Southeast Alaska Intertie Study

Phase 2

FINAL REPORT

Prepared for

The Southeast Conference

Juneau, Alaska

by

D. HITTLE & ASSOCIATES, INC.

Engineers and Consultants

December 2003

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In association with:

Commonwealth Associates, Inc.
CH2M Hill, Inc.
Northstar Power Engineering
Poseidon Engineering, Ltd.

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Phase 2

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Introduction and Conclusions

Introduction

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, 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.

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, Craig and Klawock. In communities where hydroelectric power is not available, the reliance upon diesel generation has contributed to very high retail electric rates. Diesel power generation also involves a number of problems including dramatic fluctuations in fuel price, concerns with fuel handling, fuel storage and transportation, potential interruption in fuel delivery, air pollution and noise.

Economic activity in Southeast Alaska has traditionally been focused on logging, pulp manufacturing, fishing, seafood processing, mining, government and tourism. In recent years, activity in the timber industry has declined significantly with the closure of pulp mills in Ketchikan and Sitka and federal restrictions on logging in the Tongass National Forest. Lower cost electricity throughout the region has long been identified as an important element in attracting other commercial activities that could expand the economy in the future. As a result, the Southeast Conference has undertaken the evaluation of the costs and benefits associated with constructing transmission lines between various communities in Southeast Alaska.

The immediate purpose of a Southeast Alaska transmission system is to provide lower cost hydroelectric generation to communities where electric power is presently supplied with diesel generators. In the long term, an interconnected electric system in Southeast Alaska would potentially encourage the development of new hydroelectric plants on a regional, rather than a local community basis. With a larger connected load base, the initial cost of power from new hydroelectric plants might also be lower, providing cost savings to all utility customers. Further development and utilization of hydroelectric power in the region would also reduce air pollutant emissions.

In late January 2003, the Southeast Conference retained D. Hittle & Associates, Inc. (DHA) to conduct a study of a proposed Southeast Alaska transmission system (the "Intertie Study"). Since several studies of transmission systems in the region have been conducted in the past, the

Intertie Study serves to update the previous work as well as incorporate recent developments and other new information. In order to expedite the evaluation of certain interconnections, the Intertie Study has been separated into two phases as follows:

- Phase 1 – Evaluation of transmission interconnections between (a) Kake and Petersburg and, (b) Juneau, the Kennecott Mining Company - Greens Creek Mine (KMC-GC) on Admiralty Island and Hoonah.

- Phase 2 – Evaluation of a transmission system that interconnects all of the communities of Southeast Alaska.

This report summarizes the findings of Phase 2 of the Intertie Study. The findings of Phase 1 were presented in an earlier report. The primary objective of the Intertie Study is to estimate the costs and benefits associated with the proposed transmission interconnections. Benefits are essentially identified as the net savings in power production expenses resulting from the use of transmitted hydroelectric energy to offset diesel generation. Although the costs of operating and maintaining the transmission lines are included, construction costs are assumed to be grant funded and as such, do not factor in to the analysis of costs and benefits. The Southeast Conference has indicated that it, as well as other stakeholders, will pursue State and federal grants to fund the transmission systems. The cost of construction, however, has been reviewed as part of the Intertie Study.

The Intertie Study provides a feasibility assessment of the proposed transmission systems. If the Southeast Conference or other entities decide to pursue development of one or more of the transmission lines, additional study work will be needed as will actual design and permitting. There will also need to be various contracts for power purchases, operations, and maintenance and other commercial arrangements to be negotiated.

Phase 1 of the Intertie Study focused solely on transmission lines between Juneau, KMC-GC and Hoonah (referred to as Southeast Intertie 1 or "SEI-1") and between Kake and Petersburg (referred to as Southeast Intertie 2 or "SEI-2"). SEI-1 will be used to transmit hydroelectric generation from Alaska Electric Light & Power (AEL&P) to KMC-GC and to the electric system of Tlingit-Haida Regional Electric Authority (THREA) in Hoonah. SEI-2 will be used to transmit hydroelectric generation from the Lake Tyee hydroelectric project owned by the Four Dam Pool Power Agency to THREA's service area in Kake. Both SEI-1 and SEI-2 have been studied in fairly significant detail in the recent past.

Phase 2 of the Intertie Study primarily evaluated power requirements in most of the communities throughout Southeast Alaska, identified surplus hydroelectric generation capabilities, determined when and where new transmission interconnections should be developed and estimated the costs and benefits associated with the potential new transmission systems. The Phase 2 study is very long-term in nature because of the long lifetimes of transmission systems and hydroelectric generation facilities. Further, since many of the communities in Southeast Alaska are small and electric loads are not expected to increase significantly in the near term, it is important to determine when in the future significant changes could occur in the relationship between hydroelectric capacity and regional power needs. However, although existing loads are not forecasted to increase dramatically in the near future, there is potential for new large loads in

Southeast Alaska. A regional transmission system could allow for greater flexibility in serving the electrical requirements of new mining operations or other commercial ventures than has been available in the past. It is important to include the potential impact of new large loads in any evaluation of power supply alternatives and options in the region.

The tasks undertaken for Phase 2 of the Intertie Study, are described as follows:

- Obtain and review previous studies of the transmission systems;
- Identify primary electric load centers throughout the region and forecast future power supply requirements for each load center;
- Identify existing hydroelectric generation capability in the region and estimate available surplus generation capacity at the present time and in the future;
- Review previous studies of potential hydroelectric generating facilities and determine when facilities would be developed in conjunction with a regional transmission system;
- Estimate and compare the cost of power production in the communities based on (1) the present power production system and (2) the interconnected systems;
- Determine if and when the various transmission segments will provide for cost savings that exceed the estimated costs of owning and operating the transmission lines;
- Review the proposed routes of the transmission lines and provide adjustments as needed to reflect current information;
- Review previously developed estimated costs of constructing the transmission lines, and provide adjustments as needed to reflect current information;
- Review and identify the necessary permitting requirements for the transmission lines and identify critical environmental and permitting issues;
- Estimate the costs and time required to obtain necessary permits to construct the transmission lines;
- Review issues and cost estimates associated with proposed submarine cables to be used in the transmission systems;
- Evaluate the use of newer direct current (dc) technologies for the transmission systems as compared to more traditional alternating current (ac) technologies;
- Estimate the annual costs of operating and maintaining the transmission systems;
- Estimate the annual deposit needed to establish a reserve fund for major repairs of the transmission systems;

- Summarize the results and conclusions of Phase 2 in a report.

The existing transmission system in Southeast Alaska is very limited, however, the electric systems in a few communities are currently interconnected. With the expected completion of the Tyee – Swan Intertie in 2005, the communities of Petersburg, Wrangell and Ketchikan will all be electrically interconnected. To date, the Southeast Alaska power system has developed to utilize hydroelectric resources on a sub-regional or isolated community basis. Within the sub-regions, certain transmission lines are expected to be constructed in the near future to further distribute power from relatively small hydroelectric projects. The larger, more expensive interconnections between the sub-regions are the primary subject of the Intertie Study. The sub-regions identified for purposes of this report are as follows:

- *Upper Lynn Canal Region*: Haines, Skagway, Chilkat Valley, Klukwan
- *North Region*: Juneau, KMC-GC Mine, Hoonah, Gustavus, Excursion Inlet
- *West Central Region*: Sitka, Angoon, Tenakee Springs
- *Tyee-Swan Region*: Petersburg, Wrangell, Kake, Ketchikan, Metlakatla
- *Prince of Wales Region*: Craig, Klawock, Thorne Bay, Kasaan, Hollis, Coffman Cove, Hydaburg, Naukati Bay

At the present time, the electric systems within these regions remain relatively isolated from each other. The Tyee – Swan Intertie, when completed, will establish a fairly large interconnection region. Alaska Power & Telephone Company (AP&T) has constructed interconnections between several communities on Prince of Wales Island and between Haines and Skagway. If and when new lines presently proposed by AP&T are completed, the Upper Lynn Canal Region and the Prince of Wales Region will be essentially complete. SEI-1, the Juneau – KMC-GC – Hoonah Intertie, when constructed will tie together the vast majority of the electric load in the North Region. SEI-2, the Kake – Petersburg Intertie, would essentially complete the Tyee-Swan Region, leaving only the interconnection with Metlakatla to construct. The transmission Intertie segments evaluated in the Phase 2 study are identified as follows:

- Southeast Intertie 1 or "SEI-1": Juneau – KMC-GC Mine – Hoonah
- SEI-2: Kake – Petersburg
- SEI-3: Metlakatla – Ketchikan
- SEI-4: Ketchikan – Prince of Wales
- SEI-5: Kake – Sitka

- SEI-6: Sitka – Angoon – Hawk Inlet; or Sitka – Angoon – Tenakee Springs – Hoonah[1]
- SEI-7: Hoonah – Gustavus – Excursion Inlet
- SEI- 8: Juneau – Haines

In addition to the transmission segments defined above, there are several smaller transmission lines proposed by AP&T to interconnect Hydaburg, Hollis and Coffman Cove to the existing interconnected system on Prince of Wales Island. AP&T has also proposed to construct a transmission interconnection between its Haines system and THREA's Chilkat Valley electric system. Development of these transmission lines is being conducted independently by AP&T and as such, they are identified in the Intertie Study but not included as part of the overall "Southeast Conference" system. SEI-7, the Hoonah – Gustavus interconnection, was not included in any of the previous transmission studies.

The economic analysis conducted as part of the Intertie Study looked only at the cost of power production in the communities to be served by the proposed transmission systems. The cost of power production is typically the most significant component of an electric utility's revenue requirement; however, there are other costs that figure significantly into the basis for electric rates charged retail customers. Although the cost of power production may be reduced through alternative means of power supply, other costs may continue to keep retail rates at a high level. The State's Power Cost Equalization (PCE)[2] program also affects how much of the benefit of lower production costs ultimately reach the electric consumer. Aside from the estimation of power production costs, the Intertie Study has not attempted to evaluate retail electric rates in Southeast Alaska.

Study Approach

Phase 2 of the Intertie Study relied upon the previous work of others in conjunction with new investigation and analysis. In this manner, prior studies and reports contributed significantly to the current study effort and in conjunction with the present study provide a much larger knowledge base than could be established with the Intertie study alone. The prior work reviewed includes transmission interconnection studies, power supply studies, hydroelectric generation feasibility studies, electric load forecasts and utility transmission design efforts. Because of the time and scope limitations for Phase 2 of the Intertie Study, the previous studies were relied upon most extensively with regard to technical and routing issues related to the proposed transmission systems. Much has changed in recent years with regard to transmission facilities in Southeast Alaska, and as a whole, the Intertie Study reflects a significant update to the previous studies.

[1]The Southeast Alaska Intertie System, as proposed in previous studies, includes an interconnection between the northern and southern parts of the system. The previous studies have identified options for the north-south interconnection to be between Hoonah, Angoon, Sitka and Kake or between the Snettisham hydroelectric project and Kake.

[2] The Power Cost Equalization (PCE) program subsidizes retail electric rates for residential customers and public facilities in qualifying communities. The funding of the PCE program is granted by the State legislature on an annual basis and no guarantees can be provided with regard to its continuation in the future. An endowment was created in 2002 using funds from the divestiture of the Four Dam Pool to fund a portion of the PCE program.

In conducting Phase 2 of the Intertie Study, previous studies were obtained and reviewed, new information was gathered, and discussions were held with a number of utility, community, and government representatives. A feasibility level technical evaluation of SEI-1 and SEI-2 was conducted based on a review of previous studies, discussions with utility personnel familiar with the area and consideration of current utility practice. The technical review included consideration of the line route, system configuration, design criteria, and cost. Since SEI-1 and SEI-2 have been studied more extensively in recent years than the other segments, the technical review of the other segments is less detailed. Updated cost estimates have been prepared for each of the transmission segments.

Most of the proposed routes for the transmission interconnections shown in this report are consistent with routes defined in previous feasibility studies[3]. It is important to note that additional study will be needed for all of the Intertie segments and the eventual configuration and routing of the lines could be significantly different than discussed in this report. A critical factor with regard to future transmission line development is the potential development of roads in the region. Construction and maintenance of transmission lines adjacent to existing roads can be much lower cost than in undeveloped areas. As a result, if roads are under consideration in certain areas, it would most likely be advantageous to plan to construct transmission lines along the road route[4].

A significant amount of new effort was conducted with regard to power supply analysis and the economic analysis of the Interties. This portion of the Intertie Study involved the projection of power requirements and the estimation of alternative power production costs. As with any analysis of this kind, a number of assumptions were made and it is important to note that the use of alternative assumptions could produce different results.

In conducting the economic analysis for the Intertie Study, terms and conditions of existing contracts and agreements have been acknowledged to assure that the analysis appropriately models the commercial environment in which the Interties will operate. The question then becomes, is the Intertie economically justifiable from the perspective of the specific utilities that will be connected to it? Many transmission and power supply studies in the past have looked at economic viability from a regional or possibly even a "societal" basis.

Another significant difference in the Intertie Study compared to previous studies is that the capital costs (i.e. costs of planning, permitting, construction, financing, etc.) of the Intertie systems are not included in the evaluation of costs and benefits. It has been assumed[5] that the Interties will be grant funded to the maximum extent possible and will have no capital recovery component associated with their future cost structure.

[3] The proposed routes are generally identified among the "potential power transmission corridors" in the 1997 Revision of the Tongass National Forest Land and Resource Management Plan.
[4] In the Phase 1 report, the recommended route of SEI-2 between Kake and Petersburg was identified as the southern route across central Kupreanof Island. Most of this route is along existing forest service roads. A possible year-around road between Kake and Petersburg would most likely take a northern route across the island which might suggest the route of SEI-2 would be adjusted to follow the road.
[5] This assumption has been provided by the Southeast Conference.

This study has been prepared in association with several other firms. Commonwealth Associates, Inc. was responsible for the review of overhead transmission routes and cost estimates; CH2M-Hill reviewed permitting requirements and prepared an estimate of the cost and time to obtain the necessary permits; Northstar Power Engineering prepared an evaluation of direct current (dc) transmission alternatives; and Poseidon Engineering Ltd. reviewed issues regarding the submarine cables to be used in the Interties. D. Hittle & Associates had primary responsibility for the power supply and economic analyses and for overall coordination of the study effort.

It should also be understood that the Intertie Study is a feasibility assessment. The technical information and cost estimates presented in this report are subject to change as more additional studies are conducted and more information is obtained. Actual design of the systems, if pursued in the future, will provide much more detailed specification of the system components, routes and configuration and allow for greater precision on estimating costs. The actual cost of constructing the system, however, will be subject to a number of factors including market conditions at the time bids for material and construction services are requested.

Previous Studies

Two previous studies have addressed the feasibility of developing an integrated electrical transmission intertie system for Southeast Alaska. The two previous overview studies were:

- The "*Southeast Alaska Transmission Intertie Study*" was prepared for the Alaska Energy Authority by Harza Engineering Company and dated October 1987. This study was an intensive effort that involved a significant amount of survey work in the field and evaluated transmission segments to most communities throughout the region extending from Skagway in the north to Ketchikan in the south[6]. The study consolidated much of the knowledge at the time regarding potential transmission routes and concluded: "…that a transmission system interconnecting many of the Southeast Alaska communities is technically and economically feasible".
- The "*Southeast Alaska Electrical Intertie System Plan*" was prepared for the Southeast Conference by Acres International and dated February 1997. The Acres study compiled information from previous studies and provided estimated costs and a time frame for the development of a Southeast Alaska Intertie system.

An Intertie from Juneau to Greens Creek Mine was addressed in the following study:

- *Greens Creek Transmission Line Planning Capital Cost Estimate*, prepared for the Alaska Energy Authority by R. W. Beck and Associates, Inc., December 1992.

An Intertie from Petersburg to Kake has been specifically addressed in three earlier studies starting in the early 1980's with the last being conducted in 1996. These studies were:

[6] The 1987 Harza Study also included the evaluation of transmission interconnections to Whitehorse, Yukon Territory, Prince Rupert, British Columbia, and the proposed Quartz Hill molybdenum mine in the Misty Fiords National Monument south of Ketchikan.

- *Transmission Intertie, Kake-Petersburg, A Reconnaissance Report*, prepared for the Alaska Power Authority by Robert W. Retherford Associates, January 1981.
- *Tyee-Kake Intertie Project, Detailed Feasibility Analysis, Volumes I and II* , prepared for the Alaska Power Authority by Ebasco, Inc., 1984.
- *Feasibility Study Kake-Petersburg Intertie*, prepared for the State of Alaska, Department of Community and Regional Affairs, Division of Energy by R. W. Beck, Inc., June 1996.

A number of other studies have been conducted in recent years evaluating power supply alternatives in Southeast Alaska. Several of these studies considered transmission interconnections with other communities as potential power supply alternatives to the extent that power could be obtained from generating facilities elsewhere. These studies were reviewed for basic information applicable to the Intertie Study. The studies include:

- *Thomas Bay Hydroelectric Project, Pre-Feasibility Assessment Report*, prepared for the City of Petersburg by Hosey & Associates, December 1985.
- *Juneau 20-Year Power Supply Plan Update,* prepared for Alaska Electric Light & Power, Alaska Energy Authority, Alaska Power Administration and Juneau Energy Advisory Committee by CH2M-Hill, August 1990.
- *Electric Resource Evaluation and Strategic Plan,* prepared for the City and Borough of Sitka by R.W. Beck and Associates, Inc., November 1991.
- *Feasibility Study, Lake Tyee to Swan Lake Transmission Intertie*, prepared for the Alaska Energy Authority by R.W. Beck and Associates, Inc., June 1992.
- *Power Supply Planning Study,* prepared for Ketchikan Public Utilities by R.W. Beck, Inc., December 1996, updated in 1998.
- *Final Environmental Impact Statement, Swan Lake – Lake Tyee Intertie*, US Department of Agriculture-Alaska Region, Forest Service, August 1997.
- *Record of Decision, Swan Lake – Lake Tyee Intertie*, US Department of Agriculture, Forest Service-Alaska Region, August 1997.
- *Electric Resource Evaluation and Strategic Plan, 1997 Update*, prepared for the City and Borough of Sitka by R.W. Beck, Inc., September 1997.
- *Sitka-Kake-Petersburg, HVDC Intertie Study,* prepared for the City and Borough of Sitka by Dr. George Karady and F. Mike Carson, January 2000.
- *Metlakatla-Ketchikan Intertie Project – Reconnaissance Report*, prepared for Ketchikan Public Utilities by R.W. Beck, Inc., March 2000.
- *Four Dam Pool Hydroelectric Projects, Repair, Replacement and Reclamation Plan*, prepared for the Four Dam Pool Power Agency by D. Hittle & Associates, Inc., January 2002.

Status of Transmission Development in Southeast Alaska

Since completion of the 1987 Harza Study, there have been several follow-on studies of transmission interconnections in the region as indicated above. Further, some transmission interconnections have been constructed and another, the Swan – Tyee Intertie is being developed by Ketchikan Public Utilities (KPU) and is presently under construction. Alaska Power & Telephone Company (AP&T) constructed and began operating a submarine cable connection between Skagway and Haines in 1998. The State constructed an overhead transmission line between Craig and Klawock[7] in 1988 and more recently, AP&T constructed a transmission interconnection between Craig and Thorne Bay on Prince of Wales Island.

The three AP&T interconnections are between AP&T-owned distribution centers and serve the purpose of expanding the load base to be served from AP&T's hydroelectric generating facilities, the Black Bear Lake project near Klawock and the Goat Lake project near Skagway. KPU is developing the Swan – Tyee Intertie to gain access to surplus generation at the Lake Tyee hydroelectric project. AEL&P has also performed preliminary studies and investigations with regard to the Juneau – Greens Creek – Hoonah Intertie in recent years.

The City of Ketchikan is serving as the Swan – Tyee Intertie owner, holding the necessary permits and licenses and administering the contracts for design, construction and material procurement[8]. The line is being designed by Washington Infrastructure Services, Inc. of Bellevue, Washington under a contract initially awarded to Raytheon Engineers & Constructors in 1995. Most of the design and permit application effort to date was undertaken and completed between 1995 and 1997. The need to arrange financing for construction and obtain necessary permits halted any further design work at the time. WIS continued to provide KPU with some periodic support of its design, including evaluation of alternative technologies, but did not restart its regular involvement with the design process until August 2002.

At the present time, design of the Swan – Tyee Intertie is essentially complete, all necessary permits have been obtained, approximately 18 miles of the right-of-way was cleared in 2002 and the procurement contract for the steel H-frame structures and foundation pile caps was awarded in December 2002. Remaining clearing and foundation survey work is presently underway and will be completed in 2003 pursuant to a contract with Columbia Helicopters. Construction of the line is expected to be completed in mid-2005 at a total estimated cost of $76.5 million. The Swan – Tyee line in total will be approximately 57 miles in length and entirely of overhead construction with no submarine crossings. It will be constructed for 138-kV nominal voltage but will be operated initially at 69-kV.

AEL&P and others have conducted several evaluations of developing a transmission interconnection with the Kennecott Mining Company's Greens Creek Mine on Admiralty Island.

[7] AP&T operates, maintains and is the sole user of the Craig – Klawock transmission line pursuant to a contract with the State.

[8] The City of Ketchikan and the Four Dam Pool Power Agency (FDPPA) are negotiating to transfer the Swan – Tyee Intertie project to the FDPPA. It is anticipated that the FDPPA will take ownership of the project upon its completion, if not sooner.

In 1998, AEL&P provided certain power supply availability and costing information to Kennecott as part of an evaluation of power supply alternatives being conducted by Kennecott. Kennecott subsequently decided to expand it's on site generation capability at the mine site[9] rather than pursue an interconnection to AEL&P at the time. AEL&P has continued to investigate the feasibility of constructing a transmission line to Admiralty Island as part of an eventual interconnection to Hoonah[10]. Since the 1998 proposal to Kennecott, AEL&P has constructed a significant length of overhead 69-kV transmission line on northern Douglas Island as part of its overall system expansion plan. The transmission line on Douglas Island is a critical component in the interconnection with the Kennecott Greens Creek Mine and Hoonah. The Douglas Island transmission line is complete to within a short distance of the proposed landing site of the submarine cable crossing to Admiralty Island.

Since the interconnection of Craig and Klawock in 1988, AP&T's Prince of Wales transmission system has been expanded to interconnect the Black Bear Lake hydroelectric project in 1995, Thorne Bay in 1999 and Kasaan in 2001. AP&T plans to expand the existing transmission system on Prince of Wales Island to include Hollis in 2003 and Hydaburg in 2004 at an estimated cost of $3.0 million. In the reasonably near future, AP&T plans to extend its transmission system north to Coffman Cove and Naukati at an estimated cost of $3.9 million, subject to grant funding. The Prince of Wales transmission system operates at 34.5 kilovolts (kV).

AP&T has also indicated that it has applied for federal grants to construct a transmission interconnection between Haines and THREA's Chilkat Valley/Klukwan electric system with a combination of 5 miles of upgraded 34.5-kV overhead line and 5 miles of underground cable. The estimated cost of the interconnection, as provided by AP&T, is $724,000. AP&T's 16-mile long submarine cable between Skagway and Haines includes a landing at Kasidaya Creek to accommodate future development of a hydroelectric project at this location.

Other Significant Issues Affecting Regional Transmission Development

A number of other factors and issues will significantly affect how and when future development of transmission systems in Southeast Alaska is accomplished. Most of these factors are continually changing and should continue to be monitored on a regular basis, particularly as to how they might affect the conclusions presented in this report. As such, it is important to acknowledge that the Intertie Study, which is based significantly on the power supply situation in the region as it exists today, should be updated periodically to incorporate changing conditions. Although not necessarily conducted on a coordinated basis, the various power supply and transmission related studies conducted in Southeast Alaska over the past 25 years reflect the need to continually evaluate proposed plans as conditions change.

Following are several key issues that should continue to be monitored as to the effect they may have on transmission and power supply planning in Southeast Alaska:

[9] Kennecott installed a 5,200 kW diesel-fired combustion turbine at the Greens Creek mine in 2000.
[10] AEL&P undertook its most recent investigations of the Juneau – Greens Creek – Hoonah transmission line, which involves two significant submarine cable crossings, as a follow-on to its involvement in 1999 with the replacement of the 138-kV submarine cables across Taku Inlet that are part of the Snettisham transmission line.

