program is of interest in that it targets whole communities and can be economical for relatively isolated communities. This type of program could be effective to target specific communities in Southeast Alaska.

- **Other Programs and Research**

  End Use Study—WH Pacific is conducting an Energy End Use Study for the AEA. The results of this study will add significantly to the quality and comprehensiveness of information available on how Southeast residential and commercial customers use energy. This information will greatly improve the ability of regional utilities and other entities to develop DSM/EE programs tailored to the specific circumstances of the Southeast region. The study is due to be published at the end of February 2012.

  Needs Assessment: Another current project managed by the AEA is Information Insights' conducting of a State-wide Needs Assessment to determine more effective public education and outreach methods. This project is a largely qualitative data collection effort that will complement the End Use Study data and will shed light on State-wide end user behavior. The forthcoming final report ("Recommendations for Alaska Energy Efficiency and Conservation Public Education and Outreach")will include recommendations on how best to communicate energy efficiency and energy conservation information to various Alaskan audiences in order to most effectively encourage behavior changes that lead to improved energy efficiency and conservation practices. These recommendations may have more relevance in all regions of the State, including the Southeast, than case studies or research from outside. The report will be completed in January 2012.

  Policy Report--The AEA is also reassessing State-wide policies, programs, and regulations related to energy efficiency. This project, an update to the 2008 *Energy Efficiency Program and Policy Recommendations Report*, is being written by the Cold Climate Housing Research Center and is expected to be completed by the end of January 2012. Though not specific to the Southeast region, recommendations in this report could potentially lead to State policy changes that will positively affect every region, including Southeast.

  Alaska Energy Efficiency Map--AEA is creating a database and geographic information system (GIS) visualization of energy efficiency projects State-wide. This map allows users to view a State-wide map image, a community image, or zoom in to a building aerial view to identify energy efficiency measures that have taken place or that have been identified in that building or buildings. The site will also allow public users to tell their energy efficiency story, successes and failures via text, photographs and YouTube videos. A metrics box calculates the energy and dollar savings and money invested (by source) for the selected geographic area, efficiency programs and timeframe selected by the user. The map was publicly demonstrated in the September 2011, and is expected to become publicly available in the first quarter 2012.

16.7.4 Discussion

To summarize the information on energy efficiency, there are a wide range of programs offered at the State level and these have been heavily funded over the past few years and the cumulative impact has been impressive, given that the average savings from AHFC programs is reported to be approximately 30 percent. Clearly, if State funding continues in accord with the 2008 funding levels, there is significant potential for communities in Southeast Alaska to benefit from energy efficiency programs. In the absence of State funding, it is likely that many measures and programs will continue to be cost effective, but it is likely that many of these options will go unrealized due to the high upfront cost required to realize long-term energy savings for many programs, the limited income of the populations living in older residences and buildings most in need of energy efficiency improvements, and due to the long-term uncertainty of the economic viability of many communities and local jobs.

In general, the cost effectiveness of the specific measures and programs in Southeast Alaska will depend on the specific application at the end-user level and the characteristics of the community. The remote nature and small size of many communities in Southeast Alaska will drive up the average cost of implementation. On the other hand, the energy savings will have a high value in most communities, especially those operating on diesel generation. For isolated Southeast Alaska communities, the most cost-effective approach would likely be a "whole-village" retrofit program similar to that previously performed for Nightmute, Alaska. Again, however, such a program will almost certainly require State funding and the involvement of program expertise at the State level.

16.8 SHORTAGE OF CAPITAL

Developing power projects or alternatives to electric power in the Southeast Region will require significant capital investment. The magnitude of this investment is such that development of key projects will not likely occur unless nontraditional financing in the form of State of Alaska involvement occurs.

One reason that State involvement will be required is that local utilities and municipalities have limited ability to raise the required capital. The ability for a utility to raise capital is limited by the requirement of lenders for that financing to occur, certain coverage ratios on debt must be maintained by a borrowing utility, and the utility must be able to invest retained earnings or equity funds into the project. Reasonable assumptions are that a 1.15 coverage ratio would be required and that, as a minimum, a 25 to 30 percent contribution of equity or retained earnings may be required. The municipalities in this study are generally not able to provide this level of upfront investment and raising rates to generate such funds is not an option given the already high rates in the region.

The ability to raise capital to fund IRP projects was previously studied for the Railbelt utilities in the Railbelt Regional IRP (2010). Even though the utilities in the Railbelt IRP (RIRP) study are much larger, on average, than those serving the municipalities in the current study, the RIRP nevertheless concluded the following:

> The scope of the RIRP projects is too great, and for certain individual projects, it is reasonable to conclude that there is no ability for a municipality or coop to independently secure debt financing without committing substantial amounts of equity or cash reserves. Specifically, these individual projects would include any that require large capital investment and have any of the following characteristics: exceptionally long construction period, significant construction risk, or significant technological risk. These types of risk are associated with equity rates of return and are rarely, if ever, borne by fixed income investors…It has become evident through the financial modeling and the individual debt capacity analyses of this process that the utilities on their own would not be able to accomplish such an ambitious capital plan.[52]

[52] *Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study, Final Report,* February 2010, Appendix B Financial Analysis, pp. 3, 8.

A second reason for State funding assistance relates to the inability of local power customers to absorb the rate impact of a new, capital intensive project. That is, even if the required equity funds were available for investment by the region's utilities, the construction of new hydroelectric power and transmission would result in a large rate increase under traditional financing approaches. Thus, as explained in Section 9.0, even though a hydroelectric project would result in the lowest long-term cost of energy, the initial impact of the project under traditional financing would make the resulting rates for energy prohibitive. The initial rate impact would be so large because of the high project capital cost and the lenders' requirement that a margin over and above the total debt obligations be earned through rates. Further, the borrowing rate would be high under a traditional financing arrangement that relied only on the local utilities ability to recover project costs through rates to service areas projected by the State to lose population through 2034.

Given the significant obstacle of raising capital for the power projects, it is likely that the least-cost plan for Southeast Alaska can only be implemented if an alternative financing structure is utilized. Section 9.0 presented three options involving State backing of the project that would allow capital to be raised and would result in acceptable rate increases. Such involvement would not only provide direct benefits to Southeast Region municipalities and residents, but this involvement would also benefit the entire State of Alaska in that it would reduce the high cost of power in the Southeast and reduce the need for PCE funds in the region.

17.0 Regional Expansion Plan Development

17.1 OVERVIEW

17.1.1 Project Overview

Figure 17-1 graphically summarizes the methodology followed for the completion of this study. As shown at the top in the graphic, the Southeast Alaska IRP is built upon a number of input assumptions including drivers and issues, economic and financial factors, load forecasts (i.e., high, reference, and low scenario load forecasts), forecasts of fuel prices including emissions allowance costs, existing generation and transmission resources, and reliability criteria. Each of these categories of input assumptions is discussed in Section 3.0 through Section 8.0.

Also shown on Figure 17-1 are the categories of future resources considered including hydroelectric generation, other generation resources (including conventional and renewable resources), DSM/EE, and transmission, along with the types of screening that were conducted for each category to determine which resources should be included in the detailed economic modeling. These alternative resources are discussed in detail in Section 10.0 through Section 15.0, along with the screening processes used for potential hydroelectric and transmission projects.

In addition to the detailed economic modeling, Black & Veatch considered the environmental impacts and risks associated with each resource category to develop a Preferred Resource List for each subregion.

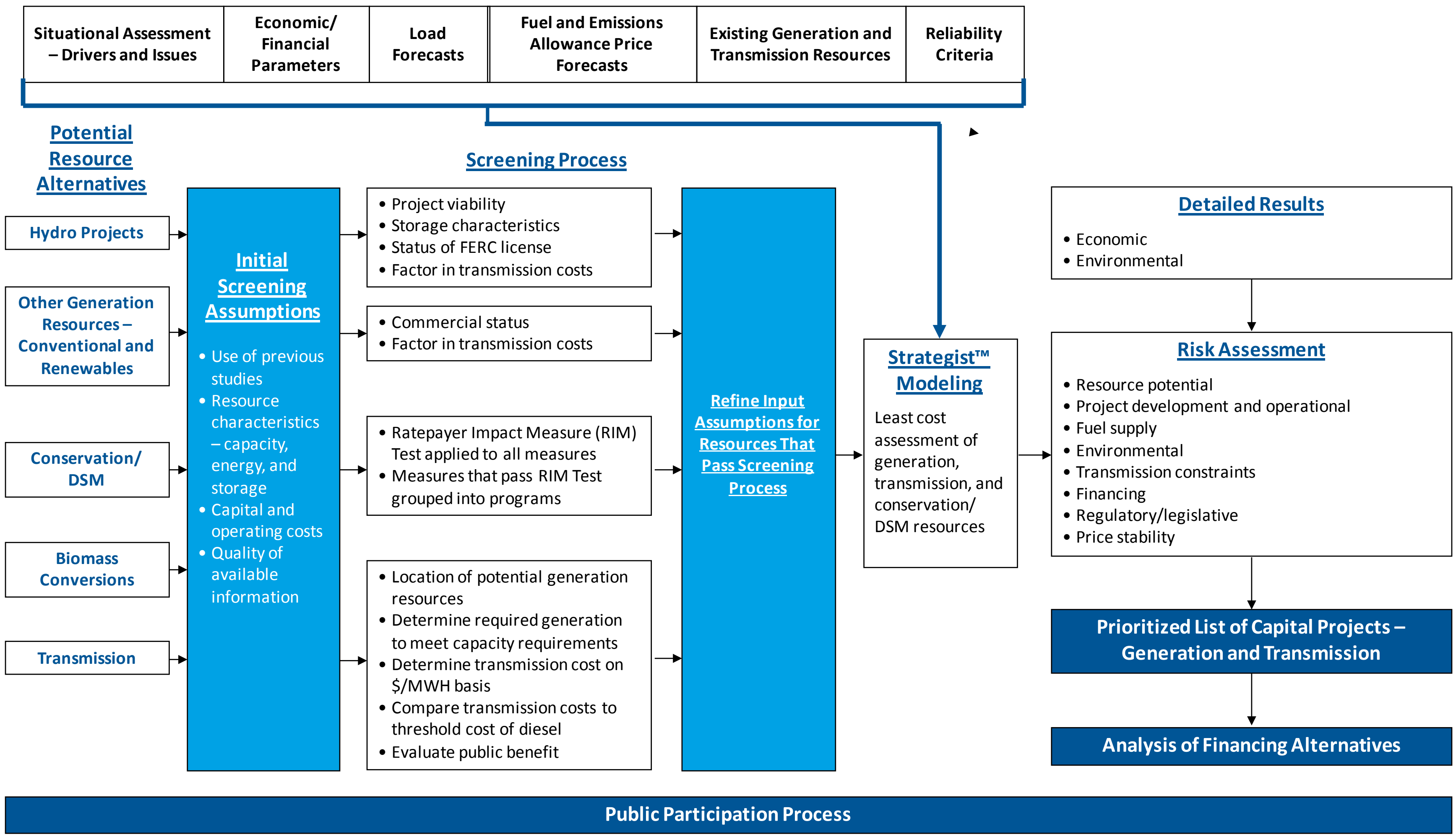

Figure 17-1 Southeast Alaska IRP Methodology

To develop these Preferred Resource Lists, Black & Veatch grouped communities into eight subregions as shown on Figure 17-2. This approach was taken due to the limited reach of the region's transmission network and the disparity of energy costs throughout the region; as a result, solutions need to be developed at the subregional level.

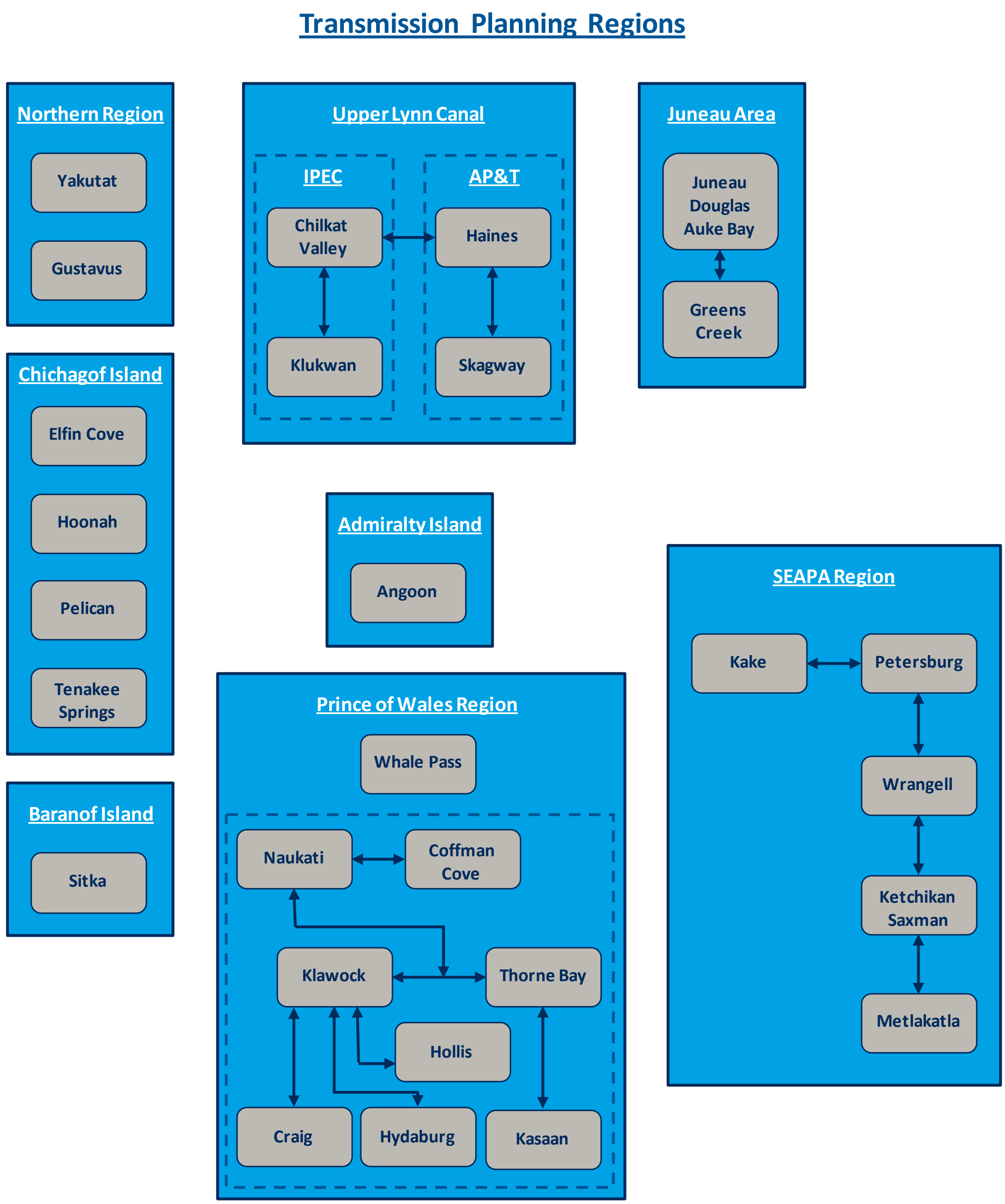

Figure 17-2 Southeast Alaska Subregions Schematic

A significant portion of the analysis (e.g., load and fuel forecasts) was completed at the community level. This analysis provided the foundation for the development of specific Preferred Resource Lists for each subregion, which were then combined to result in the overall Southeast Alaska IRP. These Preferred Resource Lists identify the potential generation, transmission, DSM/EE, and space heating resources to meet each subregion's future electrical and heating requirements.

The purpose of this section is to summarize the results of the detailed evaluation of alternative resource options that was completed during this study.

17.1.2 Elements and Limitations of Regional Expansion Plan

The Regional Expansion Plan is essentially a compilation of the Preferred Resource Lists that were developed on a subregion basis, based upon the input assumptions used and the alternative resources considered. As noted above, these Preferred Resource Lists identify for each subregion the potential generation, transmission, DSM/EE, and space heating resources to meet each subregion's future electrical and heating requirements. The Regional Expansion Plan is the integration of the elements into a comprehensive plan for the region. The following discusses how each element is integrated into the plan and gives insights gained in that integration process. This subsection presents the integrated elements as a whole for the region to reduce redundancy in repeating some of the information for each subregion. The following subsections focus on the individual subregions and present the salient information for each subregion.

17.1.2.1 Load Forecasts

Load forecasts were developed on a community and utility basis for the region and are presented in detail in Section 8.0, and each subregion's load forecasts are summarized in the following subsections. Reference, high, and low scenario load forecasts were developed for each community and utility. The lack of adequate end-use data results in there being significant uncertainty in the load forecasts. The recent rapid conversion to electric space heating, resulting in large load increases for utilities with low cost hydroelectric generation was the main focus of the reference scenario load forecast, which in general assumed things would continue much as they have. The high scenario load forecasts assumed increases in load from unspecified sources as well as load from the expected penetration of electric vehicles. The low scenario load forecast assumed the implementation and success of a significant DSM/EE program.

The recent significant conversion to electric space heating considered in the reference scenario load forecast is triggered by the high heating oil prices. In general, these recent prices have been significantly above the medium price projections presented in Section 5.0. Black & Veatch believes that in the next year or two these exceptionally high prices will trend back toward the medium heating oil prices presented in Section 5.0. As a result, the reference scenario load forecasts show a significant decline in new electric space heating conversions for the utilities with low cost hydroelectric generation after another year or two. While this appears to be a reasonable assumption, there are certainly many world events that can trigger continued high oil prices resulting in continued electric space heating conversions. The maximum exposure to electric space heating conversion is estimated in Section 15.0 and is obviously greater in the regions that have had high cost electricity and, thus, few if any conversions. Unfortunately, the uncertainty around space heating loads in the region is even greater than the uncertainty around electric loads in general. The reference scenario load forecast is also heavily based on the Alaska Department of Labor's population forecasts, which in general project a continued population decline in the region.

The high scenario load forecast indicates that loads from electric vehicles are not expected to cause a significant impact until well into the planning period. The unspecified increases included in the high scenario load forecast can cover a number of potential future events. One of the future events would be general increased economic development. It is likely that the high scenario load forecast can cover reasonably robust increases in economic development. Black & Veatch evaluated providing power to cruise ships docked in the SEAPA and Upper Lynn Canal subregions as another example of unspecified load increases. Those evaluations are presented in Subsection 8.1.2. While the high scenario load forecast for the region as a whole would be adequate to cover these cruise ship increases, the high scenario load forecast for Upper Lynn Canal subregion would not be. Potential mine development is another unspecified load potentially covered by the high scenario load forecast. Loads from potential mine development are discussed in Subsection 8.1.2. In general, these future mine loads will be addressed by hydroelectric projects specifically developed for the mine loads and are discussed in Section 10.3. Finally, the high scenario load forecast addresses continued conversion to electric space heating as discussed in Section 15.0. While the high scenario load forecast does not cover every contemplated future load possibility, it does provide a reasonable foundation for expansion planning to meet the most likely future load increases.

The low scenario load forecast results from the implementation of a significant DSM/EE program in the Southeast. The low scenario load forecast represents about a 10.4 percent reduction in energy from the reference scenario load forecast for the region as a whole. The lack of end use data for the region causes significant uncertainty in the low scenario load forecast. The level of DSM/EE program acceptance by the region will also impact the low scenario load forecast as discussed in Section 13.5.

17.1.2.2 Fuel Prices

Fuel price projections for each of the communities for diesel and heating oil are presented in Section 5.0. The fuel price projections are based on ISER projections developed for AEA. The medium projections are lower than recent prices in 2010 and 2011, but represent an upward trend over long-term prices. Parts of the region will remain largely dependent upon diesel for electric generation. For portions of the region that have access to low cost hydroelectric generation, diesel will continue to remain a significant part of the generation mix as a backup to the hydroelectric generation. Even with higher diesel prices, the lowest cost expansion plans will utilize diesel for these limit generation roles.

17.1.2.3 Economic Parameters

The economic parameters that drive the costs of the expansion plans are presented in Section 6.0. The two major parameters are the general inflation and escalation rate of 3 percent and the interest rate of 5.5 percent. These economic parameters drive the expansion plan balances between capital expenditures and operating costs. As the real interest rate (which is the difference between the projected interest rate and the projected escalation rate) increases, capital investments to reduce operating costs will decrease.

17.1.2.4 Transmission

Black & Veatch evaluated transmission interconnections for each of the subregions shown on Figure 17-2 as described in detail in Section 12.0. The Kake-Petersburg and the Ketchikan-Metlakatla interconnections are Committed Resources as described in Section 4.0 and are treated as existing interconnections beginning in 2015 and 2013, respectively. Black & Veatch evaluated nine additional interconnections or combinations of interconnections as described in Section 12.0.

The first evaluation calculated the 2011 cost per kWh transferred over the interconnection and compared it to the cost of diesel generation. The transmission costs for all of the interconnections exceeded the cost of diesel generation leading to the conclusion that additional interconnections are not cost effective for the region. The second evaluation treated the proposed interconnections as a public benefit and assumed the State would pay the capital cost for the interconnections and the utilities would only pay the O&M and R&R costs associated with the interconnections. A benefit-cost ratio was calculated for each interconnection based on the projected 50 year cumulative present worth utility cost savings due to the interconnection less the cumulative present worth cost of O&M and R&R compared to the capital cost of the interconnection. Six of the nine proposed interconnections had savings that exceeded the O&M and R&R costs, but none had a benefit-cost ratio of one or greater. The highest benefit-cost ratio was 0.32 leading to the conclusion that expenditures by the State for additional interconnections would not provide benefits to the region equal to the expenditures over the 50 year planning period. Table 17-1 presents the results of both of these evaluations.

Table 17-1 Results of Transmission Interconnection Evaluations

INTERCONNECTION	2011 TRANSMISSION INTERCONNECTION COST ($/MWH)	BENEFIT/ COST RATIO
SEI -1A - Hawks Inlet-Hoonah	2,891	--
SEI-4 - Ketchikan-Prince of Wales	797	0.14
SEI-5 - Kake-Sitka	495	0.15
SEI-6 - Hawks Inlet-Angoon-Sitka	1,015	0.23
SEI-6 Alternate - Hoonah-Tenakee Springs-Angoon-Sitka	1,868	0.25
SEI-5 and SEI-6 - North-South	262	0.32
SEI-7 - Hoonah-Gustavus	--	--
SEI-8 - Juneau-Haines	3,902	0.10
SEI-9 - Pelican-Hoonah	8,125	-
2011 Diesel Generation Costs	255	

Based on the results of the transmission evaluations presented in Section 12.0 and summarized in Table 17-1, no new interconnections beyond the Committed Resource interconnections of Kake-Petersburg and Ketchikan-Metlakatla have been included in the Regional Expansion Plan. The transmission analysis did show that the lowest cost interconnection on a $/MWh for power transmitted over the interconnection was the SEI-5 and SEI-6 North-South Interconnection, which interconnected the most subregions in the region.

Since additional transmission interconnections are not included in the Regional Expansion Plan, they will not be shown in the subregion summaries in Section 17.2.

17.1.2.5 Hydroelectric Generation

Hydroelectric generation remains the region's most dependable resource for reducing electric costs and even for reducing space heating costs through conversion to electric space heating. The current licensing environment, primarily due to the Roadless Rule, results in uncertainty regarding the development and timing of future hydroelectric facilities. Cost for new hydroelectric facilities is also uncertain, but appears to be increasing over that of existing projects. The uncertainty of availability and higher costs for future hydroelectric projects calls into question the prudence of continued high levels of conversion to electric space heating in order that the hydroelectric generation is maintained for its highest and best value to the region while space heating can be provided by lower quality energy sources. The quality and consistency of data on proposed hydroelectric projects drove the expansion plan evaluations to be based on generic hydroelectric projects as discussed in Section 10.0. Table 17-2 presents the five Committed Resource hydroelectric projects. These Committed Resources meet most of the region's hydroelectric requirements for the next 10 years under all three load forecasts. Table 17-3 presents the generic hydroelectric expansion plans in addition to the Committed Resources for the region for each of the load forecasts. The generic hydroelectric projects from Table 17-3 are summarized below.

- High Scenario Load Forecast
  - 23 Storage Projects - 188 MW
  - 22 Run-of-River Projects - 22 MW
  - Total - 45 Projects - 210 MW
- Reference Scenario Load Forecast
  - 4 Storage Projects - 46 MW
  - 4 Run-of-River Projects - 4 MW
  - Total - 8 Projects - 50 MW
- Low Scenario Load Forecast
  - 4 Storage Projects - 22 MW
  - 2 Run-of-River Projects - 2 MW
  - Total - 6 Projects - 24 MW

As shown above, the region's greatest hydroelectric need is for storage projects. If the region is successful in stemming the conversions to electric heat and does not face additional growth beyond the reference scenario load forecast, the need for new hydroelectric generation is manageable, and if the region is successful at reducing loads through DSM/EE as presented in the low scenario load forecast, the need for new hydroelectric projects is relatively small through the 50 year planning period.

Table 17-3 shows that only one 20 MW storage project located in the Ketchikan region will be required under the high scenario load forecast during the next 10 years besides a 1 MW storage project in the Yakutat region under each of the three load forecasts. Additional hydroelectric projects to serve specific purposes such as mines and electrification for cruise ships may also be required and are discussed under the respective region.

Table 17-2 Committed Resources

PROJECT NAME	CATEGORY	CAPACITY (MW)	LOCATION
Blue Lake Expansion	Storage	8.00	Sitka
Gartina Falls	Run-of-river	0.445	Hoonah
Reynolds Creek	Storage	5.00	Prince of Wales
Thayer Creek	Run-of-river	1.00	Angoon
Whitman Lake	Storage	4.60	Ketchikan

Table 17-3 Hydroelectric Expansion Plans

YEAR	LOAD FORECAST		
	HIGH SCENARIO	REFERENCE SCENARIO	LOW SCENARIO
2017	Ketchikan Storage - 20 MW Yakutat Storage - 1 MW	Yakutat Storage - 1 MW	Yakutat Storage - 1 MW
2020	Juneau Storage - 20 MW		
2028		Ketchikan Storage - 20 MW	
2029	Hoonah Storage - 1 MW		
2031	Baranof Run-of River - 1 MW		
2032	Juneau Storage - 20 MW	Hoonah Run-of-River - 1 MW	
2033	Baranof Storage - 1 MW Ketchikan Storage - 20 MW	Juneau Storage - 20 MW	
2034	Baranof Storage - 1 MW Upper Lynn Canal IPEC Storage - 5 MW		
2035	Yakutat Run-of-River - 1 MW		Hoonah Run-of-River - 1 MW
2036	Baranof Run-of River - 1 MW		
2037	Gustavus Run-of-River - 1 MW		
2038	Baranof Storage - 1 MW		
2040	Baranof Run-of River - 1 MW Prince of Wales Storage - 1 MW		
2041	Baranof Storage - 1 MW Juneau Storage - 20 MW		
2043	Baranof Storage - 1 MW Pelican Run-of-River - 1 MW Prince of Wales Storage - 1 MW		
2044		Yakutat Run-of-River - 1 MW	Metlakatla Storage - 10 MW
2046	Ketchikan Storage - 20 MW		
2048	Kake Run-of-River - 1 MW Prince of Wales Storage - 1 MW		
2049	Petersburg Run-of-River - 1 MW		Yakutat Run-of-River - 1 MW
2050	Juneau Storage - 20 MW Petersburg Run-of-River - 1 MW Yakutat Storage - 1 MW		
2051	Petersburg Run-of-River - 1 MW	Upper Lynn Canal IPEC Storage - 5 MW	Juneau Storage - 10 MW
2052	Wrangell Run-of-River - 1 MW		

YEAR	LOAD FORECAST		
	HIGH SCENARIO	REFERENCE SCENARIO	LOW SCENARIO
2053	Wrangell Run-of-River - 1 MW		
2054	Tenakee Springs Run-of- River - 1 MW Kake Run-of-River - 1 MW Prince of Wales Storage - 1 MW	Gustavus Run-of-River - 1 MW	Upper Lynn Canal IPEC Storage - 1 MW
2055	Wrangell Run-of-River - 1 MW		
2056	Upper Lynn Canal AP&T Run-of-River - 1 MW Tyee Lake Run-of-River - 1 MW	Baranof Run-of-River - 1 MW	
2057	Juneau Storage - 20 MW Tyee Lake Run-of-River - 1 MW		
2058	Hoonah Run-of-River - 1 MW Metlakatla Storage - 10 MW		
2059	Upper Lynn Canal AP&T Run-of-River - 1 MW Tyee Lake Run-of-River - 1 MW Prince of Wales Storage - 1 MW		
2060	Kake Run-of-River - 1 MW		
Totals	23 Storage Projects - 188 MW 22 Run-of-River Projects - 22 MW	4 Storage Projects - 46 MW 4 Run-of-River Projects – 4 MW	4 Storage Projects - 22 MW 2 Run-of-River Projects - 2 MW
Total	**45 Projects - 210 MW**	**8 Projects - 50 MW**	**6 Projects - 24 MW**

17.1.2.6 Diesel Generation

Diesel generation has traditionally been the dependable source of capacity for the region and will continue to be the primary source of dependable capacity for the region throughout the 50 year planning period. Diesel generation serves to backup the hydroelectric generation for areas with hydroelectric power, both from outages and from unfavorable water conditions. Diesel generation serves as the only generation source for communities that do not have access to hydroelectric generation. For this study, Black & Veatch assumed that sufficient diesel capacity would be provided to meet the peak loads of the communities with hydroelectric generation and for communities without hydroelectric generation; diesel generation capacity would be required to meet the peak loads plus a 15 percent reserve margin criterion. Black & Veatch also assumed that diesel generator life times would be 40 years for communities with hydroelectric generation where the diesel generation served only as backup and 15 years for communities where diesel generation was used for all their power needs. Specific diesel installations will need to be evaluated on a community by community basis, but these criteria should be sufficient to estimate the diesel capital requirements for the region given the directional nature of this IRP. The projected diesel requirements for each of the subregions for each of the load forecasts are presented in Table 17-4. As the region becomes more interconnected and more hydroelectric projects are developed, the region may be able to reduce its diesel backup requirements by considering firm hydroelectric capacity; however, this potential reduction will be offset by the increases in electric space heating loads that can increase substantially from normal conditions during severe weather conditions. This increase in load can be significantly correlated with low water conditions when there is cold weather in the spring resulting in increased loads and decreased snow melt. This situation was witnessed by some utilities in the region in the spring of 2011. Another factor contributing to the need for diesel backup would be the success of the DSM/EE program. If the program is successful, there will be less opportunity to reduce loads if unforeseen circumstances reduced hydroelectric generation like the 2008 avalanche that caused the outage of the Snettisham transmission line to Juneau.

Table 17-4 Diesel Additions by Subregion (MW)

SUBREGION	LOAD FORECAST		
	HIGH SCENARIO	REFERENCE SCENARIO	LOW SCENARIO
SEAPA	179	119	119
Admiralty Island	1	1	1
Baranof Island	90	60	50
Chichagof Island	5	5	4
Juneau Area	210	140	120
Northern	15.5	9	9
Prince of Wales	11	9	7
Upper Lynn Canal	31	11	11
Total Southeast Region	**542.5**	**354**	**321**

17.1.2.7 Other Generation Alternatives

Other electric generation alternatives are discussed in Section 11.0. In general, the other electric generation alternatives fall into one of the following four categories.

- Feasible and Economic.
- Unfeasible and/or Uneconomic.
- Technology Needs More Development.
- Specific Project Needs More Development.

Each category is briefly described below.

Feasible and Economic – these generating units would be considered commercial and economic for at least some role in a utility system; for instance, base, intermediate, peaking, or reserve/backup.

Unfeasible and/or Uneconomic – the generating unit would be unfeasible due to the lack of necessary resources; for example, a wind turbine would be unfeasible in a certain region if the subregion had inadequate wind. The generating unit would be uneconomic if the loads in the subregion were small enough that the generating unit was too expensive due to economies of scale or part load operation. The generating unit could also be uneconomic if for instance the transmission line required for it caused the project to be too expensive.

Technology Needs More Development - the generating unit would be considered a developing technology which would not yet be considered commercial. Thus, the technology would be viewed as being able to eventually achieve commercialization at a price that would be able to be competitive in at least some mode of utility system operation.

Specific Project Needs More Development – the generating unit in general is feasible and economic depending upon the specific application. An example would be wind where the feasibility and economics of a specific site appear possible, but the specific site has not been studied in enough detail to be sure.

Review of Section 11.0 indicates that the only generating alternatives that meet the feasible and economic category are diesels. Table 17-5 presents the generating alternatives that meet the various categories for each of the subregions other than the unfeasible and/or uneconomic.

Table 17-5 Other Generating Alternatives

SUBREGION	FEASIBLE AND ECONOMIC	TECHNOLOGY NEEDS MORE DEVELOPMENT	SPECIFIC PROJECT NEEDS MORE DEVELOPMENT
SEAPA	Diesel		Wind
		Tidal	
			Wrangell Narrows
		Biomass	
		Biomass Gasifier	
Admiralty Island	Diesel		
Baranof Island	Diesel		
Chichagof Island	Diesel		
Juneau Area	Diesel	Tidal	
			Gustineau Channel
Northern Region	Diesel	Wave Energy	
		Yakutat	
			Aquamarine Oyster
			Wave Energy/Sequestration Technology
		Wind	
		Yakutat	
		Tidal	
		Gustavus	
		Biomass	
		Biomass Gasifier	
		Yakutat	
Prince of Wales Region	Diesel		
Upper Lynn Canal	Diesel		

17.1.2.8 Space Heating

Space heating is a very large cost for the region. Oil space heating has traditionally been the technology of choice for the region and serves well from the standpoint of reliability and convenience. Unfortunately, when the price of oil increases the cost of heating oil becomes an unbearable economic burden for the region. Black & Veatch estimates the cost for oil space heating for the region could be $72 million in 2012. When oil prices spike as they did in 2008, 2010, and 2011, many customers convert to electric space heating in communities that have low cost hydroelectric generation. This conversion to electric space heating has consumed excess hydroelectric generation and strained other parts of the electric system such as distribution transformers. The three major conversion techniques are the installation of electric resistance boilers, electric resistance baseboard heaters, and portable electric space heaters. The electric resistance boilers and electric resistance space heaters are generally permanent conversions, while portable electric space heaters are not. In some instances, the electric resistance boilers are installed while leaving the oil boilers in place, but in most instances the oil boilers are removed leaving only the electric heat. Installation of baseboard heating generally leaves the oil boilers in place. The portable electric space heaters are generally used to supplement the oil heating. Customers who have switched to electric boilers have a substantial investment in the electric boiler. Baseboard heaters are less expensive, but may require electric system upgrades to higher amperage service. Portable electric space heaters are very inexpensive and seldom require any service modifications. Commercial conversions are primarily to electric boilers. Section 8.0 discusses the estimates of existing and near-term forecast conversion to electric heat. The lack of data relative to space heating causes there to be significant uncertainty associated with those projections. Figures 15-1 through 15-8 present estimates of the total potential loads that would result from converting all the oil space heating to electric in each region. Again, these estimates have significant uncertainty associated with them.

Electric heat pump technology can reduce the electric energy consumption required for electric space heating. This reduction can be in the neighborhood of a factor of 3 corresponding to a COP of 3. Unfortunately, traditional air source heat pumps lose efficiency and eventually require resistance heat when temperatures fall below 30° F. New heat pumps that function only in the heating mode are being developed that operate somewhat more efficiently down to loads of 0° F. Air source heat pumps generally require forced air systems to operate effectively because of the lower temperature that they develop. Unfortunately, most existing homes in the region do not have duct systems. In addition, heat pumps cost considerably more than the electric resistance boilers. Ground source heat pumps eliminate the ambient air temperature limitations of air source heat pumps, but are several times more expensive. While ground source heat pumps can provide a hotter working fluid than air source heat pumps, their integration into existing hot water systems can still be problematic.

Rate structures in the region have contributed to the conversion to electric space heating in the subregions with low cost hydroelectric generation. Most of the rate structures are flat or declining block, which increases the economics of electric conversions. While these rate structures may have been more appropriate in the past, they do not reflect potential increased costs of hydroelectric generation in the future. Changes to these rate structures will also be problematic because of the number of customers who have invested substantially in their electric space heating systems based on the tariff design to encourage electric space heating.

Given the current situation and the economic analysis of space heating options in Section 15.0 and Section 16.0 and the abundance of potential biomass in the region, Black & Veatch proposes a strong program to convert oil space heating to biomass as the major component of the integrated approach to solve the region's space heating issues. After evaluating available biomass options, Black & Veatch believes strong emphasis on pellets represents the best approach for the region especially for residential customers. One of the benefits of pellets is that they come closest to electric and oil space heating in terms of reliability and convenience. This reliability and convenience comes, however, at an increase in cost compared to chips or cord wood. Larger commercial facilities may find that the savings from chips and smaller commercial facilities may find savings from cord wood may be sufficient to offset greater nonfuel operation and costs.

The region's abundance of biomass resources, albeit many of the resources are under the control of the Forest Service in the Tongass National Forest, allows the opportunity for the region to provide the majority of their space heating needs through local sustainable renewable resources. An additional benefit to the region is the local jobs the biomass program would provide.

For purposes of evaluating the economics of the biomass program, Black & Veatch has assumed that 80 percent of the existing oil space heating in the region is converted to biomass in 10 years. This level of conversion represents a very substantial biomass program with approximately 129,000 tons of pellets required annually after 10 years. This volume of pellets would support at least four 30,000 ton per yearpellet mills in the region. Current data for the region is not adequate to determine if the region can sustainably support this level of biomass. Certainly it would be difficult to support with current wood waste products in the region, but the region is currently at a low point in its historical forest product production. Even if the region could not always support the level of pellets contemplated in the proposed program, the economic evaluations of the program are based on the current Sealaska price for importing pellets from the State of Washington and thus the region could still obtain the projected savings using imported pellets. The opportunity for providing pellets locally in the region at lower costs will only increase savings.

The biomass program is based on providing customers a rebate of approximately the total capital costs required to convert to pellet space heating. Providing approximately the full cost should result in very substantial penetration. Details of the estimated costs of conversion are provided in Section 16.0. The total estimated capital requirements for the conversion from oil to pellet space heating over the 10 year period are $532 million. These capital costs do not include any costs for developing the pellet mills or transportation and distribution infrastructure necessary to support the program since the pellet costs that were considered are based on delivery to customers in the region. Cost support for this infrastructure may be one of the things considered in the detailed development of the program as described in Section 15.6.

The estimated cumulative present worth savings of the proposed biomass program is $2.1 billion over the 50 year planning period including the $532 million capital expenditure. Local pellet production at lower costs than the current Sealaska price for imported pellets would increase these savings. Lower cost commercial biomass space heating projects utilizing chips or cord wood would also increase these savings.

Other alternatives for space heating including natural gas and propane were also investigated. If somehow North Slope propane could be provided to the Southeast on a dependable basis at substantially below market prices, propane would be a viable alternative. Unfortunately the propane issue is generally out of the control of Southeast Alaska and has much uncertainty associated with it. The region should continue to monitor the situation and if a viable propane option develops, nothing would preclude its implementation.

17.1.2.9 DSM/EE

The DSM/EE evaluations in Section 13.0 indicate that substantial savings are possible. Weatherization issues are discussed in Subsection 17.1.2.10. There is a lack of DSM/EE data for the region and as such, there is substantial uncertainty associated with the proposed DSM/EE program. The DSM/EE measures were selected based on the simplified typical DSM/EE cost-effectiveness tests.

- Rate Impact Test (RIM).
- Total Resource Cost Test (TRC).
- Participant Test.

The selected measures were required to pass all three tests. Passing of the TRC and participant tests are typical requirements since it makes little sense to conduct programs that do not save the region or the participant's money. Some jurisdictions do not require the RIM test. One of the components of the RIM test is the lost revenue to the utility from the reduced energy sales available to cover the utility's existing fixed costs. If measures do not pass the RIM test, rates will increase. If rates increase, bills increase for the customers that cannot or choose not to participate in the measures. If measures pass the RIM test, then customer bills will decrease whether or not customers can participate in the measure.

One of the interesting findings of the DSM/EE evaluation is that many of the utilities with high diesel fuel costs also have high nonfuel costs. These high nonfuel costs cause many of the measures evaluated for these utilities to not pass the RIM test. As a result, there are significantly less DSM/EE measures included for these utilities. This issue of increased rates for these high cost utilities will need to be addressed in the detailed DSM/EE program development discussed in Subsection 13.4.2.

The utilities were grouped into three groups due to the limited scope of the IRP for purposes of applying the cost-effectiveness tests based on avoided costs of generation and overall utility costs. The utilities were grouped as follows:

- **High Cost Utilities**--This category includes those communities that were dependent upon high cost diesel generation in 2010 and includes the communities of Angoon, Chilkat Valley, Coffman Cove, Elfin Cove, Hoonah, Kake, Klukwan, Pelican, Tenakee Springs, Whale Pass, and Yakutat.
- **Medium Cost Utilities**--This category includes those communities that have access to some low cost hydroelectric generation but have higher costs due to economies of scale and includes the communities of Craig, Gustavus, Haines, Hollis, Hydaburg, Kasaan, Klawock, Naukati Bay, Skagway, and Thorne Bay.
- **Low Cost Utilities**--This category includes those communities who have sufficient low cost hydroelectric generation to meet almost all of their electric demand and includes the communities of Juneau, Ketchikan, Metlakatla, Petersburg, Sitka, and Wrangell.

Table 17-6 presents the DSM/EE programs containing measures that passed all three cost-effectiveness tests. Black & Veatch used a set of typical penetration curves to estimate the penetration of the DSM/EE programs. These curves are the typical "S" shape with lower penetration in the early years, rapid penetration in the mid years, and slow penetration in the later years as the programs saturate. The curves also reflect the lifetime of the measures and the level of incentives included. Overall, the penetration curves result in close to their maximum penetration in about 10 years. At that time, load is reduced for the region about 10.4 percent. The load reduction for each subregion is presented in Subsection 8.1.4. The estimated costs required for the proposed DSM/EE programs are presented in Section 17.2. Black & Veatch estimates that, after the programs reach saturation in about 10 years, 25 percent of the program cost will be necessary to maintain the demand and energy savings through the planning period and those costs are also shown in Section 17.2. There is considerable uncertainty with respect to those costs due to future unknowns with respect to future efficiency levels and regulations associated with them. Table 17-7 presents the estimated utility cost savings from the DSM/EE programs assuming generic hydroelectric project additions. As shown in Table 17-7, the estimated cumulative present worth savings for the region is $137 million over the 50 year planning period.