- Total power supply requirements in the region can change significantly with the gain or loss of a single large industrial load. Although electric loads in the communities are forecasted to increase modestly in the future, the addition of a new large mining load, for example, could drastically increase the overall electricity requirement in the region. Traditionally, large industrial loads in Southeast Alaska have provided their own power supply but a more extensive transmission system could potentially allow a regional utility-based power supply for new large loads.

- Electric loads in the smaller communities and rural areas of Southeast Alaska are most likely significantly lower than they would be otherwise due to very high retail electric rates. If rates can be reduced[11], electric consumption would be expected to increase.

- The cruise ship industry may want to expand the opportunity for shore-based electric supply to reduce the air pollution emissions from the ships while in port. Presently, only Princess Cruise Lines has this capability in Juneau. Expansion of this capability elsewhere in Southeast Alaska could significantly increase overall electricity needs from the local utility systems.

- The Institute of Economic Research (ISER) of the University of Alaska Anchorage, will be preparing a projection of power supply needs for the Prince of Wales power system in the near future. Results of this study could be useful to overall planning for the Intertie systems.

- The State continues to evaluate the possibility of constructing roads between various communities in the region. Transmission lines installed in areas with road access can be much less expensive to build and operate.

- Electric generating technologies continue to show advancement. The unavailability of natural gas in Southeast Alaska limits the type of generating units that could be installed, however, smaller, "distributed" and alternative generating technologies are of growing interest for on-site installation at commercial and industrial operations around the country. Example technologies of this type include microturbines and fuel cells. Most distributed generation systems use natural gas as a fuel.[12]

- Significant advancements have been made in wind energy generation systems and other alternative generating technologies that might be applicable for utility use in Southeast Alaska. Wind generation systems can work well in conjunction with hydroelectric systems[13].

- Environmental regulations which could affect the development of new hydroelectric and transmission systems continue to change. Air pollution and fuel transportation and

[11] Although power supply costs contribute to the high retail rates, a number of other factors such as utility debt repayment, depreciation, distribution system O&M expenses and administrative costs are even larger factors.
[12] The cost of power from microturbines and fuel cells is dependent on natural gas prices.
[13] Chugach Electric Association in Anchorage recently announced plans to develop a wind power generation site at Bird Point south of Anchorage. The $6.4 million, 4.5 MW project is estimated to provide energy at 5.5¢ per kWh.

storage regulations can also significantly affect the continued reliance upon diesel generation in the region.

- Diesel fuel prices can fluctuate dramatically causing uncertainty in electric rates and electric utility operating costs. Uncertainty in electric rates can contribute to lower electric loads and reluctance on the part of businesses to invest in new facilities and operations.

- Telecommunication service providers are potentially interested in bundling fiber optic cables with new transmission lines. Fiber optic communication links within Southeast Alaska could improve overall service and enhance certain business opportunities. Joint ownership of electric/fiber optic transmission systems could potentially be advantageous for the entities involved.

- New developments near Southeast Alaska in Canada could afford certain opportunities for joint development of future transmission and power supply facilities.

- AEL&P is continuing to negotiate with KMC-GC regarding power supply and electric interconnection arrangements. AEL&P is also continuing to evaluate the development of the Lake Dorothy hydroelectric project. The Lake Dorothy project is a critical power supply element in the viability of the potential interconnection with KMC-GC as well as to the long term power supply of the Juneau area.

- New hydroelectric development, particularly for larger facilities, can be very expensive. Much of the potential advantage in the proposed transmission interconnections is tied to utilization of existing surplus hydroelectric generation capability. The price variance between surplus energy and "new resource" energy can be substantial. Many studies of new Southeast hydroelectric facilities conducted in the past are 10 to fifteen years old and proposed relatively expensive developments. Some additional study may be warranted to identify smaller, less costly new hydroelectric development opportunities[14].

- Construction of the Swan-Tyee Intertie, currently underway, should be monitored with regard to issues that may impact development of future transmission systems in Southeast Alaska. Some of these issues include actual construction costs and effort, operational performance, and arrangements for interconnected utility operation.

- It has been indicated that the Southeast Conference plans to undertake a legal/policy analysis regarding potential organizational structures related to ownership and operation of the transmission lines. The current mix of investor, municipal and consumer owned electric utility systems in Southeast Alaska makes this a relatively complicated issue.

- A number of Southeast utilities, joint operating organizations, local governments, private businesses and native corporations have indicated interest in applying for government

[14] AP&T developed a smaller, less costly Black Bear Lake hydroelectric project in 1995 than had been proposed earlier by the Alaska Energy Authority. AP&T also has recently proposed a different configuration for the Mahoney Lake Project near Ketchikan that is significantly less costly than the project proposed earlier by the State.

grants and loans related to energy infrastructure projects. How some of these efforts might be coordinated to best serve the region as a whole should potentially be evaluated. A compilation of federal and non-federal contributions towards the Southeast Alaska Intertie Project, as prepared by the Southeast Conference, is included as Appendix D to this report.

Conclusions

The following conclusions are offered with regard to Phase 1 and Phase 2 of the Intertie Study. Although these conclusions are offered at this point in the report, it is important to understand the assumptions and other factors described in subsequent sections of this report that contribute to the conclusions.

1. Both the Juneau – Greens Creek – Hoonah Intertie and the Kake – Petersburg Intertie are technically feasible. Proposed routes for both Interties have been studied before and are generally identified in existing US Forest Service land use plans. Although two primary route alternatives have been identified for the Kake – Petersburg Intertie, the Southern route alternative has been and continues to be the preferred alternative from a cost and constructability perspective. If a road were to be built between Kake and Petersburg, the location of this road could affect the recommended placement of the transmission route alternative. While construction costs for the transmission line could be higher for a route other than the Southern route alternative, location of the line near a year-round maintained road should provide for lower long term maintenance costs.

2. AEL&P has undertaken certain efforts to develop the Juneau – Greens Creek – Hoonah Intertie that should contribute to expediting the time required for development of this system. The total time required to develop and construct the Kake – Petersburg line is approximately four years, of which construction is estimated to require about two construction seasons.

3. Energy generation capability is projected to be available from the Four Dam Pool Power Agency's Lake Tyee hydroelectric project to sell to THREA for use in Kake if the Kake – Petersburg Intertie is constructed. A power sales contract will need to be negotiated between THREA and the Four Dam Pool Power Agency.

4. AEL&P will need to construct the Lake Dorothy hydroelectric project to have sufficient energy generation capability to supply KMC-GC and THREA's Hoonah service area over the proposed Intertie. AEL&P is presently in the process of obtaining necessary permits and approvals to develop the Lake Dorothy project.

5. The annual costs to operate, maintain and administer the Juneau - Greens Creek – Hoonah (SEI-1) and Kake – Petersburg (SEI-2) Interties should be relatively minor and can be reasonably recovered through charges for transmission services or, bundled in with the delivered cost of power.

6. Routes for transmission lines between the communities of Southeast Alaska have been identified based on previous studies. These routes combine lengthy submarine cables and overhead transmission lines generally through undeveloped areas. The routes for the most part, are included as identified power system corridors in the Tongass National Forest Land Management Plan. The costs to construct and develop each of these lines at current cost levels have been estimated and are summarized as follows:

		Estimated Cost (millions)	Line Length (miles)		
			Sub. Cable	Overhead	Total
SEI - 1	Juneau - KMCGC - Hoonah	$ 37.1	34.5	18.7	53.2
SEI - 2	Kake - Petersburg	23.1	1.7	49.9	51.6
SEI - 3	Metlakatla - Ketchikan	6.0	1.0	16.0	17.0
SEI - 4	Ketchikan - Prince of Wales	31.7	17.2	18.0	35.2
SEI - 5	Kake - Sitka	50.3	35.0	24.0	59.0
SEI - 6	Hawk Inlet - Angoon - Sitka	81.2	82.0	22.0	104.0
	Less: SEI-6 costs common to SEI-5	(9.5)	-	(20.0)	(20.0)
SEI - 7	Hoonah - Gustavus	26.4	29.0	1.0	30.0
SEI - 8	Juneau - Haines	69.8	2.8	82.5	85.3
	Total System	$ 316.0	203.2	212.1	415.3

It should be noted that significant alternative configurations and route options exist for SEI-2, SEI-4, SEI-6 and SEI-8 which would change the estimated length and cost of these lines. The various alternatives will need to be evaluated more thoroughly in the future as development of these lines proceeds. Depending on the timing of construction of the Intertie segments, estimated costs will need to reflect the estimated impact of inflation.

7. A number of sub-regional transmission lines and new hydroelectric resources have been evaluated by the electric utilities in Southeast Alaska. Some of these projects are well into the development process and are proposed to be constructed in the near future. These projects are summarized with their assumed on-line dates as follows:

Project	Community/Utility	Projected On-Line Year
Craig - Hollis Transmission Line	AP&T	2003
Craig - Hydaburg Transmission Line	AP&T	2004
Coffman Cove Transmission Line	AP&T	2007 *
South Fork Hydroelectric Project	AP&T Prince of Wales	2006
Lake Dorothy Hydroelectric Project	AEL&P	2007
Haines - Chilkat Valley Transmission Line	AP&T	2007 *
Kasidaya Hydroelectric Project	AP&T Upper Lynn Canal	2006
Falls Creek Hydroelectric Project	Gustavus Electric Co.	2008

* Date shown is dependent on ability to obtain project funding.

8. Electric loads in Southeast Alaska are forecasted to increase at approximately 1% per year. Some communities are expected to see slightly higher rates of growth in the next few years due to expanded economic activity in their areas. The potential for noticeable increases in energy requirements exists, however, particularly due to possible new mining operations.

9. The planned additions of new small hydroelectric facilities and the relatively slow growth expected in electrical loads reduces the near-term benefits that could be realized with Interties between certain communities.

10. An evaluation of the costs and benefits of the Intertie segments has been prepared to determine when the savings in diesel energy generation production expenses would exceed the costs of purchasing and delivering power over the Interties. The results of this analysis indicate when new Intertie segments would be considered "economically justifiable"[15]. The recommended timing of the new Intertie segments, as determined by this analysis, is as follows:

		Projected On-Line Year
SEI - 1	Juneau - KMCGC - Hoonah	2007
SEI - 2	Kake - Petersburg	2007
SEI - 3	Metlakatla - Ketchikan	2015-2020
SEI - 4	Ketchikan - Prince of Wales	2020-2025
SEI - 5	Kake - Sitka	2025-2030
SEI - 6	Hawk Inlet - Angoon - Sitka	2020-2025
SEI - 7	Hoonah - Gustavus	After 2030
SEI - 8	Juneau - Haines	After 2030

[15] The economic analysis assumes that the capital costs of the Intertie segments are to be 100% grant funded.

11. The projected timing of the Intertie segments as indicated above, could be significantly affected by a number of factors including slower or faster growth in regional and community energy requirements, the development of proposed local hydroelectric projects, the cost of diesel fuel, various regulatory and environmental constraints, the development or proposed development of roads within the region, and other factors. The Southeast Conference and the communities and electric utilities of Southeast Alaska should continue to monitor these factors.

12. Potential reductions in retail electric rates resulting from the Interties are difficult to estimate due to a number of factors including the impact of the State's PCE program, the long-term availability of regional surplus hydroelectric energy and the potential avoided costs of future new generation resources. With the SEI-1 and SEI-2 Interties, THREA may be able to offer economic incentive rates in Kake and Hoonah, with certain limitations, to encourage new commercial activity. The economic incentive rates could be tied to the cost of purchased power with a nominal margin.

13. Alternative direct current (DC) transmission alternatives may be preferable to alternating current (AC) alternatives for some of the Intertie segments, particularly for the longer submarine cable crossings.

14. The Southeast Conference should continue to evaluate the inclusion of telecommunication delivery systems in the electric transmission lines. Fiber optic strands can be relatively inexpensively included in bundled submarine cables.

Regional Power Supply Evaluation

Power Supply Evaluation

Overview

Hydroelectric generating facilities and diesel generators provide nearly all of the electric power generation in Southeast Alaska[16]. Elsewhere in Alaska, natural gas and coal are used to provide a significant portion of the electrical power supply; however, these fuels are not commercially available in Southeast Alaska. The State and federal government, as well as certain communities and utilities have developed the existing hydroelectric generating plants in Southeast Alaska.

Hydroelectric facilities require specific site conditions and generally have high initial development costs. The effective costs of hydroelectric development can be made even higher by the need to construct projects larger than the present electric loads require. This can create a surplus energy generation capability from hydroelectric plants, sometimes for a significant length of time.

The availability of diesel fuel, the ease of installing diesel generators in a wide range of capacities and relatively low initial costs have made diesel engine generators the generator of choice in most remote locations including Southeast Alaska. The operating and maintenance (O&M) expenses associated with diesel generators, however, often make them more costly than hydroelectric generation plants in the long run. Potential interruptions in fuel delivery, the susceptibility of fuel prices to wide variation, noise and air pollution issues are other negative aspects of diesel generation. Where available, hydroelectric generation is typically preferred to diesel generation.

The primary purpose of the Southeast transmission system will be to transmit power generated at lower-cost hydroelectric generation facilities to communities where diesel generation is the principal source of power supply. At the present time, some additional hydroelectric energy capability is available at the Four Dam Pool Power Agency's Lake Tyee project, the State's Snettisham project, the City of Sitka's hydroelectric system and Metlakatla Power & Light's electric system. With a transmission system that creates a larger electric load base, fuller utilization of the capability of these projects can be accomplished. Further, new hydroelectric generation projects can be more effectively developed in the future.

The electric power requirements of all the load centers involved with the Intertie segments are important to the evaluation of Intertie feasibility. Projections of power requirements were compiled in the Phase 1 study for Kake, Petersburg, Wrangell, and Ketchikan, all of which currently rely upon the output of the Lake Tyee project or will be connected to Lake Tyee through the construction of new transmission facilities. Power requirement projections were

[16] AEL&P and KMC-GC use oil-fired combustion turbines for a portion of their power supply requirement. In the past, pulp mills in Ketchikan and Sitka used production waste materials as a boiler fuel to drive steam turbines.

also been compiled for AEL&P, the Kennecott Mining Company - Greens Creek Mine (KMC-GC) and Hoonah, all of which will use power from the Snettisham and Lake Dorothy projects.

Electric power requirements for nearly all other communities and load centers in Southeast Alaska have been compiled using estimated growth factors applied to recently experienced electric generation requirements. In general, the average annual growth in electric requirements is expected to be approximately 1% per year. In some cases, such as with Hoonah, specific commercial expansion in the area is expected that would cause more significant adjustment in annual energy requirements than would be reflected with a constant, average growth rate. The communities and load centers included in the analysis are shown in Table 2-1.

TABLE 2-1
Primary Southeast Alaska Electric Utilities and 2002 Energy Sales

	Utility	Sales (MWh)	% of Total
Upper Lynn Canal Region			
Skagway	AP&T	10,521	1.4%
Haines	AP&T	11,725	1.6%
Chilkat Valley/Klukwan	THREA	1,308	0.2%
Subtotal		23,554	3.2%
North Region			
Juneau	AEL&P	311,550	41.9%
KMC-GC (Greens Creek)	Self	55,845	7.5%
Hoonah	THREA	4,161	0.6%
Gustavus	Gustavus Electric Co.	1,390	0.2%
Excursion Inlet Cannery	Self	5,375	0.7%
NPS - Glacier Bay	Self	1,000	0.1%
Subtotal		379,321	51.0%
West Central Region			
Sitka	Municipal System	91,802	12.4%
Angoon	THREA	1,737	0.2%
Tenakee Springs	Municipal System	382	0.1%
Subtotal		93,921	12.6%
Tyee-Swan Region			
Wrangell	Municipal System	25,229	3.4%
Petersburg	Municipal System	36,617	4.9%
Kake	THREA	3,964	0.5%
Ketchikan	Municipal System	142,567	19.2%
Metlakatla	Metlakatla Power & Light	13,543	1.8%
Subtotal		221,920	29.9%
Prince of Wales Region			
Craig/Klawock/Thorne Bay/Kasaan	AP&T	21,355	2.9%
Coffman Cove	AP&T	674	0.1%
Hollis	AP&T	507	0.1%
Hydaburg	AP&T	1,449	0.2%
Naukati Bay	AP&T	382	0.1%
Whale Pass	AP&T	213	0.0%
Subtotal		24,580	3.3%
Totals		743,296	100.0%
Totals - Average MW		84.9	

As can be seen in Table 2-1, total energy sales in 2002 for the load centers included in the analysis were 743,296 megawatt-hours (MWh) or 84.9 average megawatts (MW)[17]. Table 2-1 also shows that energy sales in Juneau represent nearly 42% of the regional total and KMC-GC accounts for 7.5% of the total Southeast energy sales. In 2002, energy sales in Juneau, Sitka and Ketchikan represented 73.4% of all energy sales in Southeast Alaska.

The Intertie segments will be used to transmit hydroelectric energy that is either surplus to the needs of the utility systems currently interconnected with the hydroelectric plants or from new hydro plants. Consequently, it is important to evaluate the availability of the surplus generation and identify potential new hydroelectric resources that can be developed to economically provide additional energy to the interconnected systems, as needed, in the future. Although transmission lines are generally very reliable, power deliveries over the Intertie segments will need to be considered interruptible. As such, local generation will need to be retained in each community sufficient to supply loads if the transmission lines are down due to unplanned outages or maintenance.

Although it is expected that hydroelectric energy will be the primary type of energy transmitted over the Intertie segments, fossil fuel generation (primarily diesel) can also be readily transmitted. Since power is lost during transmission, normal operation would generally favor running diesel generators, if needed, closer to the load rather than many miles away. There are situations, however, where it would be economically beneficial to use diesel generators and transmit the power rather than run local generators. Some of these situations could include opportunities to run larger, more efficient units to “firm-up” hydroelectric generation.

It is also important to note the commercial and contractual arrangements that are in place that could potentially limit the availability of power resources for sale to other utility systems. For example, the Lake Tyee project is owned and operated by the Four Dam Pool Power Agency and its output is sold to Petersburg and Wrangell pursuant to the Four Dam Pool Power Sales Agreement. Petersburg, Wrangell and eventually Ketchikan when it is interconnected, will always have first priority to the output of the Lake Tyee Project pursuant to the Power Sales Agreement. AEL&P is a regulated investor-owned utility with an obligation to provide a return to its shareholders. Any sale of power from AEL&P’s resources will need to acknowledge the rate structure that AEL&P has in place.

Power Requirements

Electric power requirements have been projected for the load centers for a twenty-year projection period. For most of the communities, the power requirement projections are based on assumed growth rates applied to recently experienced loads. Explicit adjustments have been made for new large loads that have been identified. Power requirements for Ketchikan, Petersburg and Wrangell have been compiled from previously prepared Four Dam Pool planning studies. The

[17] One MWh equals 1,000 kilowatt-hours (kWh). Electric utilities meter energy sales in kWh. Average MWs are calculated as MWh divided by the number of hours in a period. On an annual basis, the period of time is 8,760 hours.

power requirements for Sitka are based approximately on a load forecast prepared in 2001 adjusted as needed to reflect recent energy sales experience.

AEL&P has provided projections of its power requirements. KMC-GC has also provided estimates of its current power requirements and expectations of changes to the present load amount. AP&T has indicated a range of potential growth rates for the communities it serves and the information provide by AP&T was augmented with information gained from discussions with representatives from several of these communities. Direct information was also obtained from Gustavus Electric Company, the National Park Service at Glacier Bay, Metlakatla Power & Light and the Ocean Beauty cannery facility at Excursion Inlet.

Electric utilities account for their sales of electricity by the type of customer served. Typical customer classifications can include residential, small commercial, large commercial, public authorities, and street lights. Rates can be established for each customer classification in accordance with the average characteristics of the customers in the class. In 2002 in Sitka, for example, 43%, 31% and 22% of total energy sales were to residential, commercial, and public authority customers, respectively. In addition to the amount of energy sold to customers, electricity is used by the utility itself and power is lost in the transmission, transformation and distribution process. As a result, the total energy requirement of an electric utility is noticeably larger than the metered retail sales amount. The total energy requirement corresponds to the total amount of energy that must be generated.

The total energy requirement of the communities in Southeast Alaska in 2002 was 800,174 MWh, which is 56,878 MWh or 7.7% more than the total energy sales shown in Table 2-1. Table 2-2 shows the total energy requirement for each community, the percent of losses and utility own use, and the amount of hydroelectric generation. As shown in Table 2-2, total hydroelectric generation among the communities in 2002 was 692,165 MWh representing 86.5% of the total Southeast energy requirement.

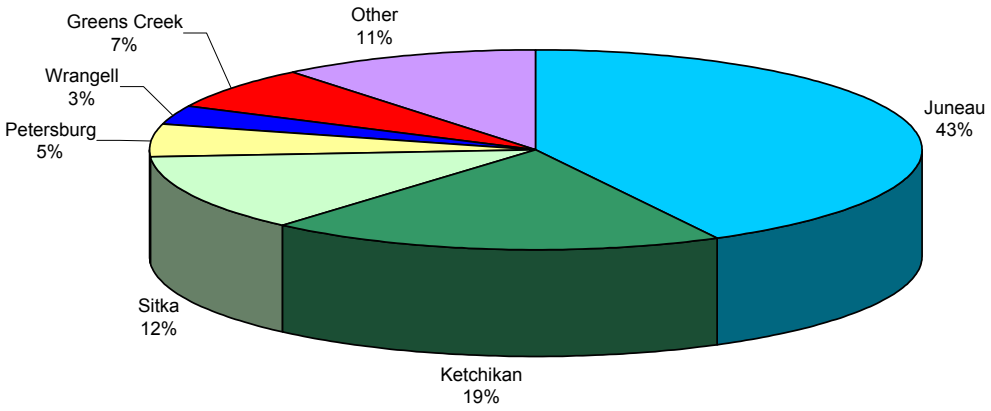
TABLE 2-2
Southeast Alaska Communities and Load Centers
2002 Energy Requirements, Energy Losses and Hydroelectric Generation

	Energy Reqs. (MWh)[1]	Loss %[2]	Hydro Energy (MWh)
Upper Lynn Canal Region			
Skagway	10,837	3.0%	10,533
Haines	12,777	9.0%	11,714
Chilkat Valley/Klukwan	1,668	27.5%	1,668
Subtotal	25,282		23,915
North Region			
Juneau	337,785	8.9%	327,934
KMC-GC (Greens Creek)	55,845	0.0%	-
Hoonah	4,557	9.5%	-
Gustavus	1,614	16.1%	-
Excursion Inlet Cannery	5,600	4.2%	-
NPS - Glacier Bay	1,000	0.0%	-
Subtotal	406,401		327,934
West Central Region			
Sitka	99,205	8.1%	98,832
Angoon	1,996	14.9%	-
Tenakee Springs	437	14.4%	-
Subtotal	101,638		98,832
Tyee-Swan Region			
Wrangell	25,742	2.0%	25,442
Petersburg	41,644	13.7%	41,010
Kake	4,291	8.2%	-
Ketchikan	153,972	8.0%	140,684
Metlakatla	14,356	6.0%	14,356
Subtotal	240,005		221,492
Prince of Wales Region			
Craig/Klawock/Thorne Bay/Kasaan	23,279	9.0%	19,992
Coffman Cove	733	8.8%	-
Hollis	565	11.4%	-
Hydaburg	1,541	6.3%	-
Naukati Bay	456	19.4%	-
Whale Pass	274	28.6%	-
Subtotal	26,848		19,992
Totals	800,174	58,254	692,165
Totals - Average MW	91.3	6.6	79.0
Total Losses - %		7.9%	
Total Hydroelectric %			86.5%

[1] Total energy requirements include energy sales, utility own use, and energy losses. This amount is representative of total energy generation.

[2] Losses are expressed as a percentage of total sales shown in Table 2-1. Loss percentages as shown are potentially an inaccurate reflection of typical long-term losses due to inconsistencies in data reporting cycles.

FIGURE 2-1
Southeast Alaska Communities and Load Centers
2002 Energy Requirements



As shown in Figure 2-1, energy requirements in Juneau, Ketchikan, Sitka, Petersburg, Wrangell and KMC-GC (Greens Creek) represent 89% of the total regional energy requirement. Except for KMC-GC, all of these larger load centers rely upon hydroelectric energy for a substantial portion, if not all, of their power supply.

In the future, electric needs in Southeast Alaska are expected to increase over time at a modest rate. In recent years, electricity requirements have remained relatively stable with some decline in certain communities such as Metlakatla and Wrangell. It is important to note that the closures of the Alaska Pulp Company pulp mill in Sitka in 1993 and the Ketchikan Pulp Company pulp mill in 1997 did not directly affect the local utility energy requirement in these communities since both mills generated their own power. A new large mining operation or wood manufacturing facility in the region, could substantially increase total energy requirements. Further, the potential exists for supplying shore-based power to cruise ships at ports other than Juneau. AEL&P indicates that its cruise ship load is approximately 10,000 MWh per year and that energy is sold at surplus power rates.

Electric energy loads have been projected for each of the communities based on either explicit load forecasts or assumed annual growth rates. The growth rates are based on information provided by the serving utilities and from the local communities. In most cases, a range of potential growth rates should be considered to acknowledge the uncertainty in future energy needs. For the purpose of the Intertie Study, however, mid-range growth rates have been used and are considered reasonable for the projections. The results of the analysis would potentially be different with alternative load growth assumptions.

It is important to note that the analysis included in this study has been based on the evaluation of energy requirements and energy generation. Electric utilities must also plan on and design their electric system to accommodate their peak demand or capacity requirement. With systems that

rely significantly upon hydroelectric generation, however, the limiting power supply factor is generally the energy generation capability of the hydro system. It is also acknowledged that significant diesel generating capacity exists to meet periodic peak demands that exceed the capacity of the hydroelectric generators.

The following table provides the assumed growth factors for the smaller load centers evaluated in the analysis.

TABLE 2-3
Assumed Average Annual Increase in Energy Requirements

	Assumed Average Annual Increase
Skagway	1.0%
Haines	1.0%
Chilkat Valley/Klukwan	2.0%
Juneau - AEL&P	
Gustavus including NPS	1.0%
Excursion Inlet	1.5%
Sitka	1.0%
Angoon	1.5%
Tenakee Springs	1.0%
Metlakatla	1.0%
Craig/Klawock/Thorne Bay/Kasaan	1.0%
Hollis	1.5%
Hydaburg	1.0%
Coffman Cove	1.5%
Naukati Bay	1.5%

The basis for and assumptions used in preparing the projected power requirements for each of the larger load centers and Kake and Hoonah are described in the following paragraphs.

Alaska Electric Light & Power

AEL&P has developed a forecast of its energy sales and total energy requirements for a 20-year period. The forecast includes sales to AEL&P's retail residential, commercial and public facility customers as well as non-firm sales that are dependent on the availability of surplus hydroelectric generation[18]. Non-firm energy sales are primarily to AEL&P's dual fuel customers and to cruise ships equipped to connect to shore-based power generation. AEL&P is projecting its total energy requirement to increase from 340,000 MWh in 2003 to 403,000 MWh in 2023, representing an average annual growth rate of 0.85%. AEL&P indicates that its forecast reflects

[18] Hydroelectric generation can vary from year to year depending on local precipitation. In dryer years, the amount of hydroelectric generation surplus to the needs of AEL&P's retail customer base is lower than in normal years.

a trend towards lower residential electric heating usage in Juneau than had been experienced in the past[19].

Ketchikan

Ketchikan Public Utilities (KPU), a municipally owned electric utility, is the second largest electric utility system in Southeast Alaska. KPU obtains the majority of its power supply from KPU-owned hydroelectric projects and the Swan Lake project, a Four Dam Pool Power Agency project. In most years, KPU's electric loads exceed the available hydroelectric generation capability and diesel generators must be used to supply the net power requirement. KPU is presently constructing the Swan-Tyee Intertie to gain access to the surplus generation capability of the Lake Tyee project[20]. The electric requirements of KPU will affect the net generation available to Kake from the Lake Tyee project.

Following the closure of the Ketchikan Pulp Company pulp mill power plant in 1997, KPU's total energy sales increased with the sale of power to the Gateway Forest Products sawmill. The sawmill closed at the end of 2001 and KPU saw a decrease in total energy sales. Electric loads are assumed to increase at average annual rates of 1.1%, 0.3% and 2.2% for base, low and high forecast scenarios, respectively. KPU's forecasted electric requirements are summarized in the following table.

TABLE 2-4
Ketchikan Public Utilities
Projected Energy Requirements – Medium Growth Scenario

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh) [1]	153,972	155,666	157,378	159,109	160,859	169,903
Less: KPU Hydro [2]	(68,460)	(68,460)	(68,460)	(68,460)	(68,460)	(68,460)
Less: Swan Lake [3]	(68,108)	(68,585)	(69,065)	(69,401)	(69,725)	(70,668)
Net Requirement [4]	17,404	18,621	19,853	21,248	22,674	30,775

[1] Assumes average growth in energy requirements of 1.1% per year.
[2] Estimated annual energy generation from KPU-owned hydroelectric projects assuming average precipitation levels.
[3] Estimated annual generation from the Swan Lake hydroelectric project assuming average precipitation levels. Average energy usage is expected to increase somewhat as the KPU load increases.
[4] Projected net energy requirement to be provided from diesel generation, new hydro project generation or the Lake Tyee hydroelectric project, assuming the Swan-Tyee Intertie is constructed.

Sitka

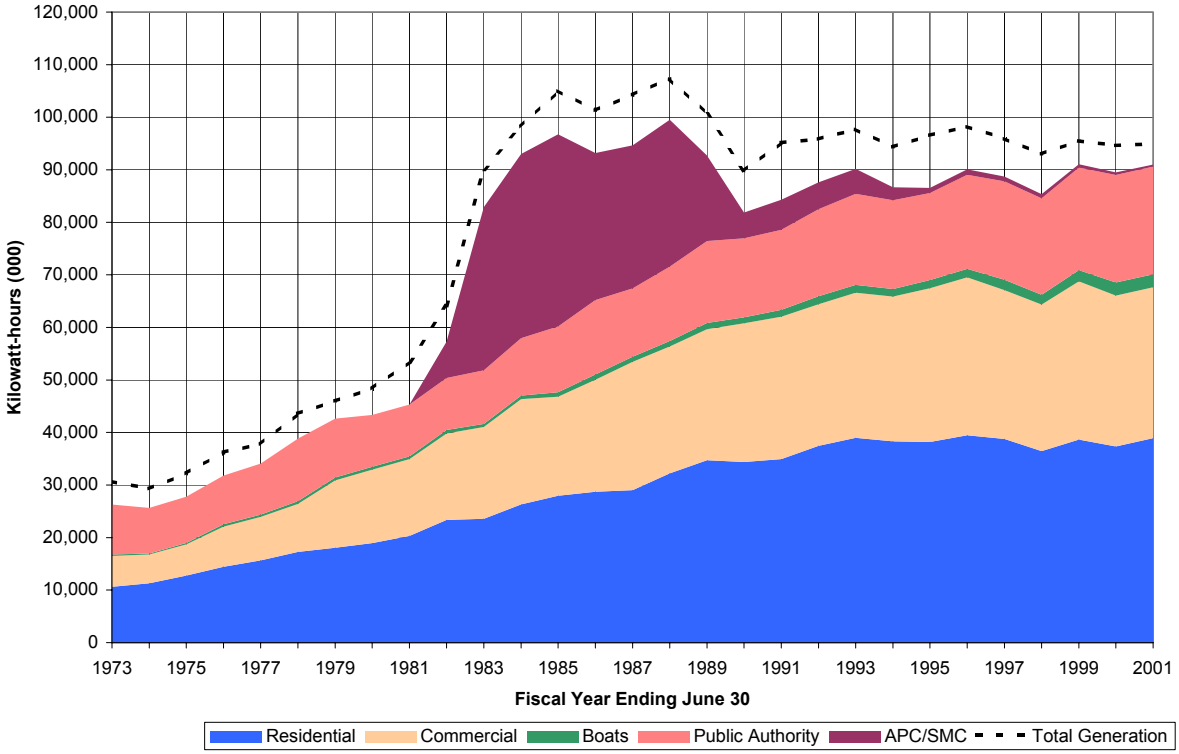
The City and Borough of Sitka Electric Department provides electric service to approximately 4,860 electric consumers. A 20-year electric load forecast for Sitka was prepared in 2001 based on projected population growth, local economic activity and recent trends in electric

[19] Kerosene-fueled heaters have become increasingly popular in Southeast Alaska for home heating and can generally provide acceptable space heating at a lower cost than electricity.
[20] The City of Ketchikan and the Four Dam Pool Power Agency (FDPPA) are presently negotiating to transfer the Swan – Tyee Intertie project to the FDPPA.

consumption. In recent years, Sitka has seen essentially no growth in energy sales and, since the closure of the Alaska Pulp Company (APC) mill in 1993, total energy requirements have actually decreased. The all time annual system peak demand was 22.0 MW in 1993 and was 19.9 MW as recently as 1996. The high demand in 1993 is attributed in part, to the partial requirements demand of APC on the Sitka electric system.

Total energy sales by customer class for the years 1973 through 2001 for Sitka are shown in Figure 2-2. As can be seen in Figure 2-2, a significant amount of energy was sold to APC between 1982 and 1990. The energy sales to APC were contractually arranged to more fully utilize the output of the 20-MW Green Lake hydroelectric project which began operation in 1982. APC continued to own and operate a power plant at its mill during this period[21]. After APC closed its operation, the City of Sitka pursued development of the former APC site as the Sawmill Cove (SMC) industrial park.

FIGURE 2-2
City and Borough of Sitka
Historical (1973-2001) Energy Sales by Customer Class and Total Generation



[21] The reference to the Sitka power sale to APC is included in this report to provide an example of an arrangement used in the past to help alleviate the potentially high cost of implementing a new, large generating resource in a utility's rate base. Power was sold to APC by Sitka at a "surplus" power rate.

The results of the forecast indicate average annual load growth over the next 20 years of 0.9% for the medium growth scenario, 2.2% average annual load growth for the high scenario and an average annual decrease in loads of 0.3% for the low growth scenario.

Kennecott Mining Company - Greens Creek Mine

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. None of these loads are interconnected with each other and separate generation systems are needed at each location. 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. The load at Young Bay is relatively small and insignificant.

KMC-GC does not expect significant changes in its electric power requirements in the future. Ventilation improvements and additional loads at the grinding plant could in total increase the overall power requirement by about 500 kW. The expected remaining operating life of the facility is estimated by KMC-GC to be approximately 10 years, subject to exploration success, metal prices and other factors. The projected power requirements for KMC-GC are summarized in Table 2-5.

TABLE 2-5
Kennecott Greens Creek Mine
Projected Energy Loads and Capacity Requirements

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh)						
Mine Load	52,560	52,560	54,662	54,662	56,064	56,064
Hawk Inlet	2,628	2,628	2,628	2,628	2,628	2,628
Total Energy Requirements	55,188	55,188	57,290	57,290	58,692	58,692
Peak Demand (kW) [1]	8,000	8,000	8,300	8,300	8,500	8,500
Loadfactor [2]	78.8%	78.8%	78.8%	78.8%	78.8%	78.8%

[1] Includes estimated present peak demand of 7,500 kW at the mine and 500 kW at Hawk Inlet. Assumes an increase of 500 kW by 2007.

[2] Ratio of average demand to peak demand on an annual basis.

Hoonah

Electric service is provided to the residents and businesses of Hoonah by THREA. In 2002, there were 342 residential customers, 69 commercial customers and 22 public facility customers in Hoonah. Average monthly energy consumption of 460 kWh per residential customer is significantly lower than that experienced in the three largest cities in Southeast Alaska, Juneau, Ketchikan and Sitka where average monthly energy consumption is 837 kWh, 860 kWh and 966 kWh, respectively[22]. The low residential energy consumption is a reflection of the high retail

[22] Based on 2002 sales data for Juneau and Sitka and 2001 sales data for Ketchikan.

cost of power, which averaged 35.4 cents per kWh[23] in 2002 to residential customers in Hoonah. Commercial rates are also in this range and undoubtedly function to significantly limit electrical consumption by commercial customers.

Over the past three years there has been a significant reduction in energy sales to the three interruptible customers in Hoonah, all of which have the ability of generating some or all of their total power needs on their own. Retail rates are approximately 18 cents per kWh for interruptible sales. THREA indicates that the change in retail sales was primarily a result of the closure of the Whitestone Logging camp in August 2001. The high retail cost of power has contributed to self generation by certain large commercial electric users in Hoonah. THREA offers an interruptible power sales rate to large customers with self-generating capability that is substantially lower than the regular commercial rate.

The number of residential electric customers served by a utility is typically related to the area population, available housing and per capita income, among other factors. The population of Hoonah in 2002 was reported to be approximately 860. Projections made by the Alaska State Department of Labor in 1998 indicate an average annual change in population of -1.34% to 0.24% for the Skagway-Hoonah-Angoon census area for the period 2003 through 2008[24]. Long-term population change through 2018 provided in the Labor Department's report is in the same general range. Recent sales information from THREA indicates that total residential customers served and average residential energy sales have remained relatively constant the past three years.

A new commercial development at Cannery Point near Point Sophia is presently under construction. The Point Sophia development involves the restoration and transformation of an old cannery into a tourist attraction and the installation of a number of other shore-based tourist activities for cruise ship passengers. The development is scheduled to begin operation in May 2004 and when fully developed, will entertain three to four cruise ship visits per week during the tourist season. Passengers will be lightered to shore in 2004; however, a dock facility is presently planned for completion in 2005. The Point Sophia development is estimated to employ upwards of 250 people during the tourist season when fully developed.

THREA's distribution lines do not extend to the development at the present time and initially, on-site diesel generation will be used to supply the Point Sophia power supply requirement. The electric power requirement is presently estimated to be approximately 500 kW beginning in 2004 with annual energy requirements estimated to be approximately 2,650 MWh. THREA is in the process of obtaining grant funds to extend its distribution system to Point Sophia and is planning to serve the new load. The Point Sophia development should somewhat stimulate the local economy in Hoonah resulting in higher electric loads among THREA's residential and

[23] The effective electricity rate to THREA's residential customers was lowered by the State's Power Cost Equalization (PCE) program to approximately 22 cents per kWh in 2001 for the first 500 kWh purchased each month. Although the PCE program provides a significant subsidization of residential power costs, it also provides an incentive to limit power consumption. It should also be noted that the funding of the PCE program is granted by the State legislature on an annual basis and no guarantees can be provided with regard to its continuation in the future. Changes in the level of eligible kWh or other aspects of the PCE program could also be made in the future.
[24] References to population projections are from Alaska Economic Trends, September 1998.

commercial rate classes than would be experienced otherwise. A new subdivision with approximately 30 residential lots is presently under development in Hoonah.

For the purpose of this analysis, the number of residential, commercial and public facility customers served in Hoonah has been assumed to increase at an average annual rate of 2% per year through 2007 and at 1% per year thereafter. The period of higher growth is during the time when the Point Sophia development will begin operation. Energy use per account is assumed to increase at 0.5% to 1.0% per year. If the Intertie and other factors[25] contribute to the lowering of THREA's retail rates, electric consumption could increase even further. In addition, the Point Sophia development is assumed to increase local loads by 500 kW beginning in 2004 for the development itself, with further increases to 1,000 kW by 2008. There may also be opportunities to sell additional energy to customers that may be using their own generators at the present time, however, the amount of energy that this would represent is not known at the present time.

With the Intertie, THREA may be able to offer an economic incentive power sales rate to new commercial/industrial customers that might encourage economic development in the Hoonah area and increase energy sales. The economic incentive rate would be tied to the incremental cost of purchased power over the Intertie and could be significantly lower than THREA's current interruptible rate. The impact of an economic incentive rate on Hoonah energy sales cannot be predicted and consequently, are not reflected in the analysis at the present time.

The projected power requirements for Hoonah are summarized in the following table.

TABLE 2-6
THREA – Hoonah Service Area
Projected Energy Loads and Capacity Requirements

	Historical			Projected					
	2000	2001	2002	2003	2004	2005	2006	2007	2012
Energy Sales (MWh)									
Residential	1,954	1,980	1,876	1,911	1,969	2,029	2,089	2,150	2,369
Commercial	868	881	795	811	827	844	860	877	962
Interruptible [1]	2,379	1,735	865	874	2,207	2,879	3,550	3,559	3,605
Public Facilities	677	667	626	638	657	676	696	717	787
Other	-	-	-	-	-	-	-	-	-
Total Sales	5,877	5,264	4,161	4,234	5,661	6,427	7,195	7,303	7,724
Increase % [2]		-10.4%	-20.9%	1.7%	33.7%	13.5%	12.0%	1.5%	1.0%
Station Service/Own Use	69	56	46	47	63	72	80	82	86
Street Lights	63	64	64	64	64	64	64	64	64
Losses	305	300	286	277	369	419	468	475	503
Total Generation (MWh)	6,314	5,684	4,557	4,622	6,157	6,982	7,807	7,924	8,377
Loss % of Gen. [3]	4.8%	5.3%	6.3%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Peak Demand (kW)	1,120	1,160	780	879	1,171	1,328	1,485	1,508	1,594
Loadfactor [4]	64.4%	55.9%	66.7%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%

[1] Assumes the Point Sophia development will begin operation in 2004 and increase electrical consumption to 2,650 MWh per year by 2006.

[2] Increase in total sales over previous year.

[3] Distribution losses and energy unaccounted for. Projected losses based on recent experience.

[25] THREA is pursuing restructuring of its debt repayment which could contribute to lower retail rates.

[4] Ratio of average demand to peak demand on an annual basis. Projected loadfactor based on recent experience.

Petersburg and Wrangell

Petersburg and Wrangell are both municipally owned electric utilities interconnected with each other by the Lake Tyee transmission line. Petersburg Municipal Power & Light owns and operates the Blind Slough hydroelectric project and purchases its remaining power supply needs from the Lake Tyee project. Wrangell Municipal Light & Power purchases essentially all of its power supply from Lake Tyee. Electric loads in Petersburg and Wrangell have been projected recently with regard to studies of the Tyee-Swan Intertie. Loads in Petersburg are assumed to increase at average annual rates of 1.0%, 0.5% and 2.0% for medium, low and high forecast scenarios, respectively. Loads in Wrangell are assumed to increase at average annual rates of 0.3%, 0.0% and 1.0% for medium, low and high forecast scenarios, respectively. In addition, the low forecast scenario for Wrangell assumes that the Wrangell Forest Products mill, a 5,000 MWh per year load, closes its operation.

Forecasted loads for Wrangell and Petersburg are summarized in the following Table.

TABLE 2-7
Petersburg and Wrangell
Projected Energy Requirements – Medium Growth Scenario

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh)						
Petersburg [1]	41,410	41,824	42,242	42,664	43,091	45,289
Wrangell [2]	26,045	26,150	26,256	26,362	26,469	27,010
Total	67,455	67,974	68,498	69,026	69,560	72,299
Less: Petersburg Hydro [3]	(11,500)	(11,500)	(11,500)	(11,500)	(11,500)	(11,500)
Less: Minimal Diesel [4]	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)
Net Requirement on Tyee [5]	54,455	54,974	55,498	56,026	56,560	59,299

[1] Assumes average growth in energy requirements of 1% per year.
[2] Assumes average growth in energy requirements of 0.5% per year and continued operation of the Silver Bay sawmill.
[3] Estimated average annual generation from PMP&L's Blind Slough hydroelectric project.
[4] Estimated diesel generation needed for backup and maintenance purposes.
[5] Projected net energy requirement of PMP&L and WML&P on the Lake Tyee hydroelectric project.

Kake

Electric service is provided to the residents and businesses of Hoonah by THREA. In 2002, there were 280 residential customers, 60 commercial customers and 12 public facility customers in Kake. Average monthly energy consumption of 450 kWh per residential customer is significantly lower than that experienced in the three largest cities in Southeast Alaska, Juneau, Ketchikan and Sitka where average monthly energy consumption is 837 kWh, 860 kWh and 966 kWh, respectively[26]. The low residential energy consumption is a reflection of the high retail

[26] Based on 2002 sales data for Juneau and Sitka and 2001 sales data for Ketchikan.

cost of power, which averaged 35.5 cents per kWh[27] in 2002 to residential customers in Kake. Commercial rates are also in this range and undoubtedly function to significantly limit electrical consumption by commercial customers.

Although the number of residential customers served in Kake has decreased somewhat the past two years, total energy sales have increased each year mostly due to increased sales of interruptible energy. The interruptible energy sales rate in Kake is approximately 17 cents per kWh. THREA indicates that the increase in interruptible sales is due to increasing power requirements at Kake Foods.

For the purpose of this analysis, the number of residential, commercial and public facility customers served in Kake has been assumed to increase at an average annual rate of 1% per year. Energy use per account is assumed to increase at 0.5% to 1.0% per year. If the Intertie and other factors[28] contribute to the lowering of THREA's retail rates, electric consumption could increase even further. There may also be opportunities to sell additional energy to customers that may be using their own generators at the present time, however, the amount of energy that this would represent is not known at the present time.

With the Intertie, THREA may be able to offer an economic incentive power sales rate to new commercial/industrial customers that might encourage economic development in the Kake area and increase energy sales. The economic incentive rate would be tied to the incremental cost of purchased power over the Intertie and could be significantly lower than THREA's current interruptible rate. The impact of an economic incentive rate on Kake energy sales cannot be predicted and consequently, are not reflected in the analysis at the present time.

The projected power requirements for Kake are summarized in the following table.

[27] The effective rate to residential customers was lowered by the State's Power Cost Equalization (PCE) program to approximately 22 cents per kWh in 2001 for the first 500 kWh purchased each month. Although the PCE program provides a significant subsidization of residential power costs, it also provides an incentive to limit power consumption to 500 kWh per month or less. It should also be noted that the funding of the PCE program is granted by the State legislature on an annual basis and no guarantees can be provided with regard to its continuation in the future.

[28] THREA is pursuing restructuring of its debt repayment which could contribute to lower retail rates.

TABLE 2-8
THREA – Kake Service Area
Projected Energy Loads and Capacity Requirements

	Historical			Projected					
	2000	2001	2002	2003	2004	2005	2006	2007	2012
Energy Sales (MWh)									
Residential	1,600	1,588	1,498	1,529	1,561	1,593	1,626	1,659	1,823
Commercial	924	931	886	891	895	899	904	908	932
Interruptible [1]	697	934	1,370	1,397	1,425	1,454	1,483	1,498	1,574
Public Facilities	384	343	210	214	221	229	237	245	268
Other	-	-	-	-	-	-	-	-	-
Total Sales	3,605	3,796	3,964	4,031	4,102	4,175	4,249	4,309	4,597
Increase % [2]		5.3%	4.4%	1.7%	1.8%	1.8%	1.8%	1.4%	1.1%
Station Service/Own Use	44	58	62	58	59	60	61	62	66
Street Lights	77	80	80	80	80	80	80	80	80
Losses	194	244	185	219	223	227	231	234	250
Total Generation (MWh)	3,920	4,178	4,291	4,388	4,464	4,542	4,621	4,685	4,993
Loss % of Gen. [3]	4.9%	5.8%	4.3%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Peak Demand (kW)	1,036	1,000	1,016	1,044	1,062	1,080	1,099	1,114	1,187
Loadfactor [4]	43.2%	47.7%	48.2%	48.0%	48.0%	48.0%	48.0%	48.0%	48.0%

[1] Assumes interruptible sales will increase at 2% per year through 2007 and at 1% per year thereafter.
[2] Increase in total sales over previous year.
[3] Distribution losses and energy unaccounted for. Projected losses based on recent experience.
[4] Ratio of average demand to peak demand on an annual basis. Projected loadfactor based on recent experience.