Table 17-6 DSM/EE Programs

RESIDENTIAL	COMMERCIAL/INDUSTRIAL
HIGH COST UTILITIES	
Water Heater	Water Heater
	Motor
	Refrigeration
	Lighting
	Cooling/Heating
MEDIUM COST UTILITIES	
Appliance	Water Heater
Water Heater	Motor
Lighting	Refrigeration
	Lighting
	Cooling/Heating
LOW COST UTILITIES	
Appliance	Water Heater
Water Heater	Office Load
Lighting	Motor
Cooling/Heating	Lighting
	Refrigeration
	Cooling/Heating

Table 17-7 DSM/EE Cost Savings (2012 Cumulative Present Worth $'000)

	WITHOUT DSM/EE UTILITY SYSTEM COSTS	WITH DSM/EE			SAVINGS WITH DSM
		UTILITY SYSTEM COSTS	DSM/EE COSTS	TOTAL	
SEAPA	288,797	195,522	39,201	234,723	54,074
Admiralty Island	8,022	8,019	25	8,044	-22
Baranof Island	97,345	84,156	11,716	95,872	1,473
Chichagof Island	51,852	46,267	301	46,568	5,284
Juneau	234,265	138,870	46,686	185,556	48,709
Northern	63,256	55,337	488	55,825	7,431
Prince of Wales	24,094	18,774	2,007	20,781	3,313
Upper Lynn Canal	44,538	25,494	2,184	27,678	16,860
Total Southeast Region	**812,169**	**572,439**	**102,608**	**675,047**	**137,122**

17.1.2.10 Weatherization

Weatherization represents a conundrum for the regional expansion plan as discussed in Section 14.0. Weatherization is commonly considered a cost-effective DSM/EE program. While weatherization measures can be cost effective based on the specific measure and the condition of the structure being weatherized, not all weatherization measures will be cost effective. While this conclusion flies somewhat in the face of common perceptions, it is generally borne out of analysis and is evidenced by market reaction in the Southeast. On the analysis side, Section 14.0 indicates that average costs for energy saved by weatherization programs can range from $186/MWh to $1,016/MWh. This compares to typical generating costs for new diesel and hydroelectric of $255/MWh and $135/MWh, respectively. From the market standpoint, there has been massive conversion to electric space heating in communities with low cost hydroelectric generation without any subsidy other than the tariff electric rates. In spite of several well funded weatherization programs, some of which result in no cost to the customer, the penetration of weatherization in the region remains low even in communities with predominately high cost fuel oil space heating.

There are a number of existing and well funded weatherization programs in place to serve the needs of the Southeast. For these programs to provide a cost-effective weatherization service, they need to provide weatherization measures on a case-by-case basis. Because of the existence of these programs, many of which are described in Sections 13.0 and 16.0, Black & Veatch is not recommending significant new programs, but rather refinement of existing programs to increase the cost effectiveness of weatherization for the region. This lack of new program recommendation on Black & Veatch's behalf does not minimize the importance of weatherization to the region, but merely recognizes that other programs such as biomass space heating have a greater opportunity to reduce costs for the region.

One area that the existing weatherization programs are not as strong in is weatherization for commercial and industrial facilities. In general, it may be even more difficult to achieve cost effectiveness for these facilities on the average due to the nature of the facilities, but many specific opportunities for cost-effective weatherization still exist. This is one area that may merit additional funding, but it also may be possible to reallocate some funding in existing programs to meet these needs.

One impediment to detailed evaluation in the region is the lack of quality end use data. With the completion of AEA's End Use Data Collection Project, a much better picture of weatherization needs will be available.

Finally on the human note, the 2005 Alaska Housing Assessment prepared for Alaska Housing Finance Corporation (AHFC) indicates that 12.4 percent of the households in the Southeast could not maintain a 70° F temperature in their home due to the condition of the home while 21.2 percent could not maintain a 70° F temperature in their home for all reasons. Many of these homes were in communities faced with high electric and space heating costs and that have exhibited significant economic decline in the last few years. While this is the latest information that Black & Veatch was able to obtain, Black & Veatch's observations are that these percentages have improved primarily from many of the marginal homes being abandoned in the communities that are suffering significant economic decline. Nevertheless, there are still opportunities for weatherization to maintain the quality of life for the citizens of the Southeast.

17.1.2.11 Committed Resources

The estimated additional costs for the Committed Resources discussed in Section 4.0 and earlier in this section are presented in Table 17-8, which also shows the amounts that the committed projects have applied for in the AEA's Round 5 Renewable Energy Grant Program.

Table 17-8 Committed Resources Costs

COMMITTED RESOURCE	TOTAL COST ($ MILLION)	EXISTING GRANTS ($ MILLION)	ADDITIONAL FUNDS REQUIRED ($ MILLION)	ROUND 5 REQUEST ($ MILLION)	ADDITIONAL FUNDS REQUIRED AFTER ROUND 5 REQUEST ($ MILLION)
Kake-Petersburg Interconnection(1)	53.78	5.49	48.29	0.00	48.29
Ketchikan-Metlakatla Interconnection	12.72	4.50	8.22	8.22	0.00
Blue Lake Hydroelectric(2)	96.50	69.00	27.50	0.00	27.50
Gartina Falls Hydroelectric	6.33	0.85	5.48	0.00	5.48
Reynolds Creek Hydroelectric(3)	28.58	20.52	8.06	1.20	6.86
Thayer Creek Hydroelectric(4)	15.20	2.16	13.04	7.00	6.04
Whitman Lake Hydroelectric(5)	25.83	12.42	13.40	3.30	10.10

(1)Existing grants were for tasks not included in Total Cost.
(2)Existing grants include $20 million of bonds issued by Sitka and allocated to the project.
(3)Existing grants include expenditures by Haida Energy Inc. of $4,000,000 and Alaska Power & Telephone of $400,000.
(4)The amount shown under existing grants is the amount shown previously expended in the Round 5 application.
(5)Existing grants include KPU cash reserves $1,400,000.

17.1.2.12 Expansion Plans

Each of the subregions shown on Figure 17-2 was modeled using the Strategist® optimal generation expansion program. Strategist® evaluates all combinations of potential generating units to develop an expansion plan that has the least cumulative present worth cost over the planning period. The expansion plans for each of the three load forecasts (high, reference, and low) are presented for each subregion in Tables 17-9 through 17-11. The expansion plans are developed from the generic hydroelectric units presented in Table 10-5 and the respective load forecasts. Diesel generation was added in accordance with the reliability criteria in Section 7.0. In Tables 17-9 through 17-11, the MS and HS refer to medium- and high-speed diesels, respectively, as presented in Section 11.8. The numbers indicate the size of the diesel in MW and the numbers in parentheses represent the number of that type of unit installed. The hydroelectric units are shown as run-of-river (ROR) and storage from Table 10-5. Table 17-12 presents the expansion plan for the reference load forecast assuming no new hydroelectric projects are added. All the expansion plans in Tables 17-9 through 17-12 include the Committed Resources presented in Table 17-8.

One observation from Tables 17-9 through 17-12 in the Baranof Island, Chichagof Island, Juneau Area, and SEAPA subregions is that diesel generation is shown to be installed in 2012, the first year of the planning period. These new diesel units are installed in accordance with the reliability criteria presented in Section 7.0. The selection of these new diesel units at the beginning of the study period indicates that the subregion was, in general, not meeting the reliability criteria presented in Section 7.0. As discussed in Subsection 17.1.2.6, individual utilities may not need to carry the backup requirements specified in Section 7.0 or may be able to extend the lifetime of diesel units beyond what is assumed in Section 7.0. Thus, it is quite possible that not all of the diesel generation additions shown in 2012 will be required at that time. On the other hand, as discussed in Subsection 17.1.2.6, the increasing electric space heating loads may require individual utilities to add more backup capacity going forward.

Table 17-9 High Scenario Load Forecast Expansion Plan

Baranof Island		
2012	MS 10 - Sitka	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019	MS 10 - Sitka	(2)
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031	Baranof - ROR	(1)
2032		
2033	Baranof Storage - 1 MW	(1)
2034	Baranof Storage - 1 MW	(1)
2035		
2036	Baranof - ROR	(1)
2037		
2038	Baranof Storage - 1 MW	(1)
2039		
2040	Baranof - ROR	(1)
2041	Baranof Storage - 1 MW	(1)
2042		
2043	Baranof Storage - 1 MW	(1)
2044		
2045		
2046		
2047		
2048		
2049		
2050	MS 10 - Sitka	(3)
2051		
2052		
2053		
2054		
2055		
2056		
2057		
2058		
2059	MS 10 - Sitka	(2)
2060		
2061		

Chichagof Island		
2012	HS 0.5 Tenakee Springs	(1)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022	HS 0.5 - Elfin Cove	(1)
2023		
2024		
2025		
2026	HS 0.5 Tenakee Springs	(1)
2027		
2028		
2029	Hoonah Storage - 1 MW	(1)
2030		
2031	HS 1 - Hoonah	(1)
2032		
2033		
2034		
2035		
2036		
2037	HS 0.5 - Elfin Cove	(1)
2038		
2039		
2040		
2041	HS 0.5 Tenakee Springs	(1)
2042		
2043	Pelican - ROR	(1)
2044		
2045		
2046		
2047		
2048	HS 0.5 - Pelican	(1)
2049		
2050		
2051		
2052	HS 0.5 - Elfin Cove	(1)
2053		
2054	Tenakee Springs - ROR	(1)
2055		
2056	HS 0.5 Tenakee Springs	(1)
2057		
2058	Hoonah - ROR	(1)
2059		
2060		
2061		

Juneau Area		
2012	MS 10 - Juneau	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020	MS 10 - Juneau	(3)
	Juneau Storage - 20 MW	(1)
2021		
2022		
2023	MS 10 - Juneau	(4)
2024		
2025		
2026		
2027		
2028		
2029	MS 10 - Juneau	(2)
2030		
2031		
2032	Juneau Storage - 20 MW	(1)
2033		
2034	MS 10 - Juneau	(1)
2035		
2036		
2037		
2038		
2039	MS 10 - Juneau	(2)
2040		
2041	Juneau Storage - 20 MW	(1)
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050	Juneau Storage - 20 MW	(1)
2051	MS 10 - Juneau	(3)
2052		
2053		
2054		
2055		
2056	MS 10 - Juneau	(5)
2057	Juneau Storage - 20 MW	(1)
2058		
2059		
2060		
2061		

Upper Lynn Canal		
2012		
2013		
2014		
2015		
2016	MS 10 - Haines-Skagway	(1)
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033	HS 1 - Chilkat Valley	(1)
2034	Upper Lynn Storage - 5 MW	(1)
2035		
2036	MS 10 - Haines-Skagway	(1)
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050		
2051		
2052		
2053		
2054		
2055		
2056	MS 10 - Haines-Skagway	(1)
	Alaska P&T - ROR	(1)
2057		
2058		
2059	Alaska P&T - ROR	(1)
2060		
2061		

SEAPA		
2012	HS 1 - Kake	(1)
	MS 10 - Ketchikan	(2)
	MS 10 - Petersburg	(1)
	MS 3 - Metlakatla	(1)
	MS 5 - Wrangell	(1)
2013		
2014		
2015		
2016	MS 10 - Ketchikan	(2)
2017	Ketchikan Storage - 20 MW	(1)
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026	HS 1 - Kake	(1)
2027	MS 3 - Metlakatla	(2)
	MS 5 - Wrangell	(1)
2028		
2029		
2030		
2031		
2032		
2033	MS 5 - Petersburg	(1)
	Ketchikan Storage - 20 MW	(1)
2034	MS 10 - Ketchikan	(2)
2035		
2036		
2037		
2038		
2039		
2040	MS 5 - Wrangell	(1)
2041	HS 1 - Kake	(1)
	MS 10 - Petersburg	(1)
2042		
2043		
2044		
2045		
2046	Ketchikan Storage - 20 MW	(1)
2047	MS 5 - Ketchikan	(1)
2048	Kake - ROR	(1)
2049	Peterburg - ROR	(1)
2050	Peterburg - ROR	(1)
2051	MS 10 - Ketchikan	(3)
	MS 10 - Petersburg	(1)
	Peterburg - ROR	(1)
2052	Wrangell - ROR	(1)
2053	Wrangell - ROR	(1)
2054	Kake - ROR	(1)
2055	Wrangell - ROR	(1)
2056	HS 1 - Kake	(2)
	MS 10 - Ketchikan	(2)
	Tyee Lake - ROR	(1)
2057	Tyee Lake - ROR	(1)
2058	Metlakatla Storage - 10 MW	(1)
2059	Tyee Lake - ROR	(1)
2060	Kake - ROR	(1)
2061		

Northern		
2012		
2013		
2014	MS 2 - Yakutat	(1)
2015		
2016		
2017	Yakutat Storage - 1 MW	(1)
2018		
2019		
2020	HS 0.5 Gustavus	(1)
2021		
2022		
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2026		
2027		
2028		
2029	MS 2 - Yakutat	(2)
2030		
2031		
2032	HS 0.5 Gustavus	(2)
2033		
2034		
2035	Yakutat - ROR	(1)
2036		
2037	Gustavus - ROR	(1)
2038		
2039		
2040		
2041		
2042		
2043		
2044	MS 2 - Yakutat	(2)
2045		
2046		
2047		
2048		
2049		
2050	Yakutat Storage - 1 MW	(1)
2051		
2052		
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2058		
2059	MS 2 - Yakutat	(2)
2060		
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Admiralty		
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2044	HS 1 - Angoon	(1)
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Prince of Wales		
2012		
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2029		
2030	MS 5 - Prince of Wales Region	(1)
2031		
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2035		
2036		
2037		
2038	MS 5 - Prince of Wales Region	(1)
2039		
2040	Prince of Wales Storage - 1 MW	(1)
	HS 0.5 - Whale Pass	(1)
2041		
2042		
2043	Prince of Wales Storage - 1 MW	(1)
2044		
2045		
2046		
2047		
2048	Prince of Wales Storage - 1 MW	(1)
2049		
2050		
2051		
2052		
2053		
2054	Prince of Wales Storage - 1 MW	(1)
2055	HS 0.5 - Whale Pass	(1)
2056		
2057		
2058		
2059	Prince of Wales Storage - 1 MW	(1)
2060		
2061		

Table 17-10 Reference Scenario Load Forecast Expansion Plan

Baranof Island		
2012	MS 10 - Sitka	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019	MS 10 - Sitka	(1)
2020		
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2051	MS 10 - Sitka	(2)
2052		
2053		
2054		
2055		
2056	Baranof - ROR	(1)
2057		
2058		
2059	MS 10 - Sitka	(1)
2060		
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Chichagof Island		
2012	HS 0.5 Tenakee Springs	(1)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022	HS 0.5 - Elfin Cove	(1)
2023		
2024		
2025		
2026	HS 0.5 Tenakee Springs	(1)
2027		
2028		
2029		
2030		
2031		
2032	Hoonah - ROR	(1)
2033		
2034		
2035		
2036		
2037	HS 0.5 - Elfin Cove	(1)
	HS 1 - Hoonah	(1)
2038		
2039		
2040		
2041	HS 0.5 Tenakee Springs	(1)
2042		
2043		
2044		
2045		
2046		
2047		
2048	HS 0.5 - Pelican	(1)
2049		
2050		
2051		
2052	HS 0.5 - Elfin Cove	(1)
2053		
2054		
2055		
2056	HS 0.5 Tenakee Springs	(1)
2057		
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Juneau Area		
2012	MS 10 - Juneau	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020	MS 10 - Juneau	(2)
2021		
2022		
2023	MS 10 - Juneau	(3)
2024		
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2031		
2032		
2033	MS 10 - Juneau	(3)
	Juneau Storage - 20 MW	(1)
2034		
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2051	MS 10 - Juneau	(2)
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2060	MS 10 - Juneau	(2)
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Upper Lynn Canal		
2012		
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2030		
2031	MS 10 - Haines-Skagway	(1)
2032		
2033	HS 1 - Chilkat Valley	(1)
2034		
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2050		
2051	Upper Lynn Storage - 5 MW	(1)
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SEAPA		
2012	HS 1 - Kake	(1)
	MS 10 - Ketchikan	(2)
	MS 10 - Petersburg	(1)
	MS 3 - Metlakatla	(1)
	MS 5 - Wrangell	(1)
2013		
2014		
2015		
2016	MS 10 - Ketchikan	(1)
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026	HS 1 - Kake	(1)
2027	MS 3 - Metlakatla	(1)
	MS 5 - Wrangell	(1)
2028	Ketchikan Storage - 20 MW	(1)
2029		
2030		
2031		
2032		
2033	MS 5 - Petersburg	(1)
2034	MS 10 - Ketchikan	(1)
2035		
2036		
2037		
2038	MS 5 - Ketchikan	(1)
2039		
2040		
2041	HS 1 - Kake	(1)
2042	MS 5 - Wrangell	(1)
2043		
2044		
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2047		
2048		
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2050		
2051	HS 1 - Wrangell	(1)
	MS 10 - Ketchikan	(2)
	MS 10 - Petersburg	(1)
	MS 3 - Metlakatla	(1)
2052		
2053		
2054		
2055		
2056	HS 1 - Kake	(1)
	MS 10 - Ketchikan	(1)
2057		
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Northern		
2012		
2013		
2014	MS 2 - Yakutat	(1)
2015		
2016		
2017	Yakutat Storage - 1 MW	(1)
2018		
2019		
2020	HS 0.5 Gustavus	(1)
2021		
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2026		
2027		
2028		
2029	MS 2 - Yakutat	(1)
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2043		
2044	MS 2 - Yakutat	(1)
	Yakutat - ROR	(1)
2045		
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2051		
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2053		
2054	Gustavus - ROR	(1)
2055		
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2058		
2059	MS 2 - Yakutat	(1)
2060	HS 0.5 Gustavus	(1)
2061		

Admiralty		
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2049	HS 1 - Angoon	(1)
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Prince of Wales		
2012		
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2030		
2031	MS 5 - Prince of Wales Region	(1)
2032		
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2037		
2038		
2039		
2040	HS 0.5 - Whale Pass	(1)
2041		
2042		
2043	MS 3 - Prince of Wales Region	(1)
2044		
2045		
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2055	HS 0.5 - Whale Pass	(1)
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Table 17-11 Low Scenario Load Forecast Expansion Plan

Baranof Island		
2012	MS 10 - Sitka	(2)
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2033		
2034	MS 10 - Sitka	(1)
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2045		
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2047		
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2050		
2051	MS 10 - Sitka	(2)
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Chichagof Island		
2012	HS 0.5 Tenakee Springs	(1)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022	HS 0.5 - Elfin Cove	(1)
2023		
2024		
2025		
2026	HS 0.5 Tenakee Springs	(1)
2027		
2028		
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2030		
2031		
2032		
2033		
2034		
2035	Hoonah - ROR	(1)
2036		
2037	HS 0.5 - Elfin Cove	(1)
	HS 1 - Hoonah	(1)
2038		
2039		
2040		
2041	HS 0.5 Tenakee Springs	(1)
2042		
2043		
2044		
2045		
2046		
2047		
2048	HS 0.5 - Pelican	(1)
2049		
2050		
2051		
2052	HS 0.5 - Elfin Cove	(1)
2053		
2054		
2055		
2056	HS 0.5 Tenakee Springs	(1)
2057		
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2061		

Juneau Area		
2012	MS 10 - Juneau	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020	MS 10 - Juneau	(1)
2021		
2022		
2023	MS 10 - Juneau	(3)
2024		
2025		
2026		
2027		
2028		
2029		
2030	MS 10 - Juneau	(1)
2031		
2032		
2033		
2034	MS 10 - Juneau	(2)
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2051	MS 10 - Juneau	(2)
	Juneau Storage - 10 MW	(1)
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2059		
2060	MS 10 - Juneau	(1)
2061		

Upper Lynn Canal		
2012		
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2032		
2033	HS 1 - Chilkat Valley	(1)
	MS 10 - Haines-Skagway	(1)
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2053		
2054	Upper Lynn Storage - 1 MW	(1)
2055		
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SEAPA		
2012	HS 1 - Kake	(1)
	MS 10 - Ketchikan	(2)
	MS 10 - Petersburg	(1)
	MS 3 - Metlakatla	(1)
	MS 5 - Wrangell	(1)
2013		
2014		
2015		
2016	MS 10 - Ketchikan	(1)
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026	HS 1 - Kake	(1)
2027	MS 3 - Metlakatla	(1)
2028		
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2035		
2036		
2037		
2038	MS 10 - Ketchikan	(1)
2039		
2040		
2041	HS 1 - Kake	(1)
	MS 5 - Petersburg	(1)
2042	MS 5 - Wrangell	(1)
2043		
2044	Metlakatla Storage - 10 MW	(1)
2045		
2046		
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2050		
2051	HS 1 - Wrangell	(1)
	MS 10 - Ketchikan	(2)
	MS 10 - Petersburg	(1)
	MS 3 - Metlakatla	(1)
2052		
2053		
2054		
2055		
2056	HS 1 - Kake	(1)
	MS 10 - Ketchikan	(1)
2057		
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Northern		
2012		
2013		
2014	MS 2 - Yakutat	(1)
2015		
2016		
2017	Yakutat Storage - 1 MW	(1)
2018		
2019		
2020	HS 0.5 Gustavus	(1)
2021		
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2027		
2028		
2029	MS 2 - Yakutat	(1)
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2043		
2044	MS 2 - Yakutat	(1)
2045		
2046		
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2048		
2049	Yakutat - ROR	(1)
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2058		
2059	MS 2 - Yakutat	(1)
2060	HS 0.5 Gustavus	(1)
2061		

Admiralty		
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2049	HS 1 - Angoon	(1)
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Prince of Wales		
2012		
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2031	MS 3 - Prince of Wales Region	(1)
2032		
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2038		
2039		
2040	HS 0.5 - Whale Pass	(1)
2041		
2042		
2043	MS 3 - Prince of Wales Region	(1)
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2052		
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2055	HS 0.5 - Whale Pass	(1)
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Table 17-12 No Hydroelectric Additions Expansion Plan

Baranof Island		
2012	MS 10 - Sitka	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019	MS 10 - Sitka	(1)
2020		
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2050		
2051	MS 10 - Sitka	(2)
2052		
2053		
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2057		
2058		
2059	MS 10 - Sitka	(1)
2060		
2061		

Chichagof Island		
2012	HS 0.5 Tenakee Springs	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022	HS 0.5 - Elfin Cove	(1)
2023		
2024		
2025		
2026	HS 0.5 Tenakee Springs	(2)
2027		
2028		
2029		
2030		
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2033		
2034		
2035		
2036		
2037	HS 0.5 - Elfin Cove	(2)
	HS 1 - Hoonah	(1)
2038		
2039		
2040		
2041	HS 0.5 Tenakee Springs	(2)
2042		
2043		
2044		
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2047		
2048	HS 0.5 - Pelican	(1)
2049		
2050		
2051		
2052	HS 0.5 - Elfin Cove	(2)
2053		
2054		
2055		
2056	HS 0.5 Tenakee Springs	(2)
2057		
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Juneau Area		
2012	MS 10 - Juneau	(2)
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020	MS 10 - Juneau	(2)
2021		
2022		
2023	MS 10 - Juneau	(3)
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2032		
2033	MS 10 - Juneau	(3)
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2051	MS 10 - Juneau	(2)
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2060	MS 10 - Juneau	(2)
2061		

Upper Lynn Canal		
2012		
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2029		
2030		
2031	MS 10 - Haines-Skagway	(1)
2032		
2033	HS 1 - Chilkat Valley	(1)
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SEAPA		
2012	HS 1 - Kake	(1)
	MS 10 - Ketchikan	(2)
	MS 10 - Petersburg	(1)
	MS 3 - Metlakatla	(1)
	MS 5 - Wrangell	(1)
2013		
2014		
2015		
2016	MS 10 - Ketchikan	(1)
2017		
2018		
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2020		
2021		
2022		
2023		
2024		
2025		
2026	HS 1 - Kake	(1)
2027	MS 3 - Metlakatla	(1)
	MS 5 - Wrangell	(1)
2028		
2029		
2030		
2031		
2032		
2033	MS 5 - Petersburg	(1)
2034	MS 10 - Ketchikan	(1)
2035		
2036		
2037		
2038	MS 5 - Ketchikan	(1)
2039		
2040		
2041	HS 1 - Kake	(1)
2042	MS 5 - Wrangell	(1)
2043		
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2049		
2050		
2051	HS 1 - Wrangell	(1)
	MS 10 - Ketchikan	(2)
	MS 10 - Petersburg	(1)
	MS 3 - Metlakatla	(1)
2052		
2053		
2054		
2055		
2056	HS 1 - Kake	(1)
	MS 10 - Ketchikan	(1)
2057		
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Northern		
2012		
2013		
2014	MS 2 - Yakutat	(1)
2015		
2016		
2017		
2018		
2019		
2020	HS 0.5 Gustavus	(1)
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029	MS 2 - Yakutat	(1)
2030		
2031		
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2041		
2042		
2043		
2044	MS 2 - Yakutat	(1)
2045		
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2047		
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2052		
2053		
2054		
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2056		
2057		
2058		
2059	MS 2 - Yakutat	(1)
2060	HS 0.5 Gustavus	(1)
2061		

Admiralty		
2012		
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2049	HS 1 - Angoon	(1)
2050		
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Prince of Wales		
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2031	MS 5 - Prince of Wales Region	(1)
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2033		
2034		
2035		
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2037		
2038		
2039		
2040	HS 0.5 - Whale Pass	(1)
2041		
2042		
2043	MS 3 - Prince of Wales Region	(1)
2044		
2045		
2046		
2047		
2048		
2049		
2050		
2051		
2052		
2053		
2054		
2055	HS 0.5 - Whale Pass	(1)
2056		
2057		
2058		
2059		
2060		
2061		

Table 17-13 presents the cumulative present worth costs for the expansion plans presented in Tables 17-9 through 17-11 for each subregion and the Southeast as a whole. The high scenario load forecast case is obviously more expensive than the reference scenario load forecast case because it serves a larger load. The other three cases all serve the same initial loads. The low load forecast case has lower loads due to the DSM/EE programs and thus includes the cost of the DSM/EE programs to be equivalent with the reference load forecast cases. Table 17-13 indicates a cumulative present worth savings to the region of $340 million over the 50 year planning period for the reference scenario load forecast case with additional hydroelectric generation compared to only diesel generation additions. Table 17-13 also shows that there is an additional $137 million cumulative present worth savings to the region with the proposed DSM/EE programs. Table 17-13 includes the fuel costs and O&M costs for new and existing units, DSM/EE costs, and the annual capital costs for new generation over the 50 year planning period. Fuel costs are based on the projected medium diesel prices presented in Table 5-4. O&M costs for existing units are presented in Section 4.0. Capital and O&M costs for new diesels are presented in Section 11.8. Capital, O&M, and R&R costs for the generic new hydroelectric units are presented in Table 10-5. Capital, O&M, and R&R costs are escalated at the 3 percent escalation rate presented in Section 6.0. Fixed charge rates for 30 years, 20 years, and 15 years, respectively, for hydroelectric, medium speed diesels, and high speed diesels, as presented in Section 6.0, are applied to the escalated capital costs. The fixed charge rates are based on a 5.5 percent interest rate as described in Section 6.0. Thus, the costs in Table 17-13 are based on 100 percent financing and do not consider grants from the State. A 5.5 percent discount rate is used to develop the present worth costs in Table 17-13 as described in Section 6.0. For the Committed Resources, only annual O&M and R&R costs are included.

Table 17-13 Expansion Plan Costs (2012 Cumulative Present Worth ’1000)

REGION	HIGH LOAD FORECAST	REFERENCE LOAD FORECAST		LOW LOAD FORECAST		
		WITH HYDRO	WITHOUT HYDRO	UTILITY COSTS	DSM/EE COSTS	TOTAL
SEAPA	516,796	288,797	456,153	195,522	39,201	234,723
Admiralty Island	8,180	8,022	8,022	8,019	25	8,044
Baranof Island	291,439	97,345	97,543	84,156	11,716	95,872
Chichagof Island	63,218	51,852	59,786	46,267	301	46,568
Juneau Area	511,353	234,265	370,673	138,870	46,686	185,556
Northern	82,187	63,256	89,495	55,337	488	55,825
Prince of Wales	57,759	24,094	24,094	18,774	2,007	20,781
Upper Lynn Canal	77,729	44,538	46,603	25,494	2,184	27,678
Total Southeast Region	**1,608,661**	**812,169**	**1,152,369**	**572,439**	**102,608**	**675,047**

As previously noted, space heating is a tremendous cost to the region. Table 17-14 presents the cumulative present worth costs for space heating for each subregion and the Southeast as a whole. Table 17-14 indicates the region will spend $4.5 billion in cumulative present worth costs with continued use of oil for space heating over the 50 year planning period. Table 17-14 indicates the region can save $1.4 billion in cumulative present worth costs with a substantial program to convert to pellets as described in Subsection 17.1.2.8. Those savings include the estimated capital cost necessary to install pellet space heating.

Section 17.2 will present the Preferred Resources Plan for the region as well as for each subregion.

Table 17-14 Space Heating Costs (2012 Cumulative Present Worth '1000)

REGION	OIL SPACE HEATING	PELLET SPACE HEATING PROGRAM			
		OIL COSTS	PELLET COSTS	PELLET CONVERSION COSTS	TOTAL
SEAPA	977,320	258,011	238,441	61,875	793,050
Admiralty Island	22,334	6,830	4,717	1,195	20,786
Baranof Island	460,426	121,745	98,280	23,655	339,552
Chichagof Island	58,459	13,753	11,950	2,806	75,077
Juneau Area	2,120,883	541,759	490,307	111,314	1,328,936
Northern	147,786	39,089	23,925	6,849	125,688
Prince of Wales	366,725	94,304	77,469	14,916	207,470
Upper Lynn Canal	347,271	90,274	67,919	16,287	202,158
Total Southeast Region	**4,501,204**	**1,165,765**	**1,013,008**	**238,897**	**3,092,717**

17.2 SUMMARY OF RESULTS

17.2.1 Regional Results

The Preferred Resources List for the region has the following three main components:

- Committed Resources List
- Capital Requirements
    - Generation
        - Hydroelectric
        - Diesel
    - DSM/EE
    - Space Heating
- Program Development Costs

The following subsections describe each of these components. Following that, Subsections 17.2.2 through 17.2.9 present the regional expansion plans and Preferred Resource List for each subregion. At the end of the section, a single unifying graphic summarizes the situation, expansion plan, and Preferred Resource List for each subregion.

17.2.1.1 Committed Resources

Table 17-15 presents the Committed Resources and their additional estimated cost to achieve commercial operation. Estimated additional costs for the Committed Resources for the region are \$143.1 million. Four of the Committed Resources (Ketchikan-Metlakatla Interconnection, Reynolds Creek Hydroelectric, Thayer Creek Hydroelectric, and Whitman Lake Hydroelectric) have submitted requests for grants from the AEA's Round 5 Renewable Energy Grant Program for a total of \$19.7 million. If these Round 5 requests were granted in their entirety, a total of \$123.4 million would remain to complete the Committed Resources.

Table 17-15 Committed Resources

COMMITTED RESOURCE	ADDITIONAL FUNDS REQUIRED ($ MILLION)	ROUND 5 REQUEST ($ MILLION)	ADDITIONAL FUNDS REQUIRED AFTER ROUND 5 REQUEST ($ MILLION)
Kake-Petersburg Interconnection	48.59	0.00	48.59
Ketchikan-Metlakatla Interconnection	8.22	8.22	0.00
Blue Lake Hydroelectric	47.50	0.00	47.50
Gartina Falls Hydroelectric	4.94	0.00	4.94
Reynolds Creek Hydroelectric	8.06	1.20	6.86
Thayer Creek Hydroelectric	13.00	7.00	6.00
Whitman Lake Hydroelectric	12.78	3.30	9.48
Total	**143.09**	**19.72**	**123.37**

17.2.1.2 Capital Requirements

The capital requirements for the Preferred Resource List are comprised of capital requirements for generation, DSM/EE, and space heating. Tables 17-16 and 17-17 present the Preferred Resource List capital requirements for the first 10 years of the planning period and the entire 50 year planning period, respectively. These capital costs are based on the low scenario load forecast, which is the reference scenario load forecast reduced by the projected DSM/EE savings, and include the costs for new diesel and hydroelectric generation as well as the projected DSM/EE costs. These capital costs also include the projected costs required for the projected conversion to biomass space heating as described in Subsection 17.1.2.8. Table 17-16 indicates that the 10 year capital requirements for the region are $742 million. It should be noted as shown in Table 17-11, the 10 year capital requirements only include a single 1 MW hydroelectric project and that project is in the northern subregion for Yakutat. The selection of it stems from the use of generic hydroelectric projects in Strategist® and its reality is discussed in Subsection 17.2.7. The 50 year capital requirements for the region are $2.0 billion as shown in Table 17-17.

17.2.1.3 Program Development Costs

The final portion of the Preferred Resources List is the program development costs necessary to initiate implementation of the expansion plan. As stated throughout the IRP, the existing quality of data and the limitations of scope based on the directional nature of the IRP prohibit the development of accurate and detailed program costs. The data available and methods applied are, however, sufficient to define the direction of the preferred expansion plan for the region and to confirm the cost effectiveness of the major programs. Table 17-18 presents estimates of the regional investment and program development costs necessary to confirm, refine, and initiate the programs identified in the preferred expansion plan. As shown in Table 17-18, these regional investment and program development costs total $23.4 million.

Table 17-16 10 Year Capital Requirements ($1000)

SOUTHEAST ALASKA ANNUAL CAPITAL COSTS										
YEAR	SEAPA	ADMIRALTY	BARANOF	CHICHAGOF	JUNEAU	NORTHERN	POW	WHALE PASS	UPPER LYNN	TOTAL
2012	64,956	144	22,905	618	31,682	782	1,330	10	1,628	124,054
2013	26,563	109	2,695	418	12,218	751	1,505	45	1,837	46,141
2014	28,271	250	2,944	331	13,145	3,623	1,746	11	1,860	52,180
2015	30,271	147	3,162	327	14,298	810	2,049	48	2,334	53,446
2016	43,478	108	3,498	516	15,863	915	2,105	18	2,237	68,737
2017	33,642	151	3,836	351	17,930	19,434	1,882	58	2,199	79,482
2018	36,583	226	4,567	322	20,673	984	1,985	8	2,330	67,677
2019	39,486	109	5,072	469	23,578	981	1,998	15	2,478	74,185
2020	41,879	161	5,492	355	38,331	1,467	2,100	64	2,634	92,484
2021	43,839	109	5,858	360	26,862	1,111	2,120	16	2,958	83,233
Total	**388,968**	**1,513**	**60,028**	**4,066**	**214,579**	**30,857**	**18,821**	**292**	**22,495**	**741,619**

Table 17-17 50 Year Capital Requirements ($1000)

SOUTHEAST ALASKA ANNUAL CAPITAL COSTS										
YEAR	SEAPA	ADMIRALTY	BARANOF	CHICHAGOF	JUNEAU	NORTHERN	POW	WHALE PASS	UPPER LYNN	TOTAL
2012	64,956	144	22,905	618	31,682	782	1,330	10	1,628	124,054
2013	26,563	109	2,695	418	12,218	751	1,505	45	1,837	46,141
2014	28,271	250	2,944	331	13,145	3,623	1,746	11	1,860	52,180
2015	30,271	147	3,162	327	14,298	810	2,049	48	2,334	53,446
2016	43,478	108	3,498	516	15,863	915	2,105	18	2,237	68,737
2017	33,642	151	3,836	351	17,930	19,434	1,882	58	2,199	79,482
2018	36,583	226	4,567	322	20,673	984	1,985	8	2,330	67,677
2019	39,486	109	5,072	469	23,578	981	1,998	15	2,478	74,185
2020	41,879	161	5,492	355	38,331	1,467	2,100	64	2,634	92,484
2021	43,839	109	5,858	360	26,862	1,111	2,120	16	2,958	83,233
2022	8,262	5	2,464	472	9,843	103	3	3	429	21,584
2023	855	1	255	7	43,003	11	0	0	44	44,176
2024	884	1	264	7	1,055	11	0	0	46	2,268
2025	915	1	273	7	1,092	11	0	0	47	2,347
2026	1,787	1	283	466	1,130	12	0	0	49	3,729
2027	6,415	1	293	7	1,170	12	0	0	51	7,949
2028	1,013	1	303	8	1,211	13	0	0	52	2,601
2029	1,048	1	314	8	1,254	4,360	0	0	54	7,039
2030	1,084	1	325	8	18,509	14	0	0	56	19,997
2031	1,121	1	336	8	1,343	14	6,118	0	58	9,001

SOUTHEAST ALASKA ANNUAL CAPITAL COSTS										
YEAR	SEAPA	ADMIRALTY	BARANOF	CHICHAGOF	JUNEAU	NORTHERN	POW	WHALE PASS	UPPER LYNN	TOTAL
2032	1,160	1	348	9	1,391	15	0	0	60	2,984
2033	1,200	1	360	9	1,440	15	0	0	19,904	22,929
2034	1,241	1	19,745	9	40,234	16	0	0	64	61,311
2035	1,284	1	386	21,719	1,543	16	0	0	66	25,016
2036	1,326	1	399	10	1,592	17	0	0	68	3,414
2037	1,370	1	412	1,810	1,643	17	0	0	71	5,324
2038	23,217	1	426	11	1,696	18	0	0	73	25,442
2039	1,460	1	440	11	1,750	18	0	0	75	3,757
2040	1,508	1	454	11	1,806	19	0	695	78	4,573
2041	15,381	1	469	727	1,864	20	0	0	80	18,543
2042	14,497	1	485	12	1,924	20	1	1	83	17,023
2043	1,661	1	501	12	1,986	21	8,723	1	85	12,991
2044	194,846	1	518	13	2,049	6,794	1	1	88	204,310
2045	1,771	1	535	13	2,115	22	1	1	91	4,549
2046	1,829	1	552	13	2,183	23	1	1	94	4,697
2047	1,889	1	571	14	2,253	24	1	1	97	4,849
2048	1,950	1	590	894	2,325	25	1	1	100	5,886
2049	2,014	1,661	609	15	2,399	32,863	1	1	103	39,666
2050	2,080	1	629	15	2,476	26	1	1	107	5,336
2051	111,014	1	64,687	16	304,120	27	1	1	110	479,978
2052	2,218	1	672	1,006	2,638	28	1	1	114	6,678

SOUTHEAST ALASKA ANNUAL CAPITAL COSTS										
YEAR	SEAPA	ADMIRALTY	BARANOF	CHICHAGOF	JUNEAU	NORTHERN	POW	WHALE PASS	UPPER LYNN	TOTAL
2053	2,290	1	694	17	2,722	29	1	1	117	5,873
2054	2,365	1	717	17	2,810	30	1	1	55,492	61,434
2055	-	1	741	18	2,900	31	1	1,083	125	4,899
2056	41,682	2	765	1,133	2,993	32	1	1	129	46,737
2057	2,605	2	790	19	3,089	33	1	1	134	6,672
2058	2,690	2	817	19	3,188	34	1	1	138	6,889
2059	2,778	2	844	20	3,290	10,586	1	1	142	17,663
2060	2,868	2	871	21	45,172	1,290	1	1	147	50,374
2061	2,962	2	900	21	3,504	37	1	1	152	7,581
	857,511	**3,219**	**166,068**	**32,699**	**745,282**	**87,563**	**33,685**	**2,092**	**101,569**	**2,029,687**

Table 17-18 Regional Supporting Studies and Other Actions

ACTIONS		
DESCRIPTION	TIME FRAME	ESTIMATED COST
General Public Outreach/Education Program • Focused on: 1) results of Southeast Alaska IRP project, 2) benefits of DSM/EE programs, and 3) benefits of biomass conversion program	2012	$250,000
Regional DSM/EE Program Startup Costs • Initial staff-related costs (e.g., salaries, benefits, space) - $1,000,000 • Customer attitudinal survey - $75,000 • Market and economic potential studies - $250,000 • Detailed program design costs - $500,000 • Vendor training/certification program - $150,000 • DSM/EE measurement and evaluation protocol - $100,000 • Program startup advertising program - $250,000	2012-2013	$2,325,000
Regional Biomass Conversion Program Startup Costs • Initial staff-related costs (e.g., salaries, benefits, space) - $1,000,000 • Customer attitudinal survey - $75,000 • Market and economic potential studies - $250,000 • Detailed program design costs - $500,000 • Vendor training/certification program - $150,000 • Program startup advertising program - $250,000	2012-2013	$2,225,000
Formation of Regional DSM/EE Entity Startup Costs • Regional entity startup costs (e.g., organizational strategy, legal, etc.)	2012	$500,000
Formation of Regional Biomass Conversion Entity Startup Costs • Regional entity startup costs (e.g., organizational strategy, legal, etc.)	2012	$500,000
Hydroelectric Project-specific High Level Reconnaissance Studies • 20 studies at $100,000 each	2012-2013	$2,000,000
Hydroelectric Project-specific FERC License Application Preparation • 10 projects at $1,000,000 each	2012-2014	$10,000,000
Regional Technical/Economic Market Potential Assessment of Non-Hydroelectric Renewable Technologies	2012	$500,000
Other Renewable Project-specific High Level Reconnaissance Studies • 5 studies at $200,000 each	2012-2014	$1,000,000
Support Tidal/Wave Technology Development	2012-2014	$1,000,000

ACTIONS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Develop Standard Power Sales Agreement	2012	$200,000
Consider Development of Open Access Policy and Related Tariff (including terms and conditions of service)	2012	$250,000
Update Southeast Alaska IRP in 2014	2014	$750,000
Support Development of Tariff Structures That Better Reflect Costs • Develop and hold workshop(s) to address the issue that the last block in tariffs should better reflect incremental costs - $50,000 • Conduct cost-of-service studies for communities to determine what rates should be for the last block - $1,500,000	2012-2013	$1,550,000
Support Development of Weather Normalized Load Forecasts • Develop and hold workshop(s) to address need for, and approaches to, weather normalized load forecasting methodologies, which will become more important as heating becomes a bigger load - $50,000 • Develop a standard load forecasting methodology - $75,000 • Develop short-term weather normalized load forecasts for each utility - $250,000	2013	$375,000
Total		**$23,425,000**

17.2.2 SEAPA Subregion

The SEAPA subregion contains three of the Committed Resources shown in Table 17-8. The Kake-Petersburg Interconnection will connect Kake with the existing SEAPA system and the Ketchikan-Metlakatla Interconnection will also connect Metlakatla to the SEAPA system. In addition, the Whitman Lake Hydroelectric project is expected to add approximately 4.6 MW and 15,900 MWh of average annual energy to the subregion. The additional capital requirements for these three Committed Resources are approximately $69.6 million as presented in Table 17-8. Table 17-19 presents the additional capital requirements for the Preferred Resource List for the SEAPA subregion. The capital requirements are summarized in Table 17-20.