Projected Regional Energy Requirements

Based on the foregoing, the total energy requirements for all of the communities and load centers have been projected for 30 years. The projected amounts in five year increments through 2022, by community and sub-region, are shown in the following table:

TABLE 2-9
All Communities and Load Centers
Projected Annual Energy Requirements – Medium Growth

	2003	2007	2012	2017	2022
Upper Lynn Canal Region					
Skagway	10,950	11,390	11,980	12,580	13,230
Haines	12,900	13,420	14,110	14,830	15,580
Chilkat Valley/Klukwan	1,700	1,840	2,040	2,240	2,480
Subtotal	25,550	26,650	28,130	29,650	31,290
North Region					
Juneau	339,930	353,140	372,700	385,030	397,660
KMC-GC (Greens Creek)	55,190	58,690	58,690	-	-
Hoonah	4,620	7,920	8,380	8,780	9,190
Gustavus incl. NPS	2,640	2,760	2,910	3,060	3,210
Excursion Inlet Cannery	5,600	5,950	6,400	6,900	7,440
Subtotal	407,980	428,460	449,080	403,770	417,500
West Central Region					
Sitka	100,200	104,260	109,560	115,160	121,030
Angoon	2,030	2,150	2,300	2,480	2,680
Tenakee Springs	441	458	483	508	533
Subtotal	102,671	106,868	112,343	118,148	124,243
Tyee-Swan Region					
Petersburg / Wrangell	67,460	69,560	72,300	75,140	77,990
Kake	4,390	4,690	4,990	5,280	5,580
Ketchikan	153,970	160,860	169,900	179,450	189,500
Metlakatla	14,500	15,100	15,870	16,680	17,530
Subtotal	240,320	250,210	263,060	276,550	290,600
Prince of Wales Region					
Craig/Klawock/Thorne Bay/Kasaan	23,630	25,080	27,020	29,110	31,360
Coffman Cove	748	810	895	988	1,091
Hollis	576	624	689	761	840
Hydaburg	1,564	1,660	1,788	1,926	2,075
Naukati Bay	465	503	555	613	677
Subtotal	26,983	28,677	30,947	33,398	36,043
Totals	803,504	840,865	883,560	861,516	899,676
Increase over Previous Year		1.1%	0.8%	-5.6%	0.9%
Average Annual Increase from 2003		1.1%	1.1%	0.5%	0.6%

In Table 2-9, the assumed closure of the KMC-GC mine in 2017 causes a relatively dramatic 5.6% drop in regional energy requirements. It could be assumed that KMC-GC continues to operate or another mining operation with similar electrical requirements begins operation at that time in which case, overall regional electrical requirements would be greater than shown in Table 2-9. Another potentially significant electrical demand could be added if additional shore-based power supply connections were provided to cruise ships. At the present time, AEL&P is providing power to about one Princess Line ship per day during the tourist season. The

estimated energy requirement of the cruise ship connection, as provided by AEL&P, is about 10,000 MWh per year.

Availability of Hydroelectric Generation

As indicated previously in Table 2-2, hydroelectric generation was used to provide 692,165 MWh or 86.5% of the total regional energy requirement in 2002. The energy generation capability of the existing hydroelectric system in Southeast Alaska is estimated to be 811,000 MWh on an average annual basis. This indicates that a much greater percentage of the overall regional energy requirement could be supplied with hydroelectric generation except for transmission limitations. Table 2-10 provides a listing of the existing hydroelectric generating facilities in Southeast Alaska, the installed capacity and annual energy generation capability of each facility.

Note that energy generation from the hydro projects can vary significantly from year to year based on local precipitation levels. The Swan Lake project for example, is projected to generate between 62,300 MWh in extreme dry years to 106,500 MWh in extreme wet years[29]. Average generation of Swan Lake is estimated to be 71,400 MWh. The full generation of the Lake Tyee project is estimated to range between 112,800 MWh and 154,800 MWh.

[29] The maximum generation estimate assumes that the connected load is sufficient to utilize the full generation of the project.

TABLE 2-10
Existing Southeast Alaska Hydroelectric Facilities

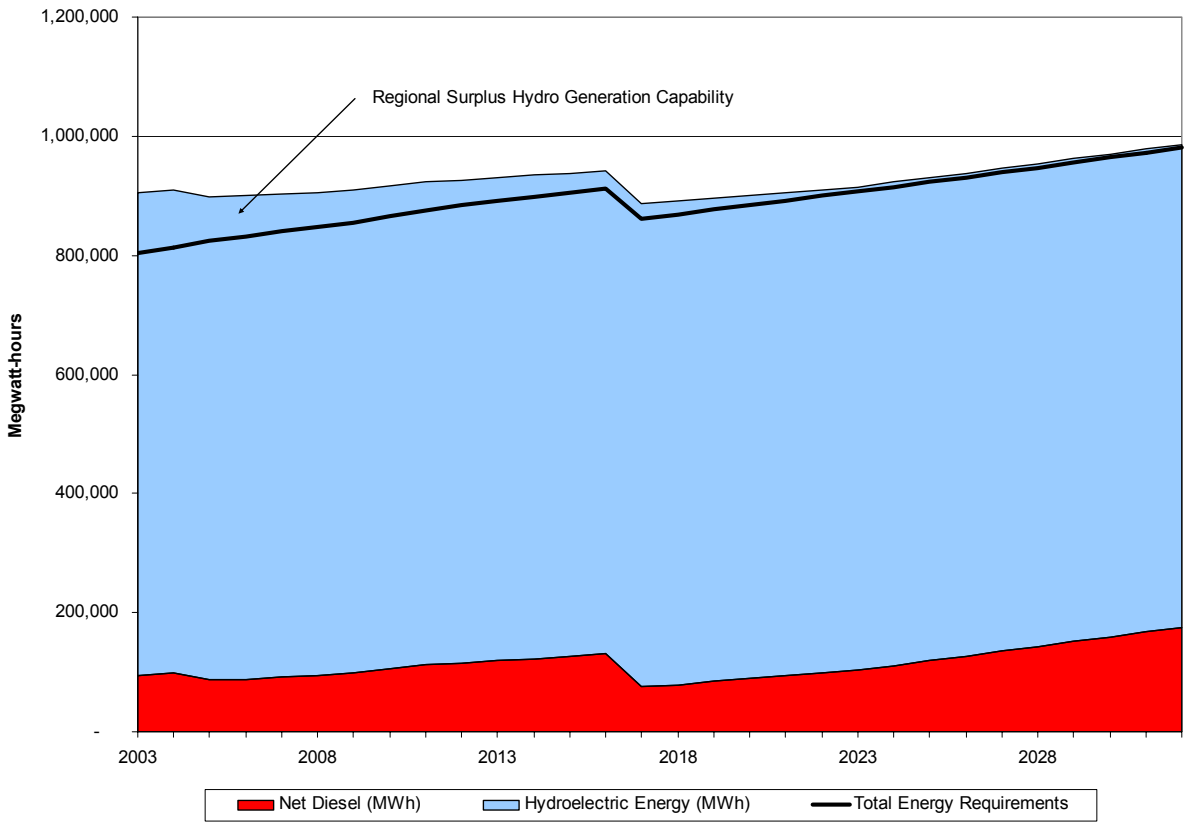
	Capacity (kW)	Annual Energy Generation Capability[1] (MWh)
Upper Lynn Canal Region		
Skagway / Haines		
Dewey Lake	975	3,500
Goat Lake	4,000	18,900
Lutak Hydro	250	800
Chilkat Valley/Klukwan	450	1,800
Subtotal	5,675	25,000
North Region		
Juneau		
AEL&P Hydro	10,400	59,000
Snettisham	78,100	294,000
Subtotal	88,500	353,000
West Central Region		
Sitka		
Blue Lake	6,000	52,100
Green Lake	18,000	58,900
Blue Lake Small Hydro[2]	700	4,700
Subtotal	24,700	115,700
Tyee-Swan Region		
Petersburg / Wrangell		
Blind Slough	2,200	11,000
Lake Tyee	20,000	120,000
Ketchikan		
KPU Hydro	11,500	67,900
Swan Lake	22,500	71,400
Metlakatla		
Purple Lake	3,900	16,885
Chester Lake	1,000	8,160
Subtotal	61,100	295,345
Prince of Wales Region		
Craig/Klawock/Thorne Bay/Kasaan		
Black Bear Lake	4,500	22,000
Totals	184,475	811,045

[1] Estimated average annual energy generation capability based on average water conditions. Energy amounts shown for Lake Tyee, Swan Lake and Green Lake projects, all of which have not had sufficient historical operations at maximum usage levels, are based on previous engineering estimates.

[2] Excludes capacity and energy for the pulp mill water supply line unit, which has not generally been operated since closure of the APC pulp mill in 1993.

In the communities and load centers where hydroelectric generation does not exist, diesel generation is used to supply the power requirement. Figure 2-4 provides a graphical representation of the total power supply in Southeast Alaska based on the foregoing projections of power requirements and the average annual generating capabilities of the existing hydroelectric facilities. In Figure 2-4, no new hydroelectric generation is assumed to be installed and no additional transmission interconnections, other than the Tyee – Swan Intertie which is expected to become operational in 2005, are assumed to be constructed. The significant drop in energy requirements and diesel generation in 2017 is due to the assumed closure of the KMC-GC mine at that time.

FIGURE 2-3
Southeast Alaska Communities and Load Centers
Projected Annual Energy Requirements and Energy Resources[1]



[1] Hydroelectric generation capability based on average water conditions.

Figure 2-4 shows that regional diesel generation begins to decline somewhat in 2005 when the Tyee- Swan Intertie comes on line. The regional surplus hydroelectric energy generation capability, most of which is found at the Lake Tyee project, begins to decline gradually at the same time and continues to decline as loads grow. By 2023, the supply of surplus hydroelectric energy generation capability is exhausted.

As indicated in the Phase 1 report, the primary purpose of the Juneau – Greens Creek – Hoonah Intertie, SEI-1, will be to transmit surplus hydroelectric generation from AEL&P's system, including Snettisham, to KMC-GC and THREA's service center in Hoonah. AEL&P owns and operates several hydroelectric projects and purchases the full output of the State-owned Snettisham hydroelectric project. Although the existing hydroelectric generation capability is sufficient to meet the full power supply requirement of AEL&P's customers, AEL&P has indicated that hydroelectric generation at the present time is insufficient to supply KMC-GC and Hoonah. Consequently, it will be necessary to construct the Lake Dorothy hydroelectric project before contractual commitments can be made to either KMC-GC or THREA.

AEL&P is in the process of permitting and designing the Lake Dorothy project. Construction could begin as early as 2004 and will require about three years to complete the project. Phase 1 of the Lake Dorothy project, also called Bart Lake, is estimated to provide 75,000 MWh[30] on an average annual basis. Phase 2, which is not currently scheduled for construction, would provide total energy generation of 169,000 MWh annually for Phase 1 and Phase 2 combined. The following table summarizes AEL&P's hydroelectric energy resources and the estimated energy available.

TABLE 2-11
AEL&P Hydroelectric Generating Resources
And Available Energy (MWh)

	2003	2004	2005	2006	2007	2012
Hydroelectric Resources [1]						
AEL&P Hydro	59,000	59,000	59,000	59,000	59,000	59,000
Snettisham	294,000	294,000	294,000	294,000	294,000	294,000
Lake Dorothy [2]	-	-	-	-	75,000	75,000
Total Resources	353,000	353,000	353,000	353,000	428,000	428,000
Energy Requirements [3]						
Firm Sales	298,167	300,438	302,620	305,538	308,619	327,246
Non-firm Sales [4]	22,568	23,657	24,657	24,657	24,657	24,657
Losses and Own Use	19,197	19,405	19,564	19,710	19,864	20,795
Total Energy Requirements	339,932	343,500	346,841	349,905	353,140	372,698
Net Hydro Energy Available [5]	13,068	9,500	6,159	3,095	74,860	55,302

[1] As provided by AEL&P based on average water conditions. Net of transmission losses and station service.
[2] Phase 1, Bart Lake estimated average annual energy generation capability.
[3] As provided by AEL&P.
[4] Estimated energy sales to "dual-fuel" customers and cruise ships supplied with shore-based power, contingent upon availability of hydroelectric generation.
[5] Estimated average annual energy generation available to KMC-GC and Hoonah.

As shown in the previous table, under average water conditions, AEL&P has relatively limited amounts of surplus hydroelectric energy available without the Lake Dorothy project if AEL&P is

[30] Firm annual energy output (i.e. the energy generation capability of the project in low water years) is estimated at 68,000 MWh.

to supply its own retail loads and committed non-firm loads. Without the Lake Dorothy project, the total hydroelectric energy generation capability available to AEL&P is 353,000 MWh under average water conditions. The annual energy generation capability would only be 295,000 MWh under low water conditions. As a result, under low water conditions, AEL&P would not be able to supply all of its loads with hydroelectric generation and would need to use oil-fired generation to fully supply its power requirement.

The generating capability of the 20-MW Lake Tyee project is presently committed to Petersburg and Wrangell. The Swan-Tyee transmission Intertie, currently under construction, will provide Ketchikan with access to generation from the Lake Tyee project that is surplus to the needs of Petersburg and Wrangell. Several estimates of the annual energy capability of the Lake Tyee project have been developed in the past; however, the loads connected to the project have never been large enough to evaluate how well the estimates compare with actual performance. Generally, it has been estimated that under average water conditions, the annual energy generation capability of the project is about 129,000 MWh. Based on actual experience and the knowledge of individuals familiar with the operation of the project, the average annual energy generation could be as low as 110,000 MWh per year.

Hydroelectric generation is highly variable from year to year depending on local precipitation and other environmental conditions. As previously indicated, the average annual estimated energy generation capability of the Lake Tyee project is 129,000 MWh. Under dry, low water conditions[31], the energy generation is estimated to be 112,700 MWh whereas it could be as high as 154,800 MWh.

The following table summarizes the energy generation available from the Lake Tyee project assuming average annual energy generation of 120,000 MWh from the project.

TABLE 2-12
Estimated Hydroelectric Energy Generation
From the Lake Tyee Project – Medium Growth, Average Water
(MWh)

	2003	2004	2005	2006	2007	2012
Lake Tyee Generation [1]	120,000	120,000	120,000	120,000	120,000	120,000
Energy Requirements [2]						
Petersburg/Wrangell	54,455	54,974	55,498	56,026	56,560	59,299
Ketchikan	17,404	18,621	19,853	21,248	22,674	30,775
Net Energy Available [3]	48,141	46,405	44,649	42,726	40,766	29,926

[1] Assumed generation for purpose of this analysis. Actual generation will vary from year to year.
[2] Based on medium growth scenario, see Tables 6-4 and 6-5.
[3] Estimated annual generation from the Lake Tyee project available to Kake.

As shown in the previous table, the net energy generation available from the Lake Tyee project in 2007 is 40,766 MWh assuming average water conditions and medium load growth in Petersburg, Wrangell and Ketchikan. This is more than enough needed to meet the energy

[31] Alternative energy generation estimates are typically derived using the lowest and highest measured streamflow data of record at the project location.

requirement of 4,685 MWh in Kake in the same year. The interconnection with Kake is proposed as SEI-2. By 2012, available energy from Lake Tyee is 29,926 MWh and, as loads continue to increase in Petersburg, Wrangell and Ketchikan, the available energy from Lake Tyee will continue to decline. Further, in dryer than average conditions, the available energy from Lake Tyee will be less than shown in Table 2-12, potentially by as much as 20,000 MWh in any particular year. If energy generation is not available from Lake Tyee, THREA would need to use its diesel generators in Kake to supply the necessary power requirement. As loads continue to grow in the interconnected region, however, new hydroelectric generation facilities could be constructed. The cost of power from these new facilities will potentially be higher than the cost of power from the Lake Tyee project.

Sitka presently has a considerable amount of energy generation capability from its hydroelectric facilities, the Blue Lake and Green Lake projects. Based on current load levels, the average annual hydroelectric energy generation surplus is approximately 15,500 MWh. As Sitka's energy requirements continue to increase, the surplus energy generation capability would gradually decline until about 2018 when it is estimated to be exhausted. At that time, Sitka would need to rely upon regular diesel generation, construct new hydroelectric facilities or purchase power over new transmission interconnections. Sitka has evaluated several potential hydroelectric developments in the past of which the 20-MW Takatz Lake project located 19 miles northeast of Sitka on the eastern side of Baranof Island has been considered the most cost effective. The Takatz Lake project is remotely located and would require a difficult transmission interconnection to Sitka.

Potential New Hydroelectric Generation Facilities

A number of new hydroelectric projects have been studied that could serve the Southeast Alaska area. Costs of these projects, as well as other factors including location, generating capacity, interconnected loads and the availability of better alternatives have precluded development of these projects. The development of a transmission interconnection system could make development of some of these projects economically and technically feasible at some later date. Hydroelectric projects that have been identified, the community they are closest to, and their estimated capacity and annual energy generation are provided in Table 2-13.

Several of the projects shown in Table 2-13 were only studied on a reconnaissance basis while others have been studied in more detail. Further, the timing of the most recent studies conducted for these projects varies significantly. In total, the combined capacity of all the projects shown in Table 2-13 is 195,300 kW, essentially the same as the current amount of installed hydroelectric capacity in Southeast Alaska. The estimated total average annual energy generation of the potential hydroelectric projects is 701,000 MWh. It should be noted that other projects have been identified for the region in the past, such as the Lake Grace project near Ketchikan, that are not included in Table 2-13 because of problems that have been identified with their potential development.

TABLE 2-13
Potential New Southeast Alaska Hydroelectric Projects

	Community / Utility	Capacity (kW)	Annual Energy Generation Capability [1] (MWh)	Estimated Capital Cost [2] ($millions)
Upper Lynn Canal Region				
Kasidaya Creek	Haines-Skagway/AP&T	3,000	12,000	7.0
Connelly Lake	Haines-Skagway/AP&T	5,000	30,000	14.0
Subtotal		5,000	30,000	
North Region				
Lake Dorothy - Phase 1	Juneau/AEL&P	15,000	75,000	
Lake Dorothy - Phase 2	Juneau/AEL&P	32,000	94,000	
Gartina Falls	Hoonah	600	1,900	3.8
Water Supply Creek	Hoonah	600	1,800	3.1
Falls Creek	Gustavus/GEC	800	2,500	4.1
Subtotal		49,000	175,200	
West Central Region				
Takatz Lake	Sitka	20,000	82,800	82.0
Katlian River	Sitka	7,000	29,800	70.5
Thayer Creek	Angoon	1,000	8,500	NA
Subtotal		28,000	121,100	
Tyee-Swan Region				
Thomas Bay (Swan Lake)	Petersburg	40,000	164,400	193.0
Lake Tyee Third Turbine	Petersburg - Wrangell	10,000	1,000	NA
Sunrise Lake	Wrangell	4,000	12,200	NA
Anita - Kunk Lake	Wrangell	8,000	28,200	NA
Virginia Lake	Wrangell	12,000	42,700	NA
Thoms Lake	Wrangell	7,300	25,600	NA
Whitman Lake	Ketchikan/KPU	4,600	19,640	7.6
Connell Lake	Ketchikan/KPU	1,900	11,640	5.5
Mahoney Lake	Ketchikan/KEC	9,600	45,600	NA
Triangle Lake	Metlakatla/MP&L	3,900	16,885	12.9
Subtotal		101,300	367,865	
Prince of Wales Region				
South Fork	Craig-Klawock/AP&T	2,000	7,000	3.5
Lake Mellon/Reynolds Creek	Craig-Klawock/AP&T	10,000	-	NA
Subtotal		12,000	7,000	
Totals		195,300	701,165	

[1] Estimated average annual energy generation.
[2] Estimated costs as derived from previous studies, adjusted to 2003 cost levels.

In addition to the Lake Dorothy Project, AEL&P has evaluated rehabilitation and expansion of existing hydroelectric facilities in the Juneau area.

A report in June 2002 by Hydro West, Inc. provided basic information on the Gartina Falls project and the Water Supply Creek project, both of which would have a generating capacity of

600 kW each. The estimated cost of the Gartina Falls project is $3.75 million while the Water Supply Creek project would cost an estimated $3.1 million. Based on assumed 50% grant funding and 50% funding with 0% interest rate loans[32], the estimated cost of energy from the two projects is 6.0 cents per kWh and 5.6 cents per kWh for the Gartina Falls and Water Supply Creek projects, respectively. The cost of power from these projects would be significantly higher if grant funding were not available.

Use of Oil-Fired Generating Facilities

Although it has been indicated that only hydroelectric generation would be transmitted over the Interties, power generated at diesel power plants could be transmitted just as well. The use of diesel generators from outside the local community, however, would need to acknowledge the additional cost associated with transmission losses as well as the cost differential between surplus hydroelectric power and diesel generation. In some cases, it could be less costly to purchase out-of-area diesel generation than run local generators. This will need to be factored in to the contracts for power supply services.

Projected Regional Power Supply Plan

Based on the projected energy requirements, the existing hydroelectric generating capacity and the most likely development schedule of new hydroelectric facilities, a projected schedule of regional hydroelectric and transmission additions has been derived. The concept of a regional plan at this point is essentially a scenario that has been developed based on the available information as previously described. There are many variables involved with this plan and any number of scenarios could be proposed to compare their relative advantages and disadvantages. Further, the cost of future resource development has not been factored in to the plan at this stage of the analysis. Rather, the energy needs of each community and the availability of local hydroelectric generation have served as the basis for the determination of when transmission interconnections would be made.

A discussion of the critical elements of the plan by sub-region follows. Detailed analytical tables showing the loads, resources and energy transfers are provided in Appendix A.

Upper Lynn Canal Region

The Upper Lynn Canal region is expected to remain relatively self-sufficient in the foreseeable future. AP&T has planned to interconnect its system in Haines with THREA's Chilkat Valley/Klukwan system. This will allow for the distribution of existing and planned hydroelectric energy within the region. Primary elements of the plan include:

- Haines – Chilkat Valley Intertie (AP&T) 2007 (dependent on available funding)

[32] These favorable financing assumptions were made by Hydro West in its evaluation of the projects for the City of Hoonah based on recent grant activity observed by Hydro West in Southeast Alaska. If grant funding is not available, the annual cost of power from the projects would most likely be significantly higher.

- Kasidaya Creek hydroelectric plant (AP&T) 2006

Table 2-14 shows the loads and resources within the Upper Lynn Canal region based on the above additions. The existing hydroelectric resources are sufficient to meet the needs of the area until about 2006. The addition of the Kasidaya Creek hydroelectric project provides surplus hydroelectric energy through at least 2022.

TABLE 2-14
Loads and Resources – Upper Lynn Canal Region
(MWh)

	2003	2004	2005	2006	2007	2012	2017	2022
Energy Requirements	25,550	25,820	26,090	26,370	26,650	28,130	29,650	31,290
Hydroelectric Energy								
Existing Resources	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
New Facilities	-	-	-	12,000	12,000	12,000	12,000	12,000
Subtotal	25,000	25,000	25,000	37,000	37,000	37,000	37,000	37,000
Transfers Within Region	-	-	-	-	40	240	440	680
Net Diesel Generation	650	890	1,130	-	-	-	-	-
Net Surplus Hydro Available	100	70	40	10,630	10,350	8,870	7,350	5,710

North Region

The North region includes AEL&P, KMC-GC, Hoonah and Gustavus. As indicated in the Phase 1 report, the interconnection between AEL&P, KMC-GC and Hoonah, SEI-1, can only be effectively accomplished if the Lake Dorothy hydroelectric project is constructed. The plan assumes that both the Lake Dorothy project and SEI-1 will be constructed and become operational in 2007. Even with these two additions, the hydroelectric resources are insufficient to meet the total load requirements as early as 2011. AEL&P will need to pursue development of Lake Dorothy – Phase 2, or other hydro projects will need to be developed at that time to limit the amount of diesel energy needed in the region. If the KMC-GC mine closes in 2017, as assumed in this analysis, hydro energy will become available for distribution within the region and for distribution to other regions.

Primary elements of the plan include:

- Juneau – KMC-GC – Hoonah Intertie (SEI-1) in 2007
- Lake Dorothy – Phase 1 hydroelectric project in 2007; 15,000 kW, 75,000 MWh annually
- Falls Creek hydroelectric project (Gustavus) in 2008; 800 kW, 2,500 MWh annually
- Gartina Falls and Water Supply Creek hydroelectric projects (Hoonah) in 2011; 600 kW each, 1,900 MWh and 1,800 MWh annually, respectively.