Table 17-19 SEAPA Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012			556,000	69,082	25,201,783		25,826,865
			20,220,000				20,220,000
			10,110,000				10,110,000
			3,489,000				3,489,000
			5,310,000				5,310,000
2013				169,869	26,393,070		26,562,939
2014				395,294	27,875,739		28,271,033
2015				828,495	29,442,860		30,271,355
2016			11,378,894	1,608,779	30,490,589		43,478,262
2017				2,892,325	30,749,354		33,641,680
2018				4,659,159	31,923,774		36,582,933
2019				6,431,005	33,054,972		39,485,977
2020				7,518,329	34,360,615		41,878,944
2021				7,969,961	35,869,061		43,839,022
2022				8,262,427			8,262,427
2023				854,857			854,857
2024				884,351			884,351
2025				914,857			914,857
2026			841,000	946,415			1,787,415
2027			5,435,748	979,064			6,414,813
2028				1,012,841			1,012,841

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2029				1,047,784			1,047,784
2030				1,083,935			1,083,935
2031				1,121,335			1,121,335
2032				1,160,026			1,160,026
2033				1,200,055			1,200,055
2034				1,241,466			1,241,466
2035				1,284,309			1,284,309
2036				1,326,248			1,326,248
2037				1,369,559			1,369,559
2038			21,803,138	1,414,284			23,217,422
2039				1,460,472			1,460,472
2040				1,508,168			1,508,168
2041			1,310,250	1,557,424			2,867,674
			12,513,363				12,513,363
2042			12,888,764	1,608,289			14,497,053
2043				1,660,817			1,660,817
2044	Metlakatla Generic - 10 MW	193,131,207		1,715,062			194,846,269
2045				1,771,080			1,771,080
2046				1,828,929			1,828,929
2047				1,888,668			1,888,668
2048				1,950,361			1,950,361
2049				2,014,070			2,014,070

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2050				2,079,861			2,079,861
2051			1,760,867	2,147,804			3,908,671
			64,037,286				64,037,286
			32,018,643				32,018,643
			11,049,757				11,049,757
2052				2,217,967			2,217,967
2053				2,290,425			2,290,425
2054				2,365,251			2,365,251
2055							-
2056			2,041,327	2,522,322			4,563,649
			37,118,382				37,118,382
2057				2,604,730			2,604,730
2058				2,689,832			2,689,832
2059				2,777,716			2,777,716
2060				2,868,475			2,868,475
2061				2,962,200			2,962,200
Total		**193,131,207**	**253,882,419**	**105,136,035**	**305,361,817**	**-**	**857,511,478**

Table 17-20 SEAPA Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	0	51.1	32.5	305.4	389.0
50 Year Total	193.1	253.9	105.1	305.4	857.5

The generic hydroelectric project identified is a 10 MW storage project in Metlakatla in 2044. The above capital costs include $39.7 million for diesel additions in 2012 in each of the five utility systems. As discussed above, some or all of these costs may be deferred. The DSM/EE program is projected to reduce cumulative present worth costs for the subregion by $54.1 million. The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $419.0 million.

Major changes to the subregion include reduced space heating costs throughout and significantly reduced electric costs for Kake. The projected volume of pellets would support a large pellet mill in the subregion.

Issues not explicitly modeled in the expansion plan that could have significant impact include the electrification of cruise ships docked in the subregion. One estimate of this load is 36,000 MWh during the cruise ship season by 2018. This level of additional load would potentially require additional hydroelectric facilities, but in general the summer nature of this load would fit well with the monthly availability of hydroelectric energy in the subregion. Since these cruise ship loads can be served by the cruise ships if power is not available, they would suit themselves nicely to interruptible loads.

17.2.3 Admiralty Island Subregion

The Admiralty Island subregion consisting of the community of Angoon contains one of the Committed Resources shown in Table 17-8. The Thayer Creek Hydroelectric project is expected to add approximately 1 MW and 8,400 MWh and bring hydroelectric power to Angoon for the first time. The additional capital requirement for the Thayer Creek Hydroelectric project is $13.0 million as presented in Table 17-8. No transmission interconnections involving Angoon evaluated in Section 12.0 were found to be cost effective. Table 17-21 presents the additional capital requirements for the Preferred Resource List for the Admiralty Island subregion. The capital requirements are summarized in Table 17-22.

Table 17-21 Admiralty Island Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012				49	143,994		144,043
2013				118	108,636		108,754
2014				268	249,470		249,738
2015				550	146,091		146,641
2016				1,064	107,117		108,181
2017				1,907	149,018		150,925
2018				3,062	222,484		225,546
2019				4,212	104,382		108,594
2020				4,907	156,312		161,219
2021				5,185	104,019		109,204
2022				5,357			5,357
2023				552			552
2024				570			570
2025				587			587
2026				605			605
2027				624			624
2028				644			644
2029				664			664

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2030				684			684
2031				705			705
2032				727			727
2033				750			750
2034				773			773
2035				797			797
2036				822			822
2037				847			847
2038				874			874
2039				901			901
2040				929			929
2041				957			957
2042				987			987
2043				1,018			1,018
2044				1,049			1,049
2045				1,082			1,082
2046				1,116			1,116
2047				1,150			1,150
2048				1,186			1,186

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2049			1,659,786	1,223			1,661,009
2050				1,261			1,261
2051				1,300			1,300
2052				1,340			1,340
2053				1,382			1,382
2054				1,425			1,425
2055				1,469			1,469
2056				1,514			1,514
2057				1,561			1,561
2058				1,610			1,610
2059				1,660			1,660
2060				1,711			1,711
2061				1,764			1,764
Total		**-**	**1,659,786**	**67,498**	**1,491,522**	**-**	**3,218,806**

Table 17-22 Admiralty Island Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	0.0	0.0	0.02	1.5	1.5
50 Year Total	0.0	1.7	0.07	1.5	3.2

There are no generic hydroelectric projects identified for Angoon. There are no DSM/EE savings projected for Angoon. This results from using 2011 costs for conducting the DSM screening tests, which, due to the high nonfuel costs, results in very few DSM/EE measures being cost effective. When the Thayer Creek project begins service, electric costs for Angoon will drop substantially if the Thayer Creek project is grant financed and if IPEC changes its postage stamp rates to reflect the cost of service for each community. The existing high nonfuel costs causing DSM/EE measures to fail the RIM test may still be a problem when the cost of electricity drops after commercial operation of Thayer Creek. The detailed development of the DSM/EE programs will need to address the issues associated with the RIM test. The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $9.6 million.

Major changes to the subregion include greatly reduced space heating costs. Electric costs will also drop substantially if Thayer Creek is grant financed and if IPEC changes its rate making policy to provide all the savings from the Thayer Creek project to Angoon. The small size of Angoon dictates that pellets will have to be imported since the pellet demand will support but a small fraction of the requirements for a pellet mill.

17.2.4 Baranof Island Subregion

The Baranof Island subregion contains one of the Committed Resources in Table 17-8, the Blue Lake Hydroelectric project at Sitka. The Blue Lake Expansion is expected to add approximately 8 MW and 34,000 MWh of average annual energy to the subregion. The additional capital requirements for the Gartina Falls project are $49.6 million as presented in Table 17-8. Table 17-23 presents the additional capital requirements for the Preferred Resource List for the Baranof Island subregion. The capital requirements are summarized in Table 17-24.

Table 17-23 Baranof Island Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012			20,220,000	20,835	2,663,683		22,904,518
2013				50,806	2,644,399		2,695,205
2014				118,059	2,825,901		2,943,960
2015				245,995	2,916,306		3,162,301
2016				477,984	3,019,677		3,497,661
2017				859,893	2,976,295		3,836,188
2018				1,386,068	3,180,577		4,566,645
2019				1,914,410	3,157,551		5,071,961
2020				2,239,525	3,252,278		5,491,803
2021				2,375,574	3,482,222		5,857,796
2022				2,464,321			2,464,321
2023				255,129			255,129
2024				264,099			264,099
2025				273,382			273,382
2026				282,992			282,992
2027				292,939			292,939
2028				303,235			303,235
2029				313,894			313,894
2030				324,928			324,928
2031				336,349			336,349

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2032				348,171			348,171
2033				360,410			360,410
2034			19,371,805	373,078			19,744,884
2035				386,192			386,192
2036				398,971			398,971
2037				412,173			412,173
2038				425,812			425,812
2039				439,902			439,902
2040				454,458			454,458
2041				469,496			469,496
2042				485,032			485,032
2043				501,081			501,081
2044				517,662			517,662
2045				534,792			534,792
2046				552,488			552,488
2047				570,770			570,770
2048				589,656			589,656
2049				609,168			609,168
2050				629,326			629,326
2051			64,037,286	650,150			64,687,436
2052				671,663			671,663

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2053				693,889			693,889
2054				716,850			716,850
2055				740,570			740,570
2056				765,076			765,076
2057				790,392			790,392
2058				816,546			816,546
2059				843,565			843,565
2060				871,479			871,479
2061				900,316			900,316
Total		**-**	**103,629,091**	**32,319,550**	**30,118,889**	**-**	**166,067,530**

Table 17-24 Baranof Island Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	0	20.2	9.7	30.1	60.0
50 Year Total	0	103.6	32.3	30.1	166.1

No generic hydroelectric projects were identified as being required for Sitka. The above capital costs include $22.2 million for diesel additions in 2012. As discussed above, some or all of these costs may be deferred. The DSM/EE program is projected to reduce cumulative present worth costs for the subregion by $1.5 million. The DSM/EE program will have less of an effect on Sitka than some of the other communities in part due to Sitka having a more significant DSM/EE program in place. The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $216.7 million.

The major change to the subregion would be reduced space heating costs. The projected volume of pellets after the 10 year proposed conversion period would be about the minimum to support a pellet mill.

Other than the reduced space heating costs due to conversion of pellets, conditions in Sitka will by and large remain similar to what they are now.

17.2.5 Chichagof Island Subregion

The Chichagof Island communities of Elfin Cove, Hoonah, Pelican, and Tenakee Springs are not interconnected and the transmission evaluations indicate that it is not cost effective for them to be interconnected and thus the expansion plan continues to have them isolated. The Chichagof Island subregion contains one of the Committed Resources in Table 17-8, the Gartina Falls Hydroelectric project at Hoonah. The Gartina Falls project is expected to add approximately 0.4 MW and 1,800 MWh of average annual energy to the subregion. The additional capital requirements for the Gartina Falls project $4.9 million as presented in Table 17-8. Table 17-25 presents the additional capital requirements for the Preferred Resource List for the Chichagof Island subregion. The capital requirements are summarized in Table 17-26.

Table 17-25 Chichagof Island Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012			303,500	557	313,738		617,795
2013				1,367	417,040		418,406
2014				3,145	327,381		330,526
2015				6,518	320,320		326,838
2016				12,628	503,357		515,984
2017				22,649	327,887		350,536
2018				36,399	285,577		321,976
2019				50,124	418,921		469,045
2020				58,461	296,444		354,906
2021				61,828	298,618		360,446
2022			407,879	63,946			471,825
2023				6,601			6,601
2024				6,812			6,812
2025				7,031			7,031
2026			459,071	7,256			466,327
2027				7,489			7,489
2028				7,729			7,729
2029				7,976			7,976

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2030				8,232			8,232
2031				8,496			8,496
2032				8,769			8,769
2033				9,050			9,050
2034				9,340			9,340
2035	Hoonah - ROR	21,709,452		9,639			21,719,091
2036				9,938			9,938
2037			635,462	10,247			645,708
			1,164,141				1,164,141
2038				10,565			10,565
2039				10,892			10,892
2040				11,230			11,230
2041			715,218	11,579			726,797
2042				11,938			11,938
2043				12,309			12,309
2044				12,691			12,691
2045				13,084			13,084
2046				13,490			13,490
2047				13,909			13,909

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2048			879,627	14,341			893,968
2049				14,786			14,786
2050				15,244			15,244
2051				15,717			15,717
2052			990,028	16,205			1,006,234
2053				16,708			16,708
2054				17,226			17,226
2055				17,761			17,761
2056			1,114,286	18,312			1,132,598
2057				18,880			18,880
2058				19,466			19,466
2059				20,070			20,070
2060				20,693			20,693
2061				21,335			21,335
Total		**21,709,452**	**6,669,211**	**810,660**	**3,509,282**	**-**	**32,698,605**

Table 17-26 Chichagof Island Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	0	0.3	0.3	3.5	4.1
50 Year Total	21.7	6.7	0.8	3.5	32.7

The generic hydroelectric project identified is a 1 MW run-of-river project at Hoonah, which is larger than the other three Chichagof Island communities put together. There is one other hydroelectric project on the refined screened potential hydroelectric project list in Table 10-4 for Hoonah. The isolated nature of the four Chichagof Island communities results in the inability to share between communities the benefits of a hydroelectric project in another community.

The transmission analysis in Table 12-12 shows the extremely high cost of interconnecting the Chichagof Island communities amongst themselves due to the small loads and high cost of transmission line construction. The only transmission alternative involving some of the Chichagof Island communities that even remotely approaches cost effectiveness does so by being part of a much larger interconnection that results in the Chichagof Island communities being ancillary beneficiaries of the larger interconnection. Without the possibility of economic interconnection to lower price hydroelectric projects, the Chichagof Island communities other than Hoonah are left with only local hydroelectric opportunities.

The small loads and the lack of any economies of scale result in the cost of hydroelectric generation exceeding that of diesel. Nevertheless, work is continuing toward small hydroelectric projects in each of the Chichagof Island communities besides Hoonah. Both Elfin Cove and Tenakee Springs have projects on the refined screened potential hydroelectric project list in Table 10-4 , while Pelican has an existing hydroelectric project that is returning to service. While these projects at Elfin Cove and Tenakee Springs are not in the expansion plan, they do offer opportunity for reduced electric costs if they are significantly grant financed.

The above capital costs include $0.3 million for diesel additions in 2012 Tenakee Springs based on the age of their existing units. They currently have two diesel generating units each of which covers their peak load. With this situation, they may be able to defer additional diesel generation. The DSM/EE program is projected to reduce cumulative present worth costs for the subregion by $6.7 million.

The DSM/EE program reduces the load for the Chichagof region by 11.4 percent in 10 years. This is a significant reduction in spite of the fact that these utilities, due to their small size and lack of economies of scale, have high nonfuel costs and, as a result, failed the RIM test for a number of DSM/EE measures. In the detailed development of the DSM/EE programs, this issue will need to be addressed carefully for these utilities with the opportunity for potentially greater savings from DSM/EE.

The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $30.0 million. This is by far the greatest cost savings available to the subregion. Unfortunately, these savings may be somewhat overstated since the same pellet price of $300 per ton in 2012 was used for all subregions. The small size of the Chichagof Island communities again will cause increases in costs for pellets due to the lack of economies of scale compared to other subregions. Fortunately, while there will be some increase in cost, the use of pellets on a relative small scale does not require any additional infrastructure other than the delivery and distribution of 40 pound bags to the communities. The Chichagof Island communities can use other forms of biomass especially cord wood without the increases in cost due to lack of economies of scale.

The major change to the subregion would be reduced space heating costs and lower electric bills due to DSM/EE programs. Hoonah will achieve lower electric costs due to Gartina Falls provided the project is significantly grant financed. While costs will be lower, they will not translate into lower rates for Hoonah unless IPEC changes from their postage stamp rate, which they appear to be working towards. Electric costs are not expected to decrease significantly for Elfin Cove and Tenakee Springs unless they are able to succeed in the development of their hydroelectric projects and the projects are grant financed. Electric costs for Pelican should reduce as their existing hydroelectric project returns to service. Due to the Chichagof Island communities' small size, the projected volume of pellets will be but a small fraction of what is necessary to support a pellet mill and the subregion will remain dependent upon their import.

17.2.6 Juneau Area Subregion

The Juneau Area subregion does not contain any of the Committed Resources. None of the transmission interconnections evaluated in Section 12.0 were found to be cost effective for the Juneau Area either. Table 17-27 presents the additional capital requirements for the Preferred Resource List for the Juneau subregion. The capital requirements are summarized in Table 17-28.

Table 17-27 Juneau Area Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012			20,220,000	82,171	11,379,543		31,681,714
2013				201,457	12,016,390		12,217,847
2014				468,808	12,675,742		13,144,550
2015				982,576	13,315,782		14,298,358
2016				1,909,210	13,953,371		15,862,580
2017				3,434,668	14,495,078		17,929,747
2018				5,536,367	15,136,673		20,673,040
2019				7,646,723	15,930,901		23,577,624
2020			12,807,046	8,945,328	16,578,970		38,331,343
2021				9,488,749	17,373,076		26,861,825
2022				9,843,227			9,843,227
2023			41,983,813	1,019,061			43,002,874
2024				1,054,889			1,054,889
2025				1,091,969			1,091,969
2026				1,130,352			1,130,352
2027				1,170,084			1,170,084
2028				1,211,212			1,211,212
2029				1,253,787			1,253,787

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2030			17,211,598	1,297,857			18,509,455
2031				1,343,477			1,343,477
2032				1,390,700			1,390,700
2033				1,439,583			1,439,583
2034			38,743,611	1,490,185			40,233,795
2035				1,542,565			1,542,565
2036				1,592,019			1,592,019
2037				1,643,059			1,643,059
2038				1,695,736			1,695,736
2039				1,750,101			1,750,101
2040				1,806,209			1,806,209
2041				1,864,116			1,864,116
2042				1,923,880			1,923,880
2043				1,985,560			1,985,560
2044				2,049,217			2,049,217
2045				2,114,914			2,114,914
2046				2,182,719			2,182,719
2047				2,252,697			2,252,697
2048				2,324,918			2,324,918

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2049				2,399,455			2,399,455
2050				2,476,381			2,476,381
2051			64,037,286	2,555,774			66,593,060
	Juneau Storage - 10 MW	237,527,024					237,527,024
2052				2,637,712			2,637,712
2053				2,722,277			2,722,277
2054				2,809,554			2,809,554
2055				2,899,628			2,899,628
2056				2,992,590			2,992,590
2057				3,088,532			3,088,532
2058				3,187,551			3,187,551
2059				3,289,744			3,289,744
2060			41,777,066	3,395,213			45,172,279
2061				3,504,063			3,504,063
Total		**237,527,024**	**236,780,420**	**128,118,626**	**142,855,526**	**-**	**745,281,595**

Table 17-28 Juneau Area Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	0	33.0	38.7	142.9	214.6
50 Year Total	237.5	236.8	128.1	142.9	745.3

The generic hydroelectric project identified is a 10 MW storage project in 2051. The refined screened potential hydroelectric project list in Table 10-4 identifies two potential hydroelectric projects each approximately three times the capacity of the generic project. The above capital costs include $22.2 million for diesel additions in 2012. As discussed above, some or all of these costs may be deferred. The DSM/EE program is projected to reduce cumulative present worth costs for the subregion by $48.7 million. The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $977.5 million.

If Juneau is successful with implementing DSM/EE programs and avoids conversion to electric space heating, the subregion will be able to go for a number of years without having to develop a new hydroelectric project unless greater loads develop. Under the high scenario load forecast, a new hydroelectric project will be required by 2020. Given the long lead time for hydroelectric project development and the uncertainty associated with future loads, it would be prudent for Juneau to pursue the development of a hydroelectric project to a level that it could be constructed if necessary. It should be noted that annual energy for the Greens Creek mine of 67,700 MWh per year is included in Juneau's load forecasts even though it is served as an interruptible load.

The most significant and major change to the subregion is the reduced space heating costs. Electric costs will also be reduced significantly through the DSM/EE programs. The projected volume of pellets would support two large pellet mills in the Juneau area.

One issue not explicitly modeled that could have a significant impact on the subregion is the potential development of mines in the Juneau area. A subsidiary of AEL&P is pursuing the development of the Yeldagalga Creek Hydroelectric project to serve the Kensington Mine. Current plans are for the project to directly serve the mine without being interconnected to the grid. Table 8-5 also identifies a couple of other potential mine developments in the Juneau area. Developing hydroelectric projects to serve mines is a difficult task. There is significant uncertainty with respect to mine development in the first place. Next, there is generally a significant difference in lifetime of the mine compared to the hydroelectric project and finally most of the potential mines are remote making interconnection to the grid difficult and costly. As such most of the plans for serving mines with hydroelectric projects are based on hydroelectric projects directly serving the mine without being interconnected to the grid. AEL&P will need to exercise care in the development of hydroelectric projects to serve mines to ensure that the hydroelectric project does not become a stranded investment. If the projected DSM/EE programs are successful and AEL&P avoids significant conversion to electric space heating, it would have relatively little capacity to absorb a hydroelectric project developed for a mine if something happened to the mine load.

17.2.7 Northern Subregion

The Northern subregion consisting of Yakutat and Gustavus does not contain any of the Committed Resources. None of the interconnections evaluated involving the Northern subregion were found to be cost effective. Table 17-29 presents the additional capital requirements for the Preferred Resource List for the Northern subregion. The capital requirements are summarized in Table 17-30.

Table 17-29 Northern Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012				850	780,689		781,538
2013				2,066	749,208		751,274
2014			2,790,167	4,743	828,232		3,623,143
2015				9,806	800,462		810,268
2016				19,990	894,554		914,544
2017	Yakutat Generic - 1 MW	18,548,385		35,953	849,210		19,433,549
2018				57,940	926,034		983,974
2019				80,008	900,927		980,934
2020			384,465	93,573	988,953		1,466,991
2021				99,235	1,011,902		1,111,137
2022				102,919			102,919
2023				10,653			10,653
2024				11,025			11,025
2025				11,410			11,410
2026				11,808			11,808
2027				12,220			12,220
2028				12,647			12,647
2029			4,346,989	13,089			4,360,078

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2030				13,546			13,546
2031				14,019			14,019
2032				14,509			14,509
2033				15,015			15,015
2034				15,540			15,540
2035				16,083			16,083
2036				16,615			16,615
2037				17,164			17,164
2038				17,732			17,732
2039				18,318			18,318
2040				18,924			18,924
2041				19,550			19,550
2042				20,197			20,197
2043				20,865			20,865
2044			6,772,468	21,555			6,794,023
2045				22,269			22,269
2046				23,005			23,005
2047				23,767			23,767
2048				24,553			24,553

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2049	Yakutat-ROR	32,837,493		25,366			32,862,859
2050				26,206			26,206
2051				27,073			27,073
2052				27,969			27,969
2053				28,895			28,895
2054				29,852			29,852
2055				30,840			30,840
2056				31,861			31,861
2057				32,916			32,916
2058				34,006			34,006
2059			10,551,284	35,132			10,586,416
2060			1,254,138	36,296			1,290,434
2061				37,498			37,498
Total		**51,385,879**	**26,099,511**	**1,347,072**	**8,730,169**	**-**	**87,562,631**

Table 17-30 Northern Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	18.5	3.2	0.4	8.7	30.9
50 Year Total	51.4	26.1	1.3	8.7	87.6

The generic hydroelectric projects identified are a 1 MW storage project in Yakutat in 2017 and a 1 MW run-of–river project in Yakutat in 2049. There are no hydroelectric projects identified on the refined screened potential hydroelectric project list in Table 10-4. In visiting Yakutat and reviewing the comprehensive potential hydroelectric project list in Appendix C, there appear to be few if any actual hydroelectric sites that could serve Yakutat especially considering the long transmission line that would be necessary to transmit the power to Yakutat. The DSM/EE program is projected to reduce cumulative present worth costs for the subregion by $7.4 million. The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $77.9 million.

Major changes to the subregion include reduced space heating costs throughout the subregion. Even if actual hydroelectric projects could be identified for Yakutat, the high cost of small projects and long transmission lines would mitigate the savings in electric costs. Both Yakutat and Gustavus will realize substantial savings if the DSM/EE programs are implemented successfully, but other than that, the situation is expected to remain very similar to what it currently is for both communities. The small size of both communities is insufficient to support but a fraction of demand necessary for a pellet mill and the communities would have to import pellets for a space heating conversion program.

17.2.8 Prince of Wales Subregion

The Prince of Wales subregion is served by AP&T and includes the communities of Craig, Hydaburg, Kasaan, Hollis, Klawock, Thorne Bay, Naukati, Coffman Cove, and Whale Pass. One of the Committed Resources, the Reynolds Creek Hydroelectric project, is in the Prince of Wales subregion. The Reynolds Creek project is expected to add approximately 5 MW and 19,300 MWh of average annual energy to the subregion. The additional capital requirements for the Reynolds Creek project are approximately $8.1 million as presented in Table 17-8. Table 17-31 presents the additional capital requirements for the Preferred Resource List for the Prince of Wales subregion. The capital requirements are summarized in Table 17-32.

Table 17-31 Prince of Wales Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012				41	1,339,824		1,339,865
2013				104	1,549,551		1,549,654
2014				246	1,757,105		1,757,351
2015				524	2,096,373		2,096,896
2016				1,018	2,122,167		2,123,185
2017				1,831	1,937,947		1,939,778
2018				2,951	1,989,936		1,992,887
2019				4,076	2,008,591		2,012,666
2020				4,768	2,159,922		2,164,689
2021				5,058	2,130,914		2,135,971
2022				5,246			5,246
2023				543			543
2024				562			562
2025				582			582
2026				602			602
2027				624			624
2028				646			646
2029				668			668

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2030				692			692
2031			6,117,983	716			6,118,699
2032				741			741
2033				767			767
2034				794			794
2035				822			822
2036				849			849
2037				876			876
2038				904			904
2039				933			933
2040			694,386	963			695,349
2041				994			994
2042				1,025			1,025
2043			8,722,780	1,058			8,723,839
2044				1,092			1,092
2045				1,127			1,127
2046				1,163			1,163
2047				1,201			1,201
2048				1,239			1,239

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2049				1,279			1,279
2050				1,320			1,320
2051				1,362			1,362
2052				1,406			1,406
2053				1,451			1,451
2054				1,498			1,498
2055			1,081,831	1,546			1,083,376
2056				1,595			1,595
2057				1,646			1,646
2058				1,699			1,699
2059				1,753			1,753
2060				1,810			1,810
2061				1,868			1,868
Total		**-**	**16,616,980**	**68,277**	**19,092,328**	**-**	**35,777,585**

Table 17-32 Prince of Wales Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	0	0	0.02	19.1	19.1
50 Year Total	0	16.6	0.07	19.1	35.8

No generic hydroelectric units or transmission interconnections were identified as cost effective for Prince of Wales. The DSM/EE program is projected to reduce cumulative present worth costs for the subregion by $3.3 million. The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $180.0 million.

Major changes to the subregion include significantly reduced space heating costs throughout the subregion. The projected volume of pellets would the minimum necessary to support a pellet mill in the subregion. Prince of Wales is home to the Viking Mill, which is the largest saw mill in the region. The Viking Mill currently has waste wood streams that are adequate to support at least the initial development of a pellet mill. Initial efforts have been underway in this development process.

Issues not explicitly modeled in the expansion plan that could have significant impact include the addition of potential mine loads in Prince of Wales. The Bokan and Niblack mines as presented in Table 8-5 have been receiving significant press lately regarding their potential development with Bokan currently having the most activity with some estimates of operation by 2015. As discussed, however, in Subsection 8.1.2.3 the mine development process has historically taken longer than anticipated. Nevertheless, these potential mine loads could be very significant for the subregion. Most of the potential mine loads would likely be served by local diesel generation and potentially dedicated hydroelectric project development. AP&T recently announced the initial development of 11 potential hydroelectric projects at Moira Sound to serve the Bokan Mine. These potential projects are presented in Table 10-3.

17.2.9 Upper Lynn Canal Subregion

The Upper Lynn Canal subregion does not contain any of the Committed Resources and no interconnections involving the subregion were cost effective. Table 17-33 presents the additional capital requirements for the Preferred Resource List for the Upper Lynn Canal subregion. The capital requirements are summarized in Table 17-34.

Table 17-33 Upper Lynn Canal Subregion Capital Costs

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2012				3,529	1,624,722		1,628,251
2013				8,734	1,828,249		1,836,983
2014				20,473	1,839,606		1,860,079
2015				43,218	2,290,523		2,333,741
2016				83,844	2,152,772		2,236,615
2017				150,603	2,048,874		2,199,477
2018				242,396	2,087,342		2,329,738
2019				334,308	2,143,628		2,477,936
2020				390,531	2,243,688		2,634,219
2021				413,690	2,543,899		2,957,589
2022				428,575			428,575
2023				44,313			44,313
2024				45,813			45,813
2025				47,366			47,366
2026				48,973			48,973
2027				50,636			50,636
2028				52,358			52,358
2029				54,140			54,140

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2030				55,984			55,984
2031				57,892			57,892
2032				59,868			59,868
2033			1,034,324	61,913			1,096,237
			18,807,578				18,807,578
2034				64,029			64,029
2035				66,220			66,220
2036				68,350			68,350
2037				70,551			70,551
2038				72,824			72,824
2039				75,172			75,172
2040				77,598			77,598
2041				80,104			80,104
2042				82,693			82,693
2043				85,368			85,368
2044				88,131			88,131
2045				90,985			90,985
2046				93,934			93,934
2047				96,980			96,980

YEAR	HYDROELECTRIC TYPE	HYDRO-ELECTRIC CAPITAL COST	DIESEL CAPITAL COSTS	ANNUAL DSM COSTS	PELLET CONVERSION COSTS	OTHER ALTERNATIVES	TOTAL CAPITAL COST
2048				100,127			100,127
2049				103,378			103,378
2050				106,736			106,736
2051				110,205			110,205
2052				113,789			113,789
2053				117,492			117,492
2054	Upper Lynn Generic - 1 MW	55,371,134		121,317			55,492,451
2055				125,268			125,268
2056				129,350			129,350
2057				133,567			133,567
2058				137,923			137,923
2059				142,424			142,424
2060				147,073			147,073
2061				151,876			151,876
Total		**55,371,134**	**19,841,902**	**5,552,618**	**20,803,304**	**-**	**101,568,958**

Table 17-34 Upper Lynn Canal Subregion Capital Requirements ($ million)

	HYDROELECTRIC	DIESEL	DSM/EE	BIOMASS	TOTAL
10 Year Total	0	0.0	1.7	20.8	22.5
50 Year Total	55.4	19.8	5.6	20.8	101.6

The generic hydroelectric project identified is a 1 MW storage project in IPEC's service area in 2054. The DSM/EE program is projected to reduce cumulative present worth costs for the subregion by $16.9 million. The biomass space heating conversion program is projected to reduce the cumulative present worth costs for the subregion by $172.8 million.

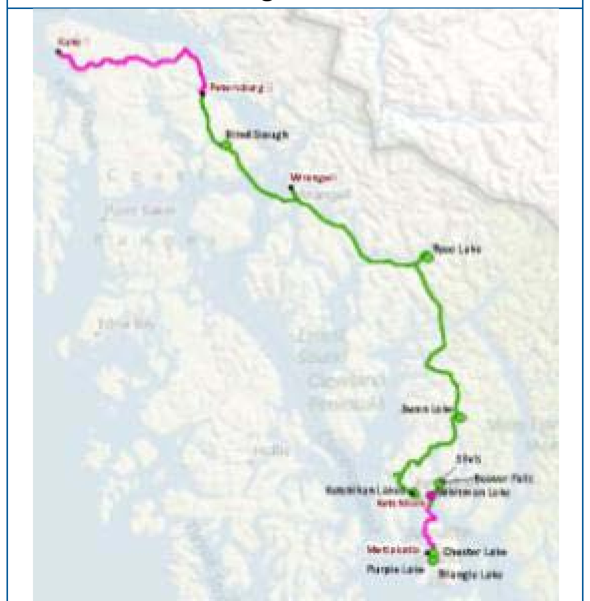
Major changes to the subregion include significantly reduced space heating costs throughout the subregion. Electric costs will also be substantially lower due to the DSM/EE programs. The projected volume of pellets approaches the minimum volume that would support a pellet mill in the subregion by the end of the conversion program. The significant electric load of a pellet mill and the relative small volume of pellets for the region will likely drive the supplier of pellets for the subregion to locate somewhere with lower electric prices. The subregion's location on the road system offers the possibility of delivery by truck.

Issues not explicitly modeled in the expansion plan that could have significant impact include the electrification of cruise ships docked in the Skagway. Black & Veatch estimated that this load could be as large as 45,000 MWh annually. This level of additional load would potentially require additional hydroelectric facilities, but in general the summer nature of this load would fit well with the monthly availability of hydroelectric energy in the subregion. The West Creek project is currently under development by Skagway in large part to serve these loads. There are also discussions under way to construct an interconnection to Yukon Energy in Canada to share seasonal energy to serve the cruise ship loads since these cruise ship loads can be served by the cruise ships themselves, if power is not available, they would be well suited to be interruptible loads.

In addition to cruise ship loads, there are potential mine loads near Haines. As previously discussed, mine loads are difficult to plan for and generally will be served by hydroelectric projects directly without interconnection to the existing transmission system.

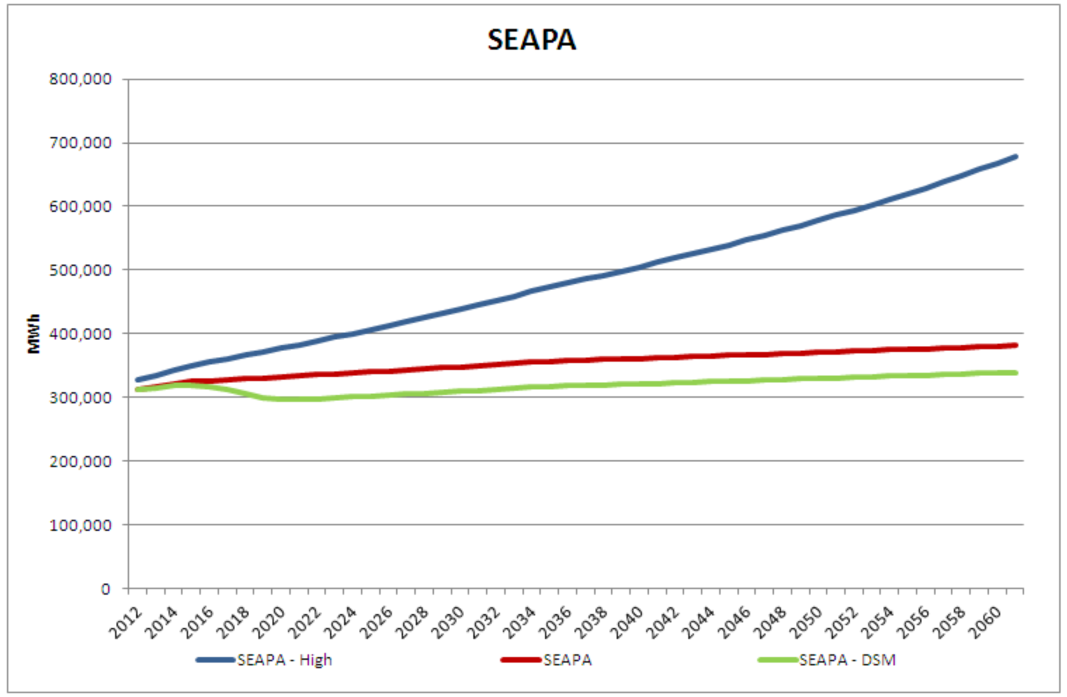
Summary of Results

Sub-Region: SEAPA

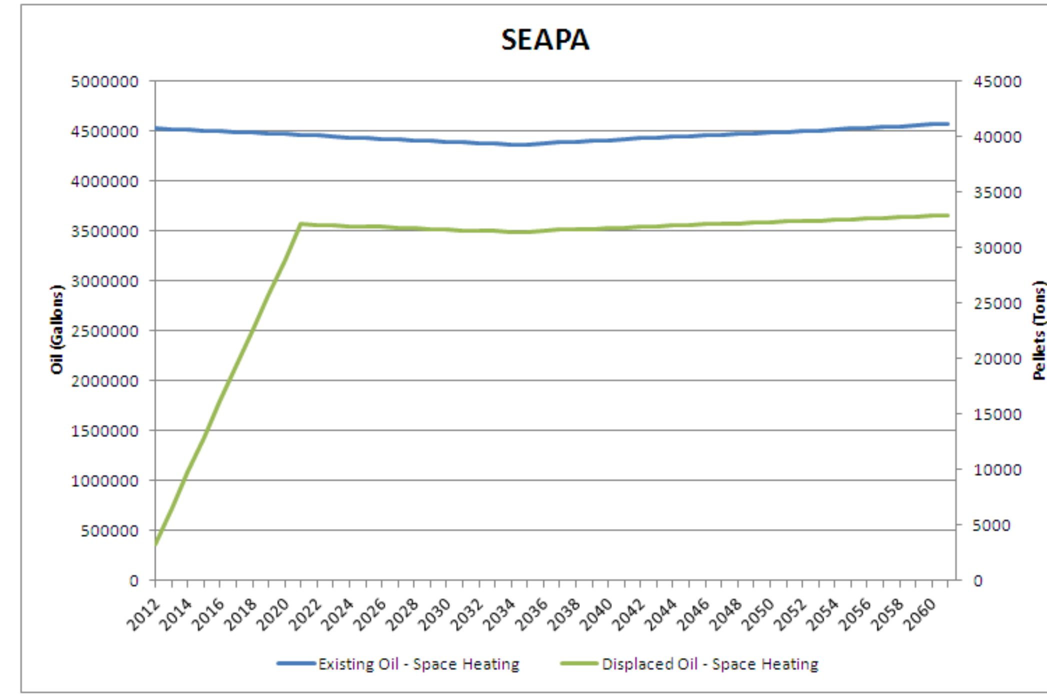


Kake
Petersburg
Wrangell
Ketchikan/Saxman
Metlakatla

Electric Load Forecast

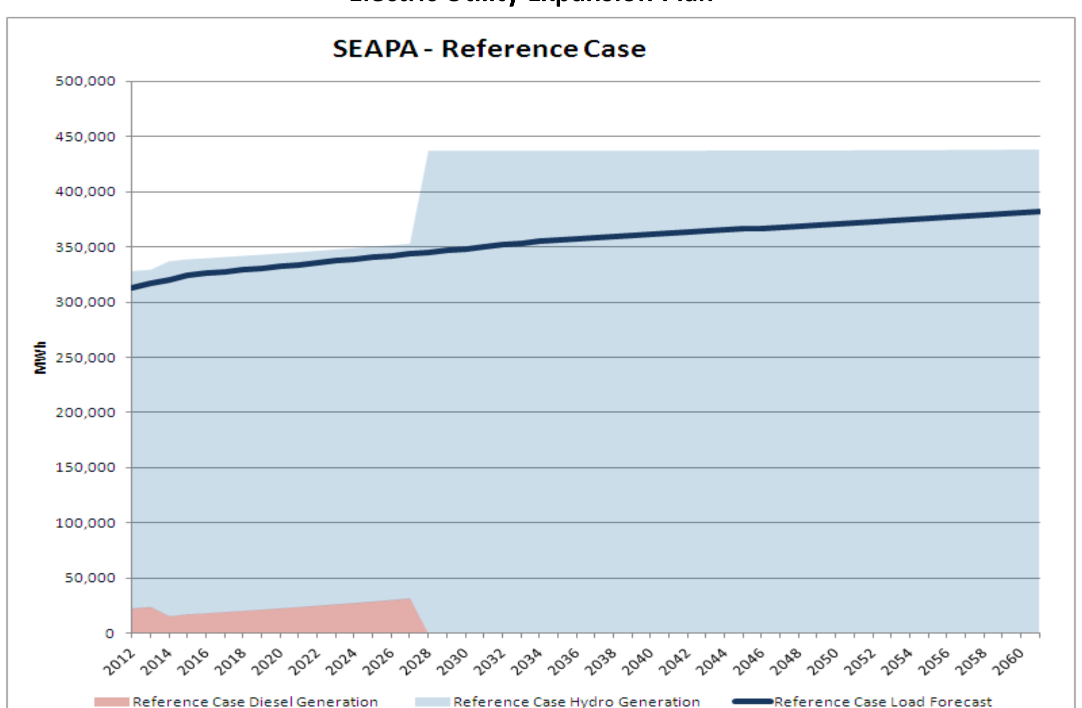


Space Heating



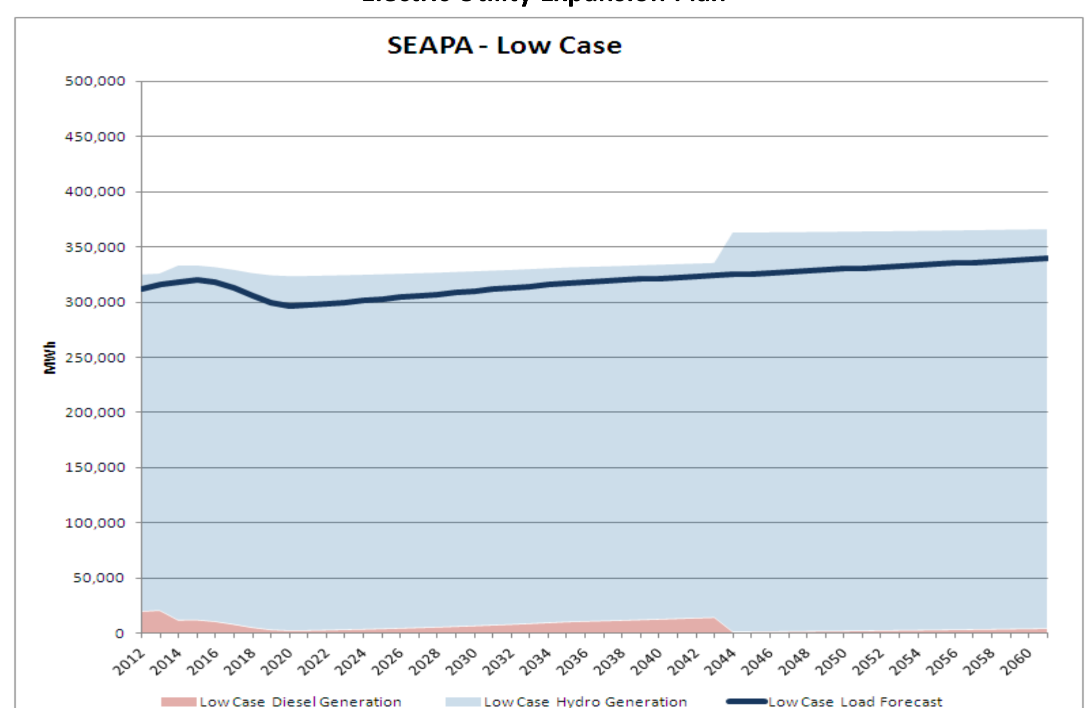
Cumulative Present Worth Cost ($ 000s) - Oil Only:	977,320
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	558,327

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	288,797

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000) - Including DSM:	234,723

Expansion Plan Alternatives:

SEAPA

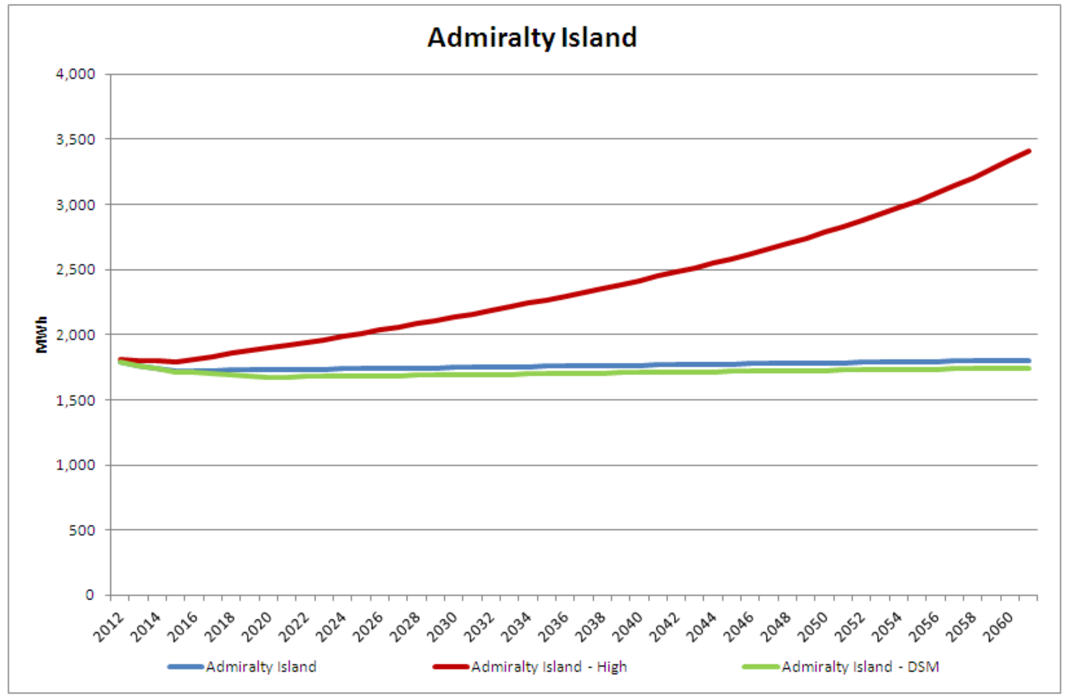
- Committed Resource – Transmission
- Committed Resource – Hydro
- Generic Hydro
- Diesel
- DSM/EE
- Biomass Space Heating
- Wind – Project Development