The loads and resources in the North Region based on the foregoing additions are summarized in the following table.

TABLE 2-15
Loads and Resources – North Region
(MWh)

	2003	2004	2005	2006	2007	2012	2017	2022
Energy Requirements	407,980	413,200	419,580	423,590	428,460	449,080	403,770	417,500
Hydroelectric Energy								
Existing Resources	353,000	353,000	353,000	353,000	353,000	353,000	353,000	353,000
New Facilities	-	-	-	-	75,000	81,200	81,200	81,200
Subtotal	353,000	353,000	353,000	353,000	428,000	434,200	434,200	434,200
Transfers Within Region	-	-	-	-	66,610	55,300	5,640	6,200
Net Diesel Generation	68,050	69,700	72,740	73,690	8,710	14,880	6,900	7,440
Net Surplus Hydro Available	13,070	9,500	6,160	3,100	8,250	-	37,330	24,140

As shown in Table 2-15, a significant amount of surplus hydroelectric energy is available beginning in 2017 with the assumed closure of the KMC-GC mine. If the mine does not close, new hydroelectric projects or interconnections with other sub-regions may be needed to reduce the increasing demand on diesel generation.

West Central Region

This area, which is essentially Sitka located on Baranof Island, has seen little interconnection development activity and will probably not see much without a significant level of effort to develop the full Southeast Intertie system. Over the years, Sitka has developed two relatively major hydroelectric facilities that have continued to supply nearly all local power requirements. In the early 1980's, the 20-MW Green Lake hydroelectric project was completed and a considerable amount of energy from the project was sold to the Alaska Pulp Company. 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.

Sitka presently has a relatively small amount of surplus hydroelectric energy generation capability. The utility hopes to encourage greater local economic development with the surplus energy. There would not be much incentive for Sitka to interconnect with Angoon or Tenakee Springs if the interconnection were not part of an extended interconnection with Juneau. Sitka has studied the development of the Takatz Lake hydroelectric project in the past. It is expected that Takatz Lake would be the next hydroelectric facility developed to serve future power needs in the Sitka area. As with Green Lake, however, the Takatz Lake project is fairly large compared to the initial power needs from it, and a transmission system with interconnections to the north or south could be helpful in justifying the project.

Sitka's hydroelectric energy surplus is projected to end around 2018, the approximate time assumed for the closure of the KMC-GC mine. If the mine actually closes around this time, construction of the Intertie between Hawk Inlet, Angoon and Sitka could be constructed to allow for transmission of power from AEL&P to Sitka. If the KMC-GC mine continues to operate,

development of the Takatz Lake project and the Intertie between Hawk Inlet, Angoon and Sitka could be developed in the same time frame so that power could be transmitted from Sitka to Juneau. If Takatz Lake is developed, it may also be advantageous to construct the Intertie between Kake and Sitka at approximately the same time. The plan for the West Central region, assuming closure of the KMC-GC mine in 2017, is summarized as follows:

TABLE 2-16
Loads and Resources – West Central Region
(MWh)

	2003	2004	2005	2006	2007	2012	2017	2022
Energy Requirements	102,671	103,705	104,749	105,803	106,868	112,343	118,148	124,243
Hydroelectric Energy								
Existing Resources	115,700	115,700	115,700	115,700	115,700	115,700	115,700	115,700
New Facilities	-	-	-	-	-	-	-	-
Subtotal	115,700	115,700	115,700	115,700	115,700	115,700	115,700	115,700
Transfers Within Region	-	-	-	-	-	-	-	-
Net Diesel Generation	2,471	2,505	2,539	2,573	2,608	2,783	2,988	8,543
Net Surplus Hydro Available	15,500	14,500	13,490	12,470	11,440	6,140	540	-

As shown in Table 2-16, the surplus energy from existing hydroelectric facilities expires in about 2017. The net diesel generation shown prior to 2017 is for supply of the loads in Angoon and Tenakee Springs. After 2017, increasing diesel generation is expected in Sitka.

Tyee – Swan Region

The Tyee – Swan region is rapidly developing into a well integrated, interconnected system. With the projected completion of the Tyee-Swan Intertie in 2005, three major load centers with significant hydroelectric capacity, Petersburg, Wrangell and Ketchikan will be interconnected. The Lake Tyee hydroelectric project, owned by the Four Dam Pool Power Agency, has the most surplus energy capability of any hydro project in Southeast Alaska. Ketchikan will have the right to purchase the firm power output of the Lake Tyee project surplus to the firm requirements of Petersburg and Wrangell following completion of the Tyee – Swan Intertie. In the Phase 1 report, the Kake – Petersburg Intertie (SEI-2) was evaluated and projected to become operational in 2007. SEI-2 will also utilize some of the surplus energy from the Lake Tyee project.

With both the Tyee-Swan Intertie and SEI-2 installed, the surplus energy from the Lake Tyee project is expected to be exhausted around 2022. At that time, load growth of all connected utilities would increase to the point that diesel generation would need to be used to supplement the hydroelectric generation. As previously mentioned, Petersburg and Wrangell have first priority to the output of the Lake Tyee project, followed by Ketchikan, so the initial shortfalls will affect Kake first of all.

Three hydroelectric projects have been identified for potential development in the Ketchikan area: Whitman Lake, Connell Lake and Mahoney Lake. In addition, surplus hydroelectric generation presently exists in Metlakatla. The interconnection between Ketchikan and Metlakatla (SEI-3) has been studied in the past and would allow for transmission of MP&L's surplus hydro energy within the Tyee-Swan region. Although the energy requirements and

existing resources in the region would imply that the Metlakatla Intertie would not be needed until around 2020, it can be reasonably expected that this interconnection would be beneficial prior to that time, particularly if an interconnection with the Prince of Wales electric system is constructed. For the purpose of this analysis, the elements of the Intertie plan for the Tyee – Swan region are as follows:

- Kake – Petersburg Intertie (SEI-2) in 2007

TABLE 2-17
Loads and Resources – Tyee-Swan Region
(MWh)

	2003	2004	2005	2006	2007	2012	2017	2022
Energy Requirements	240,320	242,750	245,220	247,710	250,210	263,060	276,550	290,600
Hydroelectric Energy								
Existing Resources	295,345	295,345	295,345	295,345	295,345	295,345	295,345	295,345
New Facilities	-	-	-	-	-	-	-	-
Subtotal	295,345	295,345	295,345	295,345	295,345	295,345	295,345	295,345
Transfers Within Region	-	-	18,080	19,810	26,250	35,590	45,430	55,780
Net Diesel Generation	19,060	20,830	4,540	4,620	-	-	-	-
Net Surplus Hydro Available	74,085	73,425	54,665	52,255	45,135	32,285	18,795	4,745

Reports of potential mining activity on Woewodski Island south of Petersburg, could indicate a greater need for power supply in the Tyee-Swan region. If a new mining operation similar in size to the KMC-GC mine were to be developed, additional energy requirements in the range of 50,000 MWh per year could be realized. Surplus energy from the Lake Tyee project sufficient to meet this requirement is expected to be available for a few more years, however, new hydroelectric projects would need to be developed if a long-term supply were needed. Alternatively, a new mine would need to construct its own local power plant similar to the plant currently in operation at the KMC-GC mine.

Prince of Wales Region

The Prince of Wales region is primarily comprised of AP&T's system, which in recent years has expanded to include several of the communities on the island. The primary generation source on Prince of Wales Island is the Black Bear Lake hydroelectric project supplemented as needed with diesel generation. The Black Bear Lake project is fully utilized by the interconnected system as it presently exists, however, and AP&T's plans to interconnect Hollis, Hydaburg, Coffman Cove and Naukati would place further demands on the interconnected system. To limit the amount of diesel generation, it will be necessary for AP&T to construct the South Fork hydroelectric project. The South Fork project would not provide sufficient energy generation to meet the full energy requirement of the region, however, and the Ketchikan – Prince of Wales Intertie (SEI-4) could be installed to allow for the purchase of hydroelectric generation from the Tyee-Swan region. The interconnection between Prince of Wales and Ketchikan would potentially expedite the schedule for the Ketchikan-Metlakatla Intertie (SEI-3) as well.

Based on the projected loads and resources, the following elements of the plan are identified for the Prince of Wales region:

- Craig-Hydaburg interconnection (AP&T) in 2004
- Craig-Hollis interconnection (AP&T) in 2003
- Coffman Cove interconnection (AP&T) in 2007 (timing dependent on project funding)
- South Fork hydroelectric project (AP&T) in 2006; 2,000 kW, 7,000 MWh annually

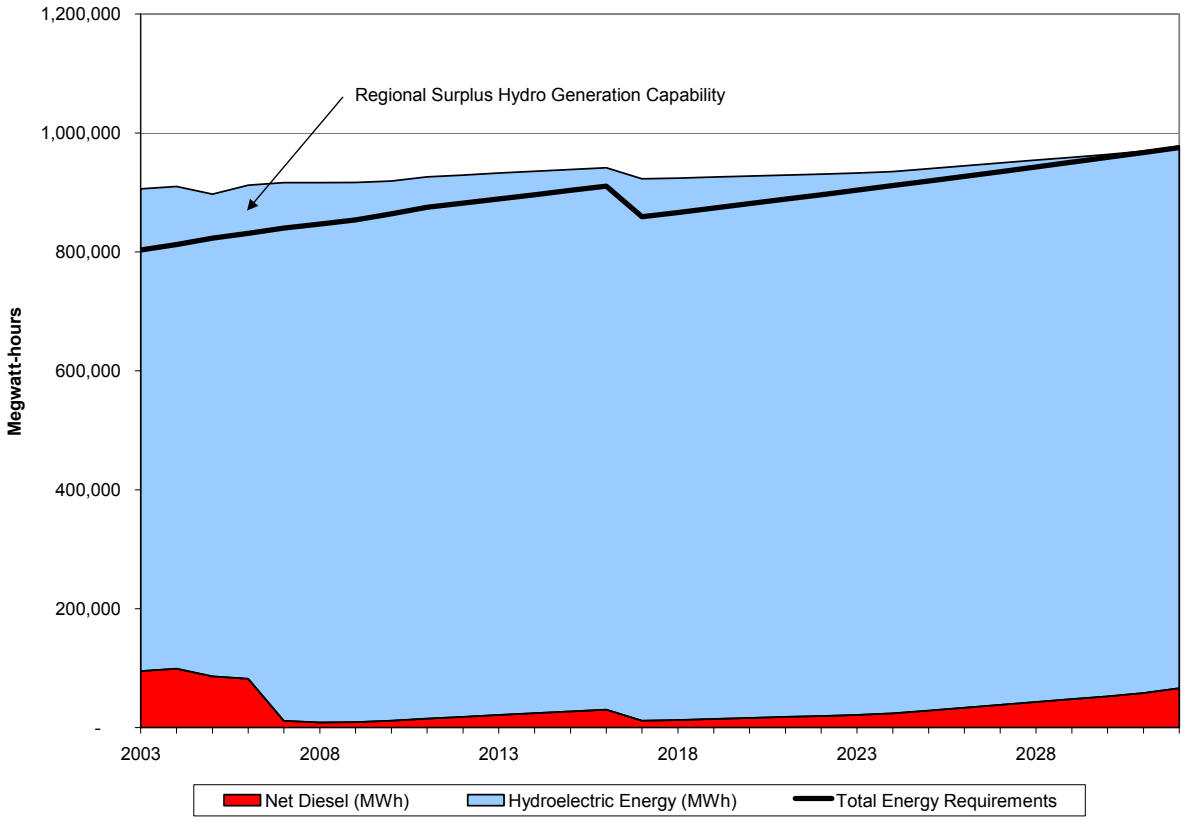
TABLE 2-18
Loads and Resources – Prince of Wales Region
(MWh)

	2003	2004	2005	2006	2007	2012	2017	2022
Energy Requirements	26,846	27,129	27,412	27,695	27,979	29,448	31,001	32,643
Hydroelectric Energy								
Existing Resources	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000
New Facilities	-	-	-	7,000	7,000	7,000	7,000	7,000
Subtotal	22,000	22,000	22,000	29,000	29,000	29,000	29,000	29,000
Transfers Within Region	-	-	-	2,204	3,509	3,290	1,980	600
Net Diesel Generation	4,846	5,129	5,412	1,261	-	448	2,001	3,643
Net Surplus Hydro Available	-	-	-	-	-	-	-	-

Total Resources With Proposed Plan

With the plan components as described in the previous paragraphs, the total Southeast Alaska loads and resources are shown in Figure 2-4. In comparing Figure 2-4 to Figure 2-3, the plan components reduce the overall dependence on diesel generation, provide for increasing hydroelectric generation and greater overall utilization of the hydroelectric generation capacity.

FIGURE 2-4
Southeast Alaska Communities and Load Centers
Projected Annual Energy Requirements and Energy Resources With Proposed Plan[1]



Economic Analysis of Interties

Introduction and Assumptions

An economic analysis has been conducted to determine if the benefits to be realized with the Intertie segments are greater than the costs of operating the Interties and purchasing power from hydroelectric resources. Benefits will be achieved primarily through the offset of diesel generation costs in communities without access to hydroelectric energy. Costs related to the Interties are direct costs of operations and maintenance (O&M), certain incremental administrative costs of the Intertie owner and the costs of purchasing power from AEL&P, the Four Dam Pool and others to serve the load requirements.

In preparing this analysis, several assumptions have been made. The most significant of these assumptions are:

- Capital costs of the Intertie systems are to be grant funded meaning that there will be no capital recovery component associated with the Interties. The cost of certain new substations and distribution facilities, such as at KMC-GC, are not included in the costs of the Interties. It is presumed, that these costs would be funded by the owners.
- Fuel costs, O&M and A&G costs will escalate at the assumed annual inflation rate of 2.5% per year.
- Existing generation capacity will be maintained for emergency backup in communities being interconnected to the regional power system. Resulting net O&M costs will be significantly lower than if the generating units were operated to supply full load.
- The agency serving as owner of the Interties[33] will contract with others to provide maintenance on the Intertie systems. Administrative costs associated with ownership and operation of the Interties will be minimal.
- A reserve fund will be established to collect monies for major maintenance and repairs in the future. The reserve fund will also serve as a self-insurance fund since transmission lines are generally not insurable.
- The cost of purchased power from AEL&P will be inclusive of all transmission and delivery charges to the point of delivery, expected to be either at the submarine termination yard on Douglas Island or at KMC-GC and Hoonah.
- Energy losses over the Interties will be 2% of the transmitted power to KMC-GC and 4% to Kake and Hoonah.

The economic analysis estimates the power production costs for each service area that will be offset if the Interties are constructed. These "benefits" are then compared to the costs of power purchases and Intertie operation to determine if the benefits of the Interties exceed the costs. It is expected that each Intertie will need to show positive benefits. To protect the interests of electric

[33] The Southeast Conference has indicated that it will not serve as owner of the Interties. More discussion of potential ownership structures is provided in Section 6 of this report.

consumers, the total costs incurred by the local utility systems, on a case-by-case basis, must be lower with the Interties than without to show economic justification for the Interties.

It should be noted that costs of operation that are the same with or without the Interties are not included in the analysis. Examples of these costs are capital recovery on existing generation plant and fixed O&M charges.

Projected Cost of Existing Diesel Generation

THREA, AP&T and the other electric utilities in Southeast Alaska own and operate diesel generators in each of the communities where they provide electric service. Total installed diesel or oil-fired generation capacity of the electric utilities is estimated to be approximately 182,300 kW in Southeast Alaska. Much of this installed capacity is used to backup or supplement hydroelectric generation. In other locations, diesel generation is the only source of power. In addition to the utilities, KMC-GC has 11,800 kW of diesel generation and Ocean Beauty has about 3,700 kW of installed diesel generation at its Excursion Inlet facility. Numerous other small diesel generators are installed in logging camps, small villages and other remote locations. The principal cost in operating diesel generators is the cost of fuel.

If Interties are constructed, THREA, KMC-GC and others could forego the use of regular diesel energy production. Without the need to operate their diesel generators except in emergency situations, operators should be able to reduce the O&M costs of the units. The need for maintenance activities, lubricants and other consumables will be substantially reduced and maintenance and operating personnel can be assigned to other activities. Based on a review of THREA's production costs, it is estimated that the variable O&M cost[34] is about 3.0 cents per kWh. The variable O&M cost for the operation of KMC-GC's power generation system is estimated to be about 1.5 cents per kWh. Since it will be necessary to maintain backup generation with the Interties, some power production O&M costs will continue to be incurred.

Table 3-1 shows the assumed variable diesel O&M costs for each community in 2003. Costs are assumed to increase at the assumed rate of general inflation in subsequent years. The variation of diesel O&M costs among the utilities is due to a number of factors including utility size, staffing levels, maintenance policies, and cost accounting methodology. Further, if significant maintenance activities occurred in 2002, the costs of these activities could be reflected in the costs shown in Table 3-1.

[34] Power production costs are often characterized as variable, those costs that are directly associated with each unit of operation, and fixed, costs that are not avoidable. The costs of operations personnel are considered fixed for THREA's Kake and Hoonah service areas.

TABLE 3-1
Assumed Variable Diesel O&M Costs
(2003 cents/kWh)[1]

Skagway-Haines (AP&T)	1.00
Chilkat Valley (THREA)	3.00
Hoonah (THREA)	3.00
Kake (THREA)	3.00
Greens Creek	1.50
Excursion Inlet	2.00
Gustavus	3.00
Sitka	3.00
Angoon (THREA)	3.00
Ketchikan	1.50
Prince of Wales (AP&T)	0.60

[1] Source: Adjusted data from utilities and the Alaska Energy Authority Statistical Report of the Power Cost Equalization Program for fiscal year 2002.

In addition to the offset of fuel and O&M costs, with the Interties operators will benefit from the extension in operating life of their existing generators. Without the Interties, continued regular operation of the existing generators would require their eventual replacement or major overhaul. For the purpose of this analysis, it is assumed that without the SEI-1 Intertie, KMC-GC will replace one of its 2,200-kW diesel generators in five years (2008) and one in 2010 at a cost of $500 per kW. With the Intertie, the cost of these new generators would be avoided. THREA has indicated that if the Intertie to Hoonah is not constructed, it will likely need to install a 1,000-KW generator in Hoonah as a replacement for an older unit. The estimated cost of the new generator is $400,000.

The cost of generation fuel is a critical factor in the cost of power production in Southeast Alaska. Fuel prices rose significantly in early 2003 and were reported to be $1.59 per gallon in Kake in March 2003, significantly higher than the average fuel price of $0.90 per gallon incurred in 2002 and $1.07 per gallon in 2001. Fuel prices in Hoonah typically average 20-30 cents more per gallon than in Kake[35]. Many of the utilities with large fuel storage facilities typically by fuel at prices based on a negotiated margin over a standard fuel price index. This should result in fuel prices at these locations somewhat lower than those in Kake, for example. It is not expected that diesel fuel prices will stay at the current high level, however, it is not expected that they will necessarily decrease to price levels experienced in 2002. For the purpose of this analysis, the price of diesel fuel has been assumed to be initially set at the prices shown in Table 3-2. Fuel prices are further assumed to increase over time at the assumed rate of general inflation, 2.5% per year.

[35] THREA operates fuel storage tanks in Kake and Angoon that allow for barge deliveries of fuel in large enough quantities to obtain lower prices. Near daily truck deliveries of fuel are needed in Hoonah causing higher prices.

TABLE 3-2
Assumed Initial Diesel Fuel Prices
($/gallon – 2003 price level)

Skagway-Haines (AP&T)	$	1.15
Hoonah/Chilkat Valley (THREA)		1.35
Excursion Inlet		1.10
Kake/Angoon (THREA)		1.20
KMC-GC (Greens Creek)		1.10
Sitka		1.10
Ketchikan		1.10
Prince of Wales (AP&T)		1.10

The quantity of fuel needed to generate electrical energy varies from location to location and by actual generating unit. Some generating units are much more efficient than others. In addition, the loading on diesel generators affects their fuel efficiency[36]. The relative fuel efficiencies of diesel generation in each community are provided in the following table.

TABLE 3-3
Diesel Generator Fuel Efficiency
(kWh per gallon)

Skagway-Haines (AP&T)	14.2
Chilkat Valley (THREA)	14.5
Hoonah (THREA)	14.5
Kake (THREA)	13.7
KMC-GC (Greens Creek)	12.0
Excursion Inlet	14.0
Gustavus	12.5
Sitka	14.0
Angoon (THREA)	13.1
Ketchikan	15.3
Prince of Wales (AP&T)	13.0

Based on the assumed fuel prices, O&M costs and fuel efficiencies shown in the previous tables, the variable cost of diesel energy generation has been estimated for each of the communities and is shown in Table 3-4. It is important to note that the costs shown in Table 3-4 are variable costs and do not necessarily reflect the full cost of production. Certain fixed O&M costs such as operating staff, and capital recovery costs or depreciation would continue to be incurred whether or not diesel generators are operated regularly.

[36] Diesel generators, as with most oil and gas-fired generators, are more efficient (i.e. the quantity of fuel needed per kWh is lower) when operated at or near their maximum capacity.

TABLE 3-4
Projected Variable Cost of Power Production with Diesel Generation[1]
(nominal cents per kWh)

	2003	2004	2005	2006	2007	2012	2017	2022
Skagway-Haines (AP&T)	9.2	9.3	9.6	9.8	10.1	11.3	12.9	14.5
Chilkat Valley (THREA)[2]	-	-	-	-	10.0	11.7	13.4	15.1
Hoonah (THREA)	12.3	12.6	12.9	13.3	13.6	15.4	17.4	19.7
Kake (THREA)	11.8	12.0	12.4	12.7	13.0	14.7	16.6	18.8
KMC-GC (Greens Creek)	9.2	9.4	9.6	9.9	10.1	11.4	-	-
Excursion Inlet	9.9	10.1	10.3	10.6	10.9	12.3	13.9	15.8
Gustavus	13.4	13.7	14.1	14.4	14.8	16.7	19.0	21.4
Angoon (THREA)	12.2	12.4	12.8	13.1	13.4	15.2	17.2	19.4
Sitka	10.9	11.2	11.5	11.7	12.0	13.5	15.3	17.4
Ketchikan	8.7	8.9	9.1	9.4	9.6	10.8	12.3	13.9
Prince of Wales (AP&T)	9.1	9.3	9.5	9.8	10.0	11.3	12.8	14.5

[1] Based on variable O&M costs provided in Table 3-1, fuel costs shown in Table 3-2 and fuel usage rates shown in Table 3-3. Assumes annual inflation of 2.5% applied to O&M and fuel costs.

[2] THREA purchases essentially all of its present Chilkat Valley power supply from a privately owned and operated hydroelectric facility.

Cost of Purchased Power

With the Interties, power is expected to be purchased primarily from AEL&P and the Four Dam Pool Power Agency. The purchased power will then be used by KMC-GC, THREA and others to offset diesel generation. Power to be purchased from AEL&P will be priced at a rate that includes delivery charges to Outer Point on Douglas Island, the origin of the Juneau-Greens Creek-Hoonah Intertie[37]. It is not expected that AEL&P will dedicate any particular generating resource to KMC-GC or THREA but rather, will guarantee a quantity of energy at a price that recovers AEL&P's cost of production and assures that AEL&P's existing customers are not negatively impacted. Power purchases from AEL&P are expected to be tied to hydroelectric generation surplus to the needs of AEL&P's retail customers and existing non-firm commitments. With the development of the Lake Dorothy project, power deliveries to KMC-GC and Hoonah will essentially be firm.

In the event that hydroelectric generation is insufficient to supply AEL&P's full retail and interruptible load at any point in time, all or a portion of the deliveries to KMC-GC and Hoonah could be temporarily curtailed. On-site generation at KMC-GC and Hoonah would be needed to supply the local power requirement under this circumstance or alternatively, energy generated at AEL&P's oil-fueled generators could be used. If AEL&P needs to operate diesel generators to supply Hoonah or KMC-GC, there would need to be a surcharge applied to the base price for energy purchases.