Summary of Results

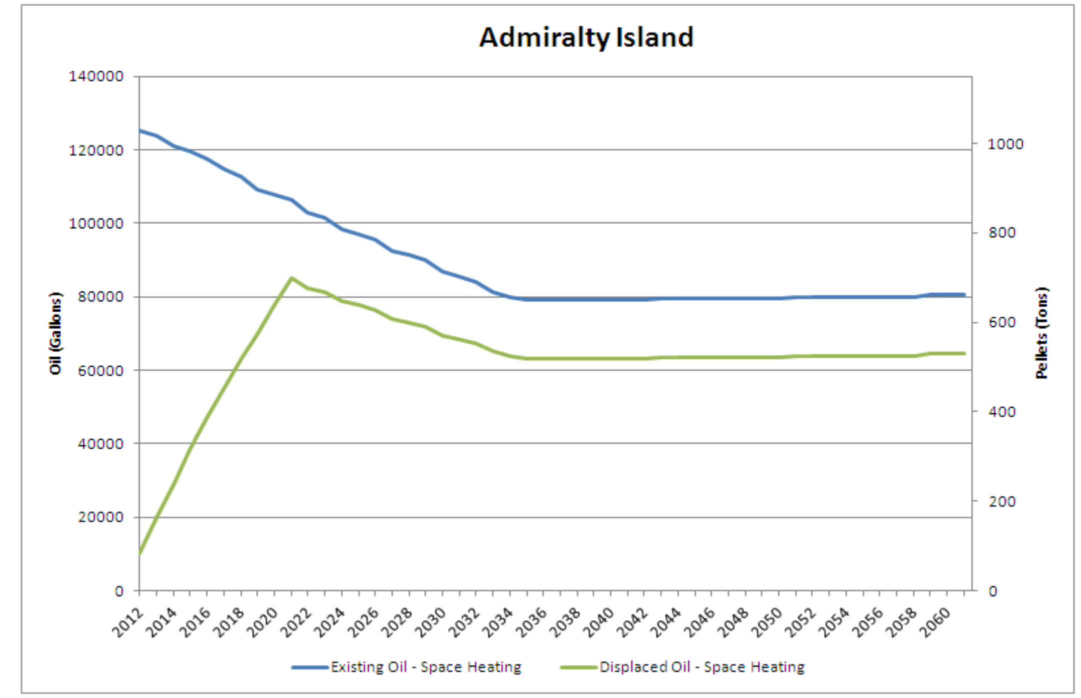
Sub-Region: Admiralty Island

Angoon

Electric Load Forecast

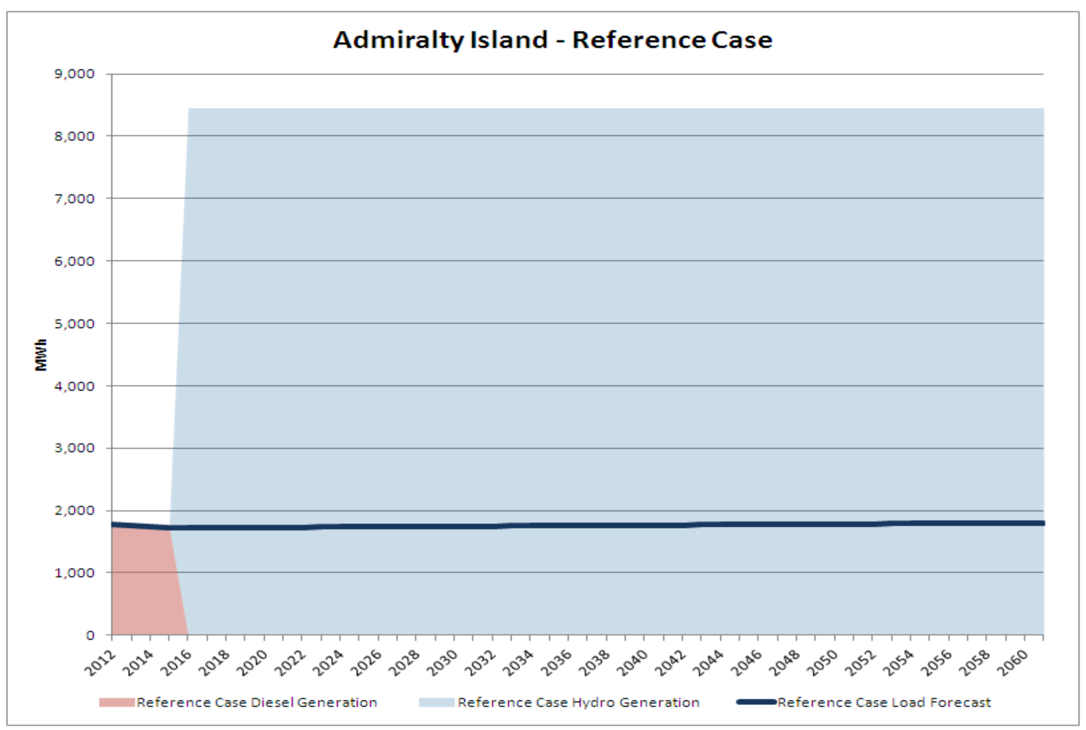


Space Heating



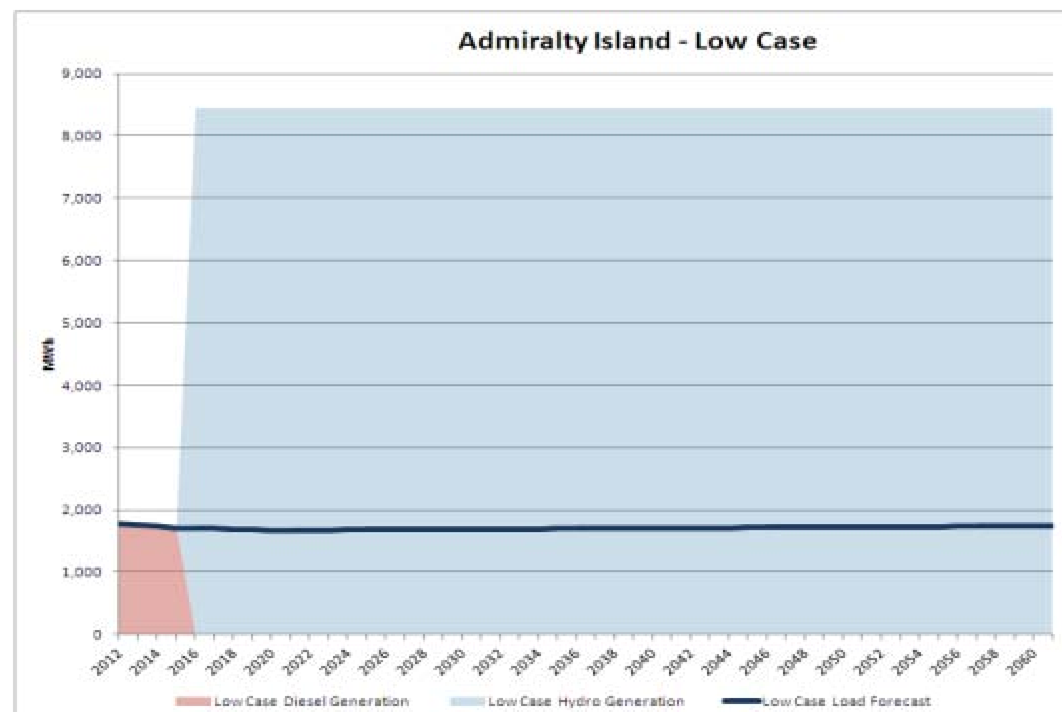
Cumulative Present Worth Cost ($ 000s) - Oil Only:	22,334
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	12,742

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	8,022

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s) - Including DSM:	8,044

Expansion Plan Alternatives:

Admiralty Island

- Committed Resource – Hydro
- Diesel
- DSM/EE
- Biomass Space Heating
- Wind – Project Development(1)
- Tidal – Technology Development(1)

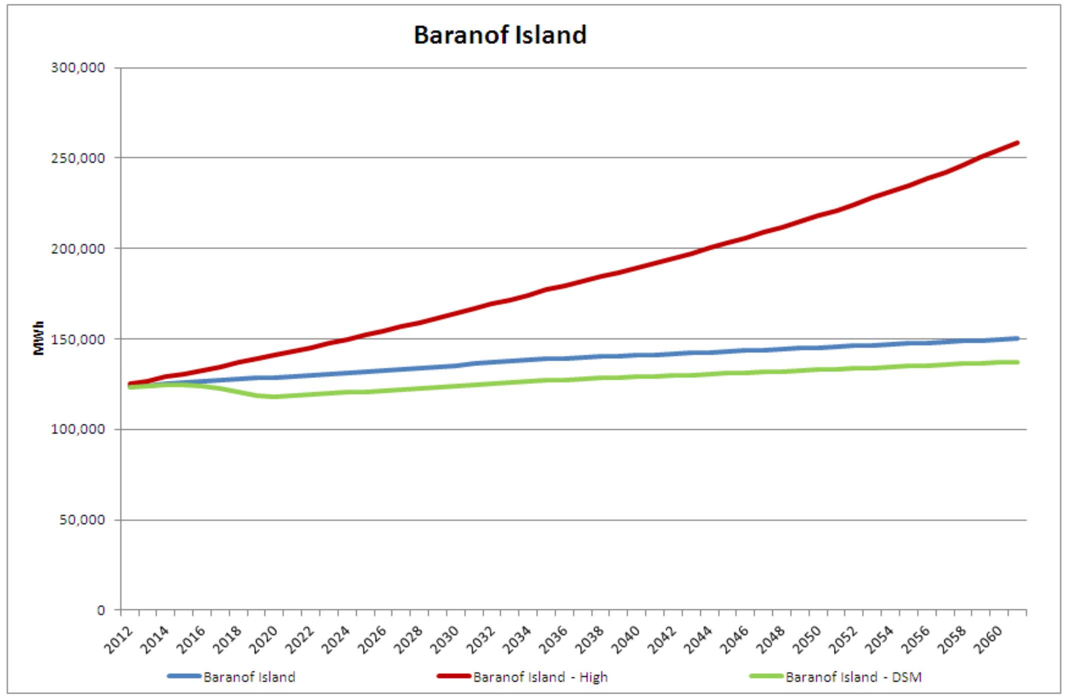
(1)May not be necessary if the Thayer Creek Hydro Project is successful.

Summary of Results

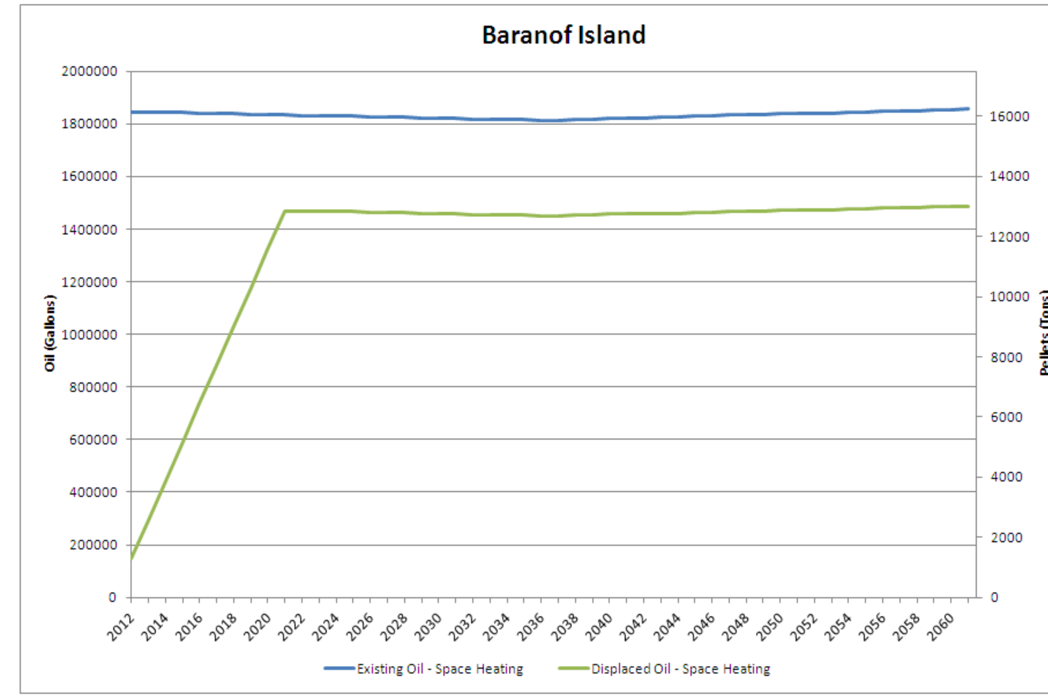
Sub-Region: Baranof Island

Sitka

Electric Load Forecast

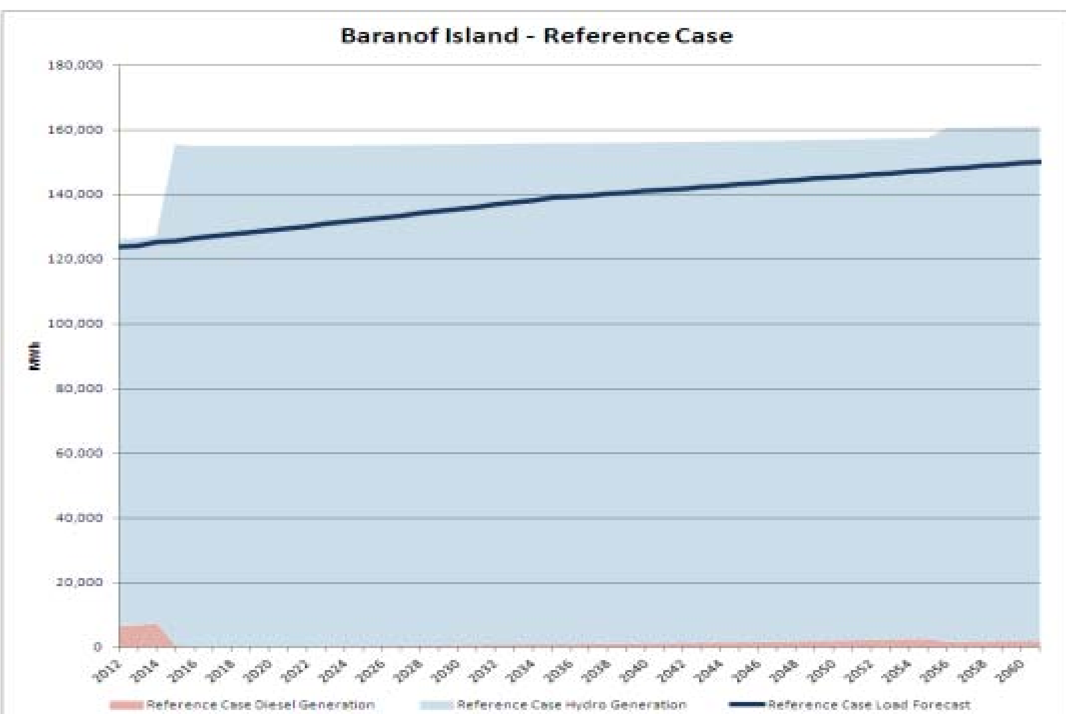


Space Heating



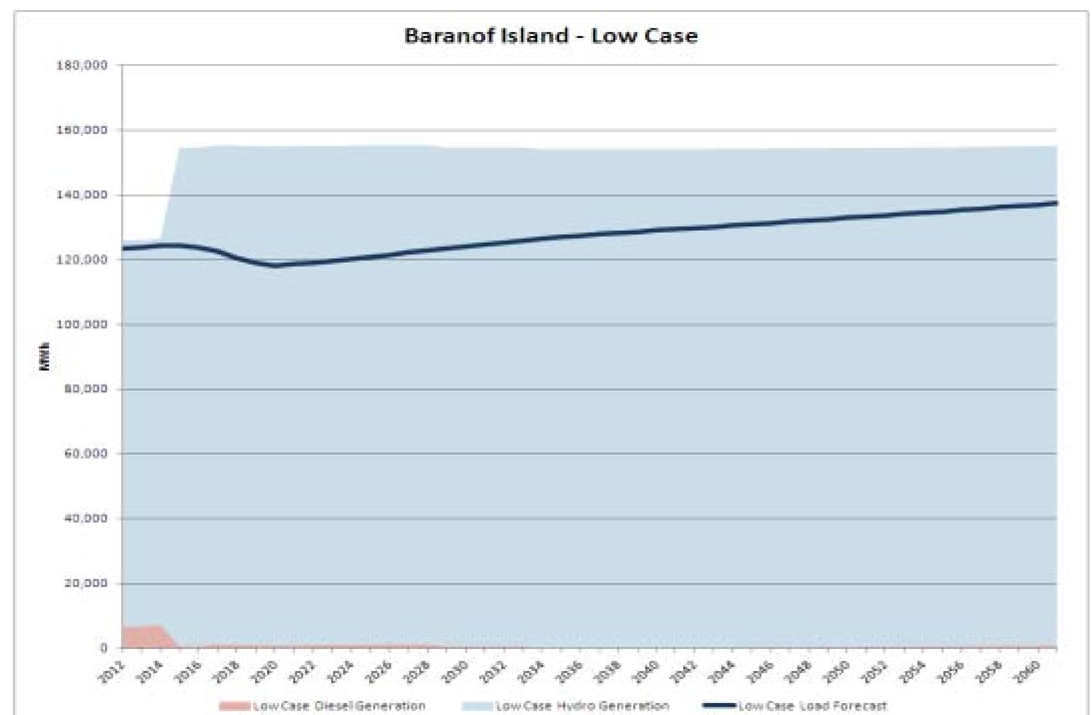
Cumulative Present Worth Cost ($ 000s) - Oil Only:	460,426
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	243,680

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	97,345

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s) - Including DSM:	95,872

Expansion Plan Alternatives:

Baranof Island

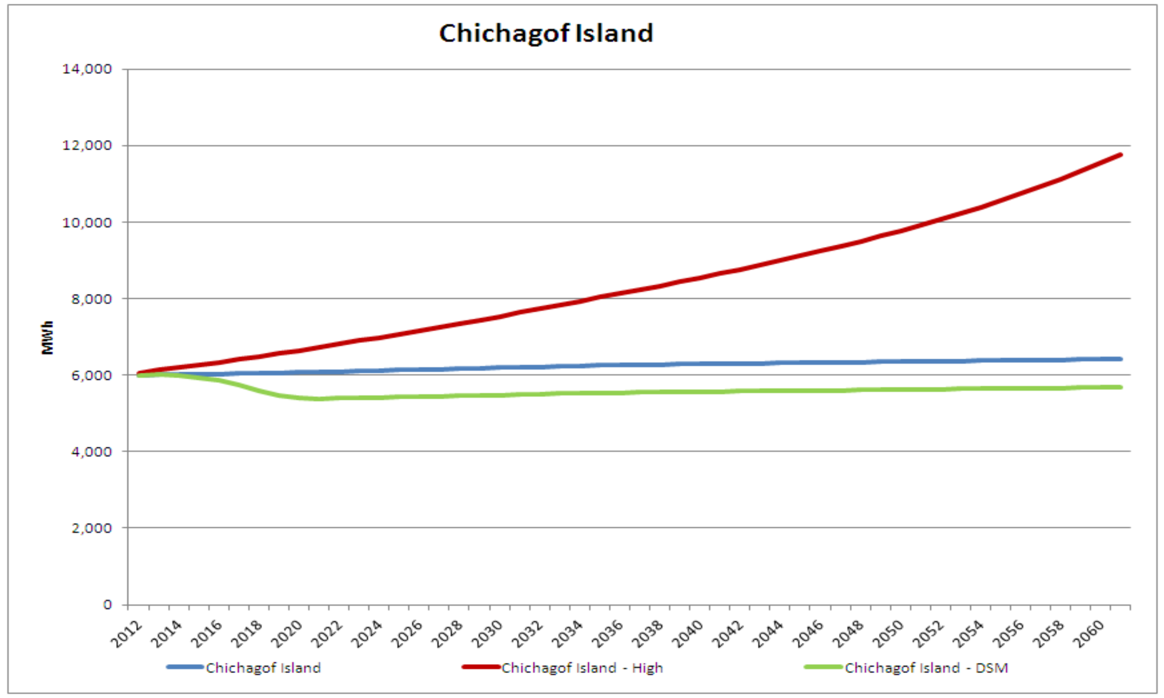
- Committed Resource – Hydro
- Generic Hydro
- Diesel
- DSM/EE
- Biomass Space Heating

Summary of Results

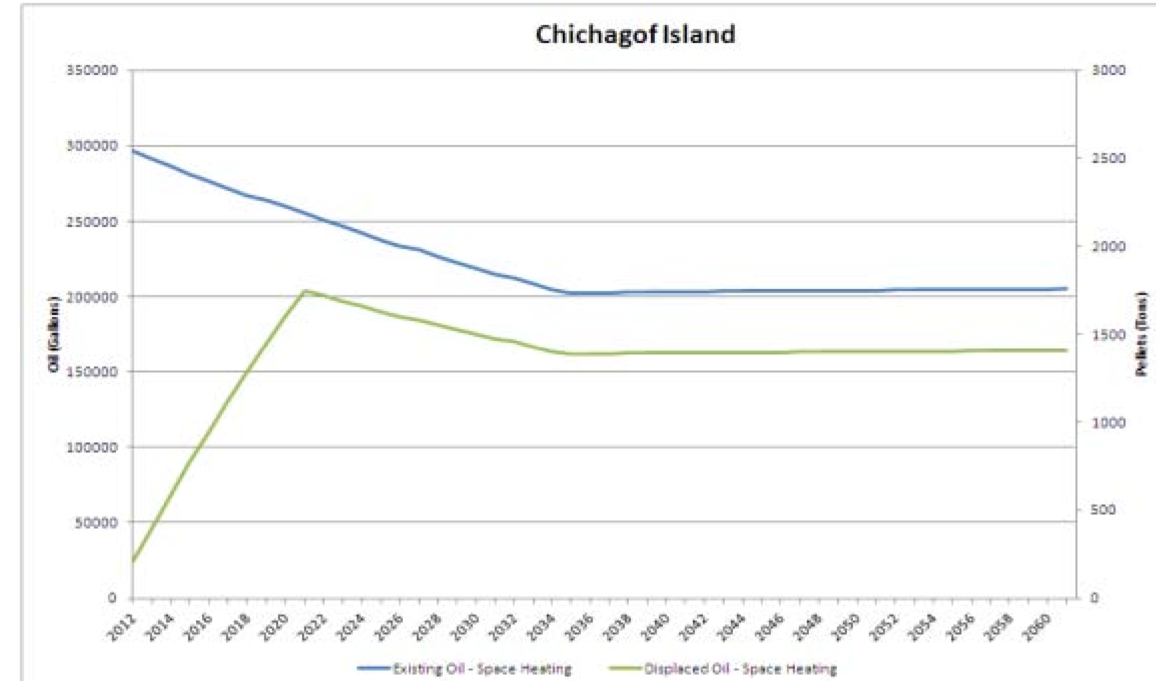
Sub-Region: Chichagof Island

Elfin Cove
Hoonah
Pelican
Tenakee Springs

Electric Load Forecast

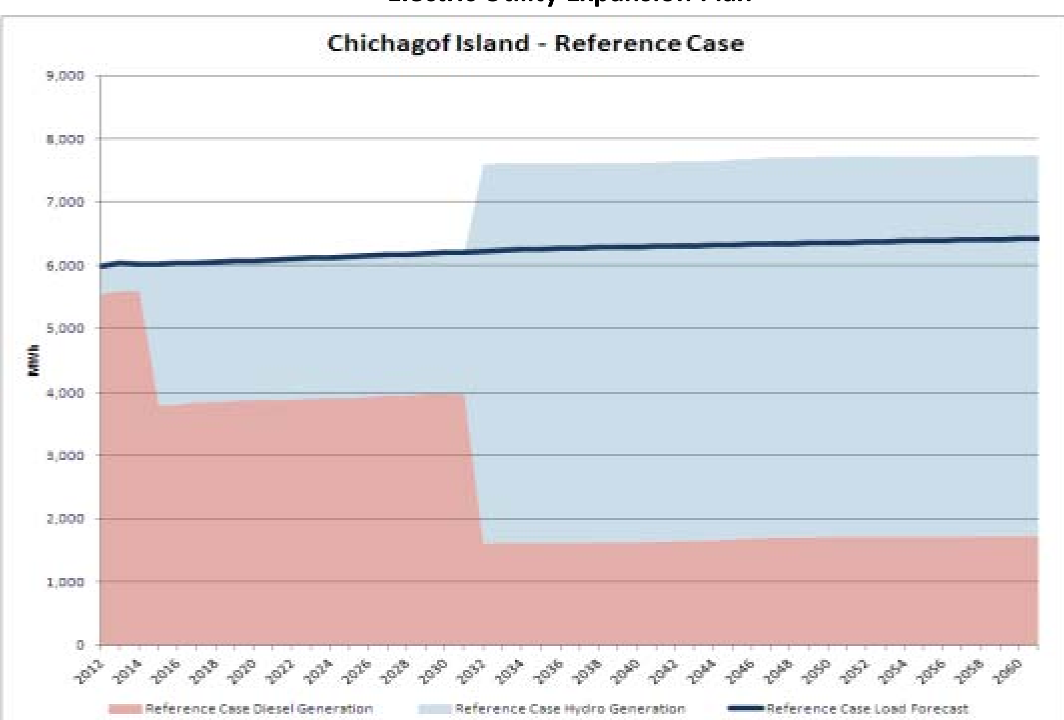


Space Heating



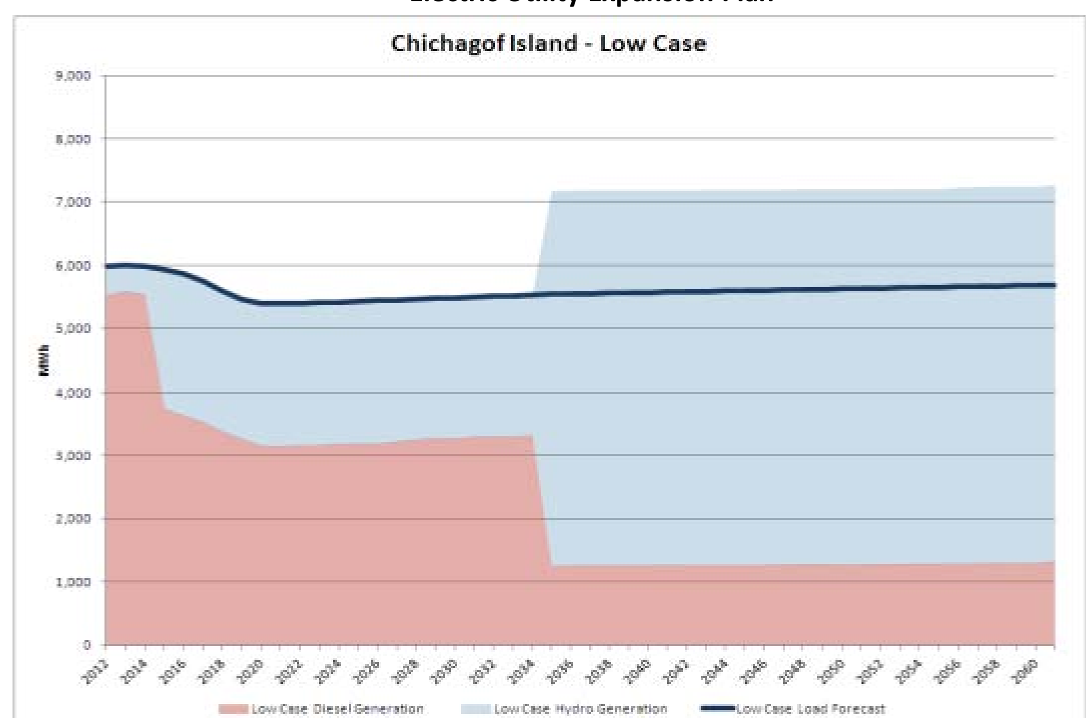
Cumulative Present Worth Cost ($ 000s) - Oil Only:	58,459
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	28,509

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	53,291

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s) - Including DSM:	46,568

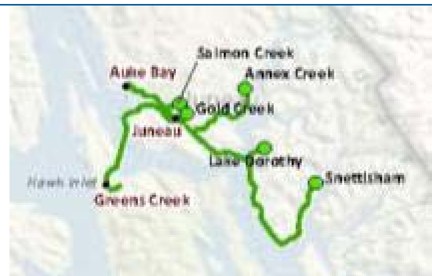
Expansion Plan Alternatives:

Chichagof Island

- Committed Resource – Hydro
- Generic Hydro
- Diesel
- DSM/EE
- Biomass Space Heating
- Geothermal – Project Development
- Tidal – Technology Development

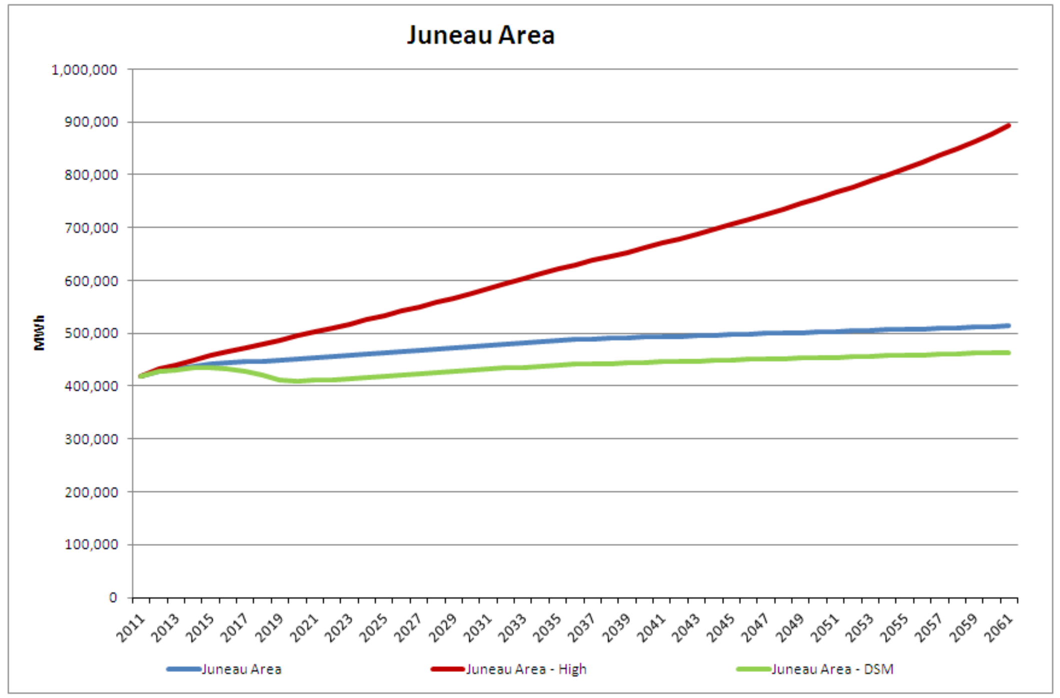
Summary of Results

Sub-Region: Juneau Area

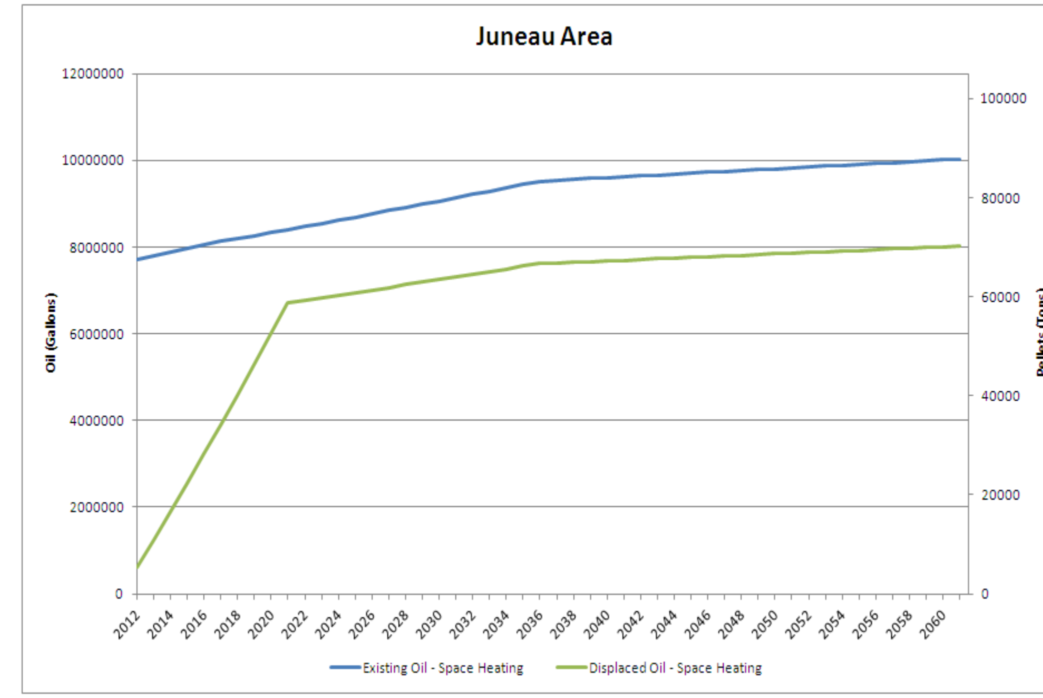


Juneau
Greens Creek

Electric Load Forecast



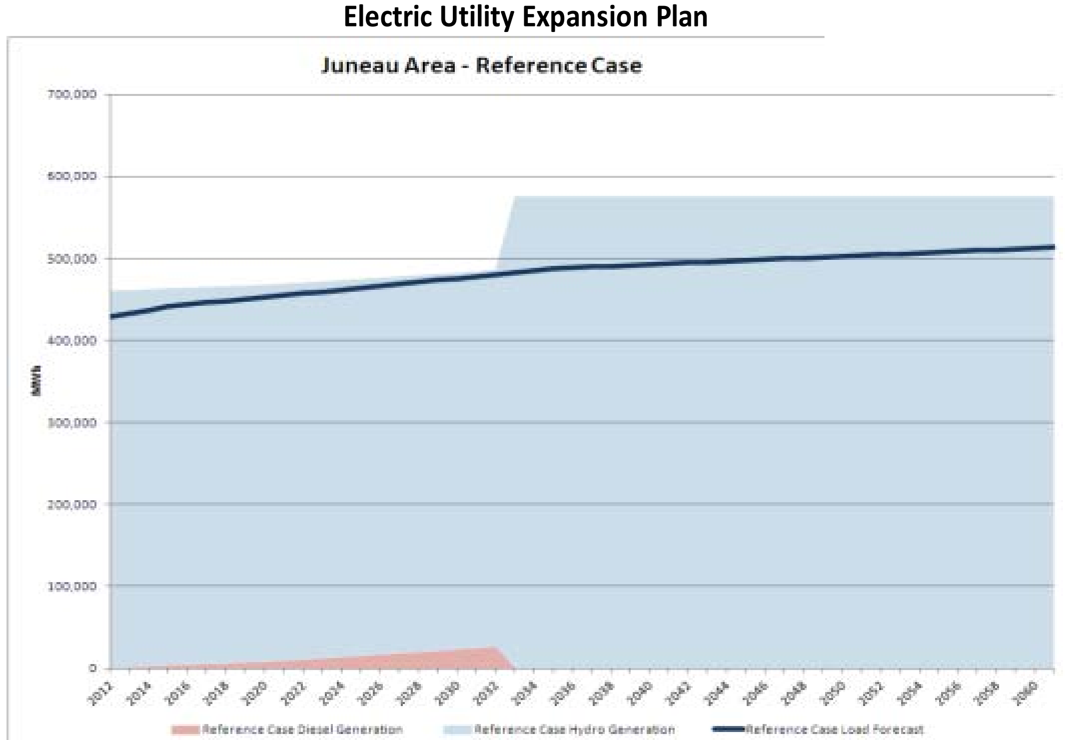
Space Heating



Cumulative Present Worth Cost ($ 000s) - Oil Only:	2,120,883
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	1,143,380

Summary of Results

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	234,265

Electric Load Forecast

xpansion Plan

Cumulative Present Worth Cost ($ 000s) - Including DSM:	185,556

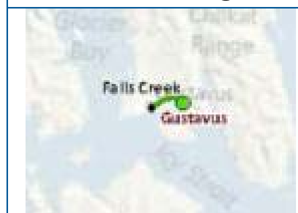
Expansion Plan Alternatives:

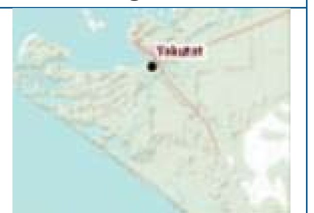
Juneau Area

- Generic Hydro
- Diesel
- DSM/EE
- Biomass Space Heating
- Tidal – Technology Development
- Biomass Generation – Technology Development

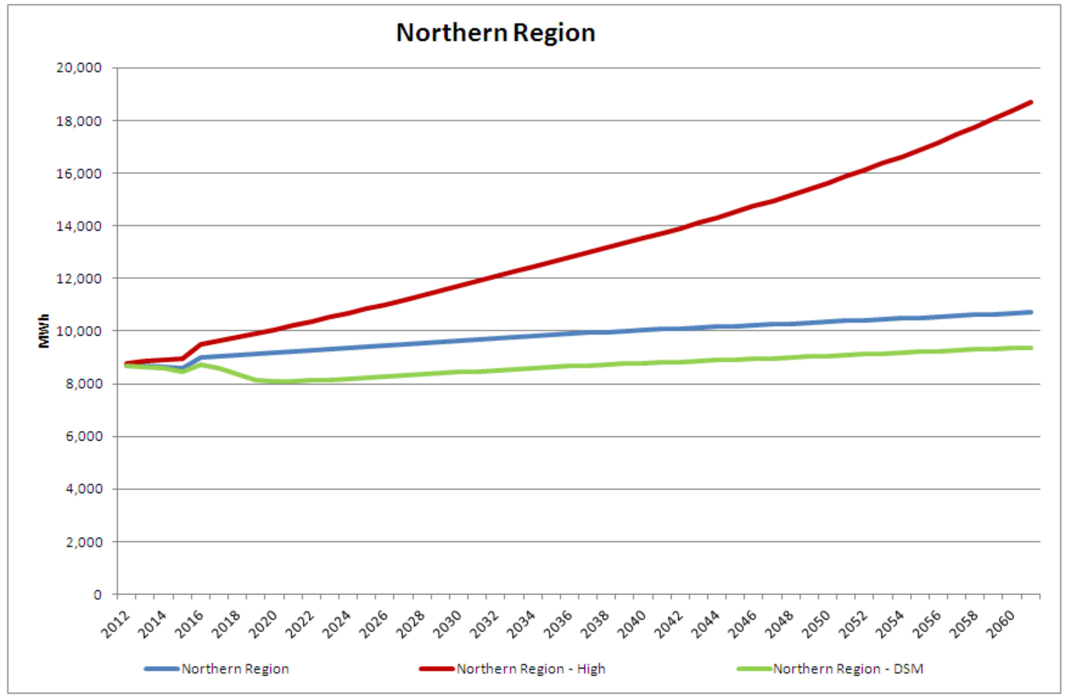
Space Heating

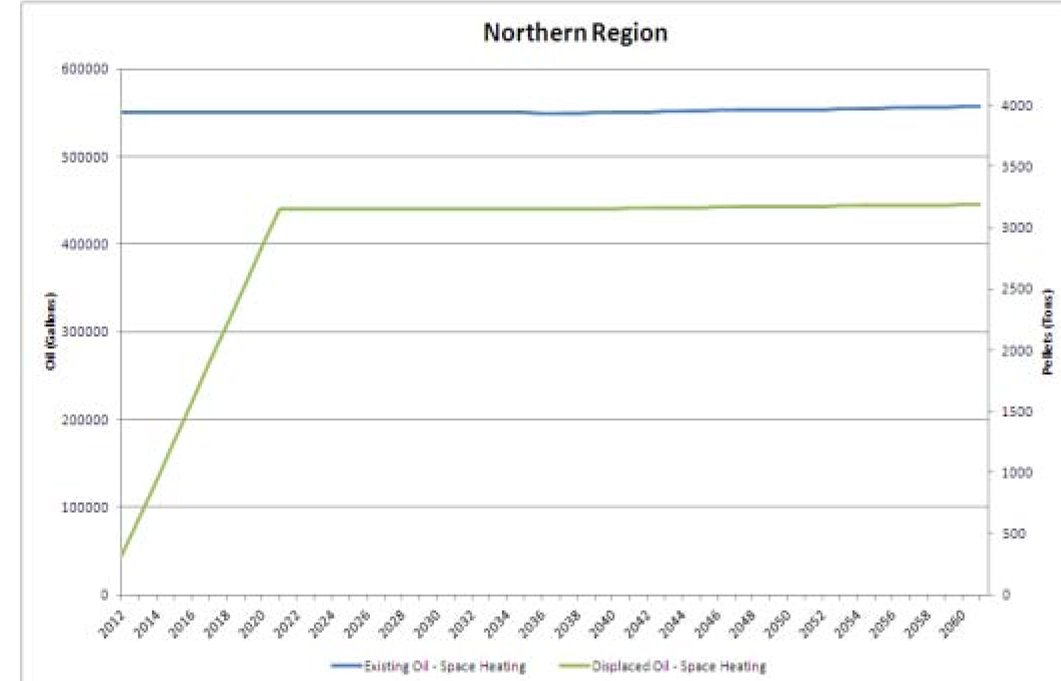
Sub-Region: Northern Region





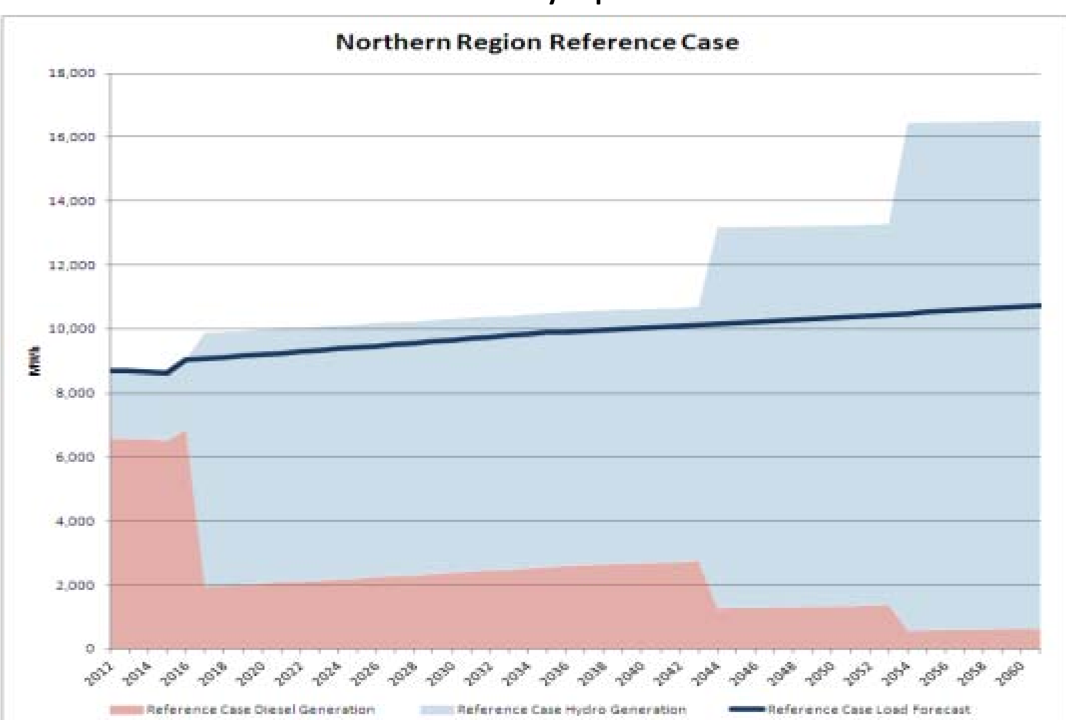
Yakutat
Gustavus





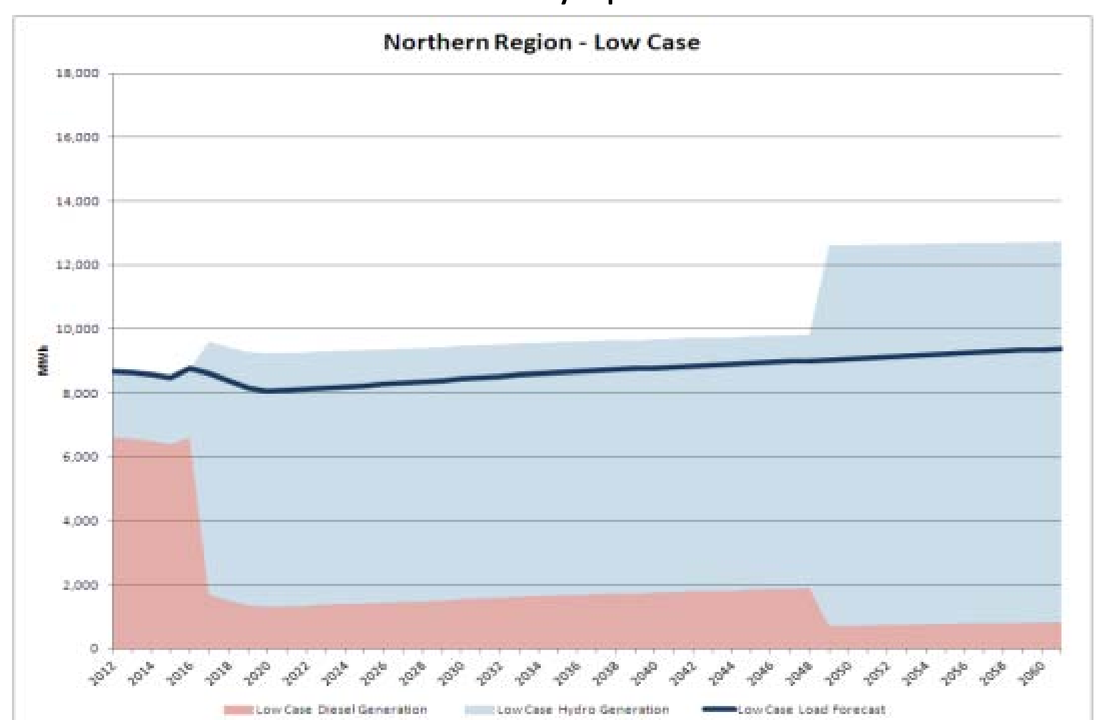
Cumulative Present Worth Cost ($ 000s) - Oil Only:	147,786
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	69,863