AEL&P has indicated that it will need to develop the Lake Dorothy hydroelectric project in order to supply the power requirement of KMC-GC and Hoonah. Consequently, the cost of power to

[37] It is expected that AEL&P will contract directly with KMC-GC and THREA and that there will be no intermediate purchase by the Intertie owner/administrator. In this circumstance, AEL&P would most likely collect an additional amount over the cost of power supply to pay for the incremental Intertie costs. This additional amount could be bundled in to the power sales rate or could be an explicit transmission charge or "wheeling" fee.

be purchased by KMC-GC and Hoonah from AEL&P will be tied to the cost of power from the Lake Dorothy project. Discussions with AEL&P indicate that an exact price for the power to be sold to KMC-GC and THREA is not available. A price range has been determined, however, and for purposes of this analysis a rate of 8.5 cents per kWh is considered a reasonable estimate. AEL&P is presently pursuing development of the Lake Dorothy project and has filed a permit application with the Federal Energy Regulatory Commission (FERC). Construction of the project could begin in 2004 at the earliest and would require about three years to complete.

Power to be purchased from the Four Dam Pool Power Agency (FDPPA) by THREA for delivery to Kake will also be interruptible. At the present time, the Four Dam Pool firm power rate is 6.8 cents per kWh. This rate could increase somewhat in the future but is expected to remain relatively constant for the next few years. Discussions with FDPPA management indicate that power could be sold to THREA at a rate that is potentially lower than the firm power sales rate because of the possibility of interruption in availability[38]. For purposes of this study, it has been assumed that power can be purchased from the Four Dam Pool at 4.0 cents per kWh through 2011, increasing by 0.5 cents per kWh in 2012 and every five years thereafter. This cost would include delivery charges to Petersburg[39] but the effective rate in Kake would need to include the O&M costs on the Kake – Petersburg transmission line. In total, the cost of power to Kake would be essentially the same as the Four Dam Pool power sales rate of approximately 2.8 cents per kWh.

Although AEL&P and the Four Dam Pool Power Agency are presently expected to be the principal providers of hydroelectric energy for delivery over the Interties in the near future, other hydroelectric facilities could be developed that will have sufficient capacity to sell a portion of the output to other load centers. The City of Sitka, for example has investigated the development of the Takatz Lake hydroelectric project. If this 20-MW project were to be developed, a significant portion of the output would be surplus to the need of Sitka itself and could be sold. With an interconnected system, new hydroelectric facilities will most likely be developed on a regional basis; lower cost projects will conceivably be developed before higher cost projects.

A number of potential new hydroelectric projects for Southeast Alaska have been studied in the past. The size, cost and operating characteristics for these projects have been estimated as part of the previous studies. Table 3-5 provides capital and operating costs for selected projects for which cost data is available. As can be seen in Table 3-5, the lowest cost project, on a cents per kWh basis, is the Whitman Lake project in Ketchikan. The cost of power as shown in the last column of Table 3-5 assumes that all energy from the projects is utilized. Annual costs shown in Table 3-5 assume that the projects are financed with 100% debt with a 5.5% interest rate and a 30-year repayment period.

Although the capital cost estimates for the projects shown in Table 3-5 have been adjusted to 2003 cost levels, there has been no attempt made to determine if costs could be revised to reflect

[38] As indicated previously and shown in Table 3-8, it is expected that the full power requirement of Kake can regularly be supplied from the Lake Tyee project for several years to come, but cannot be fully guaranteed.
[39] Energy losses from Lake Tyee to the Kake Intertie tap point near Petersburg are also expected to be effectively included in the power sales rate. Since the metering point for power sales to Kake is to be at the tap point, energy losses between the tap point and Kake will need to be included as a cost to THREA.

new technologies or different project configurations. As an example of this situation, a 1998 power supply study conducted for Ketchikan Public Utilities estimated the cost of the 10-MW Mahoney Lake hydroelectric project at approximately $28 million. AP&T in 2000, in conjunction with the Cape Fox Corporation, changed the project configuration and proposed a different construction process that would result in an estimated project cost that was much lower, potentially in the range of $20 million.

TABLE 3-5
Estimated Cost of Power from Example New Hydroelectric Facilities
(nominal cents per kWh)

	Estimated Capital Cost ($000)	Cost Year	Estimated Capital Cost (2003 $000) [2]	Total Financing Requirement (2003 $000) [3]	Annual Debt Service[4]	Annual O&M [5]	Average Annual Energy Gen. (MWh)	Initial Year Cost of Power [6] (¢/kWh)
Takatz Lake [1]	62,200	1991	$ 81,794	$ 89,276	6,143	2,000	82,800	9.8
Katlian River [7] (Sitka)	53,600	1991	$ 70,485	$ 76,932	5,293	1,500	29,800	22.8
Thomas Bay (Swan Lake) [8]	129,450	1985	$ 192,832	$ 210,471	14,482	2,400	164,400	10.3
Whitman Lake [7]	7,635	2000	$ 8,015	$ 8,748	602	200	19,640	4.1
Triangle Lake [7]	12,910	2000	$ 13,552	$ 14,791	1,018	110	16,885	6.7

[1] Estimate prepared by RW Beck in 1991. Includes $5 million for a transmission line to Warm Springs Bay where interconnection with the Intertie to Sitka would be made.
[2] Adjusted to 2003 cost level using Handy-Whitman Pacific Region index for total hydraulic plant.
[3] Includes capital cost, reserve fund equal to one year's debt service and financing expenses at 1.5%.
[4] Assumes 100% debt financing at 5.5% interest rate and 30 year repayment period.
[5] Estimated based on previous reports with certain adjustments. Costs would be expected to increase over time with inflation.
[6] Assumes full project utilization.
[7] Estimate prepared previously by RW Beck.
[8] Estimate prepared by Hosey & Associates in 1985 for the lake tap option. Includes $10 million for cost of transmission line to Petersburg.

In the past, hydroelectric projects in Southeast Alaska have been developed by the local utilities, the State or federal governments. With an interconnected system, the development of new projects could be pursued in a different manner, potentially through joint ownership. For example, the Triangle Lake hydroelectric project near Metlakatla could be constructed to serve mining loads near Wrangell. The pricing of power from generating plants would also be expected to vary by utility. AEL&P and AP&T, being regulated investor-owned utilities, generally have a different costing basis related to power sales than the consumer-owned utilities have. "Market-price" issues may also factor in to the price of power sold between utilities.

Intertie Annual Costs

The transmission systems to be constructed will require regular efforts to inspect the system condition and make necessary repairs. Generally, these activities will be relatively minor, particularly for a new system. Structures, guys, insulators, conductors and submarine cable terminations will need to be inspected visually and a program to regularly clear trees and brush from the right of way will need to be established. It is expected that the entity that owns the Interties, will contract out the regular inspection and maintenance activities to local utilities or

other providers of this kind of service. The estimated annual O&M costs for the Interties are as follows:

TABLE 3-6
Estimated Annual O&M Costs
SEI-1 and SEI-2

	SEI-1	SEI-2
Tree Trimming	$ 20,000	$ 45,000
Overhead Line Inspections	15,000	20,000
Regular Repairs/Replacements	50,000	35,000
Submarine Terminal Inspections	15,000	15,000
Switchyard Maintenance	25,000	10,000
Miscellaneous	15,000	20,000
Subtotal	$ 140,000	$ 145,000
Contractor Fee [1]	25,000	25,000
Total	$ 165,000	$ 170,000
Unit Cost (¢/kWh) [2]	0.25	3.63

[1] Administrative and other overhead costs of contractor expected to be retained to provide O&M services for the Intertie and related facilities.

[2] Unit cost of O&M assuming combined energy sales of 66,600 MWh to KMC-GC and Hoonah over SEI-1 and 4,685 MWh to Kake over SEI-2.

SEI-1: Juneau – KMC-GC – Hoonah; SEI-2: Kake - Petersburg

TABLE 3-7
Estimated Annual O&M Costs
Other Intertie Segments

	SEI-3	SEI-4	SEI-5	SEI-6	SEI-7	SEI-8
Tree Trimming	$ 10,000	$ 10,000	$ 45,000	$ 45,000	$ 20,000	$ 20,000
Overhead Line Inspections	5,000	5,000	20,000	20,000	15,000	15,000
Regular Repairs/Replacements	25,000	25,000	50,000	50,000	30,000	50,000
Submarine Terminal Inspections	10,000	20,000	25,000	40,000	25,000	25,000
Switchyard Maintenance	15,000	15,000	25,000	40,000	25,000	25,000
Miscellaneous	20,000	20,000	40,000	40,000	25,000	25,000
Subtotal	$ 85,000	$ 95,000	$ 205,000	$ 235,000	$ 140,000	$ 160,000
Contractor Fee [1]	25,000	25,000	25,000	25,000	25,000	25,000
Total	$ 110,000	$ 120,000	$ 230,000	$ 260,000	$ 165,000	$ 185,000

[1] Administrative and other overhead costs of contractor expected to be retained to provide O&M services for the Intertie and related facilities.

SEI-3: Metlakatla – Ketchikan; SEI-4: Ketchikan – Prince of Wales Island; SEI-5: Kake – Sitka; SEI-6: Hawk Inlet – Angoon – Sitka; SEI-7: Hoonah – Gustavus; SEI-8: Juneau - Haines

Much of the annual O&M cost will be related to inspections and routine checks of facilities. In areas with road access to the primary facilities, these costs will be lower than in areas requiring helicopter access. It should also be noted that the O&M costs shown for SEI-5 and SEI-6 both

incorporate the costs associated with maintenance of the overland transmission line from Warm Springs Bay to Sitka. This could be a high maintenance section of the transmission system. If both SEI-5 and SEI-6 were constructed, the combined O&M for the two segments would be approximately $70,000 lower than the combined total shown for the two segments in Table 3-7.

The agency or organization that owns the Interties, will incur certain expenses related to policy oversight, accounting, general administration and management. Some of these costs would not necessarily be incurred to the same extent if the Interties were owned and administered by a utility or other entity presently in an electric service type business. The following table provides the estimated Intertie related administrative costs assuming both the Kake – Petersburg and the Juneau – Greens Creek – Hoonah Interties are constructed (the initial two segments) and administered by the same agency. Table 3-8 also shows the estimated additional administrative cost per added segment.

TABLE 3-8
Estimated Annual Intertie Administrative Costs [1]

	Initial Two Segments	Each Additional Segment
Management [2]	$ 60,000	$ 10,000
Legal Fees	15,000	5,000
Permit Overview	10,000	5,000
Insurance [3]	30,000	15,000
Accounting/Billing	30,000	10,000
Legislative Affairs	10,000	5,000
Travel Expenses	15,000	5,000
Miscellaneous	20,000	10,000
Total	$ 190,000	$ 65,000
Unit Cost (¢/kWh) [4]	0.27	

[1] Assumes a common agency or organization owns and administers the Interties.
[2] Based on allocated cost of part-time manager.
[3] Assumed cost of insurance on switchyards and related facilities.
[4] Unit cost assuming combined energy sales over the initial two Intertie segments of 71,300 MWh to Kake, KMC-GC and Hoonah.

Intertie O&M and administrative costs are expected to be recovered through charges to each of the Intertie users that are directly proportional to the power transmitted. The charges could be included as part of the wholesale cost of power. For the purpose of this study, the O&M costs for each Intertie are assumed to be charged only to the users of that Intertie. For example, the O&M costs of the Kake – Petersburg Intertie are allocated solely to THREA's operation in Kake. The O&M costs for the Juneau – Greens Creek – Hoonah Intertie are allocated to both KMC-GC and Hoonah based on the percentage of total energy estimated to be transmitted to each load center. The unit O&M cost shown in Table 3-7 for the Kake – Petersburg Intertie is much higher than the unit O&M cost shown for the Juneau – Hoonah Intertie because estimated energy sales to KMC-GC and Hoonah are significantly greater than to Kake. The administrative costs would

most likely be allocated to each Intertie segment in proportion to the energy estimated to be delivered to each of these load centers.

In addition to O&M and administrative costs, a charge related to the accrual of reserve funds to pay for major repairs to the Interties should be included in the costs charged to the Intertie users. These costs are not expected to be significant in the early years of Intertie operation and are in lieu of a depreciation charge. The reserve fund charge is also a means for "self-insuring" the Interties since transmission lines are generally not insurable.

As a basis for the amount of this repair and replacement (R&R) reserve that should be established, the estimated cost of a major repair or replacement of a significant system component can be used. It can also be reasonably assumed that with a new system, the timing of such a major repair or replacement would be several years in the future. For the Kake – Petersburg and Metlakatla - Ketchikan lines, a reserve requirement of $1.5 million has been estimated while a $2.5 million reserve is estimated for all other Intertie segments because of the longer submarine cables involved in these systems. Annual deposits of $46,000 and $116,000 per year for these two reserve fund requirements, respectively, would be needed to build up the reserve fund balance to these amounts within 15 years with accrued interest at 5% per year. If multiple Intertie segments were to be constructed, a single reserve fund could be established with a lower total fund amount acknowledging the probability of multiple system failures.

Estimated Savings with the Interties

Based on the foregoing, the cost of power to the communities that would be expected to purchase power over the Interties has been estimated. These costs include the cost of purchased power and the allocated costs of Intertie O&M and administration to each line. The costs with the Intertie have then been compared to the costs without the Intertie to determine the net savings associated with the Intertie. The cost of power with the Interties and the estimated savings in each load center are shown on an annual basis in the following tables assuming that the Interties are constructed and begin operation approximately in the years defined in the previous section of the report. As previously indicated, the capital costs of the Interties are assumed to be grant funded and as such, do not factor in to the calculation of annual costs.

An important factor in the calculation of annual costs is the estimated cost of purchased power. This cost could vary significantly from place to place depending on the amount of surplus hydroelectric energy available and whether or not new resources will need to be constructed to supply the total power requirement. For purposes of this analysis, an approximate cost of power has been assumed for each load center based on either the cost of Four Dam Pool power or the estimated cost of power from the Lake Dorothy project. It is also important to note that the cost of purchased power needs to include a charge related to the use of the generating utility's transmission system that connects the generating facility to the Intertie.

Descriptions of the estimated savings for each Intertie segment follow.

Juneau – KMC-GC – Hoonah (SEI-1)

The estimated cost of power to THREA in Hoonah is shown in Table 3-9 assuming that SEI-1 is constructed and becomes operational in 2007. Table 3-10 provides the estimated cost of power for the KMC-GC mine. In both of these tables, it is assumed that the KMC-GC mine remains in operation through 2016. With the closure of the mine, THREA will need to cover the full operating cost of the Intertie until other future connections are made.

TABLE 3-9
Projected Cost of Power and Savings with the Intertie
THREA – Hoonah Service Area

	2007	2008	2009	2010	2011	2012	2017
Energy Requirements (MWh) [1]	7,924	8,015	8,106	8,199	8,293	8,377	8,783
Energy Purchased (MWh) [2]	8,241	8,336	8,431	8,527	8,625	8,712	9,134
Purchased Power Price (¢/kWh) [3]	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Annual Costs with Intertie ($000)							
Purchased Power [4]	$ 700	$ 709	$ 717	$ 725	$ 733	$ 740	$ 776
Intertie O&M [5]	23	23	24	25	26	27	242
Intertie A&G [6]	24	25	26	27	28	29	174
Intertie R&R [7]	14	14	14	14	14	14	116
Total Annual Costs with Intertie	$ 761	$ 771	$ 781	$ 791	$ 801	$ 810	$ 1,308
Unit Cost (¢/kWh) [8]	9.6	9.6	9.6	9.6	9.7	9.7	14.9
Savings with Intertie ($000) [9]	$ 347	$ 377	$ 408	$ 440	$ 475	$ 510	$ 251
Savings (¢/kWh) [10]	4.2	4.5	4.8	5.2	5.5	5.9	2.7
Breakeven Cost of Power (¢/kWh) [11]	12.7	13.0	13.3	13.7	14.0	14.3	11.2

[1] Estimated total energy requirements.
[2] Includes estimated transmission losses of 4% between Juneau and Hoonah.
[3] Estimated price of power purchased from AEL&P.
[4] Estimated cost of power purchased from AEL&P.
[5] Intertie O&M cost as shown in Table 3-6 allocated to THREA based on percentage of total sales over the Intertie. Assumes O&M costs increase annually at the assumed rate of general inflation.
[6] Intertie A&G cost as shown in Table 3-7 allocated to THREA based on percentage of total sales over both Interties. Assumes A&G costs increase annually at the assumed rate of general inflation.
[7] Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate. Cost allocated to THREA based on percentage of sales over the Juneau – Greens Creek – Hoonah Intertie.
[8] Total Annual Costs divided by Total Energy Requirement.
[9] Total Production Cost for the diesel generation case less Total Annual Costs with Intertie.
[10] Savings with Intertie divided by Total Energy Requirements.
[11] Estimated price for purchased power over the Intertie, exclusive of transmission related charges, that could be paid and produce no annual savings.

As shown in Table 3-9, the estimated savings to THREA in 2007, the first year of Intertie operation is $347,000. Table 6-15 also shows that the average charge for electric service in Hoonah could potentially be reduced by 4.2 cents per kWh with the Intertie[40]. Annual savings with the Intertie are expected to increase each year primarily due to assumed increases in the cost of diesel fuel that the Intertie will offset. In 2017, the first year after the assumed closure of the KMC-GC mine, the revenue recovery obligations of THREA increase and the savings decrease.

[40] Due to the effects of the State Power Cost Equalization program, any savings in THREA's cost of power due to the Intertie would not necessarily show up in reductions in the effective charges for residential electric service. Rather, the amount of subsidy from PCE provided to THREA would be reduced.

The cumulative present value to mid-2003 of the estimated annual savings to THREA with the Intertie for the 20-year period, 2007 through 2026 is $4.67 million, assuming a 5% discount rate[41].

A significant benefit to THREA with the Intertie will be the ability to establish economic incentive rates for new large commercial/industrial electric consumers. As long as regular retail energy sales remain relatively stable in Hoonah, the fixed costs of THREA's distribution system and the Intertie will be recovered through normal rates. Consequently, an economic incentive rate based on the incremental cost of purchased power (8.5 cents per kWh in the above table) plus a nominal margin could be established. This rate would need to be negotiated on a case by case basis and should have a time limit to it (e.g. 5-10 years), but could be used to attract new commercial activity to the Hoonah area.

TABLE 3-10
Projected Cost of Power and Savings with the Intertie
KMC-GC Mine

	2007	2008	2009	2010	2011	2012	2017
Energy Requirements (MWh) [1]	58,692	58,692	58,692	58,692	58,692	58,692	-
Energy Purchased (MWh) [2]	59,866	59,866	59,866	59,866	59,866	59,866	-
Purchased Power Price (¢/kWh) [3]	8.5	8.5	8.5	8.5	8.5	8.5	-
Annual Costs with Intertie ($000)							
Purchased Power [4]	$ 5,089	$ 5,089	$ 5,089	$ 5,089	$ 5,089	$ 5,089	$ -
Intertie O&M [5]	164	168	171	176	180	184	-
Intertie A&G [6]	176	180	184	188	193	197	-
Intertie R&R [7]	102	102	102	102	102	101	-
Total Annual Costs with Intertie	$ 5,531	$ 5,539	$ 5,546	$ 5,555	$ 5,564	$ 5,571	$ -
Unit Cost (¢/kWh) [8]	9.4	9.4	9.4	9.5	9.5	9.5	-
Savings with Intertie ($000) [9]	$ 1,380	$ 1,656	$ 1,826	$ 2,110	$ 2,288	$ 2,471	$ -
Savings (¢/kWh) [10]	2.3	2.8	3.1	3.5	3.8	4.1	-
Breakeven Cost of Power (¢/kWh) [11]	10.8	11.3	11.6	12.0	12.3	12.6	-

[1] Total estimated energy requirements.
[2] Includes estimated transmission losses of 2% between Juneau and the KMC-GC mine.
[3] Estimated price of power purchased from AEL&P.
[4] Estimated cost of power purchased from AEL&P.
[5] Intertie O&M cost as shown in Table 3-6 allocated to KMC-GC based on percentage of total sales over the Intertie. Assumes O&M costs increase annually at the assumed rate of general inflation.
[6] Intertie A&G cost as shown in Table 3-7 allocated to KMC-GC based on percentage of total sales over both Interties. Assumes A&G costs increase annually at the assumed rate of general inflation.
[7] Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate. Cost allocated to KMC-GC based on percentage of sales over the Juneau – Greens Creek – Hoonah Intertie.
[8] Total Annual Costs divided by Total Energy Requirement.
[9] Total Production Cost for the diesel generation case less Total Annual Costs with Intertie.
[10] Savings with Intertie divided by Total Energy Requirements.
[11] Estimated price for purchased power over the Intertie, exclusive of transmission related charges, that could be paid and produce no annual savings.

As shown in Table 3-10, the estimated savings to KMC-GC in 2007, the first year of Intertie operation is $1,380,000. Annual savings with the Intertie are expected to increase each year

[41] The discount rate for THREA is based on THREA's cost of capital, which is generally a relatively low interest rate of 5%.

primarily due to assumed increases in the cost of fuel that the Intertie will offset. The cumulative present value to mid-2003 of the estimated annual savings to KMC-GC with the Intertie for the ten-year period, 2007 through 2016 is $11.0 million, assuming an 8% annual discount rate.

Kake – Petersburg Intertie (SEI-2)

SEI-2 is assumed to become operational in 2007 at which time, THREA would be able to purchase power from the Four Dam Pool Power Agency's Lake Tyee hydroelectric project. Initially, this power purchase could be considered an interruptible sale of surplus generation capacity and could be priced at a lower rate than the normal Four Dam Pool power sales rate. As shown in Table 3-11, the assumed rate for power sales to Kake is 4.0 cents per kWh initially, however, including the Intertie related costs, the net cost of delivered power to Kake would be 9.6 cents per kWh in 2007 and 2008.

TABLE 3-11

Projected Cost of Power and Savings with the Intertie
THREA – Kake Service Area

	2007	2008	2009	2010	2011	2012	2017
Energy Requirements (MWh) [1]	4,685	4,747	4,811	4,874	4,938	4,993	5,278
Energy Purchased (MWh) [2]	4,873	4,937	5,003	5,069	5,135	5,192	5,489
Purchased Power Price (¢/kWh) [3]	4.0	4.0	4.0	4.0	4.0	4.5	5.0
Annual Costs with Intertie ($000)							
Purchased Power [4]	$ 195	$ 197	$ 200	$ 203	$ 205	$ 234	$ 274
Intertie O&M [5]	195	200	205	210	215	221	250
Intertie A&G [6]	14	15	15	16	17	17	105
Intertie R&R [7]	46	46	46	46	46	46	46
Total Annual Costs with Intertie	$ 450	$ 458	$ 466	$ 475	$ 483	$ 518	$ 675
Unit Cost (¢/kWh) [8]	9.6	9.6	9.7	9.7	9.8	10.4	12.8
Savings with Intertie ($000) [9]	$ 158	$ 173	$ 190	$ 206	$ 224	$ 215	$ 204
Savings (¢/kWh) [10]	3.2	3.5	3.8	4.1	4.4	4.1	3.7
Breakeven Cost of Power (¢/kWh) [11]	7.2	7.5	7.8	8.1	8.4	8.6	8.7

[1] Total estimated energy requirements.
[2] Includes estimated transmission losses of 4% between Petersburg and Kake.
[3] Estimated price of power purchased from the Four Dam Pool Power Agency.
[4] Estimated cost of power purchased from the Four Dam Pool Power Agency.
[5] Intertie O&M cost as shown in Table 3-6 fully allocated to THREA. Assumes O&M costs increase annually at the assumed rate of general inflation.
[6] Intertie A&G cost as shown in Table 3-8 allocated to THREA based on percentage of total sales over both Interties. Assumes A&G costs increase annually at the assumed rate of general inflation.
[7] Annual deposit to Intertie R&R fund to establish a $1.5 million balance in 15 years with accrued interest at an assumed 5% interest rate. Cost is fully allocated to THREA.
[8] Total Annual Costs divided by Total Energy Requirement.
[9] Total Production Cost for the diesel generation case (see Table 6-10) less Total Annual Costs with Intertie.
[10] Savings with Intertie divided by Total Energy Requirements.
[11] Estimated price for purchased power over the Intertie that could be paid and produce no annual savings.