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	63,256

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s) - Including DSM:	55,825

Expansion Plan Alternatives:

Northern Region

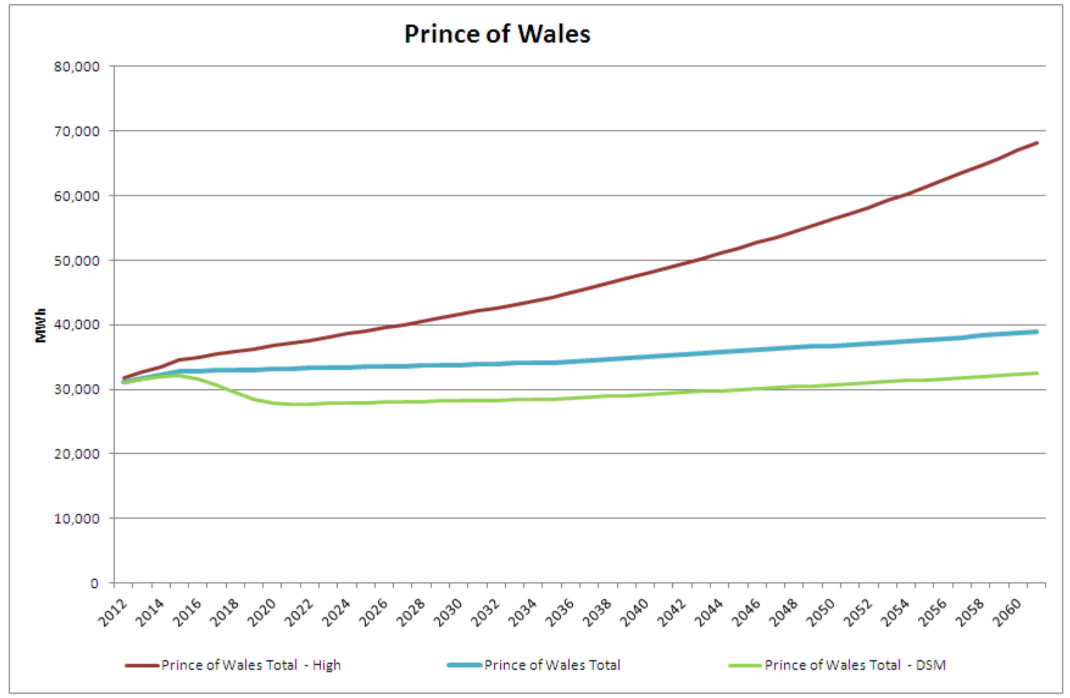
- Generic Hydro
- Diesel
- DSM/EE
- Biomass Space Heating
- Wind – Project Development
- Tidal – Technology Development
- Biomass Generation – Technology Development

Summary of Results

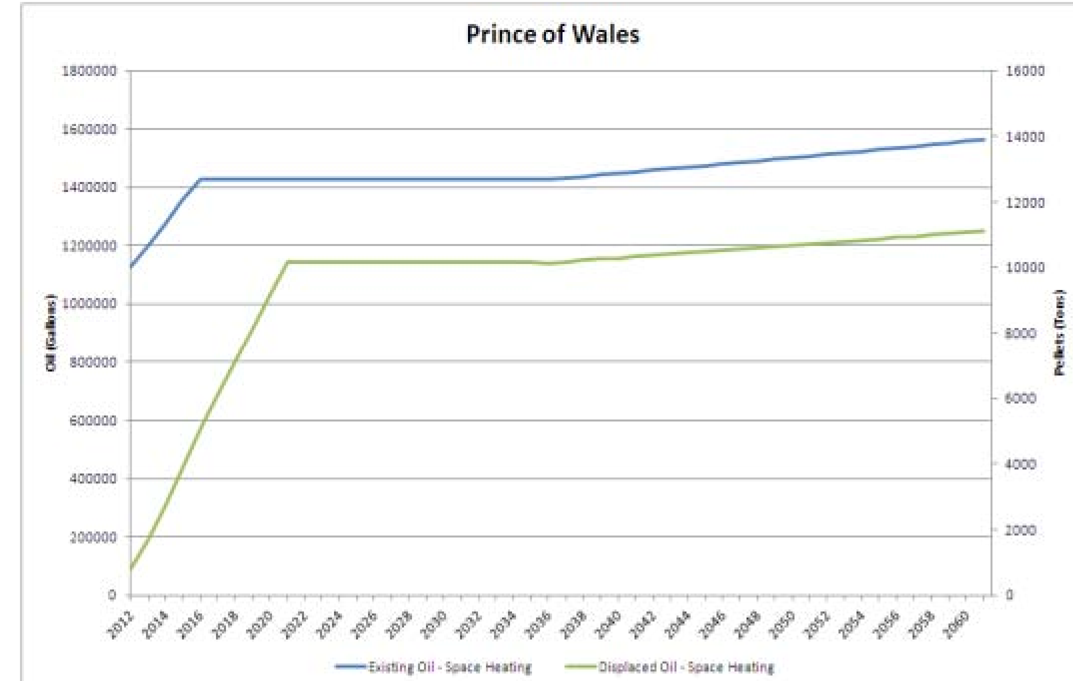
Sub-Region: Prince of Wales

Naukati
Whale Pass
Coffman Cove
Klawock
Thorne Bay
Hollis
Craig
Hydaburg
Kasaan

Electric Load Forecast

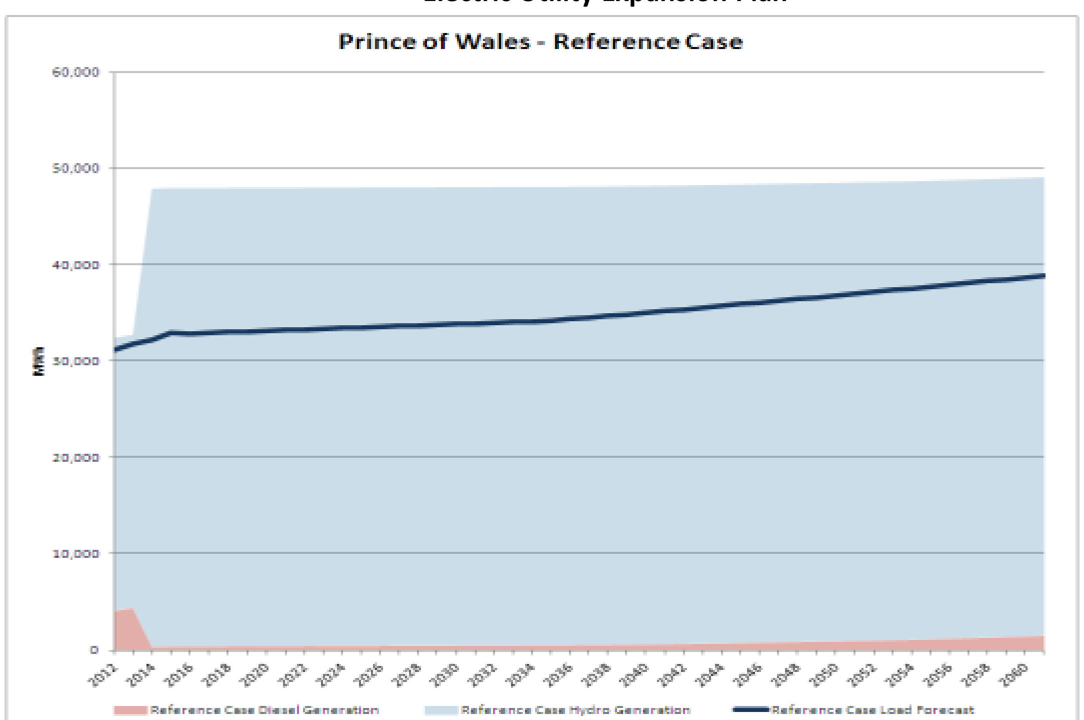


Space Heating



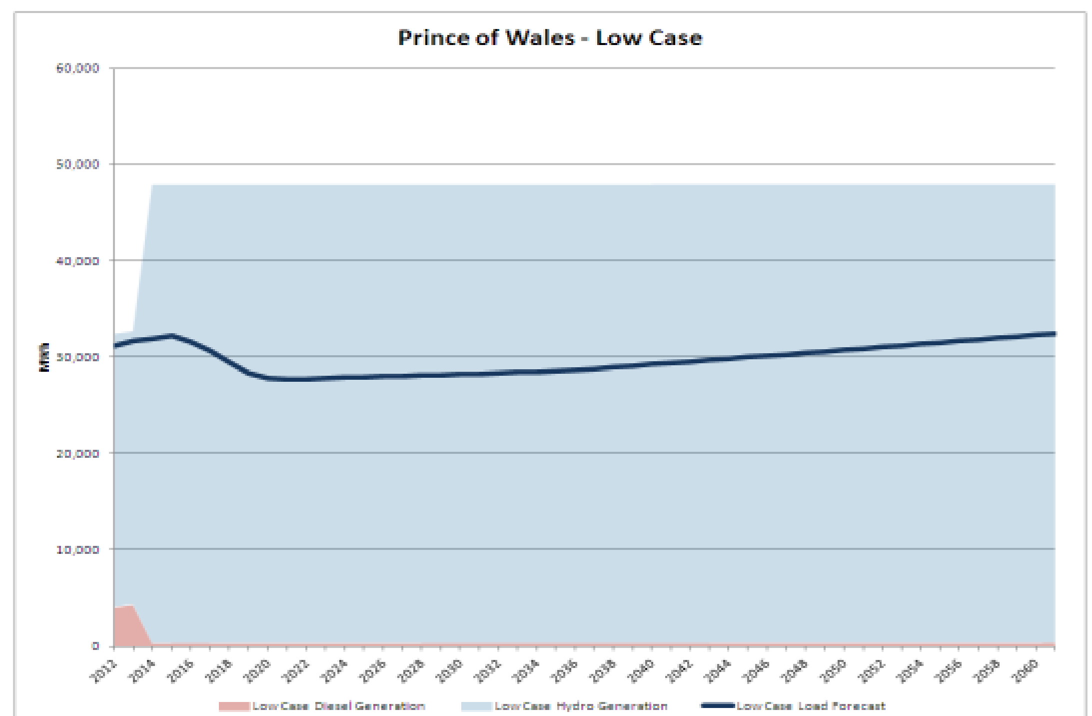
Cumulative Present Worth Cost ($ 000s) - Oil Only:	366,725
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	186,689

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	24,094

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s) - Including DSM:	20,781

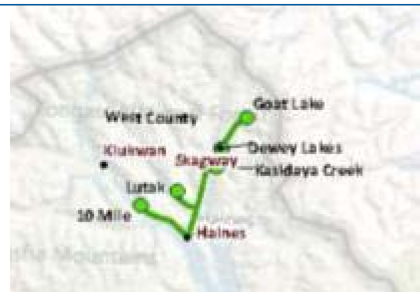
Expansion Plan Alternatives:

Prince of Wales

- Committed Resource – Hydro
- Diesel
- DSM/EE
- Biomass Space Heating

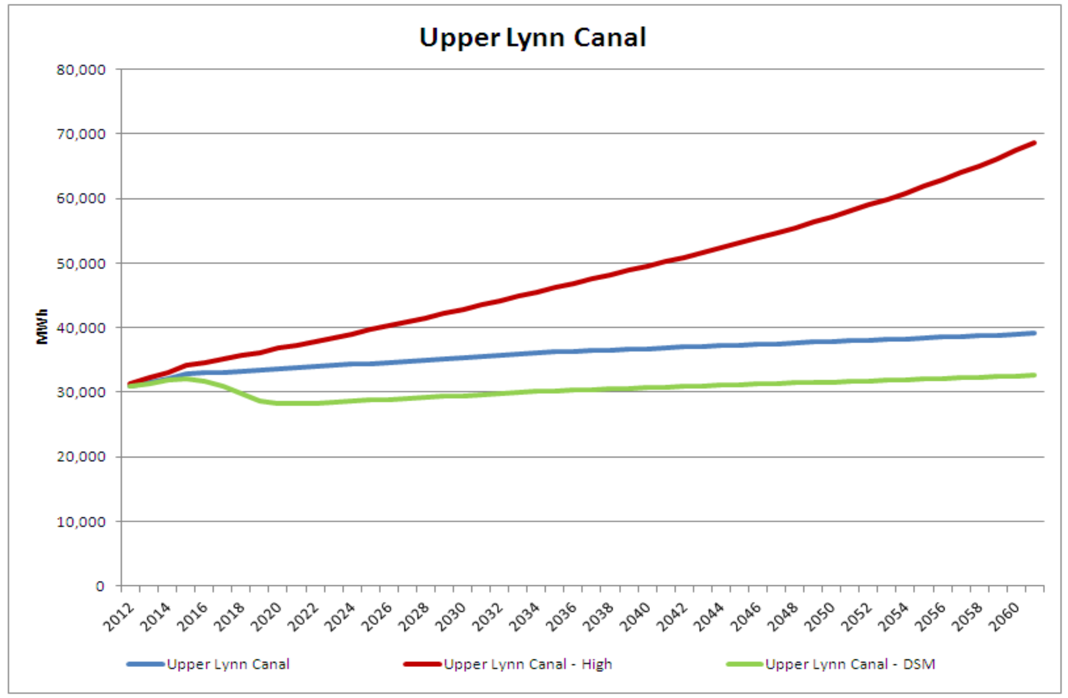
Summary of Results

Sub-Region: Upper Lynn Canal

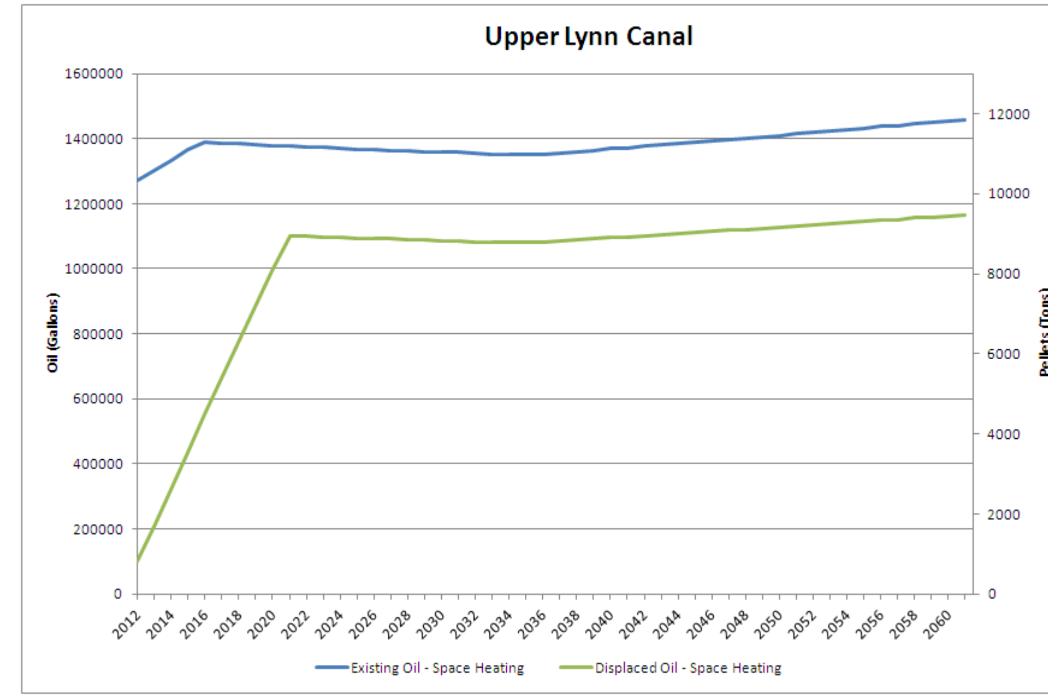


Chilkat Valley
Klukwan
Haines
Skagway

Electric Load Forecast

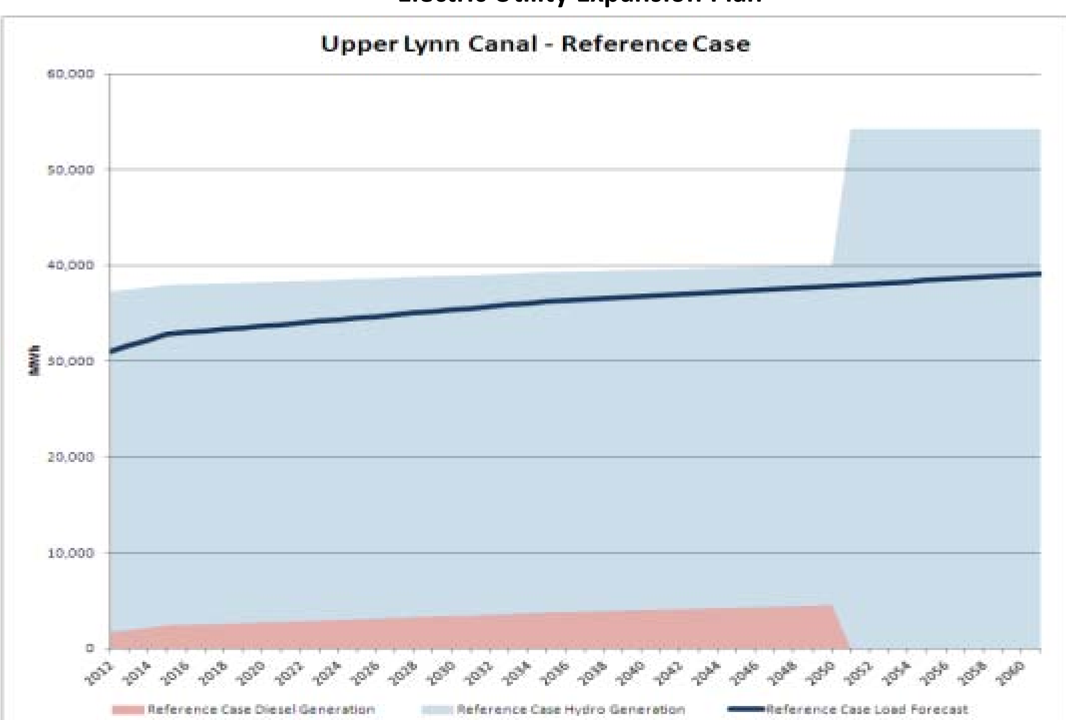


Space Heating



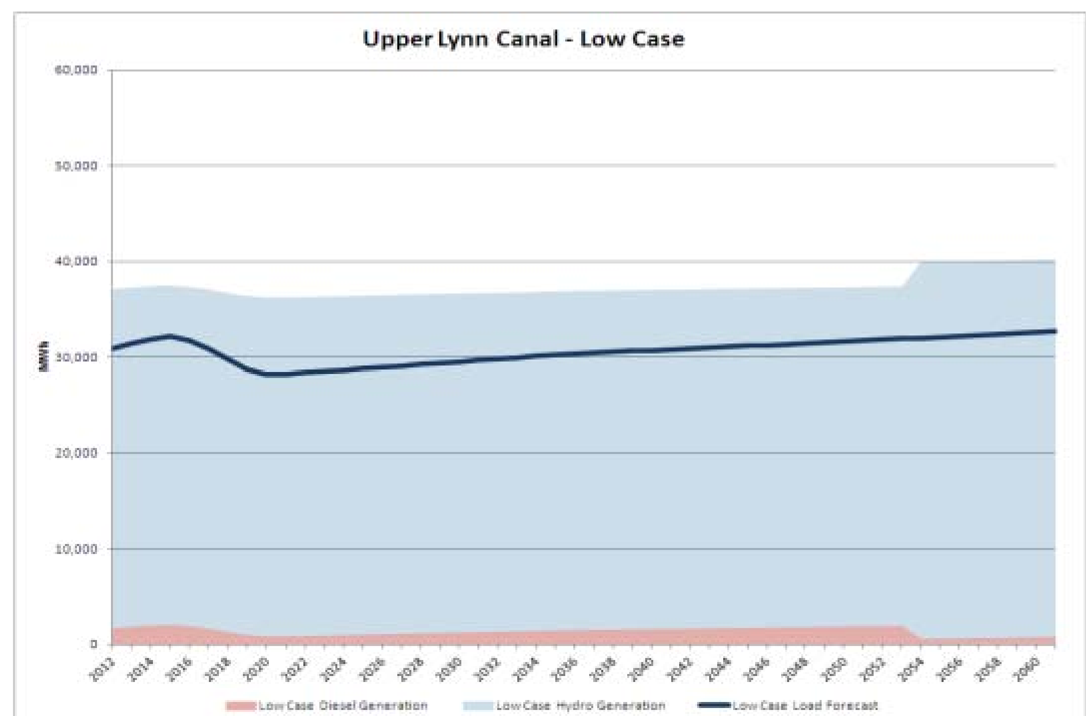
Cumulative Present Worth Cost ($ 000s) - Oil Only:	347,271
Cumulative Present Worth Cost ($ 000s) - Biomass & Oil:	174,480

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s):	44,538

Electric Utility Expansion Plan



Cumulative Present Worth Cost ($ 000s) - Including DSM:	27,678

Expansion Plan Alternatives:

Upper Lynn Canal

- Generic Hydro
- Diesel
- DSM/EE
- Biomass Space Heating

18.0 Financial Assessment

This section evaluates the various financing options available to the region to cover the cost of implementing the recommended Southeast Alaska IRP. Financing options are discussed for the first 10 years of the expansion plan.

18.1 ESTIMATED CAPITAL REQUIREMENTS TO IMPLEMENT SOUTHEAST ALASKA IRP

This subsection describes the annual capital amounts required to implement the recommended Southeast Alaska IRP. The plan consists of capital requirements for committed hydroelectric units and transmission interconnections (i.e., Committed Resources), generic hydroelectric units, generic diesel units, DSM/EE programs, and conversion from oil heating to biomass pellet heating.

Figure 18-1 presents the annual capital requirements in nominal dollars for the entire Southeast region.

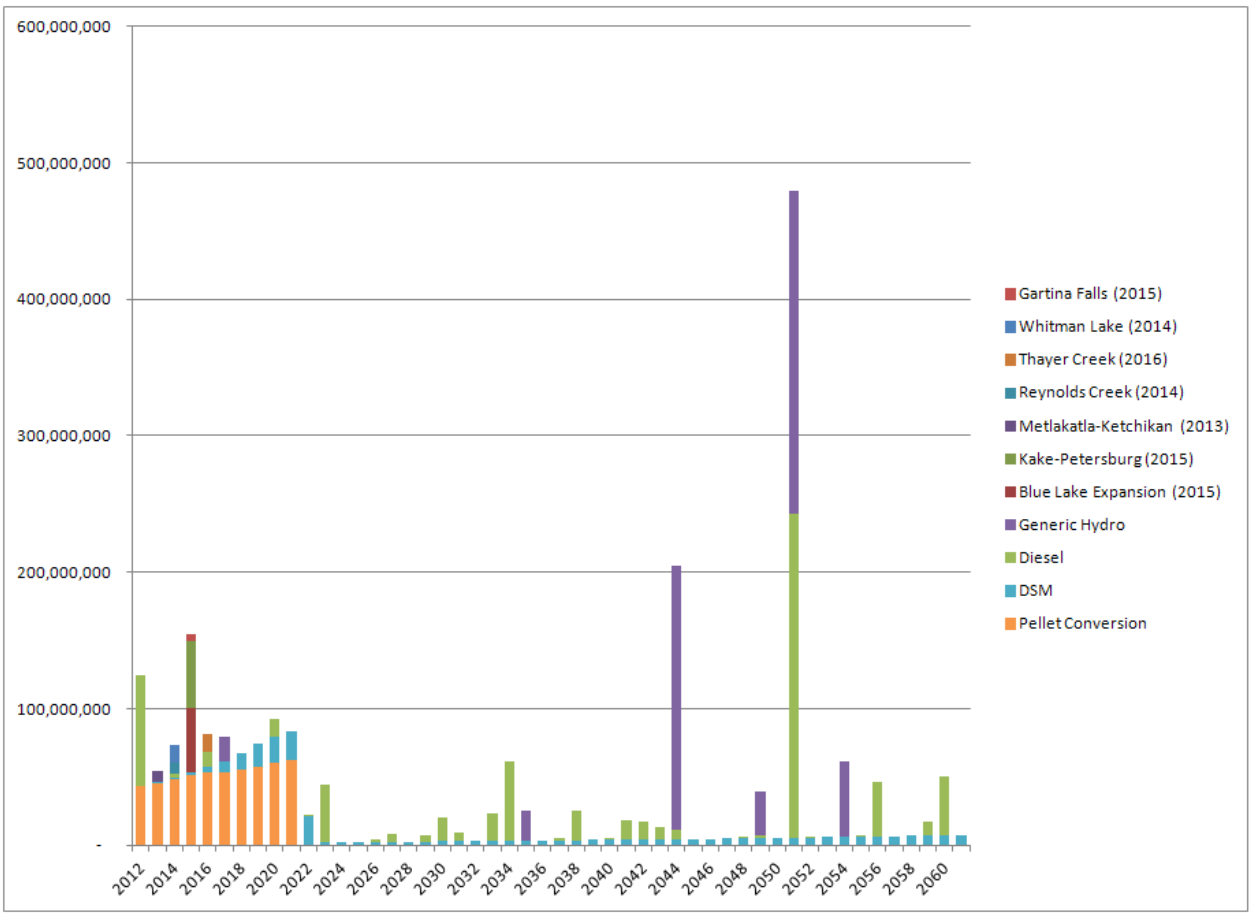


Figure 18-1 Southeast Alaska IRP Annual Capital Requirements

18.2 COMMITTED TRANSMISSION INTERCONNECTIONS

There are currently two interconnections that are Committed Resources to being constructed in the Southeast in the first five years of the study period. The Metlakatla to Ketchikan interconnection is scheduled to be completed in 2013, and the Kake to Petersburg interconnection is scheduled to be completed in 2015. Both projects have been under development for many years and have received previous grants. The remaining capital cost requirements for the Metlakatla to Ketchikan Intertie are estimated to be $8.22 million. The Metlakatla Indian Community (MIC) has made a Round 5 application to AEA's Renewable Energy Grant Fund for the remaining capital requirements. The estimate remaining capital requirements for the Kake to Petersburg Intertie are $48.59 million. This results in a total capital need of $56.81 million in the first five years of the study period for the two transmission interconnections.

Generally, traditional financing of transmission interconnections is difficult to obtain due to the low amount of revenues that occur for a transmission project in the early years of installation because of the low amounts of power flowing over the line. In order to generate the revenues required to recover the costs in the early years, wheeling rates would need to be raised significantly, thus significantly increasing the cost to the ratepayers. Specific detailed evaluation of the financing capability of individual owners is beyond the scope of this directional IRP, but to obtain traditional financing, the financing entity must have a strong credit rating and significant capitalization. Without detailed evaluation, it appears that both MIC and Kwaan Electric Transmission Intertie Cooperative, Inc., the current respective owners of the Metlakatla to Ketchikan and the Kake to Petersburg interconnections would have difficulty in meeting the credit worthiness requirements for financing. Even if a more credit worthy organization, such as SEAPA, were to take over ownership, traditional financing would still be a problem due to mismatch between the power flow on the line and the revenue necessary to support the financing. It appears that the only feasible financing approach for these two interconnections is through significant grant financing either through the AEA's Renewable Energy Grant Fund or in some other manner.

18.3 COMMITTED HYDROELECTRIC PROJECTS

18.3.1 Blue Lake Expansion Hydro

The Blue Lake Expansion does not have applications for funding during the Round 5 process of the AEA Renewable Energy Grant Fund program. Blue Lake was originally scheduled to be brought online in 2014, but that schedule has changed and now it will become commercial in 2015. As described in Section 4, the total estimated capital cost is $96.5 million. Sitka has received or been approved for a total of $49 million in State funding. In 2010, Sitka completed a bond issue with $20 million of net proceeds for the project. Therefore, $27.5 million is required to complete the funding of the project.

Sitka's bond issue which provided the $20 million for the Blue Lake Expansion was for approximately $50 million total. Again without detailed evaluation of the specific financing capacity of Sitka, it may be possible to finance the remaining capital necessary for Blue Lake Expansion through another bond issue.

18.3.2 Gartina Falls Hydro

The Gartina Falls Hydro project does not have applications for funding during the Round 5 process of the AEA Renewable Energy Grant Fund program. Gartina Falls Hydro is expected to become commercial in 2015. As described in Section 4, the estimated project cost is $5.79 million in 2011 dollars. Three years of escalation based on the escalation rate in Section 6, will add another $537,000 to the capital cost. IPEC has received previous grants totaling $850,000 leaving estimated remaining costs of $5.48 million to reach commercial operation.

IPEC does not have as strong of a credit rating as Sitka. Gartina Falls generation will be initially relatively expensive on an S/MWh basis. Without conducting detailed evaluation of IPEC's financing capability, it appears unlikely that IPEC will be able to obtain significant financing from the private market. IPEC does have a couple of RUS loans. It may be possible for IPEC to obtain an additional RUS loan, but RUS requirements have become relatively strict such as evaluating the loss of the utilities largest customers, and Gartina Falls may not be able to pass those requirements. Ultimately, grant financing from the AEA or other sources may be required to finance the remaining capital requirements.

18.3.3 Reynolds Creek Hydro

The Reynolds Creek Hydro project is scheduled to become commercial in 2014 near Hydaburg on Price of Wales Island. Reynolds Creek has a Round 5 application for a grant from AEA's Renewable Energy Grant Fund. If the full amount of $1.2 million requested during Round 5 is granted, the project will have an estimated $6.86 million in capital costs remaining. The project is jointly owned by Haida Energy, Inc. and AP&T, with AP&T's ownership share being 10 percent. It is likely that AP&T would be able to finance and/or provide equity for their 10 percent ownership share. It is less likely that Haida Energy, Inc. will be able to provide financing and/or equity for their 90 percent share of the remaining capital costs. Ultimately, the AEA will need to provide additional loans or grants through the Renewable Energy Grant Fund or other sources to complete the project.

18.3.4 Thayer Creek Hydro

The Thayer Creek Hydro project is scheduled for commercial operation in 2014, but based on past project performance, Black & Veatch has assumed that the commercial operation date will slip to January 1, 2016. The Thayer Creek Hydro project has made a Round 5 AEA Renewable Energy Grant Fund grant application for $7 million. If the entire Round 5 grant request is granted, the project will have an estimated remaining capital requirement of $6.04 million. It is unlikely that Kootznoowoo, Inc., the current project developer, will be able to provide equity and/or financing for the remaining capital requirements. As such, a significant portion of the remaining capital requirements will need to be supplied by the AEA or other State entity either as a loan similar to that for Reynolds Creek or through grants.

18.3.5 Whitman Lake Hydro

The Whitman Lake Hydro project is scheduled to become commercial in 2014. Whitman Lake Hydro has an application for a $3.3 million grant from Round 5 of AEA's Renewable Energy Grant Fund. If the entire grant request is granted, the estimated remaining capital requirements for the Whitman Lake Hydro project will be $10.1 million. Ketchikan conducted a bond referendum election in October 2011 for $15 million for 20-year bonds at 4.5 percent. The referendum passed overwhelmingly with a seven to two majority. The bonds should be able to cover the remaining project costs.

18.4 GENERIC HYDROELECTRIC PROJECTS

As shown in Figure 18-1, there is one generic hydroelectric project that is included in the Preferred Expansion plan during the first 10 years of the study period. That project is a 1 MW hydro project for Yakutat in 2017. While Yakutat has needs for projects to reduce its dependence on diesel generation, it is unlikely that a specific hydro project located close enough to Yakutat to be cost-effective will be identified. Other forms of specific generation that might be identified for Yakutat, are unlikely to be commercially demonstrated to the extent that hydro is. If the financing requirements are small and the project is of a proven technology such as hydro, it is possible that Yakutat could finance the project; however, it is unlikely that either of these requirements will be met. If that is the case, financing will require State assistance either through grants or loans such as issued by the AEA for Reynolds Creek.

For larger generic hydro projects identified for later in the study period, other forms of financing as discussed in Section 9 may be available. In general, these financing forms will require assistance from the State or at a minimum be backed by the State.

18.5 DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY

As discussed in Section 13.5, Black & Veatch believes that a regional entity should be formed to develop and deliver the DSM/EE programs. The details of the structure of this entity will be developed with the Regional DSM/EE Program Start-up Costs discussed in Section 17.2. Until the detailed structure is developed, it is not possible to develop a financing plan. The total DSM/EE costs for the region are considerable and estimated to be $83.34 million for the first 10 years of the planning period.

The entity developed to deliver the DSM/EE services will have no source of revenue unless the utilities reimburse the entity for the services. Achieving this reimbursement will likely be problematic. There is always tension between utilities and DSM/EE providers in that under rate structures existing in Alaska, the implementation of DSM/EE measures will reduce utility revenues. Currently there is no mechanism in place to force utilities to accept and pay for these services. The detailed development of these programs will have to address these issues. While it is not possible at this time to completely predict the structure of the DSM/EE programs, it appears likely that the programs will need to be financed in some way or another by State appropriations.

18.6 CONVERSION TO BIOMASS SPACE HEATING

Financing for the conversion to biomass space heating is even more problematic than for DSM/EE for two reasons. First, the estimated capital requirements are much larger, estimated to be $532.1 million compared to the $83.3 million for the DSM/EE programs. Second, there is no commercial entity in place that directly benefits from the biomass conversion. For DSM/EE, at least the utilities benefit from reduced utility costs. For biomass using pellets, the pellet suppliers would benefit, but to the level of financing all of the conversion costs. In the detailed development of the program, there may be the opportunity to get some help on the cost from the pellet suppliers, but if the pellets are supplied on the open market, this assistance in financing the conversion costs would be difficult to obtain and manage.

Once again it appears that some sort of State appropriation will be necessary to finance the biomass conversion costs. Because of the significant savings expected with the use of pellets, it is likely that less than the full cost of conversion will be necessary to obtain significant penetration which will be determined in the marketing studies. Even if significantly less than the full cost of the conversion is necessary to obtain significant penetration, much of the region will need to face the issue that low income residents may not have the means to participate in a program if it requires an up-front out-of-pocket cost. This issue will need to be addressed in the program development.

18.7 ALTERNATIVE FINANCIAL MODELS

Section 9 discusses four alternative financial models that could be used to minimize the initial cost impact of hydroelectric and transmission projects. As noted in that section, minimizing the initial rate impacts can be especially challenging for small hydroelectric projects given the high installed cost per kW and the possible inability of participants to fully utilize the project output early in the project life. As stated earlier in this section, the first 10 years of the Preferred Resource List resulting from this study consists primarily of Committed Resources, DSM/EE programs, and conversion from oil heating to biomass pellet heating. The financing history for each Committed Resource is discussed in previous sub-sections. The nature of the recommended DSM/EE and biomass conversion programs are such that these alternative financing models are not applicable.

As discussed in Section 1 and Section 20, Black & Veatch recommends that, this IRP be updated in the 2014-2015 timeframe to make the longer-term resource selections that would be implemented in subsequent years. By updating the Southeast Alaska IRP in 2014 or 2015, the region will have: 1) better project-specific information to make a definitive selection among specific alternative hydro and other renewable projects, and 2) actual experience with the implementation of DSM/EE and biomass conversion programs to better determine the level to which the region, and individual subregions, can rely on these programs over the long term. The results of the updated Southeast Alaska IRP might include the development of additional hydro projects and or transmission interconnections. If that is the case, then the use of one of the alternative financing models discussed in Section 9 might be appropriate.

19.0 Implementation Risks and Issues

In this section, Black & Veatch identifies a number of general risks and issues that must be addressed regardless of the resource future that is chosen by stakeholders, including the utilities and state policy makers.

A discussion is included about the risks and issues associated with each alternative generation resource type, including transmission, and the actions that should be taken to address these resource-specific risks and issues.

19.1 GENERAL RISKS AND ISSUES

In this subsection, Black & Veatch identifies and discuss a number of general issues and risks that relate to the implementation of this Southeast Alaska IRP. These general issues and risks are grouped into the following categories:

- Resource
- Fuel Supply
- Transmission
- Market Development
- Financing and Rate
- Legislative and Regulatory

19.1.1 Resource Risks and Issues

There are a myriad of risks and issues associated with the implementation of specific resource options, whether DSM/EE, generation, or transmission. General areas of risk are discussed below and resource-specific issues and risks are discussed in the next subsection.

19.1.2 Fuel Supply Risks and Issues

Diesel has been the predominant source of fuel for heating and for electric generation for many of the utilities, and the future availability and variability of prices of fossil fuels represents a fundamental challenge to the region in developing a sustainable and affordable energy future. This issue is critically important for those communities that are partially or completely dependent on diesel fuel for heating and the generation of electricity.

19.1.3 Transmission Risks and Issues

As previously noted, the Southeast Alaska electric transmission grid, which is owned and operated by SEAPA, is very limited in terms of reach, interconnections, and redundancies, in direct contrast to the integrated, interconnected, and redundant grid that is in place throughout the lower 48 states. This characterization reflects the fact that the SEAPA transmission system is an isolated grid with no external interconnections to other areas and that it is essentially a single transmission line running from Wrangell to Ketchikan, with limited total transfer capabilities and redundancies.

As a result of the limited transmission system within the Southeast region, each utility is required to maintain higher generation reserve margins (reserve margins reflect the amount of extra capacity beyond the peak load requirement that a utility needs to ensure reliable system operation in the event that a generating unit fails or there is not adequate water for required hydroelectric generation) and higher spinning reserve requirements (spinning reserve represents the amount of capacity that is available to serve load instantaneously if an operating generator disconnects from the grid) than elsewhere in order to ensure reliability in the case of a generation or transmission grid outage.

19.1.4 Market Development Risks and Issues

19.1.4.1 Competitive Power Procurement

An important market development-related issue relates to the ability of independent power producers (IPPs), or non-utility generators of electricity, to enter the market. To date, the level of IPP penetration is the Southeast region has been virtually nonexistent. Several IPP development activities are under way; however, none of these current activities are guaranteed to succeed. There are a number of reasons for lower IPP activity in the Southeast region than has occurred in other regions of the country. Not the least of these reasons is the fact that IPPs must work with individual utilities to gain acceptance on their projects, including the negotiation of power purchase agreements under varying terms and conditions and dealing with various generation interconnection requirements. The region might benefit from the adoption of policies that attract IPP development of project alternatives under the resource addition parameters established by this IRP.

19.1.4.2 Load Growth

With regard to native load growth (e.g., normal load growth resulting from residential and commercial customers), Southeast Alaska utilities have generally experienced limited, stable growth over the past decade, except for certain communities with access to low-cost hydroelectric power, which have seen accelerated growth due to recent conversions to electric space heating, and some communities which are limited to diesel generation and have seen declines in load growth as diesel prices have increased. Slow load growth is expected to continue in the years ahead. Significant economic development gains in the region or continued electric space heat conversions due to high diesel prices will accelerate growth, while increased promotion of DSM/EE programs will decrease growth.

19.1.5 Financing and Rate Risks and Issues

19.1.5.1 Financing

As noted above, Southeast Alaska utilities face a very significant challenge in terms of their ability to finance the future. Traditional means of financing by many of the region's utilities going forward independently simply are inadequate given the capital investment requirements over the next 50 years.

19.1.5.2 Rate Design

In addition to the challenge associated with securing the required financing, that capital investment will need to be recovered through rates, thereby, resulting in higher monthly bills for residential and commercial customers. While the need to recover capital investments is a reality, innovative rate design options (e.g., Construction-Work-in-Progress [CWIP]) are available to smooth out these rate increases over time so that they are more affordable to residential and commercial customers. CWIP also helps to address the cash flow issues associated with financing new projects.

19.1.6 Legislative and Regulatory Risks and Issues

19.1.6.1 State Energy Policy

The development of an IRP is not the same as the development of a State Energy Plan; nor does it set state policy. Setting energy-related policies is the role of the governor's office and state legislature. With regard to energy policy making, however, the Southeast Alaska IRP does provide a foundation of information and analysis that can be used by policy makers, within the region or at the state level, to develop important policies.

Having said this, the potential modification of the State's Energy Policy and/or the development of related policies could directly impact the specific resource plan chosen for the region's future. As such, this IRP should be readdressed as future energy-related policies are enacted.

19.1.6.2 Regulatory Commission of Alaska

While it is not within the scope of this IRP to address the level and quality of regulation, the level and quality of regulation will impact current and future investment decisions by electric utilities.

19.2 RESOURCE-SPECIFIC RISKS AND ISSUES

19.2.1 Introduction

The purpose of this section is to identify the primary issues and risks associated with the development of the following resource options:

- DSM/EE.
- Generation resources, including fuel oil, hydroelectric, wind, geothermal, solid waste tidal/wave, coal, and modular nuclear.
- Transmission resources.

19.2.2 Resource Specific Risks and Issues – Summary

Table 19-1 provides Black & Veatch's assessment of the relative magnitude of various categories of risks and issues for each resource type, including the following:

- **Resource Potential Risks** – the risk associated with the total energy and capacity that could be economically developed for each resource option.
- **Project Development and Operational Risks** – the risks and issues associated with the development of specific projects, including regulatory and permitting issues, the potential for construction cost overruns, actual operational performance relative to planned performance, and so forth. This category also includes non-completion risks once a project gets started, the risk that adverse operating conditions will severely damage the facilities resulting in a shorter useful life than expected, and project delay risks.
- **Fuel Supply Risks** – the risks and issues associated with the adequacy and pricing of required fuel supplies.
- **Environmental Risks** – the risks of environmental-related operational concerns and the potential for future changes in environmental regulations.
- **Transmission Constraint Risks** – the risk that the ability to move power from specific generation resources to where that power is needed, an issue that is particularly important for large generation projects and remote renewable projects.
- **Financing Risks** – the risk that a regional entity or individual utility will not be able to obtain the financing required for specific resource options under reasonable and affordable terms and conditions.
- **Regulatory/Legislative Risks** – the risk that regulatory and legislative issues could affect the economic feasibility of specific resource options.
- **Price Stability Risks** – the risk that wholesale power costs will increase significantly as a result of changes in fuel prices and other factors (e.g., CO_2 costs).

Table 19-1 Resource Specific Risks and Issues - Summary

RESOURCE	RELATIVE MAGNITUDE OF RISK/ISSUE							
	RESOURCE POTENTIAL RISKS	PROJECT DEVELOPMENT AND OPERATIONAL RISKS	FUEL SUPPLY RISKS	ENVIRONMENTAL RISKS	TRANSMISSION CONSTRAINT RISKS	FINANCING RISKS	REGULATORY/ LEGISLATIVE RISKS	PRICE STABILITY RISKS
DSM/EE	Moderate	Limited	N/A	N/A	N/A	Limited - Moderate	Moderate	Limited
Generation Resources								
Diesel	Limited	Limited	Significant	Moderate	Limited	Limited	Moderate	Significant
Hydroelectric	Limited - Moderate	Moderate	N/A	Moderate	Moderate	Limited - Moderate	Limited	Limited
Biomass	Limited - Moderate	Limited	Moderate	Limited	N/A	Limited-Moderate	Limited	Limited-Moderate
Wind	Moderate	Moderate	N/A	Limited	Significant	Limited - Moderate	Limited	Limited - Moderate
Geothermal	Significant	Limited - Moderate	N/A	Limited - Moderate	Moderate – Significant	Limited – Moderate	Limited	Limited
Solid Waste	Significant	Moderate-Significant	N/A	Significant	Moderate	Limited – Moderate	Limited-Moderate	Moderate
Tidal/Wave	Limited	Significant	N/A	Significant	Moderate - Significant	Moderate – Significant	Moderate - Significant	Limited - Moderate
Coal	Significant	Moderate-Significant	Moderate	Significant	Significant	Significant	Significant	Moderate
Modular Nuclear	Limited	Significant	Moderate	Significant	Moderate	Significant	Significant	Moderate
Transmission	Limited	Significant	N/A	Moderate	N/A	Significant	Moderate - Significant	N/A

The following provides some commentary related to the basis for these qualitative assessments of resource specific risks and issues:

- **Resource Potential Risks**

  Resource potential risks are deemed to be moderate or significant for some of the renewables resource options primarily due to the fact that enough resource potential studies have not been completed to provide a high degree of confidence in the amount of capacity and energy that could be provided by these different resource options. For other renewable resource options, initial studies indicate significant resources are available, but more detailed studies have not been conducted to ensure that these potential resources can actually be converted into renewable generation. Additional studies must be completed to identify the most attractive locations and to firm up the resource potential estimates for each type of renewable resource technology.

  Resource potential risks and issues are relatively lower for fuel oil and modular nuclear, as well as for additional transmission resources.

  Resource potential risks associated with DSM/EE programs are more commonly related to the reliability, or lack thereof, of the resource in that it is less under the control of the utility and relies more on mass market decision-making and/or behavior.

- **Project Development and Operational Risks**

  Project development and operational risks and issues are significant for modular nuclear, tidal/wave, and transmission. They are also fairly significant for coal and solid waste. In the case of hydroelectric, these risks are moderate due to the various environmental and permitting issues that would need to be addressed. Additionally, the potential for significant construction cost overruns is moderate for hydroelectric.

  Tidal/wave power represents an option with significant potential in the Southeast Alaska region. However, this technology has not been widely commercialized, and there are significant environmental and permitting risks and issues associated with this technology.

  In the case of transmission, project development risks are deemed significant due to not in my back yard (NIMBY) concerns and the rough terrain and difficult construction conditions that exist.

  Coal, solid waste, and modular nuclear face NIMBY concerns as well as permitting and licensing concerns.

  The project development-related risks are believed to be lower, or moderate, for the other types of renewable resources, including hydroelectric, wind, and geothermal; they are even lower, or minimal, for DSM/EE resources, and generation resources that are fueled by fuel oil.

- **Fuel Supply Risks**

  Fuel supply-related risks are very significant for fuel oil, and moderate for coal and modular nuclear. These types of risks do not apply to DSM/EE and the various renewable resources.

- **Environmental Risks**

  Environmental-related risks are believed to be moderate for fuel oil generation and significant for coal and modular nuclear. Future carbon restrictions represent an important risk for all generation resources that rely on fossil fuels and are very significant in the case of coal.

  Environmental-related risks are shown as significant for solid waste and tidal/wave power due to their potential environmental impact.

  They are believed to be moderate for small hydroelectric and geothermal, and limited for wind based, in large part, on experience with these technologies in other regions of the country and elsewhere in the world.

- **Transmission Constraint Risks**

  Existing transmission constraints are moderate to significant for large hydroelectric because the current transmission network is insufficient to move substantive amounts of capacity and energy throughout the region, which would be required for any large hydroelectric project to be economic.

  Transmission constraints also represent a moderate to significant issue for wind, geothermal, and tidal/wave, depending upon the ultimate amount of these resources developed within the region.

  They are believed to be moderate with regard to smaller hydroelectric and solid waste due to the typical size of these projects and the fact that they can generally be developed throughout the Southeast region, thereby reducing the need to have transmission to move the related capacity and energy from one subregion to another.

  Transmission constraints are deemed limited for fuel oil-fuel generation, again due to the typical size of these projects and the fact that they can be located throughout the region, and they do not exist with regard to DSM/EE resources due to the distributed nature of these resources.

- **Financing Risks**

  Financing risks and issues are significant for capital intensive resource options including coal, modular nuclear, hydroelectric, and transmission resources. They are moderate for fuel oil generation.

  Financing risks are limited to moderate for most of the renewable resources (e.g., including small hydroelectric, wind, geothermal, and solid waste) depending upon the actual size of the projects developed; likewise, they are limited to moderate for DSM/EE resources.

- **Regulatory/Legislative Risks**

  Regulatory and legislative risks and issues are limited for smaller-scale renewable resources, including small hydroelectric, wind, and geothermal, and limited to moderate for solid waste.

  They are moderate for DSM/EE resources, primarily due to the fact that regulatory (and potentially legislative) changes would be required to eliminate the disincentive that exists under the current regulatory framework for utilities to encourage customers to use less electricity. They are also believed to be moderate for fuel oil.

  Regulatory and legislative risks and issues are believed to be significant for modular nuclear and large hydroelectric, and moderate to significant for tidal/wave and transmission resources.

- **Price Stability Risks**

  Price stability risks and issues are limited for DSM/EE programs, hydroelectric, and geothermal; limited to moderate for wind and tidal/wave. They are moderate for coal and solid waste, and significant for fuel oil and modular nuclear.

More detailed information related to the risks and issues associated with each type of resource option is provided in the following subsection.

19.2.3 Resource Specific Risks and Issues – Detailed Discussion

This subsection provides more detailed information related to the risks and issues associated with each of the following types of resource options:

- DSM/EE
- Generation
  - Diesel
  - Hydroelectric
  - Biomass
  - Wind
  - Geothermal
  - Solid waste
  - Tidal/wave
  - Coal
  - Modular nuclear
- Transmission

This subsection consists of a series of tables that identifies the most significant risks and issues for each type of resource option, broken down by the major risk/issue categories discussed in the previous section. These tables also identify the primary actions that should be taken to address these risks and issues.

19.2.3.1 DSM/EE

Table 19-2 Resource Specific Risks and Issues – DSM/EE

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Total economic resource potential is unknown • General lack of Alaska-specific data to determine economic resource potential, including end-use saturations, measure persistence, weather sensitive impacts, and cost effectiveness • Reliability is a key concern with DSM since utilities have less control over its acquisition and management	• Establish Alaska-specific baseline information through the completion of region-wide residential and commercial end-use saturation surveys and customer attitudinal surveys (currently underway by AEA) • Complete comprehensive economically achievable potential study that includes a detailed cost-effectiveness evaluation of all feasible DSM/EE measures • Complete vendor surveys to determine availability and relative costs of DSM/EE measures in the Southeast region • Develop regional DSM/EE program measurement and evaluation protocols
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing their own DSM/EE programs • Ineffectiveness and inefficiencies associated with lack of coordination between the electric utilities, AHFC and AEA • Lack of customer awareness regarding DSM/EE options and economics	• Evaluate the potential benefits of forming a regional entity to develop and deliver, in coordination with the Southeast Alaska utilities, DSM/EE efficiency programs to all customers in the region • Develop and implement regional DSM/EE programs in close coordination with AHFC and AEA • Develop public outreach program to increase awareness of DSM/EE options • Develop and learn from near-term DSM/EE pilot programs throughout the Southeast region
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Not applicable	• Not applicable
Transmission Constraints	• Not applicable	• Not applicable

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Financing	• Lack of funding source for initial activities (e.g., collect baseline information and consumer education) required to build a viable and successful DSM/EE program • Lack of stable source of long-term financing for DSM/EE program	• Legislature should appropriate funds for the initial development of a regional DSM/EE program, including 1) customer attitudinal survey, 2) vendor surveys, 3) comprehensive evaluation of economically achievable potential, and 4) detailed DSM/EE program design efforts • Increase state funding of low income weatherization and residential and energy audit (both residential and commercial) program • Aggressively pursue available Federal funding for DSM/EE programs • Consider implementation of a System Benefit Charge, or SBC, (i.e., a surcharge on customer bills that would be dedicated to the funding of DSM/EE programs) to provide for the long-term funding of DSM/EE programs
Regulatory/Legislative	• The implementation of DSM/EE reduces energy sales and, therefore, reduces the ability of utilities to recover costs under current rate design principles • Lack of strict building codes and enforcement of those codes	• Implement a decoupling mechanism so that utilities can still recover their costs even with lower sales • Establish more stringent residential and commercial building codes that lead to lower energy use in new homes and buildings and increase the enforcement of those building codes • Establish targets for DSM/EE savings based on the economics of the programs • Establish state goals for reducing energy usage at state facilities • Develop and implement programs to increase energy efficiency in state buildings and schools

19.2.3.2 Generation Resources

19.2.3.2.1 Generation Resources – Diesel

Table 19-3 Resource Specific Risks and Issues – Generation – Diesel

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• See Fuel Supply	• See Fuel Supply
Project Development and Operational	• Development risks are well known and understood	• Not applicable
Fuel Supply	• Near-term and long-term adequacy and cost of fuel oil supplies	• Reduce dependence on fuel oil through development of projects on Preferred Resource List
Environmental	• Risk of accident	• Continue efforts to enforce safety and operational regulations
Transmission Constraints	• Proper location of diesel generation resources mitigates transmission constraints	
Financing	• Ability to finance new projects is utility specific	
Regulatory/Legislative	• Potential future environmental regulations related to emissions, including carbon and other emissions	• Monitor Federal legislative and regulatory activities related to emission regulations

19.2.3.2.2 Generation Resources – Hydroelectric

Table 19-4 Resource Specific Risks and Issues – Generation – Hydroelectric

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Total economic resource potential is sufficient for region's needs • Resource potential may be constrained by regional system regulation requirements	• Develop regional regulation strategy for nondispatchable resources
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing small hydro projects • Lack of standard power purchase agreements for projects developed by IPPs • Infrastructure needs to support construction may be significant	• Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• Potential impact of climate change	• Monitor water flows
Environmental	• Site-specific environmental issues including impact on fish	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of nondispatchable resources into SEAPA transmission grid poses challenges	• Expand regional transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of nondispatchable resources
Financing	• Cost per kW can be significant	• Aggressively pursue state financial assistance and available Federal funding for renewable projects
Regulatory/Legislative	• Region already exceeds state's renewable power targets • Roadless Rule may limit licensability and increase costs	• Monitor judicial challenges to Roadless Rule

19.2.3.2.3 Generation Resources – Biomass

Table 19-5 Resource Specific Risks and Issues – Generation – Biomass

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Total economic resource potential is unknown	• Complete regional economic potential assessment, including the identification of the most attractive sites
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing biomass projects	• Approach development of biomass projects throughout the region in a coordinated manner
Fuel Supply	• Further analysis is required to ensure an adequate and stable supply to meet future demand	• Further analysis of potential fuel supplies and supply chain logistics
Environmental	• Not significant	• Not applicable
Transmission Constraints	• If located properly, biomass facilities should not add to transmission constraints	• Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the encouragement of biomass facilities
Financing	• Small size of projects should minimize financing issues	• Pursue state assistance for development of biomass projects
Regulatory/Legislative	• Region already exceeds state's renewable power targets • Tongass Land and Resource Management Plan may limit availability of fuel	• Work with Forest Service to obtain sustainable biomass fuel supply

19.2.3.2.4 Generation Resources – Wind

Table 19-6 Resource Specific Risks and Issues – Generation – Wind

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for nondispatchable resources
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing wind projects • Lack of standard power purchase agreements for projects developed by IPPs	• Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Site-specific environmental issues	• Comprehensive evaluation of site-specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of nondispatchable resources into SEAPA transmission grid poses challenges	• Expand SEAPA transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of nondispatchable resources
Financing	• Cost per kW can be significant	• Aggressively pursue state financial assistance and available Federal funding for renewable projects
Regulatory/Legislative	• Region already exceeds state's renewable power targets	• Not applicable

19.2.3.2.5 Generation Resources – Geothermal

Table 19-7 Resource Specific Risks and Issues – Generation – Geothermal

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Total economic resource potential is unknown	• Complete regional economic potential assessment, including the identification of the most attractive sites
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing geothermal projects • Lack of standard power purchase agreements for projects developed by IPPs • Infrastructure needs to support construction are likely significant	• Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects • Explore if synergies can be achieved for infrastructure with hydro projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Site-specific environmental issues	• Comprehensive evaluation of site-specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand SEAPA transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• Cost per kW can be significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Region already exceeds state's renewable power targets	• Not applicable

19.2.3.2.6 Generation Resources – Solid Waste

Table 19-8 Resource Specific Risks and Issues – Generation – Solid Waste

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Total economic resource potential is unknown	• Complete regional economic potential assessment, including the identification of the most attractive sites
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing solid waste projects • Lack of standard power purchase agreements for projects developed by IPPs	• Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• See Resource Potential	• Not applicable
Environmental	• Site-specific environmental issues	• Comprehensive evaluation of site-specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand SEAPA transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• Cost per kW is very significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Region already exceeds state's renewable power targets • Potential future environmental regulations related to emissions, including carbon and other emissions	• Monitor Federal legislative and regulatory activities related to emission regulations

19.2.3.2.7 Generation Resources – Tidal/Wave

Table 19-9 Resource Specific Risks and Issues – Generation – Tidal/Wave

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by SEAPA regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for nondispatchable resources
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing tidal/wave projects • Lack of standard power purchase agreements for projects developed by IPPs • Significant permitting challenges exist • Public acceptability of tidal/wave is unknown • Potential for construction cost overruns is significant • Technology not fully developed	• Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects • Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of tidal/wave • Implement best practices related to management of construction costs • Support research and development of technology and pilot projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Environmental impacts of tidal/wave projects are potentially significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of tidal/wave facilities into SEAPA transmission grid poses challenges • Integration of nondispatchable resources into SEAPA transmission grid poses challenges	• Expand SEAPA transmission network • Complete required studies to ensure the ability to integrate tidal/wave projects into the transmission grid • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of nondispatchable resources
Financing	• Financing requirements for a tidal/wave project pose significant challenges	• Consider alternative forms of state assistance for tidal/wave projects • Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Region already exceeds state's renewable power targets	• Not applicable

19.2.3.2.8 Generation Resources – Coal

Table 19-10 Resource Specific Risks and Issues – Generation – Coal

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Generally speaking, coal cannot be appropriately sized to fit with the region's limited size	• Not applicable
Project Development and Operational	• Development risks are generally known and understood	• Not applicable
Fuel Supply	• Analysis of potential sources of coal is required to make this option viable	• Analysis of potential sources
Environmental	• See Regulatory/Legislative	• See Regulatory/Legislative
Transmission Constraints	• Location of new facilities will likely add to transmission constraints	• Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• Financing can be difficult given the financial strength of the region's utilities	• Secure potential state financial assistance should this technology be seriously considered
Regulatory/Legislative	• Potential future environmental regulations related to emissions, including carbon and other emissions, and coal mining • Potential regulations regarding ash disposal	• Monitor Federal legislative and regulatory activities related to emission regulations and coal mining • Monitor technological developments regarding carbon capturing technologies (e.g., carbon sequestration) • Implement appropriate design to mitigate environmental impacts

19.2.3.2.9 Generation Resources – Modular Nuclear

Table 19-11 Resource Specific Risks and Issues – Generation – Modular Nuclear

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• Resource potential would be large, but technology not demonstrated	• Monitor development and licensing of technology
Project Development and Operational	• Significant permitting challenges exist for modular nuclear • Public acceptability of modular nuclear is unknown • Potential for construction cost overruns is significant • Technology not fully developed	• Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of modular nuclear • Implement best practices related to management of construction costs • Support research and development of technology and pilot projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Environmental impacts of modular nuclear may not be significant, but public perception about environmental impacts may be very significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements
Transmission Constraints	• The small size of the modular nuclear projects should not pose transmission constraints if located properly	• Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• The lack of technology demonstration at this small size may create concerns in the financing community • Costs per kW may be significant	• Consider alternative forms of state assistance to reduce resistance to finance • Aggressively pursue available Federal funding
Regulatory/Legislative	• Nuclear Regulatory Commission (NRC) licensing is uncertain	• Monitor NRC licensing process

19.2.3.3 Transmission

Table 19-12 Resource Specific Risks and Issues – Transmission

RISK/ISSUE CATEGORY	DESCRIPTION	PRIMARY ACTIONS TO ADDRESS RISK/ISSUE
Resource Potential	• "Resource potential" is not limited; issue is determining the most appropriate projects, voltage, and siting	• Implement transmission plan included in this IRP
Project Development and Operational	• Ineffectiveness and inefficiencies associated with individual utilities developing transmission projects • Potential for construction cost overruns is significant	• Potentially position SEAPA to assume a more expansive role in terms of regional transmission • Implement best practices related to management of construction costs • Centralize all siting and permitting at the state level
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Potential for local environmental issues	• Pursue statewide permitting by a regional entity (e.g., SEAPA)
Transmission Constraints	• Not applicable	• Not applicable
Financing	• Financing requirements of transmission projects are significant	• Consider alternative forms of state assistance for transmission projects
Regulatory/Legislative	• Siting and permitting issues are potentially significant • Roadless Rule may limit licensability and increase costs	• Develop streamlined siting and permitting processes for transmission projects • Monitor judicial challenges to Roadless Rule

20.0 Conclusions and Recommendations

This section provides an overview of the conclusions and recommendations resulting from this study.

PURPOSE AND LIMITATIONS OF THE SOUTHEAST ALASKA IRP

- The development of this Southeast Alaska IRP is not the same as the development of a State Energy Plan; nor does it set State policy. Setting energy-related policies is the role of the Governor and State Legislature. With regard to energy policy making, the Southeast Alaska IRP does provide a foundation of information and analysis that can be used by policy makers to develop important policies.

  However, the existence of the State's Energy Policy and or the potential development of other related policies could directly impact the specific resources chosen for the region's future. As such, the Southeast Alaska IRP will need to be readdressed as future energy-related policies are enacted.
- This IRP, consistent with all IRPs, should be viewed as a "directional" plan. In this sense, the Southeast Alaska IRP identifies alternative resource paths that the region can take to meet the future energy needs of the region's citizens and businesses; in other words, it identifies the types of resources that should be developed in the future. These paths are summarized through the Preferred Resource Lists shown in this plan for each of eight subregions in Southeast Alaska. The granularity of the analysis underlying this IRP, and the quality and inclusiveness of available information on potential projects as discussed elsewhere, is not sufficient to identify the optimal combination of specific resources that should be developed.
- The capital costs and operating assumptions used in this study for alternative demand-side management/energy efficiency (DSM/EE) and generation and transmission resources do not consider the actual owner or developer of these resources. In other words, we assumed the same form of financing for all resource options. Ownership could be in the form of individual utilities, a regional entity, or an independent power producer (IPP).
- As with all IRPs, the Southeast Alaska IRP should be periodically updated (e.g., every three to five years) to identify changes that should be made to the Preferred Resource Lists, to reflect changing circumstances (e.g., resolution of uncertainties), improved cost and performance of emerging technologies (e.g., tidal), and other developments.

20.1 CONCLUSIONS

The primary conclusions from the Southeast Alaska IRP study are grouped in three categories and discussed below:

- General
- Analysis and Results
- Moving Forward

20.1.1 Conclusions – General

1. The current situation facing the Southeast region includes a number of issues that place the region at a historical crossroad regarding the mix of generation, DSM/EE, end-use conversions, and transmission and transportation resources that it will rely on to economically and reliably meet the future electric and heating needs of the region's citizens and businesses. As a result of these issues, the Southeast utilities and communities are faced with the following challenges:
    - Evolving federal and State energy policy legislation.
    - The inability of the region to take full advantage of economies of scale due to its limited size.
    - A heavy dependence on diesel for both electric generation and heating.
    - Declining economies and populations in communities.
    - Fossil fuel availability and variability of prices, including the high cost of space heating.
    - Increasing conversions to electric space heating, leading to rapidly declining excess hydroelectricity in communities with access to hydroelectric generation.
    - An isolated transmission network that is very limited in terms of reach, transfer capabilities, interconnections, and redundancies.
    - Difficulties in the development of new hydroelectric and transmission interconnection projects, including restrictive land use regulations.
    - Low current levels of weatherization and energy efficiency.
    - Regulatory uncertainties and risk management issues.
    - The region's limited financing capability, both individually and collectively among the region's utilities and communities.
2. The key factors that drive the results of Black & Veatch's analysis include the following:
    - Limitations in the quality and inclusiveness of capital cost and operating information on specific hydroelectric projects from previous studies and other sources provided to Black & Veatch during the course of this study.
    - The inclusion of the Committed Resources as the next set of resources to be developed within the region.
    - Future load forecasts which are driven by projected population trends, economic forecasts, and recent electric heat conversions.
    - The future availability and price of diesel.

- The uncertainties and risks that exist for all DSM/EE, generation, and transmission resource options available to the region.
- Potential future CO_2 emission allowance prices, which would impact all fossil fuels, which may or may not result from proposed federal legislation.
- The region's existing transmission network, which is limited in terms of: 1) the number of communities connected to the network, 2) the ability to transfer power between areas within the region, and 3) the resulting limited amount of dispatchable resources that can be integrated into the region's transmission grid and, thus, can be economically dispatched to minimize total electric costs on a regional basis.
- The ability of the region to raise the required financing and mitigate the rate impacts of constructing new resource alternatives.

3. Another key driver is the fact that the Southeast region, as a whole, is currently short of hydroelectric storage capacity. As a result, potential hydroelectric projects with storage capabilities are more valuable, particularly from a system integration (i.e., matching of generation capability with electric demands in connected load centers) or utilization perspective, than potential run-of-the-river hydroelectric projects; more specifically, low-altitude, large storage hydroelectric projects are of the greatest value.

4. The "achilles heel" of the current hydroelectric system is the recent trend towards conversion of diesel space heating to electric space heating in those communities with access to low-cost hydroelectricity. While this trend is resulting in significant savings for those residential and commercial customers that convert, it is leading to a rapid decline in the "excess" hydroelectric capacity in the region. In this context, "excess" refers to capacity and annual generation relative to loads. As a result of the limited storage capability of the region, spilling of water (i.e., water flowing over dams without generating electricity) occurs on a regular basis in certain months of the year (e.g., spring and fall) when electric loads are low and water flows are high due to the limited storage capability.

5. There are a number of region-specific uncertainties that underlie the completion of this study, including the following:

   - Load uncertainties, including the following:
     - The future level of electric space heating conversions which will be driven, in large part, by the future price of oil.
     - The potential for load increases due to economic development, including potential mines.
     - The potential penetration of electric vehicles.

- Resource uncertainties, including the following:
  - The wide variety in the quality and inclusiveness of available information on potential hydroelectric projects related to capital costs and operating performance.
  - The total potential for significant load reductions resulting from DSM/EE programs and biomass space heating conversions if the region is able to develop effective delivery mechanisms (including the development of a reliable and cost-effective biomass supply chain), and residential and commercial customers show a willingness to participate in these programs.
  - The potential of other renewable technologies given the limited site-specific resource potential studies that have been completed to date.
  - The ultimate impact of the Roadless Rule with regard to development of new generation and transmission projects.
- The potential future development of the region's transmission network and related issues, such as the following:
  - The future role of SEAPA in the expansion and operation of this network.
  - Whether SEAPA will provide open access to its transmission network to better enable IPPs to develop projects in the Southeast region.
- The level of financial assistance that will be provided by the State to better enable the region to: 1) build generation and transmission facilities, 2) aggressively implement DSM/EE programs, and 3) support a viable biomass industry, and the conditions under which this financial assistance will be provided.

These uncertainties drive home the need for the region to: 1) develop multiple options, 2) move towards a more balanced portfolio of resources (i.e., the solution to the region's energy challenges is not as simple as adding more hydroelectricity and some transmission), and 3) maintain flexibility with regard to the selection of resource options over time as the uncertainties above become more resolved.

CALL TO ACTION

The energy challenges facing the Southeast region are not new, and they have been studied, debated, and acted upon over the years. There have been numerous studies that have been completed in the past, including project feasibility studies and regional transmission studies. These studies have served an important role, and the results of these studies, to varying degrees, have been reviewed as part of this effort to develop a Southeast Alaska IRP. Additionally, ongoing efforts like the Southeast Conference energy programs and the United States Forest Service (USFS)-funded Juneau Economic Development Council's Renewable Energy Cluster provide important forums to help move the region forward in meeting its energy challenges. As the various quotes from regional consumers and business representatives that are contained in the Executive Summary of this report demonstrate, the need is great, the problem is regional in nature, and regional solutions are required. The objective of this Southeast Alaska IRP is to help put some "stakes in the ground," better enabling the region to move forward in meeting its energy challenges.

20.1.2 Conclusions – Analysis and Results

6. The key assumptions used in Black & Veatch's analysis have been discussed in detail in previous sections, as listed below. These key input assumptions are not repeated here, but the reader should review these sections to more fully understand the assumptions that underlie the results of Black & Veatch's analysis.

   - Section 4.0 – Description of Existing System and Committed Resources
   - Section 5.0 – Fuel Price Projections
   - Section 6.0 – Economic Parameters
   - Section 7.0 – Reliability Criteria
   - Section 8.0 – Load Forecasts
   - Section 9.0 – Financing Alternatives
   - Section 10.0 – Potential Hydroelectric Projects
   - Section 11.0 – Other Generating Unit Alternatives
   - Section 12.0 – Transmission Interconnection Alternatives
   - Section 13.0 – Demand-Side Options
   - Section 14.0 – Weatherization
   - Section 15.0 – Space Heating Conversion

7. To complete this study, Black & Veatch grouped the region's communities into eight subregions as shown on Figure 20-1. This approach was taken due to the limited reach of the region's transmission network and the disparity of energy costs throughout the region, which require solutions be developed at the subregional level. A significant portion of the analyses (e.g., load and fuel forecasts) were completed at the community level. This analysis provided the foundation for the development of specific Preferred Resource Lists for each subregion, as discussed in Section 17.0, which were then combined to result in the overall Southeast Alaska IRP.

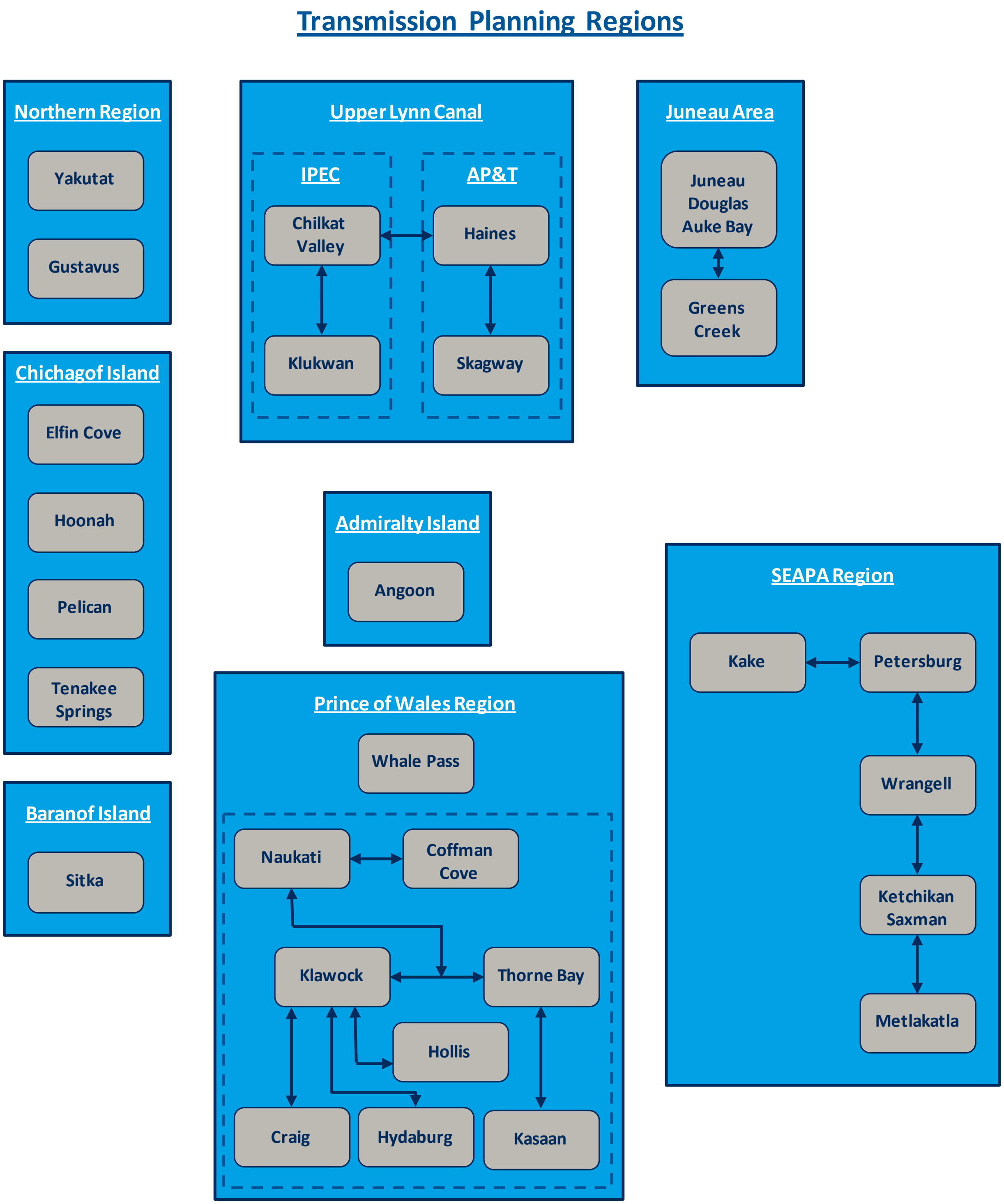


Figure 20-1 Southeast Alaska Subregions Schematic

8. As discussed in Section 10.0, the development of hydroelectric projects in the Southeast region is a very dynamic process. Many potential hydroelectric projects have a long history and have evolved in size and configuration through the years, whereas other potential projects have undergone little development through the years. One significant impediment to the completion of the this IRP was the wide variety in the quality and inclusiveness of information available to evaluate specific hydroelectric projects, including the following:

    - Realistic commercial operation dates (CODs).
    - Capital costs.
    - Storage capacity, if any, and monthly energy output.
    - Environmental, permitting, and licensing issues.
    - Business structure and agreements, including ownership structure, project development capabilities, power sale and interconnections agreements, etc.

    As a result of this wide variation in data quality across the spectrum of potential hydroelectric projects in the Southeast region, it is impossible to conduct a true "apples to apples" comparison of hydroelectric projects. In a similar manner, it is impossible to complete a definitive comparison of the economics of potential hydroelectric projects to other resources (e.g., biomass, other renewable technologies, and DSM/EE).

    To get all projects to a comparable level of data quality requires a significant amount of further study, and this effort is outside of the scope of this study; consequently, it is impossible at this time to make a definitive selection of which specific resources (e.g., hydroelectric, other renewable technologies, or DSM/EE) should be developed within each subregion to meet future electric requirements.

9. Despite the discussion above regarding the inability to complete a definitive comparison of all potential resources and projects, the reality remains that the region must do something to address its energy challenges. To provide guidance despite the uncertainties, Black & Veatch evaluated two "Integrated Cases" to develop a balanced strategy for the region, and each subregion, to move forward with now and provide the basis for making longer-term resource decisions in the years ahead. The two Integrated Cases analyzed were:

    - **Optimal Hydroelectric/Transmission Case** – This case is based upon the generic hydroelectric projects discussed in Section 10.0 and the potential transmission segments discussed in Section 12.0. This case compares the economics, on a subregion basis, of adding Committed Resources, additional generic hydroelectric projects, and potential transmission interconnections between subregions, to the costs associated with the subregions continuing to rely on existing generation resources, Committed Resources, and the burning of diesel to meet electric load requirements. In essence, this is an electric supply side only case with continued reliance upon fuel oil for space heating.
    - **Optimal DSM/EE, Biomass, and Other Renewables Case** – This case shows the economic impact of adding Committed Resources, DSM/EE, and biomass for space heating in each subregion, relative to the costs associated with the subregions continuing to rely on existing generation resources, Committed Resources, and the burning of diesel to meet electric load requirements.

    Both cases are compared to a status quo case on which the region continues to rely on diesel for electric generation and space heating.

As noted above, this approach does not provide "definitive" results, in terms of a direct comparison of actual projects, it was required due the aforementioned issues regarding the quality and inclusiveness of information currently available on potential hydroelectric projects and other alternative resources. Having said that, this approach does provide "illustrative" results, from which conclusions can be drawn regarding the most appropriate way for the region to move forward in achieving the objective of developing a balanced portfolio of supply-side and demand-side resources.

10. Black & Veatch computed the total capital costs and cumulative net present value (CNPV) costs, over the 50 year planning horizon for each of these two Integrated Cases, relative to the Status Quo Case (which includes only existing generation and transmission resources and Committed Resources). These regional results are shown in Table 20-1.

Table 20-1 Results of Integrated Cases – Regional Summary

INTEGRATED CASE	TOTAL CAPITAL COSTS ($'000,000)	TOTAL CUMULATIVE NET PRESENT VALUE (CNPV) COST ($'000,000)	TOTAL CUMULATIVE NET PRESENT VALUE (CNPV) SAVINGS RELATIVE TO STATUS QUO CASE ($'000,000)
Optimal Hydroelectric/ Transmission Case	1,407	5,313	340
Optimal DSM/EE, Biomass, and Other Renewables Case	2,030	3,093	2,561
Status Quo Case	770	5,654	--

The subregional results are shown in Tables 20-2 and 20-3.

Tables 20-1 through 20-3 show that the cost associated with a greater reliance on hydroelectric power, DSM/EE, and renewable resources (including biomass) is less than the continued heavy reliance on diesel, based upon the base case diesel price forecast that was used in this analysis

Based on these results, Black & Veatch concludes that an integrated, balanced solution represents the most appropriate way for the region to move forward. Table 20-1 clearly shows that a balanced portfolio of resources (essentially a combination of the Optimal Hydroelectric/Transmission Case and Optimal DSM/EE, Biomass, and Other Renewables Case) is more cost-effective that a "build only hydroelectric and transmission" solution, and the Status Quo Case.

Table 20-2 Results of Integrated Cases – Subregional Total Costs

OPTIMAL HYDROELECTRIC/TRANSMISSION CASE			
	Total Cumulative Net Present Value (CNPV) Costs – 2012-2061 ($'000)		
	Utility System Costs	Oil Space Heating Costs	Total Costs
SEAPA	288,797	977,320	1,266,117
Admiralty Island	8,022	22,334	30,356
Baranof Island	97,345	460,426	557,771
Chichagof Island	51,852	58,459	110,311
Juneau	234,265	2,120,883	2,355,148
Northern	63,256	147,786	211,042
Prince of Wales	24,094	366,725	390,819
Upper Lynn Canal	44,538	347,271	391,809
Total Southeast Region	**812,169**	**4,501,204**	**5,313,373**

OPTIMAL DSM/EE, BIOMASS AND OTHER RENEWABLES CASE							
	Total Cumulative Net Present Value (CNPV) Costs – 2012-2061 ($'000)						
	Utility System Costs	DSM Costs	Utility System Costs Plus DSM Costs	Oil Space Heating Costs	Biomass Fuel Costs	Biomass Conversion Incentive Costs	Total Costs
SEAPA	195,522	39,201	234,723	258,011	238,441	61,875	793,050
Admiralty Island	8,019	25	8,044	6,830	4,717	1,195	20,786
Baranof Island	84,156	11,716	95,872	121,745	98,280	23,655	339,552
Chichagof Island	46,267	301	46,568	13,753	11,950	2,806	75,077
Juneau	138,870	46,686	185,556	541,759	490,307	111,314	1,328,936
Northern	55,337	488	55,825	39,089	23,925	6,849	125,688
Prince of Wales	18,774	2,007	20,781	94,304	77,469	14,916	207,470
Upper Lynn Canal	25,494	2,184	27,678	90,274	67,919	16,287	202,158
Total Southeast Region	**572,439**	**102,608**	**675,047**	**1,165,765**	**1,013,008**	**238,897**	**3,092,717**

STATUS QUO CASE (NO GENERIC HYDROELECTRIC PROJECTS)			
	Total Cumulative Net Present Value (CNPV) Costs – 2012-2061 ($'000)		
	Utility System Cost	Oil Space Heating Costs	Total Costs
SEAPA	456,153	977,320	1,433,473
Admiralty Island	8,022	22,334	30,356
Baranof Island	97,543	460,426	557,969
Chichagof Island	59,786	58,459	118,245
Juneau	370,673	2,120,883	2,491,556
Northern	89,495	147,786	237,281
Prince of Wales	24,094	366,725	390,819
Upper Lynn Canal	46,603	347,271	393,874
Total Southeast Region	**1,152,369**	**4,501,204**	**5,653,573**

Table 20-3 Results of Integrated Cases – Subregional Savings

OPTIMAL HYDROELECTRIC/TRANSMISSION CASE - SAVINGS RELATIVE TO STATUS QUO CASE						
	Total Cumulative Net Present Value (CNPV) Savings – 2012-2061 ($'000)					
	Utility System Costs		Oil Space Heating Plus Biomass Costs		Total	
	$	%	$	%	$	%
SEAPA	167,356	37%	0	0%	167,356	12%
Admiralty Island	0	0%	0	0%	0	0%
Baranof Island	198	0%	0	0%	198	0%
Chichagof Island	7,934	13%	0	0%	7,934	7%
Juneau	136,408	37%	0	0%	136,408	5%
Northern	26,239	29%	0	0%	26,239	11%
Prince of Wales	0	0%	0	0%	0	0%
Upper Lynn Canal	2,065	4%	0	0%	2,065	1%
Total Southeast Region	**340,200**	**30%**	**0**	**0%**	**340,200**	**6%**

OPTIMAL DSM/EE, BIOMASS, AND OTHER RENEWABLES CASE - SAVINGS RELATIVE TO STATUS QUO CASE						
	Total Cumulative Net Present Value (CNPV) Savings – 2012-2061 ($'000)					
	Utility System Plus DSM Costs[(1)]		Oil Space Heating Plus Biomass Costs		Total	
	$	%	$	%	$	%
SEAPA	221,430	49%	418,993	43%	640,423	45%
Admiralty Island	(22)	0%	9,592	43%	9,570	32%
Baranof Island	1,671	2%	216,746	47%	218,417	39%
Chichagof Island	13,218	22%	29,950	51%	43,168	37%
Juneau	185,117	50%	977,503	46%	1,162,620	47%
Northern	33,670	38%	77,923	53%	111,593	47%
Prince of Wales	3,313	14%	180,036	49%	183,349	47%
Upper Lynn Canal	18,925	41%	172,791	50%	191,716	49%
Total Southeast Region	**477,322**	**41%**	**2,083,534**	**46%**	**2,560,856**	**45%**
[(1)]Includes savings from generic hydroelectric projects.						

OPTIMAL DSM/EE, BIOMASS, AND OTHER RENEWABLES CASE - SAVINGS RELATIVE TO OPTIMAL HYDROELECTRIC/TRANSMISSION CASE						
	Total Cumulative Net Present Value (CNPV) Savings – 2012-2061 ($'000)					
	Utility System Plus DSM Costs		**Oil Space Heating Plus Biomass Costs**		**Total**	
	$	**%**	**$**	**%**	**$**	**%**
SEAPA	54,074	19%	418,993	43%	473,067	37%
Admiralty Island	(22)	0%	9,592	43%	9,570	32%
Baranof Island	1,473	2%	216,746	47%	218,219	39%
Chichagof Island	5,284	10%	29,950	51%	35,234	32%
Juneau	48,709	21%	977,503	46%	1,026,212	44%
Northern	7,431	12%	77,923	53%	85,354	40%
Prince of Wales	3,313	14%	180,036	49%	183,349	47%
Upper Lynn Canal	16,860	38%	172,791	50%	189,651	48%
Total Southeast Region	**137,122**	**17%**	**2,083,534**	**46%**	**2,220,656**	**42%**

11. The region's limited size directly affects the ability to justify the expansion of the region's transmission network, based on fundamental economics. Simply stated, regional loads are insufficient to result in sufficient flows of electricity over an expanded transmission network to justify the capital and operating costs.