As shown in Table 3-11, the estimated savings to THREA in 2007, the first year of Intertie operation is $158,000. Annual savings with the Intertie are expected to increase each year primarily due to assumed increases in the cost of fuel that the Intertie will offset. The cumulative

present value to mid-2003 of the estimated annual savings to KMC-GC with the Intertie for the 20-year period, 2007 through 2026 is $2.49 million, assuming a 5% annual discount rate.

Compared to the savings shown related to the Juneau – Greens Creek – Hoonah Intertie, the annual savings shown for the Kake – Petersburg Intertie are much less due to the need to allocate the operating costs of this Intertie over a much smaller load base in Kake than the combined Greens Creek – Hoonah load.

A significant benefit to THREA with the Intertie will be the ability to establish economic incentive rates for new large commercial/industrial electric consumers. As long as regular retail energy sales remain relatively stable in Kake, the fixed costs of THREA's distribution system and the Intertie will be recovered through normal rates. Consequently, an economic incentive rate based on the incremental cost of purchased power (4.0 cents per kWh in the above table) plus a nominal margin could be established[42]. This rate would need to be negotiated on a case by case basis and should have a time limit to it (e.g. 5-10 years), but could be used to attract new commercial activity to the Kake area.

The savings estimated for THREA's Hoonah and Kake service areas could, but would not necessarily be transferred directly through to a reduction in rates for electric service in Kake and Hoonah. THREA presently charges the same rates for all of its service areas[43] based on the combined costs of the entire system. The estimation of THREA's power rates is beyond the scope of this study. The State's Power Cost Equalization program would also affect how much of the Intertie provided savings would be realized by residential consumers in Kake and Hoonah[44]. The PCE program is funded each year by the State legislature and its funding magnitude as well as its continuation is uncertain.

Ketchikan – Metlakatla Intertie (SEI-3)

Without an interconnection between Ketchikan and Prince of Wales or additional load growth in the Tyee – Swan region, the Ketchikan – Metlakatla Intertie would not be needed as an alternative to supply loads in Ketchikan until approximately 2024. If SEI-4 between Ketchikan and Prince of Wales were constructed, the Metlakatla Intertie could supply loads on Prince of Wales as early as 2021. Metlakatla should have surplus hydroelectric energy available to it well beyond this time and would not need to purchase any power from other utilities to meet its own load. Consequently, the sole purpose of SEI-4 will be for other utilities to gain access to Metlakatla's surplus hydroelectric energy.

The analysis shown in Table 3-12 assumes that SEI-3 is constructed and becomes operational in 2020 and that all estimated surplus hydroelectric energy from existing facilities is sold to other

[42] The Four Dam Pool Power Agency would also need to be involved in any discussions of additional energy purchases for economic incentive purposes.
[43] THREA has indicated that it may need to establish rates in each service area based on the cost of service in the respective areas, at the request of the Regulatory Commission of Alaska (RCA).
[44] Essentially, the PCE program provides a subsidy to residential electric consumers. The amount of the subsidy is based on the local cost of power production. According to the program formula, if the cost of power production decreases, as it does when fuel prices drop, the magnitude of the subsidy would also decrease. The amount of the subsidy is also a function of the legislatively approved contribution to the program each year.

utilities in the Tyee – Swan region. The power sales rate is assumed to be 8.0 cents per kWh in 2020 increasing to 8.5 cents per kWh in 2027 based on previous analyses. The cost of power over the Intertie is compared to the cost of diesel generation in Ketchikan to determine the Intertie savings. The power sales rate would be negotiated and Metlakatla Power & Light (MP&L) would have a significant amount of flexibility in the rate it will charge. In 2000, MP&L indicated a potential power sales rate to Ketchikan at approximately the Four Dam Pool power sales rate, presently at 6.8 cents per kWh.

TABLE 3-12
Estimated Annual Savings with the Ketchikan – Metlakatla Intertie (SEI-3)

	2020	2021	2022	2023	2024	2028
Energy Delivered (MWh)[1]	7,855	7,685	7,515	7,335	7,155	6,435
Purchased Power Price (¢/kWh) [2]	8.0	8.0	8.0	8.0	8.0	8.5
Annual Costs with Intertie ($000)	-	-	-	-	-	-
Purchased Power [3]	$ 654	$ 639	$ 625	$ 610	$ 595	$ 569
Intertie O&M [4]	168	172	176	180	185	204
Intertie A&G [5]	99	101	104	107	109	121
Intertie R&R [6]	46	46	46	46	46	46
Total Annual Costs with Intertie	$ 966	$ 958	$ 951	$ 943	$ 935	$ 940
Unit Cost (¢/kWh) [7]	12.3	12.5	12.7	12.9	13.1	14.6
Savings with Intertie ($000) [8]	72	83	93	102	109	88
Savings (¢/kWh) [9]	0.9	1.1	1.2	1.4	1.5	1.4

[1] Total estimated surplus hydroelectric energy available in Metlakatla from existing resources.
[2] Assumed price of power to be sold by Metlakatla Power & Light (MP&L) to Ketchikan.
[3] Estimated cost of power purchased by Ketchikan from MP&L. Assumes energy losses of 4%.
[4] Intertie O&M cost as shown in Table 3-7 for SEI-3. Assumes O&M costs increase annually at the assumed rate of general inflation.
[5] Intertie A&G cost as shown in Table 3-8 for additional Intertie segments. Assumes A&G costs increase annually at the assumed rate of general inflation.
[6] Annual deposit to Intertie R&R fund to establish a $1.5 million balance in 15 years with accrued interest at an assumed 5% interest rate. Cost is fully allocated to Ketchikan.
[7] Total Annual Costs divided by Total Energy Requirement.
[8] Estimated production cost for diesel generation in Ketchikan less Total Annual Costs with Intertie.
[9] Savings with Intertie divided by Total Energy Delivered.

Table 3-12 indicates that SEI-3 would provide small, yet positive benefits when compared to diesel generation in Ketchikan. Another comparison to make from the values in Table 3-12 is that if additional power is needed in Ketchikan by 2020, the cost of a new resource to be developed locally would need to be less than 12.0 cents per kWh to provide lower cost power than the Metlakatla Intertie.

Ketchikan – Prince of Wales Intertie (SEI-4)

SEI-4 would provide an interconnection between the Tyee – Swan system and AP&T's Prince of Wales system. The primary purpose of SEI-4 would be to transmit power from the Four Dam Pool, Ketchikan or Metlakatla to AP&T. At the present time, the Prince of Wales region fully utilizes the Black Bear Lake hydroelectric project and has a net diesel generation requirement. AP&T has indicated it expects to construct the South Fork hydro project and begin operation in 2006. With the South Fork project and intra-Island interconnection of Hollis, Hydaburg and

Coffman Cove, there would be surplus hydro on Prince of Wales through about 2009. At that time, the construction of SEI-4 would allow for the purchase of power from the Four Dam Pool, Ketchikan or Metlakatla if SEI-3 were constructed.

Table 3-13 provides the estimated savings to AP&T assuming the Intertie to Ketchikan is constructed in 2012. The price of purchased power to AP&T is assumed to be 7.5 cents per kWh initially increasing to 8.0 cents per kWh in 2017.

TABLE 3-13

Estimated Annual Savings with the Ketchikan – Prince of Wales Intertie (SEI-4)

	2012	2013	2014	2015	2016	2020	2025
Energy Delivered (MWh)[1]	448	756	1,064	1,372	1,681	2,977	4,667
Purchased Power Price (¢/kWh) [2]	7.5	7.5	7.5	7.5	7.5	8.0	8.0
Annual Costs with Intertie ($000)	-	-	-	-	-	-	-
Purchased Power [3]	$ 35	$ 59	$ 83	$ 107	$ 131	$ 248	$ 388
Intertie O&M [4]	150	154	158	162	166	183	207
Intertie A&G [5]	81	83	85	87	90	99	112
Intertie R&R [6]	116	116	116	116	116	116	116
Total Annual Costs with Intertie	$ 382	$ 412	$ 442	$ 472	$ 502	$ 646	$ 823
Unit Cost (¢/kWh) [7]	85.3	54.5	41.5	34.4	29.9	21.7	17.6
Savings with Intertie ($000) [8]	(332)	(324)	(315)	(305)	(292)	(235)	(95)
Savings (¢/kWh) [9]	(74.0)	(42.9)	(29.6)	(22.2)	(17.4)	(7.9)	(2.0)

[1] Total energy required by AP&T to offset diesel energy requirement.
[2] Assumed price of power to be sold to AP&T.
[3] Estimated cost of power purchased by AP&T. Assumes energy losses of 4%.
[4] Intertie O&M cost as shown in Table 3-7 for SEI-4. Assumes O&M costs increase annually at the assumed rate of general inflation.
[5] Intertie A&G cost as shown in Table 3-8 for additional Intertie segments. Assumes A&G costs increase annually at the assumed rate of general inflation.
[6] Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate.
[7] Total Annual Costs divided by Total Energy Requirement.
[8] Estimated production cost for diesel generation on Prince of Wales less Total Annual Costs with Intertie.
[9] Savings with Intertie divided by Total Energy Delivered.

As can be seen in Table 3-13, SEI-4 would not show positive savings until after 2025. The lack of savings is primarily tied to the relatively small amount of power to be transmitted over the line. If loads grow faster on Prince of Wales than presently anticipated, positive savings would be realized earlier. Also, if AP&T does not develop the South Fork project, positive savings could be expected as early as 2015. This would mean that the earliest that SEI-4 would be economically justifiable is 2015.

Kake – Sitka Intertie (SEI-5)

The Kake – Sitka Intertie would interconnect Sitka with the Tyee-Swan region. Sitka is projected to have average annual hydroelectric energy generation surplus to the needs of its own customers for about fifteen years at the assumed rate of growth. This surplus could be sold to other communities if a transmission interconnection existed. Further, the proposed Takatz Lake

hydroelectric project is located near the proposed route of SEI-5[45]. Transmission access to the Takatz Lake project was identified in earlier studies as a primary problem in developing the project. The output of the Takatz Lake project would far exceed the immediate need in Sitka and could be used to supply loads elsewhere in the Tyee-Swan region if SEI-5 were installed. If the Takatz Lake project were not developed, SEI-5 could be used to deliver energy from the Tyee-Swan region to Sitka. Table 3-14 provides the estimated comparative savings with SEI-5 assuming that SEI-5 is used to deliver power to Sitka beginning in 2018.

TABLE 3-14
Estimated Annual Savings with the Kake - Sitka Intertie (SEI-5)
Based on Transmission of Energy to Sitka

	2018	2019	2020	2021	2022	2026
Energy Delivered (MWh)[1]	610	1,770	2,940	4,130	5,330	10,240
Purchased Power Price (¢/kWh)[2]	8.0	8.0	8.0	8.0	8.0	8.0
Annual Costs with Intertie ($000)	-	-	-	-	-	-
Purchased Power[3]	$ 51	$ 147	$ 245	$ 344	$ 443	$ 852
Intertie O&M[4]	333	341	350	359	368	406
Intertie A&G[5]	94	97	99	101	104	115
Intertie R&R[6]	116	116	116	116	116	116
Total Annual Costs with Intertie	$ 594	$ 701	$ 810	$ 920	$ 1,030	$ 1,488
Unit Cost (¢/kWh)[7]	97.4	39.6	27.5	22.3	19.3	14.5
Savings with Intertie ($000)[8]	(498)	(416)	(324)	(220)	(105)	473
Savings (¢/kWh)[9]	(81.7)	(23.5)	(11.0)	(5.3)	(2.0)	4.6

[1] Total energy required by Sitka to offset diesel energy requirement.
[2] Assumed price of power to be sold to Sitka.
[3] Estimated cost of power purchased by Sitka. Assumes energy losses of 4%.
[4] Intertie O&M cost as shown in Table 3-7 for SEI-5. Assumes O&M costs increase annually at the assumed rate of general inflation.
[5] Intertie A&G cost as shown in Table 3-8 for additional Intertie segments. Assumes A&G costs increase annually at the assumed rate of general inflation.
[6] Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate.
[7] Total Annual Costs divided by Total Energy Requirement.
[8] Estimated production cost for diesel generation in Sitka less Total Annual Costs with Intertie.
[9] Savings with Intertie divided by Total Energy Delivered.

The information in Table 3-14 indicates that positive savings would not begin to accrue until about 2023. By this time, if Sitka were relying upon regular energy deliveries from the Tyee-Swan region, new energy generation facilities would be needed within the interconnected system. If a new large load, such as a mine, were to begin operation in the Tyee-Swan region, the deliveries of power from Sitka could potentially show benefits much earlier.

Hawk Inlet – Angoon – Sitka Intertie (SEI-6)

SEI-6 would be used primarily to transmit power from Juneau to Angoon and Sitka and could be developed in two stages, 1) Hawk Inlet to Angoon and 2) Angoon to Sitka if desired. As previously indicted for SEI-5, Sitka is estimated to have surplus hydroelectric energy generation

[45] Note that the submarine cable route of SEI-6 is also proposed to use the same overland route as SEI-5 to cross Baranof Island. Both routes would make transmission access to the Takatz Lake project much easier.

available to it until approximately 2018. As long as the KMC-GC mine continues to operate, AEL&P is not expected to have much surplus hydroelectric energy, even with the Lake Dorothy project. If the mine closes in 10-15 years, as presently assumed, a significant amount of surplus generation could become available to AEL&P. This energy could be sold to Angoon and Sitka. Table 3-15 shows the estimated savings to Angoon and Sitka with the installation of SEI-6 in 2018 and assuming that power can be purchased from AEL&P at rates previously identified for sale to KMC-GC and Hoonah in the analysis of SEI-1.

TABLE 3-15
Estimated Annual Savings with the Hawk Inlet - Angoon - Sitka Intertie (SEI-6)

	2018	2019	2020	2021	2022	2026
Energy Delivered (MWh)[1]	3,130	4,330	5,540	6,770	8,010	13,080
Purchased Power Price (¢/kWh) [2]	8.5	8.5	8.5	8.5	8.5	8.5
Annual Costs with Intertie ($000)	-	-	-	-	-	-
Purchased Power [3]	$ 282	$ 390	$ 499	$ 610	$ 722	$ 1,179
Intertie O&M [4]	377	386	396	405	416	459
Intertie A&G [5]	94	97	99	101	104	115
Intertie R&R [6]	116	116	116	116	116	116
Total Annual Costs with Intertie	$ 869	$ 988	$ 1,109	$ 1,233	$ 1,357	$ 1,868
Unit Cost (¢/kWh) [7]	27.8	22.8	20.0	18.2	16.9	14.3
Savings with Intertie ($000) [8]	(330)	(241)	(143)	(32)	89	702
Savings (¢/kWh) [9]	(10.5)	(5.6)	(2.6)	(0.5)	1.1	5.4

1 Total energy required by Sitka and Angoon to offset diesel energy requirement.
2 Assumed price of power to be sold to Sitka and Angoon from AEL&P.
3 Estimated cost of power purchased by Sitka and Angoon. Assumes energy losses of 6%.
4 Intertie O&M cost as shown in Table 3-7 for SEI-6. Assumes O&M costs increase annually at the assumed rate of general inflation.
5 Intertie A&G cost as shown in Table 3-8 for additional Intertie segments. Assumes A&G costs increase annually at the assumed rate of general inflation.
6 Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate.
7 Total Annual Costs divided by Total Energy Requirement.
8 Estimated production cost for diesel generation in Sitka and Angoon less Total Annual Costs with Intertie.
9 Savings with Intertie divided by Total Energy Delivered.

As shown in Table 3-15, positive savings are not realized until 2022 with SEI-6, approximately the same timeframe when savings could potentially be realized with SEI-5.

With the analysis provided above for SEI-5 and SEI-6, both lines were evaluated exclusive of each other. Installation of both SEI-5 and SEI-6 would provide the interconnection of the North region to the Tyee-Swan region and would essentially complete the Southeast Alaska transmission system. The connection of the northern system to the southern system, however, would most likely only be done if loads increased significantly in one region and power new hydroelectric generation resources were to be developed in the other. An example of this would be if a new large mining load developed in the Tyee-Swan region and AEL&P constructed Phase 2 of the Lake Dorothy hydroelectric project to supply load. Another justification for both SEI-5 and SEI-6 together would be to transmit energy both directions, north and south, from the proposed Takatz Lake hydroelectric project on Baranof Island. Further study of these issues will

be needed in the future as load growth becomes more apparent and a more thorough evaluation of potential new hydroelectric facilities from a regional perspective is conducted.

It should also be noted that an alternative overland transmission route between Hoonah and Sitka has been considered for SEI-6. The evaluation of economic benefits would be similar for this route. Further, SEI-6 could be developed in segments if needed. The most likely initial segment would be an interconnection between Hawk Inlet and Angoon or Hoonah and Angoon. Table 3-16 shows the estimated annual savings for a Hawk Inlet – Angoon interconnection.

TABLE 3-16
Estimated Annual Savings with the Hawk Inlet - Angoon Intertie (SEI-6a)

	2012	2013	2014	2015	2016	2020	2025
Energy Delivered (MWh)[1]	2,300	2,330	2,360	2,400	2,440	2,600	2,800
Purchased Power Price (¢/kWh) [2]	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Annual Costs with Intertie ($000)	-	-	-	-	-	-	-
Purchased Power [3]	$ 203	$ 206	$ 209	$ 212	$ 216	$ 230	$ 248
Intertie O&M [4]	150	154	158	162	166	183	207
Intertie A&G [5]	81	83	85	87	90	99	112
Intertie R&R [6]	116	116	116	116	116	116	116
Total Annual Costs with Intertie	$ 550	$ 559	$ 568	$ 577	$ 587	$ 628	$ 683
Unit Cost (¢/kWh) [7]	23.9	24.0	24.1	24.0	24.1	24.1	24.4
Savings with Intertie ($000) [8]	(201)	(197)	(191)	(184)	(178)	(147)	(96)
Savings (¢/kWh) [9]	(8.7)	(8.5)	(8.1)	(7.7)	(7.3)	(5.6)	(3.4)

1 Total energy required by Angoon to offset diesel energy requirement.
2 Assumed price of power to be sold to Angoon from AEL&P.
3 Estimated cost of power purchased by Angoon. Assumes energy losses of 4%.
4 Intertie O&M cost as shown in Table 3-7 for SEI-4 (i.e. same cost as for Ketchikan-Metlakatla line). Assumes O&M costs increase annually at the assumed rate of general inflation.
5 Intertie A&G cost as shown in Table 3-8 for additional Intertie segments. Assumes A&G costs increase annually at the assumed rate of general inflation.
6 Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate.
7 Total Annual Costs divided by Total Energy Requirement.
8 Estimated production cost for diesel generation in Angoon less Total Annual Costs with Intertie.
9 Savings with Intertie divided by Total Energy Delivered.

As can be seen in Table 3-16, benefits are estimated to exceed Intertie related costs through at least 2025. For the purpose of this analysis, the full costs O&M, A&G and R&R for the Hawk Inlet – Angoon line are assumed to be allocated to energy purchases by Angoon. This analytical approach is similar to the approach taken for all other Intertie segments. If these costs could be allocated over a larger load base, net benefits with the Intertie could potentially realized earlier.

Hoonah – Gustavus Intertie (SEI-7)

SEI-7 would interconnect Gustavus with the interconnected Hoonah – KMC-GC – Juneau system. Although Gustavus and the adjacent Glacier Bay National Park Service (NPS) facilities are totally dependent on diesel generation, Gustavus Electric Company (GEC) has indicated it intends to develop the 800-kW Falls Creek hydroelectric project in the near future. With the Falls Creek project, the need for energy deliveries to Gustavus and the NPS to offset diesel generation are greatly reduced. Nevertheless, regular diesel energy generation is estimated to

continue to be needed. Table 3-16 provides the estimated savings to Gustavus and the NPS assuming SEI-7 is constructed and becomes operational in 2017 and assuming that power will be purchased by GEC and the NPS from AEL&P. The evaluation included in Table 3-16 also assumes that the Falls Creek project is constructed in 2008.

TABLE 3-17

Estimated Annual Savings with Hoonah - Gustavus Intertie (SEI-7)

	2017	2018	2019	2020	2021	2025
Energy Delivered (MWh)[1]	560	590	620	650	680	800
Purchased Power Price (¢/kWh) [2]	8.5	8.5	8.5	8.5	8.5	8.5
Annual Costs with Intertie ($000)	-	-	-	-	-	-
Purchased Power [3]	$ 50	$ 52	$ 55	$ 57	$ 60	$ 71
Intertie O&M [4]	233	239	245	251	257	284
Intertie A&G [5]	92	94	97	99	101	112
Intertie R&R [6]	116	116	116	116	116	116
Total Annual Costs with Intertie	$ 491	$ 501	$ 512	$ 523	$ 535	$ 583
Unit Cost (¢/kWh) [7]	87.7	84.9	82.6	80.4	78.6	72.9
Savings with Intertie ($000) [8]	(385)	(386)	(388)	(390)	(393)	(399)
Savings (¢/kWh) [9]	(68.7)	(65.4)	(62.6)	(60.0)	(57.8)	(49.9)

[1] Total energy required by GEC and NPS to offset diesel energy requirement.
[2] Assumed price of power to be sold to GEC and NPS from AEL&P.
[3] Estimated cost of power purchased by GEC and NPS. Assumes energy losses of 4%.
[4] Intertie O&M cost as shown in Table 3-7 for SEI-7. Assumes O&M costs increase annually at the assumed rate of general inflation.
[5] Intertie A&G cost as shown in Table 3-8 for additional Intertie segments. Assumes A&G costs increase annually at the assumed rate of general inflation.
[6] Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate.
[7] Total Annual Costs divided by Total Energy Requirement.
[8] Estimated production cost for diesel generation in GEC and NPS less Total Annual Costs with Intertie.
[9] Savings with Intertie divided by Total Energy Delivered.

Table 3-16 indicates that the costs associated with SEI-7 far exceed the benefits well beyond 2025. An alternative configuration for SEI-7 would be to provide an additional connection to Ocean Beauty's Excursion Bay facility. Ocean Beauty presently uses diesel generation for its full power supply requirement. Without development of the Falls Creek project, net benefits with SEI-7 could be realized a few years earlier but benefits are still not expected to exceed costs until after 2025.

Juneau – Haines/Skagway Intertie (SEI-8)

SEI-8 would interconnect the Upper Lynn Canal electric system with Juneau. If AP&T develops the Kasidaya Creek hydroelectric project as it presently expects to do, the Upper Lynn Canal region will have surplus hydroelectric energy available to it for an estimated 30 years, based on the assumed load growth defined previously. Some surplus hydroelectric energy would be available that AP&T could sell to AEL&P if SEI-8 were constructed and loads continue to grow in Juneau and elsewhere. For the purpose of this analysis, development of SEI-8 has been estimated to be beyond the study period. SEI-8 could be economically beneficial at an earlier date if AP&T does not develop the Kasidaya Creek project or additional energy generation is needed in the interconnected Juneau region.

Proposed Timing of Intertie Development

In Section 2 of this report a specific timeline for development of new resources and transmission lines was proposed. The proposed plan for Intertie development was based on the need for additional hydroelectric energy in each of the communities and load centers. Several hydroelectric developments and transmission interconnections have been proposed and are being developed by the utilities. These projects are assumed to play a vital role in the future overall Southeast regional power supply system. They are not, however, considered to be within the control of any particular Southeast Alaska regional power supply organization.

The following table lists the proposed timeline for development of the Intertie segments based on both the loads and resource analyses shown in Section 2 and the economic analysis included in this section of the report. The time range shown for the various segments reflects the uncertainty with regard to load growth, fuel costs and other factors that affect when benefits with the Interties would be realized.