TRANSMISSION DEVELOPMENT PHILOSOPHY

Transmission is often thought of as the electric equivalent of the interstate highway system for several reasons. Without question, the interstate highway system has served as the foundation for economic growth, jobs, business supply chain efficiencies and cost savings, and so forth, producing great public benefit. Despite the level of public benefit, few of the communities that have directly benefited from the interstate highway system could have financed and afforded their full share of the costs incurred to build and maintain the system. A similar situation exists with regard to transmission investments, particularly in Southeast Alaska due to the high capital costs associated with the construction of transmission lines and the relatively small loads served by these transmission lines. While the public benefit of transmission investments is undeniable (such as the lowering of energy costs for those communities connected to the transmission grid resulting in significant cost savings for residents and businesses and providing the foundation of potential economic development, the provision of local construction jobs, etc.), local communities and their utilities are not able to finance and afford the high up-front capital costs associated with potential transmission projects. In this regard, transmission projects are not a traditional utility type project. This leads to two legitimate questions: 1) what are the proper goals for transmission planning and investment and 2) how should the State and region look at the economics of potential transmission investments?

From a public benefit perspective, transmission investments are not the same as investment in generation resources. Returning to the interstate highway system analogy, public policy decision makers decided to view the highway system as a public benefit investment, but left the investment in trucks, cars, and gas stations (investments required to take advantage of the highway system) to private citizens and businesses. From a public policy perspective, transmission investments can be viewed similarly to the investment in the highway system, while investments in generation resources (which produce the electrons whose transfer take advantage of the transmission system) can be viewed similarly to the investment in trucks and cars.

Additionally, potential future transmission segments in Southeast Alaska typically have significantly more transfer capability than required to meet the electric needs of the connected communities, due to the lumpiness (i.e., large increases in transfer capacity that cannot be closely matched over time to load requirements) of transmission capacity. Conversely, there are numerous potential hydroelectric generation projects in the region that are small in size and more aligned with the needs of local communities. Stated in another way, it is easier to develop appropriately sized hydroelectric projects in the region than transmission.

As a result of these considerations, an argument can be made that the level of State financial assistance for transmission projects should be greater than the level of any assistance provided for generation resources, such as hydroelectric plants. This is a policy decision for the Governor's office and the State Legislature to make and is outside the scope of this study. However, to help inform this policy discussion, the AEA directed Black & Veatch to consider transmission from the perspective of a "public benefit investment" as part of our evaluation of potential transmission segments.

Like the interstate highway system, it is one thing to build a transmission network, but it is another thing to maintain the network to ensure that it remains a sustainable investment for generations. This leads to the question, "what is a sustainable transmission project?" The following are important elements of sustainability:

- In addition to financing the initial construction costs, annual O&M costs must be covered and the funding of a repair and replacement (R&R) reserve must be adequate to ensure long-term operations and reliability. Even if the State chose to provide a grant to cover 100 percent of the construction costs, the annual O&M expenses and R&R reserve funding can be a high hurdle for a local Southeast utility, as a result of the small loads that would be served by any specific transmission segment.
- The developer and operator of transmission projects needs to have the organizational capabilities required to successfully build the project and operate the transmission line in terms of moving power over the line. This consideration may lead to the conclusion that one regional entity be given the responsibility for expanding the region's transmission network. This entity could be SEAPA or, perhaps, another entity formed to build and operate new transmission facilities.
- Public money should not be invested in new transmission facilities until there are interconnection, power purchase, and business structure agreements in place among all of the affected parties. These agreements should: 1) ensure that adequate program management capabilities are committed to the development of each project, 2) establish the terms, conditions, and wheeling costs for transmission service, 3) establish the terms and conditions for the purchase of power to be transferred over the transmission line, 4) provide for the joint economic dispatch of connected generation facilities, and 5) ensure adequate financing capabilities are present to ensure a long-term sustainable project.
- To protect the public interest, if the State provides financial assistance, sufficient State oversight of transmission projects is required. While this may increase the cost of individual transmission projects, this oversight (if effectively applied) will increase the probability that the project will be successfully built and operated in a sustainable manner, thereby better protecting the public's investment.
- Some economies of scale can be achieved in terms of design and project development costs if more than one transmission project is developed at the same time. These potential costs savings should be evaluated in more detail as part of a regional transmission network expansion program strategy.

As a result of the AEA's directive, Black & Veatch analyzed the economics of potential transmission investments in two ways. First, Black & Veatch, used the best information available (modified where appropriate based upon Black & Veatch's transmission construction and operating experience) regarding the capital and O&M costs of specific transmission segments (including segments that would transfer power within a subregion as well as between subregions). Then an initial economic evaluation was conducted which compared the annual capital carrying costs and O&M expenses of transmission segments to the value of the diesel power displaced. This approach did not include the effect of any State financial assistance.

Additionally, Black & Veatch evaluated the economics of potential transmission segments assuming: 1) that the State provided financial assistance in the form of a grant equal to 100 percent of the construction capital costs and 2) the local utility would be responsible for covering the annual O&M expenses, as well as an annual contribution to a R&R fund to ensure adequate monies for future major repairs and replacement investments to keep the transmission system in good shape for decades.

This initial economic evaluation of the transmission interconnections simply determines the annual cost in 2011 dollars from the capital, O&M, and R&R costs developed in Section 12.5 and divides the annual cost by the maximum projected flow over the interconnection to determine a $/MWh cost for each transmission interconnection. This analysis does not include any State financial assistance (note: the resulting impact of State financing of these transmission interconnections (i.e., the Public Benefit Case as discussed in Section 12.1) as discussed in Section 12.7. To put these annual transmission costs in perspective, they are compared to the 2011 cost of diesel generation.

The results of the initial economic evaluation of the transmission interconnections indicates that none of the interconnections evaluated have estimated transmission costs that are lower than the projected diesel costs. It is important to note that the 2011 annual transmission interconnection costs do not include any cost for generating the electricity that would be transmitted over each interconnection. In other words, the costs shown are only for the annual costs of the transmission interconnection. These results are discussed in more detail in Section 12.6.

Section 12.7 discusses the results of the evaluation of the transmission interconnection alternatives from the perspective of the transmission interconnections being constructed using State grant funds and only the transmission O&M and R&R costs included in the system costs. In order to evaluate the relative benefits of each interconnection, the benefit-cost ratio for each interconnection was calculated by comparing the cumulative present worth cost savings associated with each interconnection to the estimated capital cost of each interconnection presented in Section 12.5.

Table 12-13 presents the results of the public benefit screening, showing the cumulative present worth savings from the interconnected operation, minus the O&M and R&R costs for the interconnection, compared to the estimated capital cost of the proposed interconnections to determine the estimated benefit-cost ratio for each interconnection. As indicated in Table 12-13, the benefit-cost ratios are low indicating that there are not enough savings from the interconnection to offset the capital cost of the interconnection.

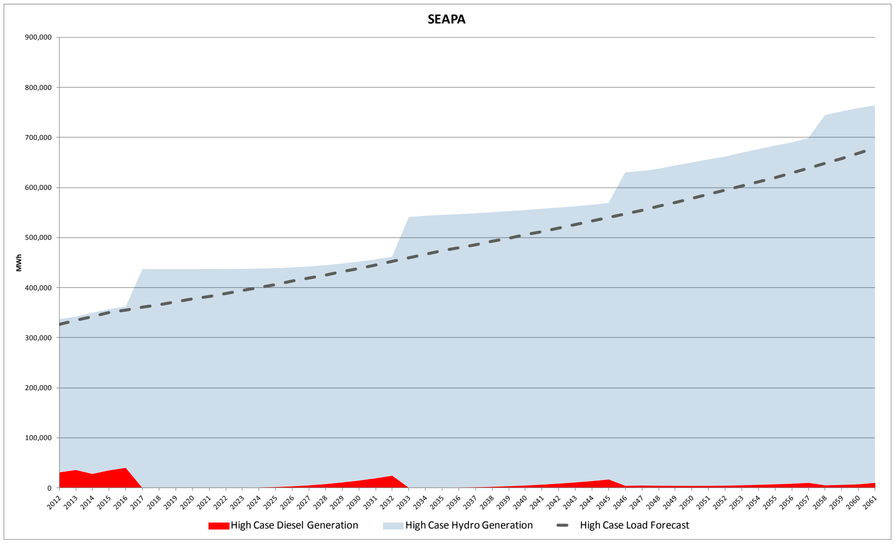
12. One specific resource addition considered in this study was the development of the AK-BC Intertie, which would connect the Southeast region to the BC Hydroelectric transmission network, allowing for the import or export of power to or from British Columbia and the lower 48 states. As discussed in Section 12.0, Black & Veatch conducted a screening analysis of the AK-BC Intertie and concluded that it was not a viable resource given current conditions. However, given the 50 year time horizon for this study, and given the volatility that exists related to North American power market dynamics and other factors that affect the economic viability of the AK-BC Intertie, it is impossible to conclude with absolute certainty that the AK-BC Intertie would not, under any set of conditions, become a viable project. Therefore, it is appropriate to consider the various set of conditions under which the AK-BC Intertie might become economical. The following is a list of such conditions:

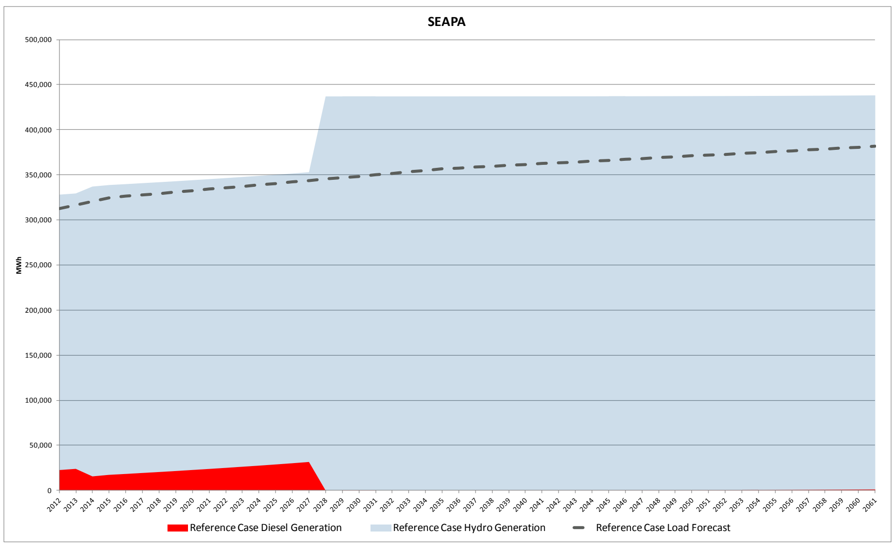
    - The expected monthly profile of electric sales (or purchases) and whether those sales (or purchases) would be under the terms of a long-term firm contract or on the spot market is clearly defined.
    - Prices in potential export markets in North America (principally British Columbia (BC), the Pacific Northwest (PNW), and/or the Southwestern region of the United States) increase significantly due to capacity and energy shortages, continued increases in applicable RPSs, and/or increased environmental regulations that cause existing generation facilities to be retired or prohibit planned facilities from being built.
    - For potential import, costs for new generation will have to increase substantially over the costs for potential hydroelectric projects capable of meeting Southeast Alaska's energy requirements. This could be the result of large project cost increases or significant load increases that exceed the availability of lower cost regional hydroelectric projects, or regulatory and or legislative prohibitions to the development of Southeast resources.

13. In addition to comparing the total capital costs and CNPV costs, over the 50 year planning horizon for each of the two Integrated Cases (i.e., the Optimal Hydroelectric/Transmission Case and Optimal DSM/EE, Biomass, and Other Renewables Case), Black & Veatch evaluated how long the next hydroelectric project could be delayed as a result of the aggressive implementation of DSM/EE and biomass conversion programs.

    Figures 20-2 through 20-9 include a series of graphs that compare, for each subregion, future electric load projections to existing and potential generic hydroelectric projects, as follows:

    - Figure 20-2 – SEAPA
    - Figure 20-3 – Admiralty Island
    - Figure 20-4 – Baranof Island
    - Figure 20-5 – Chichagof Island
    - Figure 20-6 – Juneau Area
    - Figure 20-7 – Northern Region
    - Figure 20-8 – Prince of Wales
    - Figure 20-9 – Upper Lynn Canal





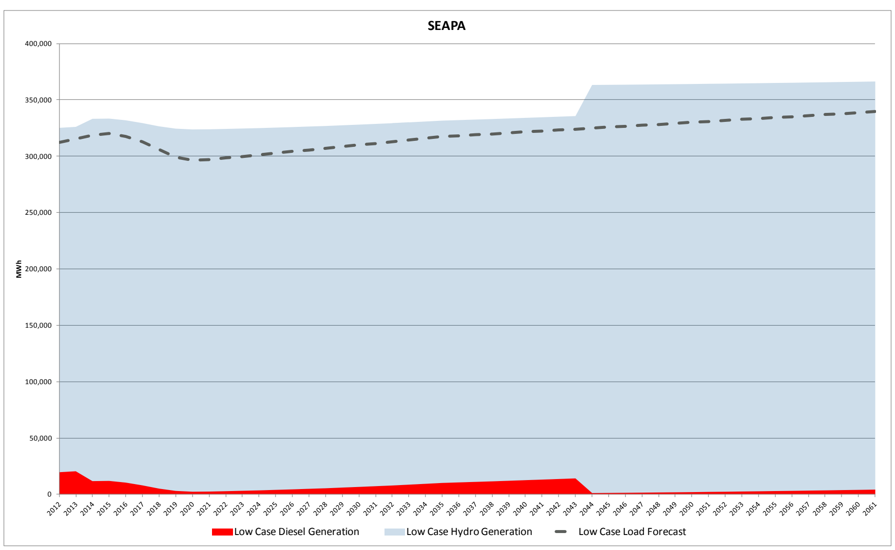
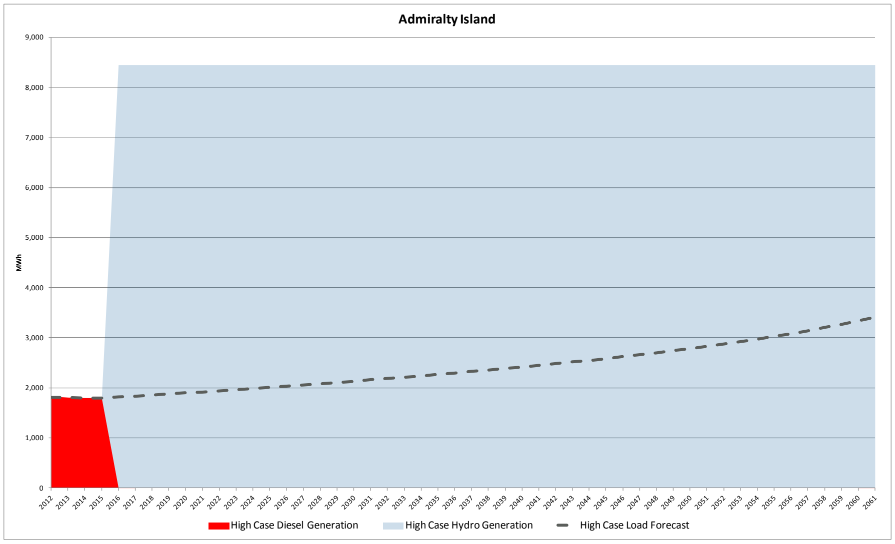
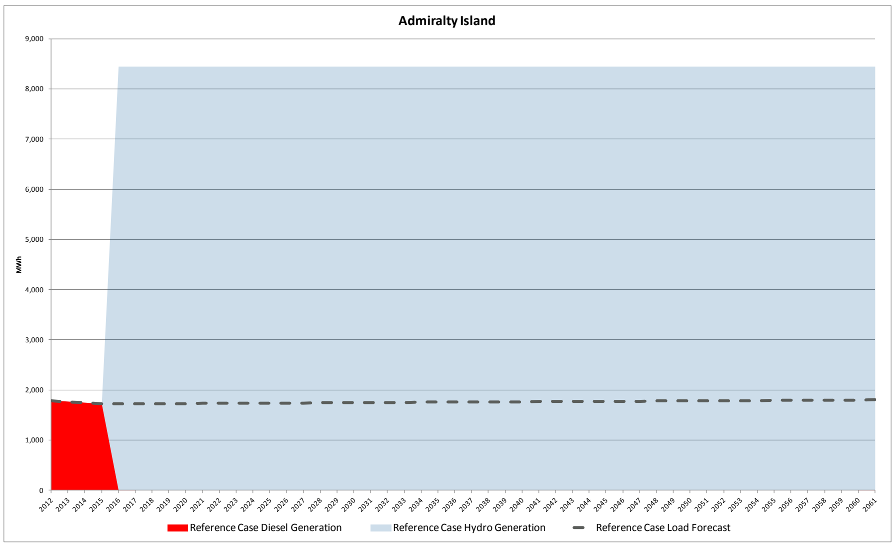


Figure 20-2 SEAPA





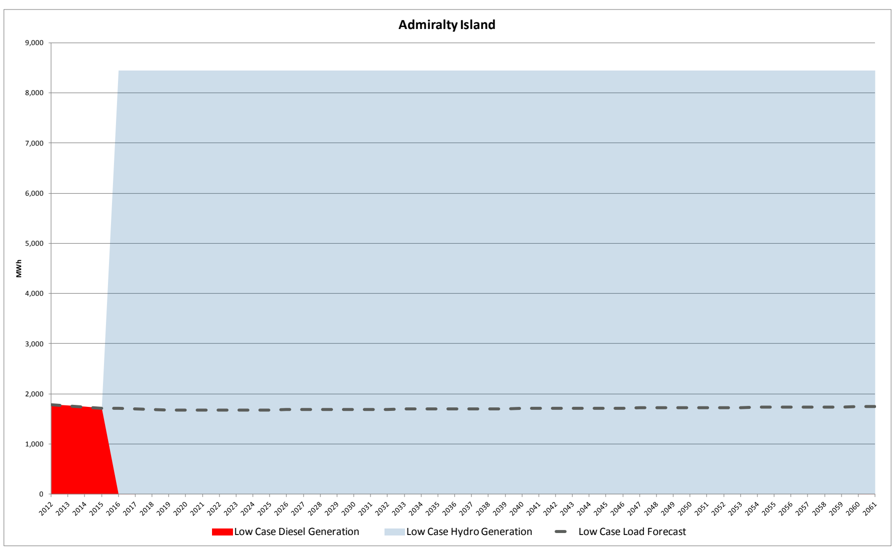
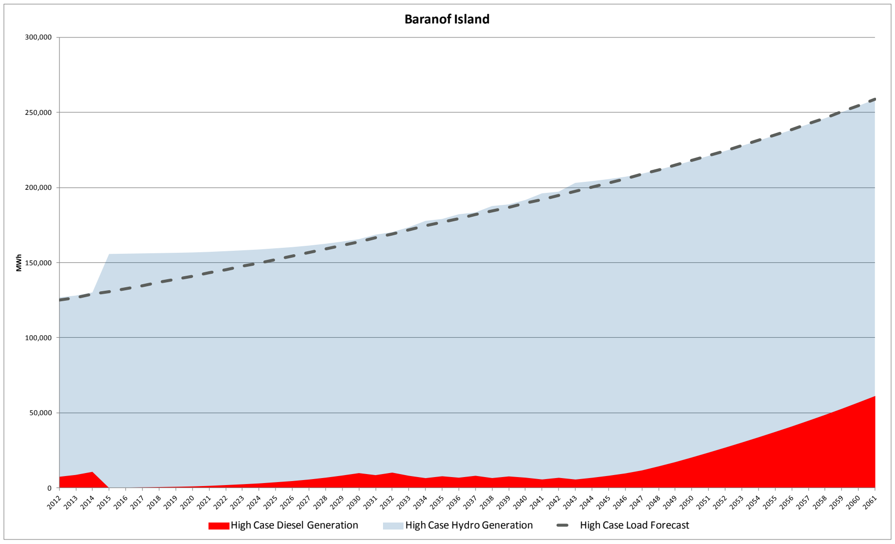
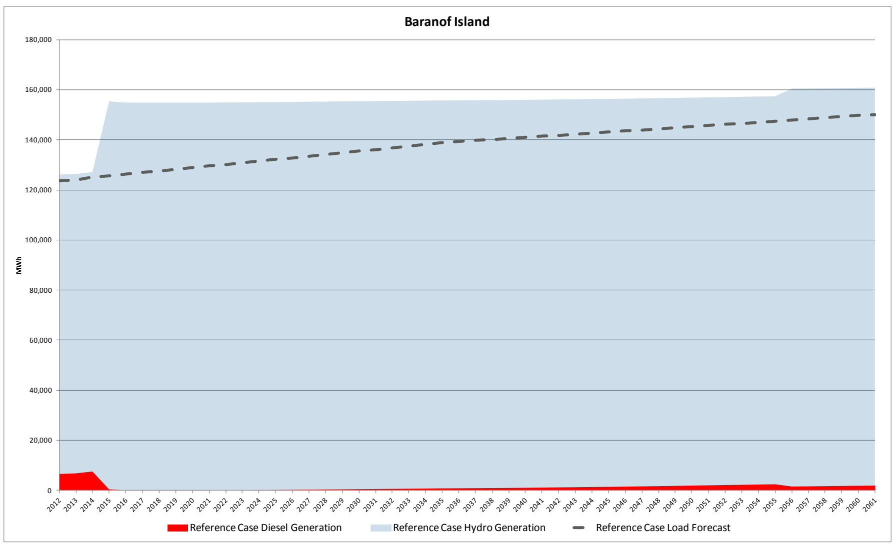


Figure 20-3 Admiralty Island





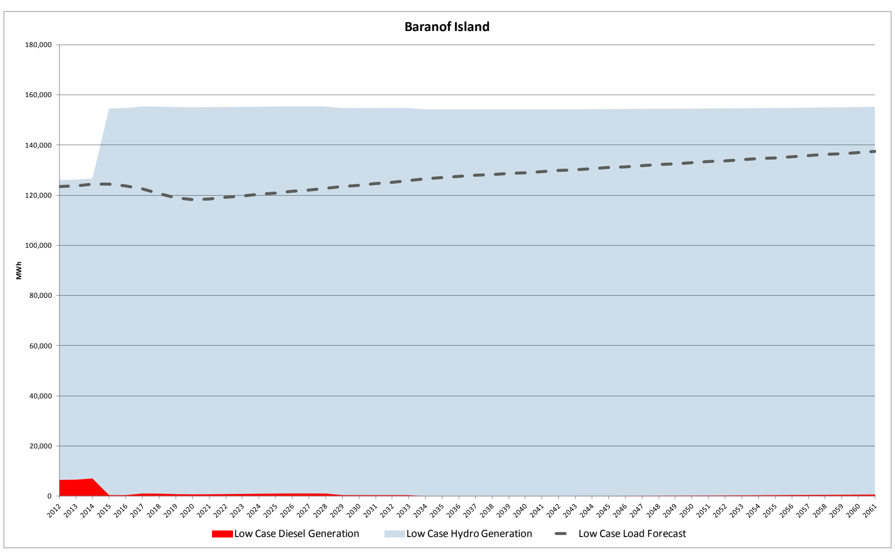
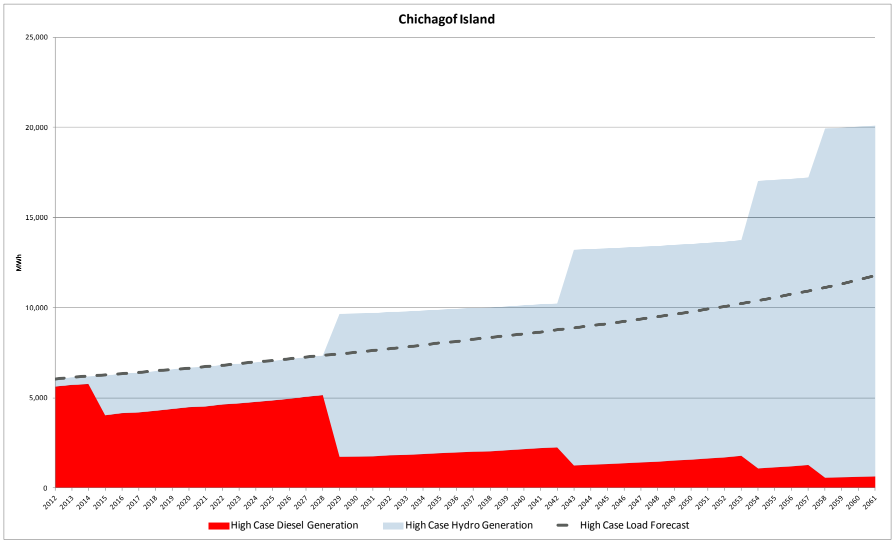
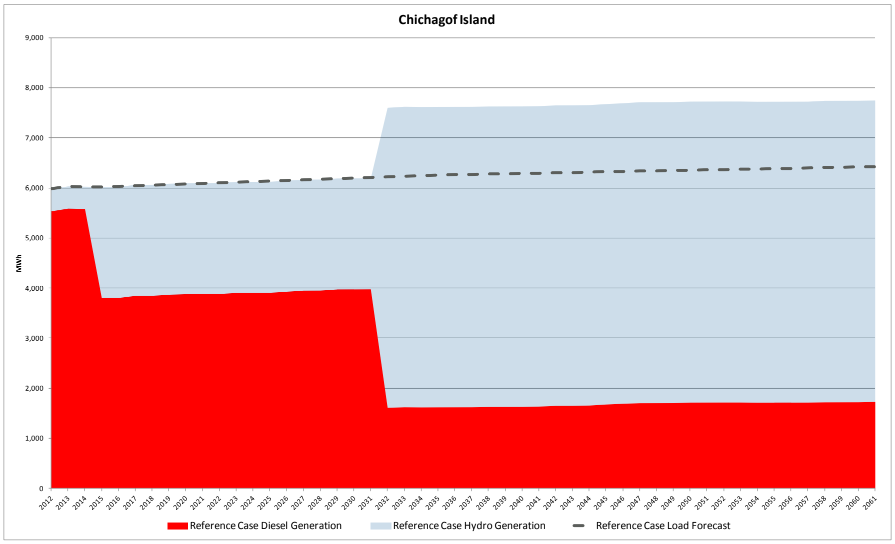


Figure 20-4 Baranof Island





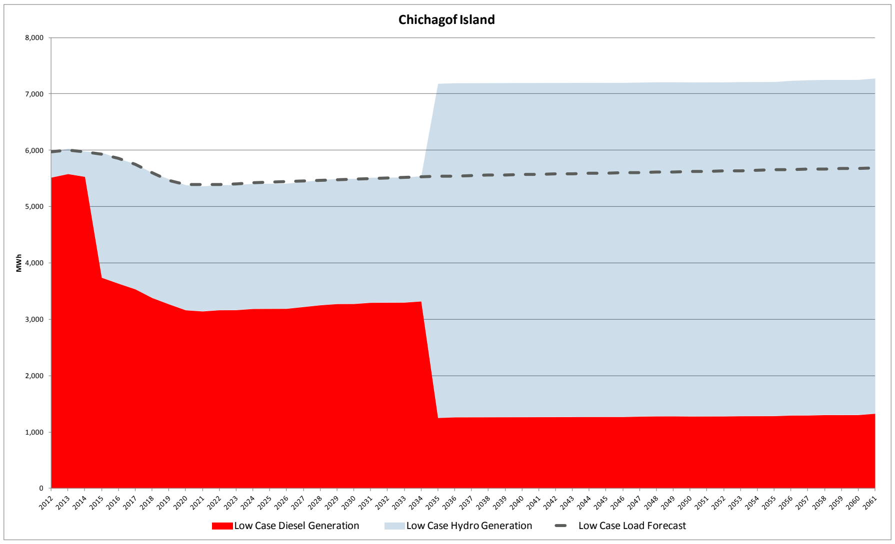
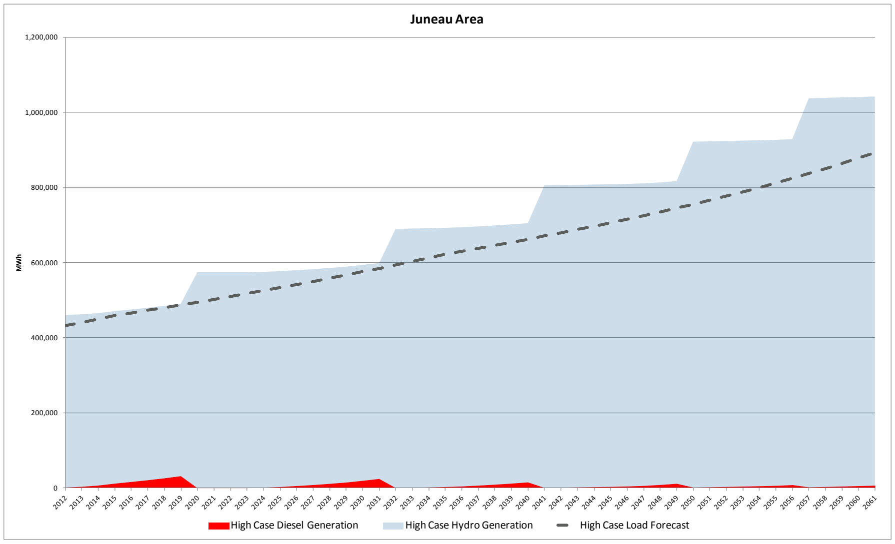
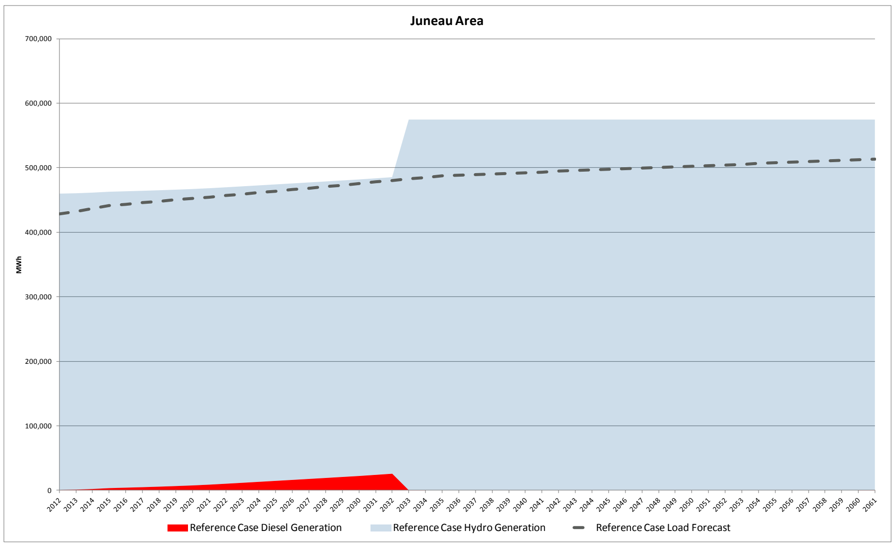


Figure 20-5 Chichagof Island





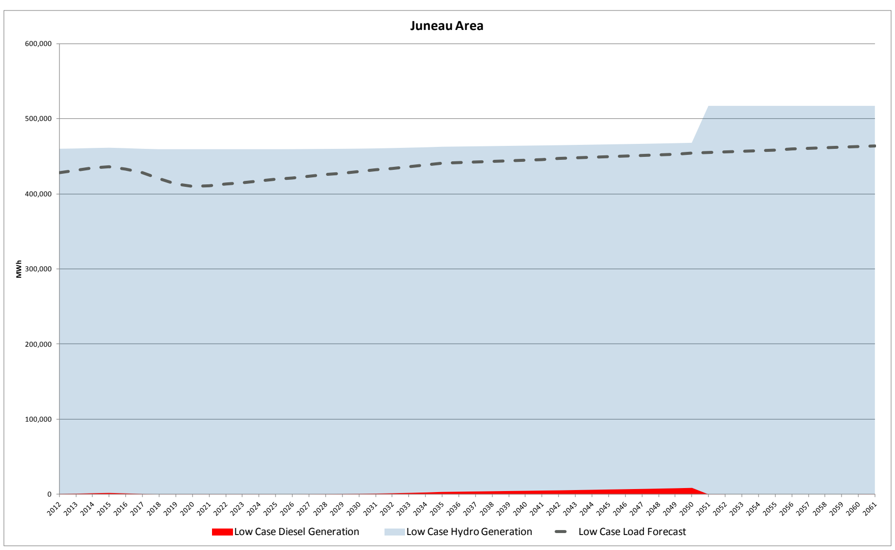


Figure 20-6 Juneau Area

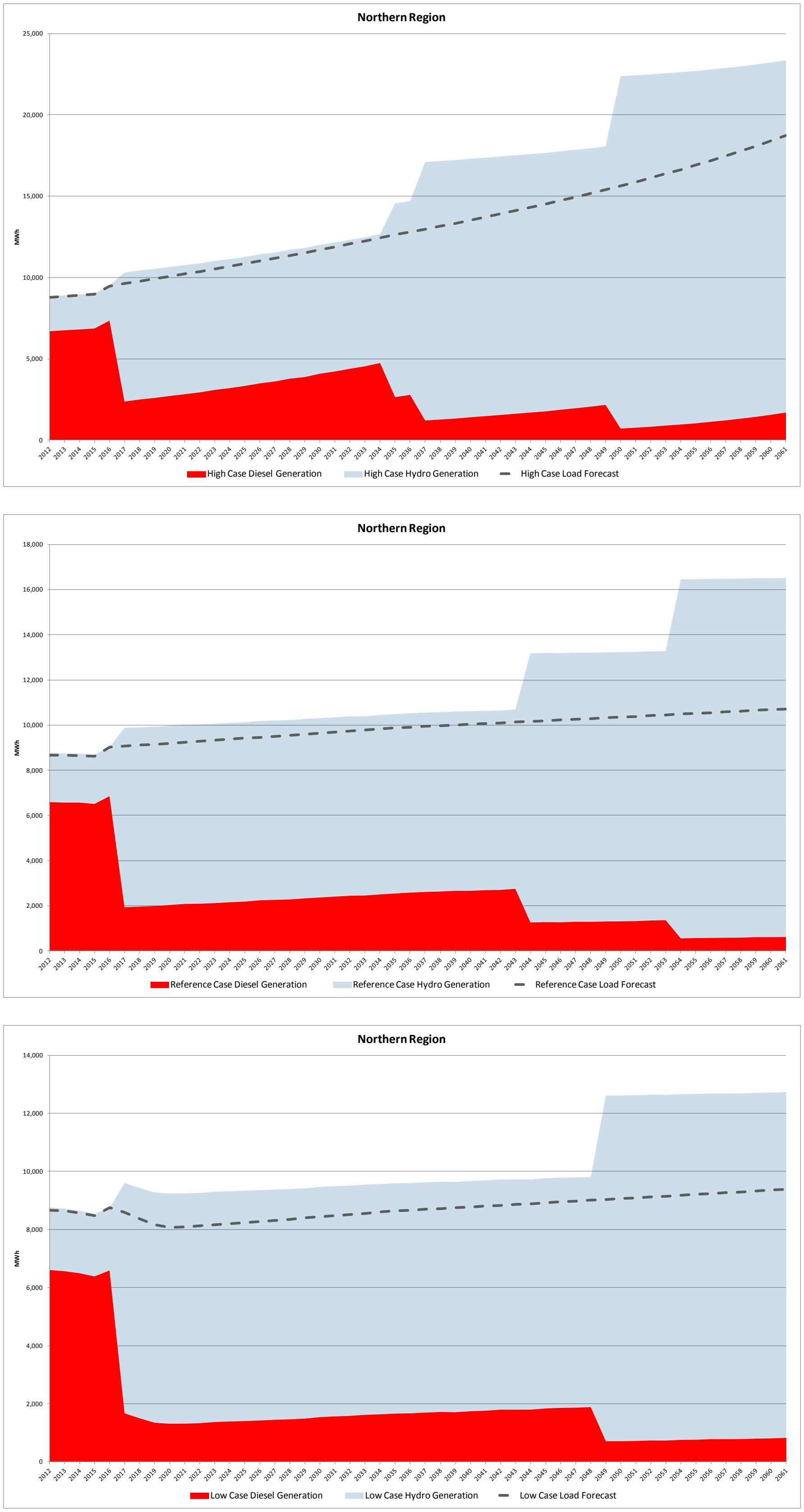


Figure 20-7 Northern Region

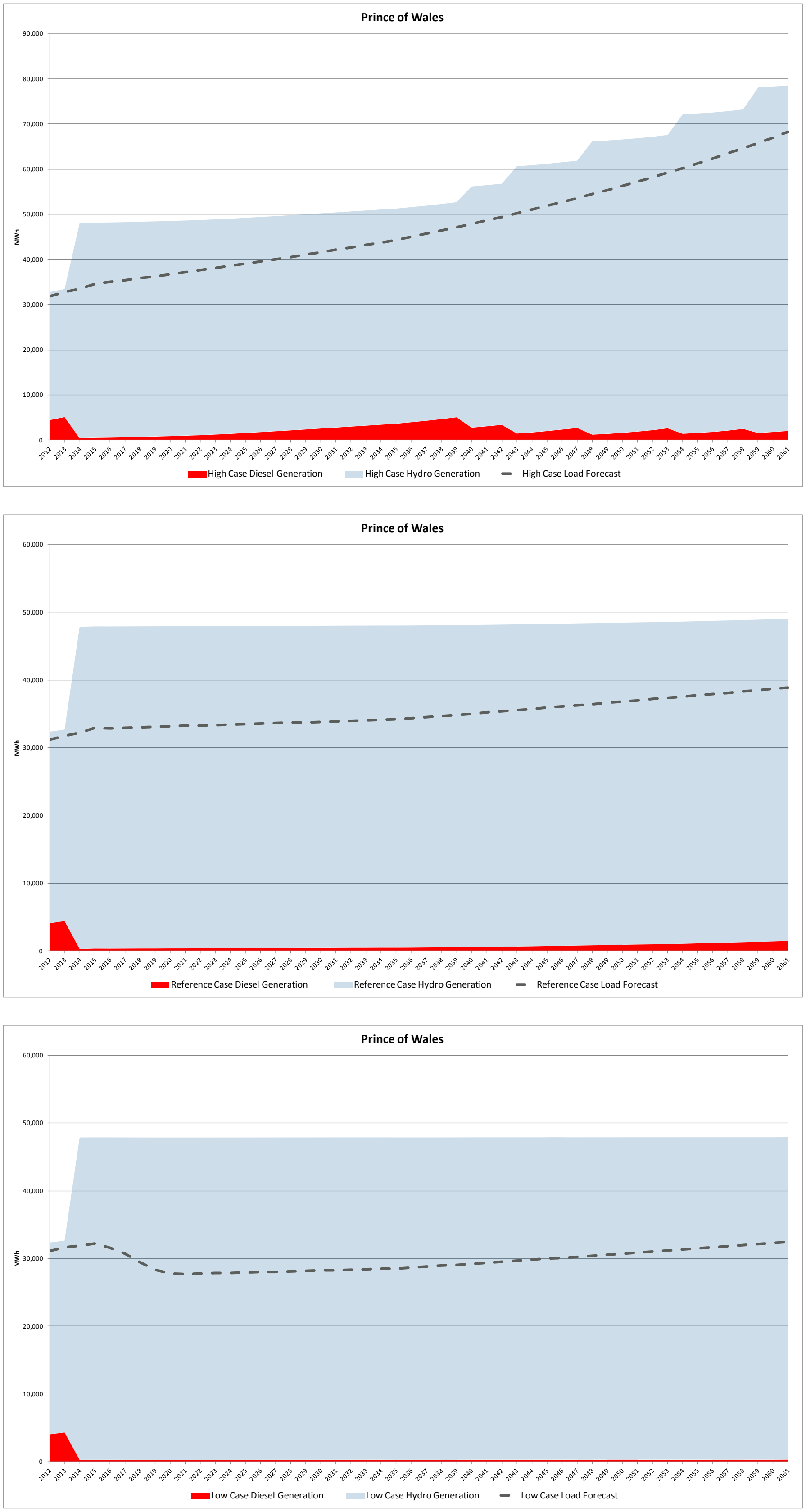
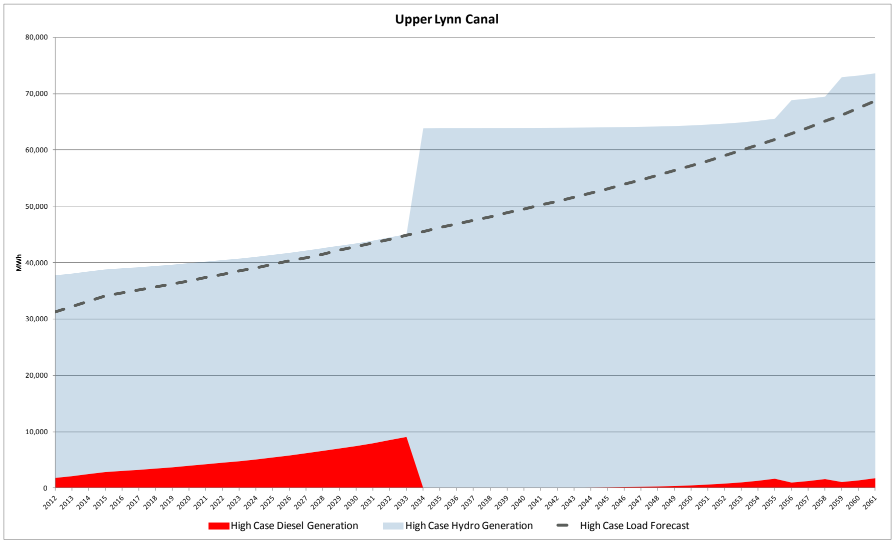
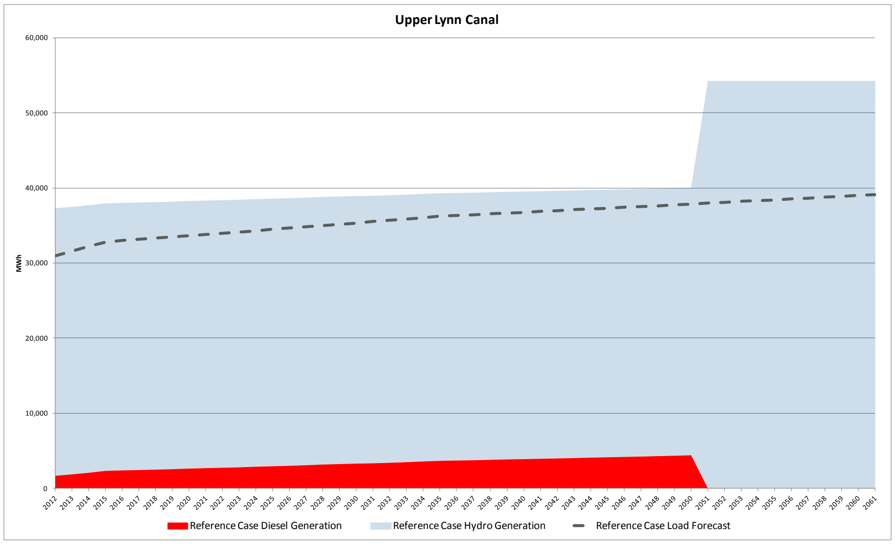


Figure 20-8 Prince of Wales





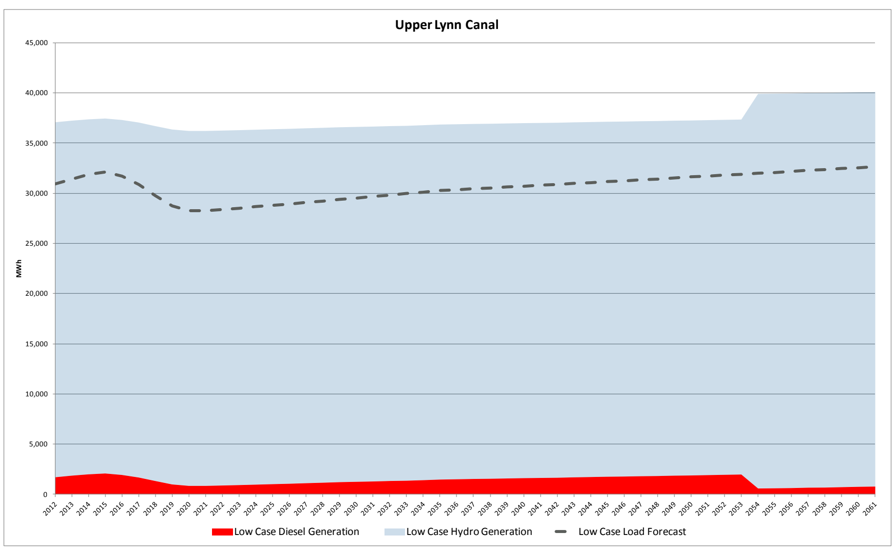


Figure 20-9 Upper Lynn Canal

Three graphs are shown in each figure. The top graph shows the total hydroelectric generation (including existing hydroelectric facilities, Committed Resources, and additional generic hydroelectric projects) and resulting diesel generation, based upon the High Case Load Forecast. The middle graph shows the same information based upon the Reference Case Load Forecast, and the bottom graph shows the same information based on the Low Case Forecast.

The following considerations need to be kept in mind when reviewing these graphs:

- The hydroelectric generation levels shown include generation from generic hydroelectric projects; as stated earlier, these generic hydroelectric projects are not based on actual potential hydroelectric projects available within each subregion.
- The shaded area above the load forecast in each graph represents spilled hydroelectric, resulting from the fact that the loads in the subregion are not large enough to use all of the hydroelectric capability in many of the years shown.

HIGHEST VALUE USE OF HYDROELECTRIC AND THE FUTURE ROLE OF BIOMASS

As has been discussed previously in this report, communities with access to low cost hydroelectric power have seen a recent increase in the number of conversions to electric space heating. While these conversions have resulted in significant savings for those residential and commercial customers who have made the conversions, they have led to a significant reduction in the amount of hydroelectric capacity available to meet future electric demands. As a result, absent the development of new hydroelectric or other generation projects or restrictions on future conversions to electric space heating, all customers in these communities will pay higher rates for electricity as a result of higher future use of diesel for electric generation, and communities will be denied new economic development opportunities.

This reality raises the question, what is the highest value use of current and future hydroelectric power? An important element of this question is the alternative energy sources that can be used to meet specific end-uses. For example, in the case of lighting, there is no practical alternative to electricity that provides the same level of quality of life. However, in the case of space heating, there are alternatives such as biomass, including the use of wood pellets and heat pumps.

Given the fact that the region’s transmission network is very limited in terms of the number of communities connected, and the size of loads within the region adversely affect the direct economics of additional transmission segments, hydroelectric power within the region will remain a limited resource. Therefore, the region should carefully consider the best use of this limited resource.

Biomass is a particularly good option given the local and abundant nature of this solution, and the relative economics and availability of supplies within the region, both as a short-term solution for the region as well as a long-term solution for certain communities. Our analysis also shows that biomass is economical in most cases even if it is shipped in from the lower 48 states. As discussed elsewhere, one supply chain-related challenge that should be addressed for wood biomass to be utilized to its optimal level is the development of one or more pellet manufacturing facilities within the region and securing long-term fiber supplies. This will provide a more secure fuel supply, lower costs, and produce jobs within the region.

20.1.3 Conclusions – Moving Forward

14. Given the previous discussion, Black & Veatch believes that it is important for the region to think about the future in two phases with regard to long-term resource decisions, as shown in Table 20-4 and discussed below:

- **Phase 1** - the next 5 years (2012-2016)
- **Phase 2** - beyond the next 5 years (2017 and beyond)

Table 20-4 General Strategy for Adding Regional Resources

RESOURCES	PHASE 1 (2012-2016)	PHASE 2 (2017 AND BEYOND)
Committed Resources	√	
DSM/EE Programs	√	√
Biomass Conversion Programs	√	√
Next Increment of Hydroelectric and Other Renewable Projects		√

In **Phase 1**, the regional emphasis should be on adding the Committed Resources and aggressively pursuing the implementation of DSM/EE and biomass space heating conversion programs.

In parallel, the region should move forward with the completion of reconnaissance and feasibility studies of all potential hydroelectric projects listed in the Refined Screened Potential Hydroelectric Project List (see Table 10-4 in Section 10.0). These reconnaissance and feasibility studies should be completed consistent with the AEA-directed process and standards.

Finally, as part of Phase 1, this IRP should be updated in the 2014-2015 timeframe to make the longer-term resource selections that would be implemented in Phase 2. By updating the Southeast Alaska IRP in 2014 or 2015, the region will have: 1) better project-specific information to make a definitive selection among specific alternative hydroelectric and other renewable projects, and 2) actual experience with the implementation of DSM/EE and biomass conversion programs to better determine the level to which the region, and individual subregions, can rely on these programs over the long term.

In **Phase 2**, the region would develop the hydroelectric and other renewable projects, as well continue to implement DSM/EE and biomass conversion programs as appropriate, based upon the results of the updated Southeast Alaska IRP.

15. This two-phase approach is appropriate given the following challenges that exist with each resource type:

- **Hydroelectric Projects –** The need to improve the quality and inclusiveness of project-specific estimates regarding capital costs, operating costs, annual and monthly energy output, ability to utilize annual and monthly energy outputs in nearby load centers, etc**.**
- **DSM/EE Programs –** Issues related to DSM/EE programs include the following:
  - The total market potential for these programs (which will be addressed in large part by the AEA's current Energy End Use Data Collection Project).
  - The ability of the region, and subregions, to implement a comprehensive and aggressive set of DSM/EE programs.
  - Determining the most effective way to leverage existing DSM/EE programs in the region (including existing Alaska Housing Finance Corporation (AHFC), AEA, and Rural Alaska Community Action Program, Inc. (RurAL CAP) programs discussed in Section 16.0).
  - Determining the most effective way to deliver these programs (e.g., each utility developing their own DSM/EE programs, a regional entity that would develop and deliver these programs in close coordination with local utilities, and/or development of public-private partnerships to deliver these programs).
  - Actual response of residential and commercial customers to the DSM/EE programs offered.
- **Biomass Conversion Program –** Issues related to a regional biomass conversion programs include the following:
  - Future price of oil which will impact the level of conversions from diesel space heating that will occur.
  - The total market potential for biomass conversion in each subregion.
  - The ability of the region, and subregions, to implement an aggressive biomass conversion program.
  - Determining the most effective way to leverage existing biomass conversion programs in the region (e.g., biomass programs being implemented by the Coast Guard, USFS, and Sealaska).
  - Similar to the DSM/EE discussion above, there is a need to determine the most effective way to deliver these programs (e.g., individual utilities, a regional entity, and or public-private partnerships).
  - Actual receptiveness of residential and commercial customers.
- **Transmission Projects –** While none of the proposed transmission interconnections considered were selected for inclusion in the region's expansion plan (other than the transmission Committed Resources), the State may decide to move forward with one or more of these interconnections for non-economic reasons.

It is Black & Veatch's opinion that the long-term definitive selection of specific potential projects cannot be made until: 1) these challenges are addressed, 2) better information is available regarding the capital and operating costs of specific projects, and 3) experience is gained with regard to the implementation of DSM/EE and biomass conversion programs. Again, the level of these uncertainties drive home the need for the region to: 1) develop multiple options, 2) move towards a more balanced portfolio of resources (i.e., the solution to the region's energy challenges is not as simple as adding more hydroelectric and some transmission), and 3) maintain flexibility with regard to the selection of resource options over time as the uncertainties above become more resolved.

16. The Preferred Resource Lists that were developed for each subregion as part of this study, which are discussed in more detail in Sections 17.0 and 21.0, include a portfolio of resources that have been identified based upon the specific circumstances faced by each subregion. If implemented, the Southeast Alaska IRP will lead to the following:

- The development of a more diverse resource mix resulting from a regional planning process.
- Allow for moving forward with certain resources now (including the Committed Resources, DSM/EE, and biomass programs), while developing better fact-based information to make long-term resource decisions.
- A reduction in the overall costs for electricity and heating.
- Greater reliance on DSM/EE and renewable resources, including hydroelectric power and biomass, and a lower dependence on diesel.
- A somewhat more expansive transmission network as a result of the completion of the transmission Committed Resources.
- A stronger foundation upon which to base future economic development efforts.

17. Included in the Preferred Resource Lists are the following Committed Resources, which are described in Table 20-5. As discussed earlier in this report, these hydroelectric and transmission projects were identified by the Advisory Work Group (AWG) (adopted through a resolution) as projects that should be developed based upon the economic benefits that they would provide to the region. As stated in the AWG resolution, these "projects have been under development for many years, have completed or nearly completed exhaustive FERC licensing or similar process, and have broad public support." From a modeling perspective, consistent with this AWG directive, Black & Veatch treated these projects as existing resources:

- Blue Lake Expansion Hydroelectric
- Gartina Falls Hydroelectric
- Reynolds Creek Hydroelectric
- Thayer Creek Hydroelectric
- Whitman Lake Hydroelectric
- Kake – Petersburg Intertie
- Ketchikan – Metlakatla Intertie

While these Committed Resources are included in the Preferred Resource Lists, it is important to note that significant work is still required to bring these projects to reality. For example, several of the hydroelectric projects on this Committed Resource list require additional engineering and design work, as well as additional environmental and permitting work, before they can move to construction. For the transmission projects on the Committed Resource list, not only is additional engineering and design, environmental, and permitting work required, but operational agreements with SEAPA must also be developed, as well as construction funding acquired.

Table 20-5 Committed Resources

PROJECT	DISCUSSION	TOTAL CAPITAL COST ($ MILLION)	REMAINING CAPITAL COST ($ MILLION)
Blue Lake Expansion Hydro (Sitka, City of Sitka Electric)	Expansion will increase the capacity of the existing Blue Lake Hydro Project by an estimated 8 MW and increase the average annual energy from the project by approximately 34,500 MWh.	$96.5	$47.5
Gartina Falls Hydro (Hoonah, IPEC)	New run-of-river project near Hoonah that will provide an estimated 0.44 MW of capacity and approximately 1,800 MWh of average annual energy.	$6.3	$5.5
Reynolds Creek Hydro (Hydaberg, Haida Energy and AP&T)	New storage project located that will provide an estimated 5 MW of capacity and approximately 19,300 MWh of average annual energy.	$28.6	$8.1
Thayer Creek Hydro (Angoon, Kootznoowoo, Inc.)	New run-of-river project that will provide an estimated 1 MW of capacity and approximately 8,400 MWh of average annual energy.	$15.2	$13.0
Whitman Lake Hydro (Ketchikan, KPU)	New storage project at an existing lake located that will provide an estimated 4.6 MW of capacity and approximately 15,900 MWh of average annual energy.	$25.8	$13.4
Kake – Petersburg Intertie (Kwaan Electric Transmission Intertie Cooperative)	New 69 kV overhead and submarine cable transmission line connecting Kake and Petersburg.	$53.8	$48.3
Ketchikan – Metlakatla Intertie (Metlakatla Indian Community)	New 34.5 kV overhead and submarine cable transmission line connecting Ketchikan and Metlakatla.	$12.7	$8.2
	Totals	**$238.9**	**$144.0**

18. As stated above, the region should significantly increase the implementation of DSM/EE programs consistent with the State's target of 15 percent increase in energy efficiency by 2020, building upon the current programs offered by the AHFC, AEA, and RurAL CAP. These programs will lower total energy requirements, thereby reducing the draw on hydroelectric resources in those communities with access to hydroelectric power, and lower costs and/or improve the quality of living in all communities. However, to achieve these projected savings, the region will need to address a number of important delivery issues, including: 1) how best to leverage existing AHFC, AEA, and RurAL CAP programs; 2) whether additional DSM/EE programs should be developed on a regional basis and implemented in close coordination with local utilities versus requiring each utility to develop its own DSM/EE-related staff and skills; 3) establishing region-specific costs for higher efficient appliances and equipment; and 4) financing the up-front DSM/EE program development costs as well as ongoing incentives to residential and commercial customers to install more efficient appliances and equipment.

19. Also, as stated above, the region should also pursue policies and programs that reduce the number of residential and commercial customers converting to electric space heating. One particularly promising resource option to accomplish this goal is the regional adoption of wood pellet technology for space heating. Additionally, rate structures could be modified (e.g., increased rates for higher consumption levels) to discourage electric space heating conversions. Similar to DSM/EE programs, this resource option would provide benefits to all subregions. Additionally, the region should address a number of important delivery issues, including: 1) how best to leverage current programs underway within the region to encourage the adoption of wood pellet technologies, 2) whether additional wood pellet programs should be developed on a regional basis and implemented in close coordination with local utilities versus relying solely on private parties and/or each utility to develop its own wood pellet-related staff and skills, 3) establishing region-specific customer educational and contractor certification programs, and 4) the financing of the up-front wood pellet conversion costs.

20. There are a number of risks and uncertainties regardless of the resource options chosen, including the following categories, which are discussed in Section 19.0 along with their potential implications.

    - **Resource Potential Risk -** The risk associated with the total energy and capacity that could be economically developed for each resource option; this risk is particularly important with regards to certain renewable technologies such as wind and geothermal.
    - **Project Development and Operational Risks -** The risks and issues associated with the development of specific projects, including regulatory and permitting issues, the potential for construction cost overruns, actual operational performance relative to planned performance, etc. This category also includes non-completion risks once a project gets started, the risk that adverse operating conditions (e.g., an earthquake) will severely damage or impair the facilities resulting in a shorter useful life than expected, and project delay risks. These risks are particularly important for hydroelectric projects.
    - **Fuel Supply Risks -** The risks and issues associated with the adequacy and pricing of required fuel supplies, including diesel and biomass.

- **Environmental Risks -** The risks of environmental-related operational concerns and the potential for future changes in environmental regulations; these risks could significantly impact each of the resources contained in the Preferred Resource Lists.
- **Transmission Constraint Risks -** The risk related to the ability to move power from a specific generation resources to a load center is impaired, such as a transmission line outage due to an avalanche.
- **Financing Risks** – The risk that a regional entity or individual utility will not be able to obtain the financing required for specific resource options under reasonable and affordable terms and conditions.
- **Regulatory/Legislative Risks** – The risk that regulatory and legislative issues could affect the economic feasibility or operations of specific resource options.
- **Price Stability Risks** – The risk that wholesale power costs will increase significantly as a result of changes in fuel prices and other factors (e.g., CO_2 emission allowance costs).

In some cases, these risks and uncertainties might completely eliminate a particular resource option. Due to these risks and uncertainties, it will be important for the region to maintain flexibility so that changes to the Preferred Resource Plan can be made, as necessary, as these resource-specific risks and uncertainties become clearer or get resolved.

21. Another risk facing the region is the potential for large load increases resulting from economic development efforts (e.g., the development of one or more mines). Although the High Scenario Load Forecasts, discussed in Section 8.0, were developed to illustrate the potential for significantly higher load growth than shown in the Reference Scenario Load Forecasts, they may not adequately capture the impact of a large mine load increase (or any other large, discrete, increase) because of the potential size of mine loads and the fact that, if developed, the impact of a new mine would be site specific. Due to the speculative nature of these potential load increases, it is impossible in this study to identify how these potential loads would be served. Most proposed mines are in remote locations and far removed from potential grid access. It is likely that hydroelectric resources in close proximity to the mines could be developed to displace diesel-generated power.

22. Given the size of the Southeast region and the financial capabilities of the region's utilities, it will be critical for the State to continue to provide financial assistance to enable the region to lower costs and meet its electric and heating needs going forward. Black & Veatch's recommendations regarding the projects, and other supporting studies and actions, which should be considered for State assistance, are discussed in Section 21.0. Furthermore, Section 18.0 provides the results of Black & Veatch's evaluation of alternative options for State financial assistance.

23. Integrated resource plans are typically updated on a periodic basis, most typically every 3 to 5 years to reflect changes that occur over time, as well as other alternative resources and projects that are identified. Given the uncertainties that exist in the Southeast, coupled with the limited development work that has occurred with regard to many of the resources contained in the Preferred Resource Lists, it will be very important to update the Southeast Alaska IRP on a periodic basis.

RELATIONSHIP BETWEEN THE SOUTHEAST ALASKA IRP AND THE *"ALASKA ENERGY PATHWAY"*

In July 2010, the AEA published *"Alaska Energy Pathway – Towards Energy Independence."* This report, which was the result of extensive consultations between the AEA and communities throughout Alaska, was developed to provide direction and focus to the goal that all Alaskans should have access to affordable power. This report was part of the AEA's effort to develop a long-term energy strategy for the State of Alaska. The first step in that effort was the 2009 publication of *"Alaska Energy – A First Step Toward Energy Independence,"* which contained information on available energy technologies and a database of community energy resources.

Alaska Energy Pathway laid out an overall direction for the State, including aggressive targets for energy efficiency and conservation as well as renewable energy development; recommendations which have been adopted, with certain modifications, by the State Legislature and Governor. For areas of the State outside of the Railbelt Region, the report focused on the use of locally available resources whenever possible to meet energy needs for heat and electricity. An assessment of possible options for each community was completed, yielding a potential pathway for each community. This resulted in a recommended community resource development strategy that would involve the deployment of renewable resources, including hydroelectric power, where economically feasible, but also the continued use of diesel as a major fuel source for both electricity and heating.

There are many similarities between the Southeast Alaska IRP and the *Alaska Energy Pathway*, including the underlying objectives and resources considered. In that sense, this IRP is a logical next step on the journey to developing community plans to lower energy costs. The Southeast Alaska IRP, however, differs from the *Alaska Energy Pathway* is several important ways. First, the analysis completed as part of this IRP (e.g., projected heating and electric load forecasts, the costs of available resources including generation and transmission, etc.) was at a more granular level of detail. Second, the analytical approach was different in that it was more detailed and considered the interaction between alternative resources in more detail. Finally, the level of involvement of regional stakeholders throughout the development of this IRP was greater.

As a result, the results of this IRP, including the Preferred Resource Lists for each subregion, represent a more comprehensive and tailored set of near-term and long-term solutions for addressing the region's energy challenges. In that sense, the Southeast Alaska IRP builds upon the *Alaska Energy Pathway* and provides a more detailed pathway for the Southeast region.

20.2 RECOMMENDATIONS

This subsection summarizes the overall recommendations arising from this study, broken down into the following two categories:

- Recommendations – Capital Projects
- Recommendations – Other

20.2.1 Recommendations – Capital Projects

The following general actions should be taken to ensure the timely implementation of the Southeast Alaska IRP:

1. As stated previously, Black & Veatch believes that the region should move forward with regard to long-term resource decisions, as follows:

   - **Phase 1** - the next 5 years (2012-2016)
   - **Phase 2** - beyond the next 5 years (2017 and beyond)

   In **Phase 1**, the regional emphasis should be on adding the Committed Resources and aggressively pursuing the implementation of DSM/EE and biomass space heating conversion programs.

   In parallel, the region should move forward with the completion of reconnaissance and feasibility studies of all potential hydroelectric projects listed in the Refined Screened Potential Hydroelectric Project List (see Table 10-4 in Section 10.0). These reconnaissance and feasibility studies should be completed consistent with the AEA-directed process and standards.

   Finally, as part of Phase 1, this IRP should be updated in the 2014-2015 timeframe to make the longer-term resource selections that would be implemented in Phase 2. By updating the Southeast Alaska IRP in 2014 or 2015, the region will have: 1) better project-specific information to make a definitive selection among specific alternative hydroelectric and other renewable projects, and 2) actual experience with the implementation of DSM/EE and biomass conversion programs to better determine the level to which the region, and individual subregions, can rely on these programs over the long term.

   In **Phase 2**, the region would develop the hydroelectric and other renewable projects, as well as continue to implement DSM/EE and biomass conversion programs as appropriate, based upon the results of the updated IRP.

2. The State should work closely with the region's utilities and other community stakeholders to confirm the recommended Preferred Resource Lists for the region as a whole, and for each subregion, resulting from this study. As part of this effort, the region should develop a prioritized list of resource options, and supporting studies and actions, for submission to the Governor's Office and State Legislature for consideration of potential State financial assistance.

3. Black & Veatch believes that the region-wide Preferred Resource List, provided in Table 20-6, should be the starting point for the selection of resources to be developed to meet the region's future energy requirements. This table is based upon the subregion Preferred Resource Lists discussed in Section 17.0.

Table 20-6 Region-Wide Preferred Resource List

SUBREGION	RESOURCE	ESTIMATED CAPITAL COSTS ($'000,000)	PROJECTED COMMERCIAL OPERATION DATE (COD)
PHASE 1: COMMITTED RESOURCES 2012-2016			
SEAPA	Kake-Petersburg Interconnection Ketchikan-Metlakatla Interconnection Whitman Lake Hydro Diesel DSM/EE Biomass	48.6 8.2(1) 13.4(1) 51.1 3.1 139.4	2015 2013 2014 2012-2016 2012-2016 2012-2016
Admiralty Island	Thayer Creek Project DSM/EE Biomass	13.0(1) 0.0(3) 0.8	2016 2012-2016 2012-2016
Baranof Island	Blue Lake Hydro Diesel DSM/EE Biomass	47.5 20.2 0.9 14.1	2015 2012-2016 2012-2016 2012-2016
Chichagof Island	Gartina Falls Hydro Diesel DSM/EE Biomass	5.5 0.3 0.0 1.9	2015 2012-2016 2012-2016 2012-2016
Juneau	Diesel DSM/EE Biomass	20.2 3.6 63.3	2012-2016 2012-2016 2012-2016
Northern	Diesel DSM/EE Biomass	2.8 0.0 4.1	2012-2016 2012-2016 2012-2016

SUBREGION	RESOURCE	ESTIMATED CAPITAL COSTS ($'000,000)	PROJECTED COMMERCIAL OPERATION DATE (COD)
Prince of Wales	Reynolds Creek Hydro DSM/EE Biomass	5.5[(2)] 0.0[(3)] 8.9	2014 2012-2016 2012-2016
Upper Lynn Canal	DSM/EE Biomass	0.2 9.7	2012-2016 2012-2016
PHASE 2: RESOURCES 2017-2061			
SEAPA	Hydro – Storage (10 MW) Diesel DSM/EE Biomass	193.1 202.8 102.1 166.0	2044 2017-2061 2017-2061 2017-2021
Admiralty Island	Diesel DSM/EE Biomass	1.7 0.1 0.7	2017-2061 2017-2061 2017-2021
Baranof Island	Diesel DSM/EE Biomass	83.4 31.4 16.1	2017-2061 2017-2061 2017-2021
Chichagof	Hydro – Run of River (1 MW) Diesel DSM/EE Biomass	21.7 6.4 0.8 1.6	2035 2017-2061 2017-2061 2017-2021
Juneau	Hydro – Storage (10 MW) Diesel DSM/EE Biomass	237.5 216.6 124.5 79.5	2051 2017-2061 2017-2061 2017-2021

SUBREGION	RESOURCE	ESTIMATED CAPITAL COSTS ($'000,000)	PROJECTED COMMERCIAL OPERATION DATE (COD)
Northern	Hydro – Storage (1 MW) Hydro – Run of River (1 MW) Diesel DSM/EE Biomass	18.6 32.8 23.3 1.3 4.7	2017 2049 2017-2061 2017-2061 2017-2021
Prince of Wales	Diesel DSM/EE Biomass	16.6 66.4 10.2	2017-2061 2017-2061 2017-2021
Upper Lynn Canal	Hydro – Storage (1 MW) Diesel DSM/EE Biomass	55.4 19.8 5.4 11.1	2054 2017-2061 2017-2061 2017-2021

(1)Additional funds required to complete project not considering any pending grant requests.
(2)Additional funds required to complete project.
(3)Cost is zero due to rounding. Actual cost is 0.002.

20.2.2 Recommendations - Other

Other actions, related to the implementation of this IRP, that should be undertaken include the following:

4. The State and the region should develop a public outreach program to inform the general public regarding the Southeast Alaska IRP and the Preferred Resource Lists, including the costs and benefits of developing the projects included. Additionally, the benefits of DSM/EE and biomass conversions should be included as part of this public outreach program.

5. The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the region's utilities in developing the generation resources and transmission projects identified in the Preferred Resource List. Additionally, the State should indicate the "standard" form and conditions to qualify for this State assistance to provide better guidance to project proposers.

6. The AEA is proposing a decision framework and policy requiring developers of each potential project to develop a standard set of information, at an appropriate level and quality of detail, prior to any decisions being made with regard to which projects should be developed. The AEA proposes that this policy would apply to all projects for which the State will be providing financial assistance, and it recommends that it also apply to cases where the project proponents decide not to seek State financial assistance so that the permitting agencies can compare the benefits consistently between all projects.

   This decision framework would include the following elements:

   - Establishing the owner, operator, power sales agreement (PSA), standards of development, and capacity of the proposer to complete the project.
   - Identify major hydroelectric increments (e.g., Southeast Alaska IRP projects) with basic capacity/production requirements and capital budget requirements.
   - Make recommendations for financing approaches (e.g., Bradley Lake model, Reynolds Creek model, etc.) as part of the project loan package, along with established rate impact goals.
   - Develop approaches to allow partially subscribed projects to be brought into operation without rate shock.
   - Address the lack of reliable project information that precludes the development of a prioritized Preferred Resource List.
   - Identify the need for an ordered process with State involvement to ensure projects are selected for the benefit of the region's ratepayers.

Furthermore, the AEA would develop standards for the next increment of hydroelectric projects, including the following:

- Coordinating this set of standards with the Renewable Energy Grant Fund (REGF) program.
- Directing funding through the project risk matrix approach discussed in Section 10.0.
- Ensuring all grant funding development work conforms to standards set by the AEA.
- Ensuring most feasible projects receive funding.

This decision framework and related information standards is intended to yield a minimum threshold of information, thereby providing the foundation of decisions regarding the next increment of hydroelectric projects. It is also intended to identify any fatal flaws that would prohibit a proposed project from being developed.

Black & Veatch believes that this type of decision framework and information standards should be adopted as it will effectively address the issues associated with the quality and inclusiveness of information available on specific projects and enable the region to make more fact-based decisions regarding which hydroelectric projects should be developed.

7. The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, to supplement current programs offered by the AHFC, AEA, and RurAL CAP. This appropriation should be directed at the following elements of a comprehensive DSM/EE program:

    - Leverage of the AEA's State-wide residential and commercial end-use saturation survey that is currently underway. The purpose of this survey is to gather more detailed Southeast Alaska-specific information on how residential and commercial customers use energy, which will greatly enhance efforts to develop targeted DSM/EE programs that will be successful.
    - Salaries and other related costs (e.g., benefits and office space) to enable regional utilities to add staff with the required DSM/EE-related skills and experience.
    - Conducting residential and commercial customer attitudinal surveys. The information gathered from these surveys will help: 1) identify the elements of DSM/EE programs (e.g., level of rebates offered for weatherization and the purchase of high efficient appliances/equipment) necessary to incent residential and commercial customers to make these types of investments and 2) help regional utilities develop targeted educational and marketing campaigns.
    - Completing a market and economic potential study, based upon the results of the AEA State-wide residential and commercial end-use saturation survey, which will result in a more definitive estimate of the economic market potential for DSM/EE programs in the region.
    - Completing detailed DSM/EE program plans. These DSM/EE program plans commonly include the following elements:
        - Detailed description of the program.
        - Reasons why the program would be successful in the utility's service territory.

    - Number of customers within the customer class/segment that are likely to adopt/use the proposed program.
    - Achievable energy savings.
    - Marketing plans which should include incentives, rebates, and preferred distribution channels and how each reduces existing barriers to proposed program adoption/acceptance.
    - Detailed budget plans complete with explanations of anticipated increases/decreases in financial and human resources during the expected life of the program.
    - Recommended methodology or tracking tools for recording actual performance to budget.
    - Proposed program evaluations and reports.
- Conducting trade ally surveys and training/certification programs, to identify willing vendors and ensure that they are adequately trained and certified to install weatherization measures and high-efficiency equipment. The region will not be successful without the active involvement of trained trade allies.
- Developing a regional DSM/EE program measurement and evaluation (M&E) protocol.
- Developing a startup advertising program.
- Aggressively pursuing available federal funding for DSM/EE programs and renewable projects.

It should be noted that the Southeast region can learn from the lessons of others with regard to the development and execution of a comprehensive DSM/EE program. Many regions of the country, as well as other countries, have been delivering DSM/EE programs for a number of years; some utilities have been implementing DSM/EE programs for 30 years. Consequently, there are many “lessons learned” and the region should do everything it can to take advantage of this experience.

8. The State Legislature should appropriate funds for the initial stages of the development of a regional biomass conversion program, to supplement current programs offered in the region. This appropriation should be directed at the following elements of a comprehensive biomass conversion program:

- Leverage existing biomass conversion programs (e.g., biomass programs being implemented by the Coast Guard, USFS, and Sealaska).
- Salaries and other related costs (e.g., benefits and office space) to enable regional utilities to add staff with the required biomass conversion-related skills and experience.
- Conducting residential and commercial customer attitudinal surveys. The information gathered from these surveys will: 1) help identify the elements of a biomass conversion program (e.g., level of rebates offered) necessary to incent residential and commercial customers to make these types of investments and 2) help regional utilities develop targeted educational and marketing campaigns.

- Complete a market and economic potential study, which will result in a more definitive estimate of the economic market potential for biomass conversions in the region.
- Completing detailed biomass conversion program design efforts.
- Conducting trade ally surveys and training/certification programs, to identify willing vendors and ensure that they are adequately trained and certified to install biomass conversion equipment.
- Developing a startup advertising program.

It should be noted that the Southeast region can learn from the lessons of others with regard to the development of biomass space heating programs, especially those programs that have been implemented in Europe.

9. Evaluate the potential benefits and costs of forming a regional entity, or utilizing an existing entity, to develop and deliver DSM/EE programs, in close coordination with the region's utilities, to residential and commercial customers throughout the Southeast region. Black & Veatch does not believe that the region will be successful in developing an aggressive DSM/EE program if each utility has to develop: 1) its own DSM/EE program, including hiring the appropriate staff, 2) detailed DSM/EE program plans, 3) a set of qualified vendors, and 4) an education and marketing campaign.

10. Evaluate the potential benefits and costs of forming a regional entity, or utilize an existing entity, to accelerate the development of a biomass conversion program.

11. Consistent with the need to improve the quality and inclusiveness of available information on potential hydroelectric projects, the State Legislature should appropriate funds to assist hydroelectric project proposers complete high-level reconnaissance studies. These relatively low-cost reconnaissance studies would provide the necessary information to determine whether a proposed hydroelectric project should move forward to the preparation of a FERC license application.

12. For those proposed hydro projects that meet the needs identified as the next increment of hydro and have completed reconnaissance studies that show they are sufficiently viable to move to the FERC license process, the State Legislature should appropriate funds to assist project proposers in preparing the FERC license application. The FERC licensing process is a multi-year and multi-million dollar process that could prohibit the development of some feasible projects without State financial assistance.

13. Complete a regional technical and economic market potential assessment, including the identification of the most attractive sites, for all non-hydroelectric renewable resources included in the Preferred Resource List.

14. Similar to many proposed hydroelectric projects, there is a need to improve the quality and inclusiveness of available information on potential non-hydroelectric renewable projects. As a result, the State Legislature should appropriate funds to assist non-hydroelectric renewable project proposers complete high-level reconnaissance studies. These reconnaissance studies would provide the necessary information to determine whether a proposed renewable project should move forward to the next step of the development process.

15. Further development of tidal and wave power should be encouraged due to its resource potential in the Southeast region. Although this technology is not commercially available, in Black & Veatch's opinion, at this point in time, it has the potential to become economic within the planning horizon. In fact, the Southeast region could become a research, development, and demonstration center for the development of tidal and wave technologies.

16. Develop a standard power sales agreement (PSA) to: 1) facilitate the provision of State financial assistance and 2) provide IPPs an equal opportunity to submit qualified proposals to develop specific projects.

17. Consider the development of an open access policy for the region's transmission network, based on the FERC Open Access Transmission Tariff (OATT), which governs the planning and operation of the transmission grids in the lower 48 states.

18. Consistent with previous comments, this IRP should be updated in the 2014-2015 timeframe to make the longer-term resource selections that would be implemented in Phase 2. By updating the Southeast Alaska IRP in 2014 or 2015, the region will have: 1) better project-specific information to make a definitive selection among specific alternative hydroelectric and other renewable projects and 2) actual experience with the implementation of DSM/EE and biomass conversion programs to better determine the level to which the region, and individual subregions, can rely on these programs over the long term.

19. The regional utilities, perhaps with the assistance of the AEA, should evaluate the benefits of developing tariff structures that better reflect actual costs, particularly with regard to the additional long-term costs that will be incurred as a result of electric space heating conversions. As part of this effort, workshops should be held to focus on the issue that the last block in tariffs need to better reflect incremental costs. Additionally, cost-of-service studies should be completed for each utility facing the impact of electric space heating conversions to determine what rates should be for higher consumption.

20. To the extent that electric space heating conversions continue to increase a utility's electric load, those utilities should evaluate the benefits of developing weather normalized load forecasts. As part of this effort: 1) workshops should be held to focus on the need for, and approaches to, weather normalized load forecasting methodologies, 2) a standard weather normalized load forecasting methodology should be developed, and 3) short-term weather normalized load forecasts for each relevant utility should be developed.

21. The State and the region's utilities should work closely with resource agencies to identify changes that can be made to streamline State and Federal regulatory and permitting processes related to the resources contained in the Preferred Resource List.

22. Federal legislative and regulatory activities, including those related to emissions regulations, should be monitored closely and influenced to the degree possible.

21.0 Near-Term Regional Implementation Action Plan (2012-2014)

The purpose of this section is to provide Black & Veatch's recommended near-term implementation plan, covering the period from 2012 to 2014. Black & Veatch's recommended actions, which are consistent with the Preferred Resource Lists presented in Section 17.0 and the recommendations resulting from this study that are discussed in detailed in Section 20.0, are grouped into the following categories:

- Capital Projects – SEAPA Subregion
- Capital Projects – Other Subregions
- Regional Supporting Studies and Other Actions

The near-term implementation plans shown in the following tables serve two objectives. First, they identify the steps that should be taken during the next three years regardless of the alternative resource plan that is chosen as the preferred resource plan. Second, they are intended to maintain flexibility as the uncertainties and risks associated with each alternative resource become more clear and/or resolved.

21.1 CAPITAL PROJECTS – SEAPA SUBREGION

Table 21-1 Near-Term Implementation Action Plan – Capital Projects – SEAPA Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Committed Resources • Kake-Petersburg Transmission Intertie (SEI-2) o Estimated total cost - $53,780,000 o Previous grants - $5,490,000 o Remaining project cost - $48,290,000 • Ketchikan-Metlakatla Transmission Intertie (SEI-3) o Estimated total cost - $12,725,200 o Previous grants - $4,500,000 o Remaining project cost - $8,225,200 • Whitman Lake Hydroelectric o Estimated total cost - $25,830,000 o Previous grants - $12,420,000 o Remaining project cost - $13,400,000	2013-2015 2012-2013 2012-2014	$48,290,000 $8,225,200 $13,400,000
Replacement of Existing Diesel Generation Facilities	2012	$39,685,000
DSM/EE Programs	2012 2013 2014	$69,100 $169,900 $395,300
Biomass Conversion Program	2012 2013 2014	$25,201,800 $26,393,100 $27,875,700
SEAPA Subregion Total (2012-2014)		**$189,705,100**

21.2 CAPITAL PROJECTS – OTHER SUBREGIONS

21.2.1 Admiralty Island Subregion

Table 21-2 Near-Term Implementation Action Plan – Capital Projects – Admiralty Island Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIMEFRAME**	**ESTIMATED COST**
Committed Resources • Thayer Creek Hydroelectric o Estimated total cost - $15,201,100 o Previous grants - $2,156,100 o Remaining project cost - $13,045,000	2012-2016	$13,045,000
DSM/EE Programs	2012 2013 2014	$100 $100 $300
Biomass Conversion Program	2012 2013 2014	$144,000 $108,600 $249,500
Admiralty Island Subregion Total (2012-2014)		**$13,547,600**

21.2.2 Baranof Island Subregion

Table 21-3 Near-Term Implementation Action Plan – Capital Projects – Baranof Island Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Committed Resources • Blue Lake Hydro o Estimated total cost - $96,500,000 o Previous State funding - $49,000,000 o Previous bond net proceeds - $20,000,000 o Remaining project cost - $27,500,000	2012-2015	$27,500,000
Replacement of Existing Diesel Generation Facilities	2012	$20,220,000
DSM/EE Programs	2012 2013 2014	$20,800 $50,800 $118,100
Biomass Conversion Program	2012 2013 2014	$2,663,700 $2,664,400 $2,825,900
Baranof Island Subregion Total (2012-2014)		**$56,063,700**

21.2.3 Chichagof Island Subregion

Table 21-4 Near-Term Implementation Action Plan – Capital Projects – Chichagof Island Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Committed Resources • Gartina Falls Hydroelectric o Estimated total cost - $6,330,000 o Previous grants - $850,000 o Remaining project cost - $5,480,000	2012-2015	$5,480,000
Replacement of Existing Diesel Generation Facilities	2012	$303,500
DSM/EE Programs	2012 2013 2014	$600 $1,400 $3,100
Biomass Conversion Program	2012 2013 2014	$313,700 $417,000 $327,400
Chichagof Island Subregion Total (2012-2014)		$6,846,700

21.2.4 Juneau Area Subregion

Table 21-5 Near-Term Implementation Action Plan – Capital Projects – Juneau Area Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Replacement of Existing Diesel Generation Facilities	2012	$20,220,000
DSM/EE Programs	2012 2013 2014	$82,200 $201,500 $468,800
Biomass Conversion Program	2012 2013 2014	$11,379,500 $12,016,400 $12,675,700
Juneau Area Subregion Total (2012-2014)		**$57,044,100**

21.2.5 Northern Subregion

Table 21-6 Near-Term Implementation Action Plan – Capital Projects – Northern Region Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Replacement of Existing Diesel Generation Facilities	2014	$2,790,200
DSM/EE Programs	2012 2013 2014	$900 $2,100 $4,700
Biomass Conversion Program	2012 2013 2014	$780,700 $749,200 $828,200
Northern Region Subregion Total (2012-2014)		**$5,156,000**

21.2.6 Prince of Wales Subregion

Table 21-7 Near-Term Implementation Action Plan – Capital Projects – Prince of Wales Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Committed Resources • Reynolds Creek Hydroelectric o Estimated total cost - $28,581,500 o Previous grants - $20,520,000 o Remaining project cost - $8,061,500	2012-2014	$8,061,500
DSM/EE Programs	2012 2013 2014	$100 $100 $200
Biomass Conversion Program	2012 2013 2014	$1,339,800 $1,549,600 $1,757,100
Prince of Wales Subregion Total (2012-2014)		**$12,708,400**

21.2.7 Upper Lynn Canal Subregion

Table 21-8 Near-Term Implementation Action Plan – Capital Projects – Upper Lynn Canal Subregion

CAPITAL PROJECTS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
DSM/EE Programs	2012 2013 2014	\$3,500 \$8,700 \$20,500
Biomass Conversion Program	2012 2013 2014	\$1,624,700 \$1,828,200 \$1,839,600
Upper Lynn Canal Subregion Total (2012-2014)		**\$5,325,200**

21.3 REGIONAL SUPPORTING STUDIES AND OTHER ACTIONS

Table 21-9 Near-Term Implementation Action Plan – Regional Supporting Studies and Other Actions

SUPPORTING STUDIES AND OTHER ACTIONS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
General Public Outreach/Education Program • Focused on: 1) results of Southeast Alaska IRP project, 2) benefits of DSM/EE programs, and 3) benefits of biomass conversion program	2012	\$250,000
Regional DSM/EE Program Start-up Costs • Initial staff-related costs (e.g., salaries, benefits, office space) for first year of program startup - \$1,000,000 • Customer attitudinal survey - \$75,000 • Market and economic potential study - \$250,000 • Detailed program plan - \$500,000 • Trade ally surveys and training/certification program - \$150,000 • DSM/EE measurement and evaluation protocol - \$100,000 • Startup advertising program - \$250,000	2012-2013	\$2,325,000
Regional Biomass Conversion Program Startup Costs • Initial staff-related costs (e.g., salaries, benefits, office space) for first year of program startup - \$1,000,000 • Customer attitudinal survey - \$75,000 • Market and economic potential study - \$250,000 • Detailed program plan - \$500,000 • Trade ally surveys and training/certification program - \$150,000 • Startup advertising program - \$250,000	2012-2013	\$2,225,000

SUPPORTING STUDIES AND OTHER ACTIONS		
DESCRIPTION	**TIME FRAME**	**ESTIMATED COST**
Formation of Regional DSM/EE Entity Startup Costs • Regional entity startup costs (e.g., organizational strategy, legal, etc.)	2012	$500,000
Formation of Regional Biomass Conversion Entity Startup Costs • Regional entity startup costs (e.g., organizational strategy, legal, etc.)	2012	$500,000
Hydroelectric Project-specific High Level Reconnaissance Studies • 20 studies at $100,000 each	2012-2013	$2,000,000
Hydroelectric Project-specific FERC License Application Preparation • 10 projects at $1,000,000 each	2012-2014	$10,000,000
Regional Technical/Economic Market Potential Assessment of Non-Hydro Renewable Technologies	2012	$500,000
Other Renewable Project-Specific High Level Reconnaissance Studies • 5 studies at $200,000 each	2012-2014	$1,000,000
Support Tidal/Wave Technology Development	2012-2014	$1,000,000
Develop Standard Power Sales Agreement	2012	$200,000
Consider Development of Open Access Policy and Related Tariff (including terms and conditions of service)	2012	$250,000
Update Southeast Alaska IRP in 2014	2014	$750,000
Support Development of Tariff Structures That Better Reflect Costs • Develop and hold workshop(s) to address the issue that the last block in tariffs should better reflect incremental costs - $50,000 • Conduct cost-of-service studies for communities to determine what rates should be for the last block - $1,500,000	2012-2013	$1,550,000
Support Development of Weather Normalized Load Forecasts • Develop and hold workshop(s) to address need for, and approaches to, weather normalized load forecasting methodologies, which will become more important as heating becomes a bigger load - $50,000 • Develop a standard load forecasting methodology - $75,000 • Develop short-term weather normalized load forecasts for each utility - $250,000	2013	$375,000
Total		**$23,425,000**