TABLE 3-18
Proposed Timing of Regional Intertie Segments

		Projected On-Line Year
SEI - 1	Juneau - KMCGC - Hoonah	2007
SEI - 2	Kake - Petersburg	2007
SEI - 3	Metlakatla - Ketchikan	2015-2020
SEI - 4	Ketchikan - Prince of Wales	2020-2025
SEI - 5	Kake - Sitka	2025-2030
SEI - 6	Hawk Inlet - Angoon - Sitka	2020-2025
SEI - 7	Hoonah - Gustavus	After 2030
SEI - 8	Juneau - Haines	After 2030

The timeline of development shown in Table 3-18 is dependent on a number of factors. It will be necessary for the Southeast Conference and other entities involved with power supply in Southeast Alaska to continue to monitor power supply needs and available resources.

Transmission Line Routes and Technical Characteristics

Introduction

Several separate transmission lines have been evaluated as part of the Intertie Study. 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. Most of the proposed routes have been evaluated in the past as part of previous studies and investigations. The two transmission lines evaluated as part of Phase 1 of the Intertie Study, the Juneau – Greens Creek – Hoonah transmission line (SEI-1) and the Petersburg – Kake line (SEI-2) have been studied in the most detail. Both of these lines are considered technically feasible and with grant funding, are estimated to provide net benefits to the interconnected utilities and load centers.

The other transmission segments are:

- SEI-3: Metlakatla – Ketchikan
- SEI-4: Ketchikan – Prince of Wales
- SEI-5: Kake – Sitka
- SEI-6: Sitka – Angoon – Hawk Inlet; or Sitka – Angoon – Tenakee Springs – Hoonah[46]
- SEI-7: Hoonah – Gustavus – Excursion Inlet
- SEI- 8: Juneau – Haines

This section of the report provides a brief description of each of these lines and the estimated cost of construction for each line. Costs are presented in current, i.e. 2003, cost levels. 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.

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-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 Tyee-Swan Intertie, presently under construction, will also be constructed for 138-kV and operated at 69-kV. AEL&P's internal transmission system is

[46]The Southeast Alaska Intertie System, as proposed in previous studies, includes an interconnection between the northern and southern parts of the system. The previous studies have identified options for the north-south interconnection to be between Hoonah, Angoon, Sitka and Kake or between the Snettisham hydroelectric project and Kake.

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.

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.

Another factor associated with system voltage include 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.

Oversized submarine and underground transmission cables can negatively affect system performance and require that additional equipment to compensate for higher system capacitance be installed. 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 at 69-kV. This is due in part to AEL&P's preliminary design specification of this voltage for SEI-1. The power transfers as discussed in the previous section of this report would also indicate that 69-kV 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% higher than for the 69-kV system.

Transmission Line Segment Descriptions

Juneau – Greens Creek – Hoonah Transmission Line (SEI-1)

A complete description of the proposed route and configuration of SEI-1 is provided in the Phase 1 report. In general, SEI-1 will interconnect AEL&P's existing transmission system on North Douglas Island to the KMC-GC mine and Hoonah.

The existing AEL&P transmission line on Douglas Island is constructed for and operated at 69-kV. AEL&P has initially specified that SEI-1 will be operated at 69-kV. Submarine cables will be sized to accommodate reasonably expected power flow requirements. The AEL&P plan is based on transmitting a maximum of 60 MW between Juneau and Hawk Inlet and 30 MW between Hawk Inlet and Hoonah. This variance is due to the much higher power demand at KMC-GC, approximately 10 MW, compared to the load at Hoonah of around 2 MW. It is important to note that the 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 that is uncertain but potentially somewhere between 10 and 15 years in the future.

The proposed transmission line will include a 9.5 mile-long submarine cable between Douglas Island and Young Bay on Admiralty Island, 6 miles of new overhead line between Young Bay and Hawk Inlet, 9 miles of new overhead line between Hawk Inlet and the mine, a 25 mile-long submarine cable between Hawk Inlet and Spasski Bay on Chicagof Island and 3.5 miles of new overhead line between Spasski Bay and the Hoonah powerhouse.

Interconnection facilities will include submarine cable termination yards on Douglas Island, on Admiralty Island at Young Bay and Hawk Inlet, and at Spasski Bay on Chicagof Island approximately 3 miles east of Hoonah. The submarine cable termination yards will serve as the interface between overhead sections of the line and submarine cables. They will generally be located near the shoreline but behind existing treelines to limit visibility from the water. Other facilities include a new substation in Hoonah and a substation at the Greens Creek mine, both of which will connect to the existing electric systems in these locations.

It is expected that AEL&P's standard single wood pole design will be used for the overhead portion of SEI-1. Figure 4-5 depicts the general framing of this structure type. 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.

Two separate submarine cable crossings will be needed for SEI-1. The first, between Douglas Island and Young Bay on Admiralty Island will be about 9.5 miles long and is a relatively straight-forward crossing. The second, between Hawk Inlet on Admiralty Island and Spasski Bay on Chicagof Island is much longer, approximately 25 miles, and involves much more significant depths.

AEL&P's preliminary design concept for the Douglas Island – Young Bay crossing provides for the use of a single-armored, 3-phase, dielectric submarine cable with bundled fiber optic communication lines. The bundled cable will be about 6 inches in diameter. Figure 4-6 provides a cross-section layout of a cable similar to that presently proposed for the crossing. For the Hawk Inlet – Spasski Bay crossing, AEL&P has initially specified the use of both double armored and single-armored, 3-phase dielectric submarine cable. Figure 4-7 provides a cross-section diagram of the double-armored cable.

Submarine cable termination yards will be needed on Douglas Island, on Admiralty Island at Young Bay and Hawk Inlet, and at Spasski Bay on Chicagof Island approximately 3 miles east of Hoonah. 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. Other facilities include a new substation in Hoonah and a substation at the KMC-GC mine, both of which will connect to the existing electric systems in these locations.

THREA's and KMC-GC's generating units will be interconnected with the AEL&P system but will not generally be used at the same time that power is being delivered from Juneau.

Kake – Petersburg Transmission Line (SEI-2)

A complete description of the proposed route and configuration of SEI-2 is provided in the Phase 1 report. In general, SEI-2 will interconnect the community of Kake on Kupreanof Island to the interconnected electric systems of Petersburg and Wrangell. Petersburg and Wrangell are connected to and purchase most of their respective power supplies from the Lake Tyee hydroelectric project owned by the Four Dam Pool Power Agency (FDPPA). SEI-2 will be used to transmit surplus hydroelectric power purchased from the FDPPA to THREA's electric system in Kake, thereby offsetting diesel generation in Kake.

At the present time, the City of Ketchikan is constructing a transmission line to interconnect its electric system with the Tyee-Wrangell-Petersburg (TWP) electric system. This new interconnection will provide Ketchikan with access to the surplus generation capability of the Lake Tyee hydroelectric project. Although Kake's power requirements from the Lake Tyee project will be subordinate to the requirements of Petersburg, Wrangell and Ketchikan[47], current forecasts indicate that sufficient energy should be available to supply Kake's load for several years in to the future.

The SEI-2 transmission line has been studied in reasonable detail in the past, most recently in 1996 with a feasibility study prepared by R.W. Beck for the State of Alaska, Department of Community Affairs, Division of Energy (the "1996 Feasibility Study"). The 1996 Feasibility Study was a follow-on to the 1987 Southeast Alaska Transmission Intertie Study prepared for the Alaska Power Authority by the Harza Engineering Company (the "1987 Intertie Study").

[47] Pursuant to provisions in the Four Dam Pool Power Sales Agreement.

Both the 1987 Intertie Study and the 1996 Feasibility Study identified two primary routes for the line. One alternative route goes to the north of the Petersburg Creek – Duncan Salt Chuck Wilderness Area, while the other route goes to the south of the Wilderness Area. In both of the previous studies, the southern route alternative was preferred because of its shorter length, lower estimated construction cost and generally lesser environmental impact.

The present Intertie Study has focused primarily on the Southern Route Alternative based on the conclusions and recommendations outlined in the 1996 Feasibility Study regarding the preferred routing. The northern route will continue to be a viable alternative, particularly if a State highway between Kake and Petersburg is anticipated. The highway would most likely need to follow a northerly route across Kupreanof Island.

The proposed route of the Southern Alternative begins at a tap of the 69-kV FDPPA transmission system connecting the Lake Tyee hydroelectric project to Wrangell and Petersburg. The tap point and the east terminal of the Wrangell Narrows submarine crossing is proposed to be in the vicinity of the former Alaska Experimental Fur Farm, about 5 miles south of Petersburg. The Forest Service operates a warehouse at this location. For estimating purposes it has been assumed that the new single wood-pole line will tap the existing Lake Tyee-Petersburg 69-kV line at a new Petersburg Tap 69-kV switchyard, extend east crossing Mitkof Highway and then parallel the highway to the east submarine terminal structure location near the Fur Farm. The overhead line distance between the tap point and the submarine cable termination point is about 1.0 mile based on following the highway.

The total length of SEI-2 is 51.6 miles of which 49.9 miles is overhead and 1.7 miles is submarine cable.

It is expected that the overhead portions of SEI-2 will be single pole 69-kV construction similar to that described for SEI-1. Generally, the overhead routes will follow existing US Forest Service roads. Two separate submarine cable crossings will be needed for SEI-2. The first, crosses Wrangell Narrows about five miles south of Petersburg and is slightly less than one mile in length. Tide movements are indicated to be very limited at this location and the waters are generally calm. The second crossing is about 1.25 miles in length and crosses Duncan Canal between points about 1.75 miles south of the mouth of Mitchell Slough on the east and about 2.5 miles south of Indian Point on the west side of Duncan Canal.

Cables to be used for the SEI-2 submarine crossings would be similar to the crossing between Douglas Island and Young Bay as described for SEI-1, above. The cable would be a single-armored, 3-phase, dielectric submarine cable with potentially bundled fiber optic communication lines. The bundled cable will be about 6 inches in diameter, however, the exact cable specification will not be known until it is known whether or not further interconnections will be made to SEI-2 to load centers beyond Kake. Additional cable specification will occur during the design of SEI-2. It is expected that both the Wrangell Narrows and the Duncan Canal crossings would be placed at essentially the same time with the same cable laying equipment.

Submarine cable termination yards will be needed on both ends of the Wrangell Narrows and the Duncan Canal crossings. The submarine cable termination yards are expected to require relatively small areas that will serve as the interface between overhead sections of the line and

submarine cables. They will generally be located near the shoreline but behind existing treelines to limit visibility from the water. The termination yards will contain lightning arrestors and risers that connect the overhead system to the submarine cable. Disconnect switches would also be installed to allow for the electrical isolation of the cable for maintenance and testing. A switchyard will also be needed at the tap point of the Lake Tyee – Petersburg transmission line. This switchyard will include circuit breakers, disconnect switches, other protective and control equipment and would most likely be the location of revenue metering for the power to be delivered to THREA's Kake system.

Other facilities include a new substation which will connect to the existing electric system in Kake. THREA's generating units will be interconnected with the TWP system but will not generally be used at the same time that power is being delivered from Lake Tyee. The Kake substation is expected to be constructed near the Kake powerhouse and will serve as the termination of SEI-2. The substation is expected to include breakers, a disconnect switch and a 69/12.47-kV transformer to interconnect with the THREA distribution system in Kake. The low voltage side of the substation will connect to the 12.47-kV bus at the Hoonah powerhouse.

Metlakatla – Ketchikan Transmission Line (SEI-3)

A potential transmission interconnection between Ketchikan and Metlakatla has been studied in the past, most recently by Ketchikan Public Utilities (KPU) in early 2000[48] as part of an evaluation of alternative power supply options. Metlakatla Power & Light (MP&L) has surplus hydroelectric generation capacity that could be sold to Ketchikan or other utilities located in the Tyee-Swan region.

As identified in the 2000 study, the proposed Metlakatla – Ketchikan Intertie project is 17 miles in length and includes overhead and submarine components. The line would originate at KPU's Mountain Point substation and cross underwater to Race Point on Annette Island, a cable crossing distance of about one mile. A 16-mile overhead line on Annette Island would extend from the cable landing point to an MP&L substation to complete the system.

At the time of the 2000 study, the line was sized 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.

Although earlier studies identified a possible route for the portion of the Metlakatla – Ketchikan Intertie on Annette Island following a proposed road alignment to Walden point, a shorter route along the Upper and Lower Todd Lakes was used for the purposes of the 2000 study. This shorter route would interconnect the MP&L system in Metlakatla to the cable landing at Race Point.

[48] Information on the transmission line between Metlakatla and Ketchikan is provided in the report, "Metlakatla-Ketchikan Intertie Project Reconnaissance Report", prepared by R.W. Beck, Inc., March 2000.

Note that the SEI-3 alternative as proposed connects directly to the KPU transmission system. MP&L could arrange to transmit power to other utilities, AP&T for example, but would need to transmit or "wheel" the power over KPU's lines. Arrangements of this type are common in the electric utility industry but usually require payment to the transmission owner. Contractual rights of access to transmission lines owned by others is a fundamental issue in recent orders from the Federal Energy Regulatory Commission (FERC).

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 Tyee – Swan regional system. The 1987 Harza study identified two primary alternatives for this interconnection. The first alternative involved a submarine cable crossing from Ketchikan to Grindall Point on Prince of Wales Island. The line would then proceed overland northwest up the Kasaan Peninsula to an interconnection point near Thorne Bay. The overall length of this alternative is 43.8 miles of which 17.2 miles is submarine cable and 26.6 miles is overhead, not including about 5.5 miles of new line in Ketchikan.

The second primary alternative identified in the 1987 Harza study was a connection to Thorne Bay from a point directly east on the Cleveland Peninsula. This second alternative was provided in conjunction with a Cleveland Peninsula routing of the Tyee-Swan Intertie, a route that was eventually abandoned. Other possible connections to Prince of Wales Island are a northern connection from the Lake Tyee transmission line to the Coffman Cove vicinity.

In recent years, AP&T has extended its Prince of Wales transmission system to Kasaan. The section of line between Kasaan and Thorne Bay is not considered adequate to support reliable delivery of power to the island system. Although the existing line could be upgraded, discussions with AP&T indicate a preference to extend the submarine cable to a landing at Hollis. This would provide a better, more reliable interconnection with AP&T's system and would avoid the need for an overland route on the Kasaan Peninsula. A submarine cable between Ketchikan and Hollis, however, would be approximately 40 miles in length. This length generally exceeds the typical operating length of AC transmission cables. Consequently, the combination submarine and overland route originally proposed in the 1987 Harza study has been used as the basis of SEI-4 for the Intertie Study. Alternatively, a DC cable could be extended from Ketchikan to Hollis.

SEI-4 would tap into the 115-kV Swan Lake transmission line near Ward Cove. A substation would be needed at the tap location to transform the voltage to 69-kV and approximately 5.5 miles of overhead transmission line would be needed to connect to the submarine cable landing site located on Mud Bay northeast of Ward Cove[49]. From the cable termination site, a bundled, 3-phase submarine cable would cross Clarence Strait to a point on Prince of Wales Island near Grindall Point. A submarine cable termination yard would be located at this site. From this

[49] KPU owns and operates a 34.5-kV transmission line along this route that connects to its North Point Higgins substation. Depending on the anticipated power flows in the future, a 34.5-kV tap off KPU's system could be an alternative to constructing a new higher voltage line along the same route. AP&T's Prince of Wales transmission system is also at 34.5-kV. KPU's system would most likely need significant upgrade to accommodate such an alternative. Additional investigation related to this alternative should be considered.

point, an overhead single-pole aerial line would proceed approximately 5.5 miles north and east along the eastern side of the Kasaan Peninsula. It would then turn west, cross the peninsula and follow the shoreline in a northwesterly direction to Kasaan. The total length of the overland portion of the line is approximately 12.5 miles. A 69-kV/34.5-kV substation would be located in Kasaan. Depending on the required power flows, AP&T's 34.5-kV transmission system from Kasaan would potentially need upgrading.

In total, the length of SEI-4 between Ketchikan and Kasaan is 29.7 miles, not including the line length in Ketchikan between the 115-kV tap and the submarine cable termination yard. The proposed route of SEI-4 is shown in Figure 4-2.

Kake – Sitka Transmission Line (SEI-5)

A transmission line between Kake and Sitka would interconnect the loads and resources of the Sitka Municipal Electric Department with the interconnected electric utilities of the Tyee – Swan region. The line was evaluated in the past as part of the 1987 Harza study and more recently in 2000 with regard to a potential high voltage DC interconnection. 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.

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 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 State has considered 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 overhead line cost for SEI-5 as presented in Section 5 of this report, did not include the effects of a road. 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 high

elevations, steep slopes and high avalanche potential. If a road is eventually constructed maintenance would be easier, however, reliability is still expected to be lower due to the terrain.

The current proposed plan is for SEI-5 to be at 69-kV. Approximately four miles of new transmission line will need to be constructed from the Kake powerhouse to Point White. An important aspect of SEI-5 is that its submarine cable termination site in Warm Springs Bay will be only about four miles south of the proposed Takatz Lake powerhouse. If SEI-5 is constructed, it would provide a significant advantage toward future development of the Takatz Lake project. The overland portion of SEI-5 is also the overland portion of SEI-6 across Baranof Island. The proposed route of SEI-5 is shown in Figure 4-3.

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[50].

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-6 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 but it has been indicated by vendors that it could be accomplished. A DC option for SEI-6 has also been evaluated as part of the Intertie Study.

A submarine cable termination yard would be needed 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 most 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 THREA'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 in Figure 4-4.

[50] AEL&P has indicated that limited space exists at the proposed location of the Hawk Inlet submarine cable termination yard. If both SEI-1 and SEI-6 are to be developed, it will be necessary to coordinate the siting of the termination facilities at Hawk Inlet even it SEI-6 is not to be developed well into the future.

Hoonah – Tenakee Springs – Angoon – Sitka (SEI-6 Alternative)

The 1987 Harza study identified a potential transmission route that is primarily overland between Hoonah, Tenakee Springs and Sitka. A tap of this line near Chatham on southern Chicagof Island and a submarine cable crossing of Chatham Strait was proposed to provide an interconnection to Angoon. The proposed route extended south from a substation located in Hoonah following existing forest service logging roads into the Game 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, a total distance of 28.6 miles between Hoonah and Tenakee Springs.

At Tenakee Springs, the proposed route would cross Tenakee Inlet (3 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). The Harza report indicated that 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 Power house 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 wood H-frame structures would be used. The line routing would create some visual impact to the State Marine Ferry system in the area of Peril Strait. Also the shoreline of Chicagof Island has many eagle nests which 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 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 has been identified as a potential transmission corridor in the 1997 Revision of the Tongass National Forest Land and Resource Management Plan.

Hoonah – Gustavus Transmission Line (SEI-7)

A transmission interconnection between Hoonah and Gustavus was not included as a potential route in the 1987 Harza study or in the 1997 Southeast Alaska Electrical Intertie System Plan. A transmission connection between Hoonah and Gustavus would 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-1. 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.

A potential option for SEI-7 would be to bring the submarine cable ashore at either Porpoise Island or Pleasant Island and provide a tap for a submarine cable spur to Excursion Inlet. A submarine cable between Porpoise Island and Excursion Inlet would be approximately 7.5 miles in length.

Juneau – Haines Transmission Line (SEI-8)

The 1987 Harza report discussed a 138-kV overhead interconnection between Juneau (Thane Substation) and Skagway a distance of 113.5 miles. A 34.5 kV AC underwater cable (2.8 miles) crossing was proposed approximately 14 miles south of Haines.

The proposed Harza route followed an existing 69-kV line from Thane Substation north to Auke Bay (14 miles). The line was proposed to continue overhead from Auke Bay north along the existing highway to Bridget Cove (21.5 miles) and from Bridget Cove north along the east side of Lynn Canal to Skagway (75 miles). A 34.5-kV AC underwater cable (2.8 miles) was proposed to connect Haines via crossing Lynn Canal at a point approximately 14 miles south of Skagway. Since the 1987 Harza study Skagway and Haines have been interconnected with a 34.5 kV underwater cable.

A current proposed option is to interconnect Juneau, Haines and Skagway via continuation of the 69-kV overhead line from Auke Bay to a point east of Haines (82.5 miles) where the line would be transformed to 34.5 kV and continue underwater to Haines (2.8 miles) to tap the existing 34.5 kV underwater cable that interconnects Skagway and Haines.

The proposed route would extend 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 34.5 kV underwater cable. The section from Bridget Cove to Haines is

roadless and it is anticipated that wood H-frame structures would be used. The State has proposed the construction of a highway along the east side of Lynn Canal, however, 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, however reliability is still expected to be low due to avalanches.

Estimated Costs of Construction

Introduction

The costs to develop and construct the Interties have been estimated. The cost estimate for SEI-1, the Juneau – Greens Creek – Hoonah transmission line is based significantly on the preliminary estimate of this system as previously prepared by AEL&P. The cost estimates for all other segments are based on information from previous reports adjusted as appropriate for changed conditions.

The estimated costs of the Interties as provided in this report 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 Interties used as the basis for the cost estimate is still very preliminary, a contingency factor of 20% 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 very significantly from the engineer's estimate due to market conditions for the materials and services needed at the time of procurement. As an example, the cost of submarine cable is potentially on the rise at the present time because of a recent reduction in the number of cable manufacturers.

The cost estimates included in this report are based on the routing and technical information described in Section 4. Primary characteristics of the line are primarily 69-kV, single-pole construction alongside existing roads where available. Submarine crossings are to be made with single 3-phase, dielectric cables with armor and potentially with fiber-optic communication lines bundled in. It is expected that the owner of the Interties will contract for all services of permitting, design, construction and construction management related to the Interties. The estimated costs of these services are included in the total cost estimate.

Juneau – Greens Creek – Hoonah (SEI-1)

A description of the basis for the estimate of the cost of SEI-1 is provided in the Phase 1 report. The cost estimate for SEI-1 is shown in Table 5-1. It should be noted that Table 4-1 does not include the cost of removing the overhead line between Hawk Inlet and the Greens Creek mine upon the eventual closure of the mine. AEL&P has estimated that the cost to remove the line would be about $250,000 at today's cost level. It should also be noted that the cost of the substation that will be needed at the Greens Creek mine to take delivery of power at 69-kV over SEI-1, has not been included in Table 5-1. The new substation at the mine will be constructed and financed by either AEL&P or KMC-GC and as such, is not included as a component of SEI-1.

TABLE 5-1 (Page 1 of 2)
Estimated Cost of Project Development and Construction
Juneau – Greens Creek – Hoonah Transmission Line

		Estimated Cost
Overhead Lines		
Poles	$	815,700
Framing		701,500
Guys and Anchors		262,900
Conductor		812,400
Fiber Optic Cable - 48 strands		195,400
Foundations and work pads		263,700
Distribution transformer		122,500
Special Transportation and Helicopters		500,000
Staging area		65,000
Subtotal	$	3,739,100
Clearing		
Heavy Timber, Clearing w/Timber Credit	$	-
Light Clearing		223,010
Subtotal	$	223,010
Submarine Cable - Outer Pt. - Young Bay		
Cable - 3Φ bundled, Single Armor, 240mm^2	$	3,151,900
Fiber Optic System - 48 strands		200,600
Installation		406,400
Mob/Demob		605,000
Subtotal	$	4,363,900
Submarine Cable - Hawk Inlet - Spasski Bay		
Cable - 3Φ bundled, S/D Armor, 120mm^2	$	7,817,800
Fiber Optic System - 48 strands		549,100
Installation		745,200
Mob/Demob		865,000
Subtotal	$	9,977,100
Submarine Cable Term. Yards (Four) - Subtotal		
Site Prep, Foundations	$	220,000
Ground Grid and Fencing		90,000
Structures, Lightning Arrestors		240,000
Cable Terminations		96,000
Cathodic Protection		240,000
Shunt Reactor, Disconnect		360,000
Circuit Breakers, Relaying		360,000
Revenue Metering		80,000
SCADA, Other		340,000
Subtotal	$	2,026,000

TABLE 5-1 (Page 2 of 2)
Estimated Cost of Project Development and Construction
Juneau – Greens Creek – Hoonah Transmission Line

Hoonah Substation		
Civil Site Prep & Foundations	$	120,000
Ground Grid and Fencing		45,000
Bus Works		26,000
Control Cable and Conduit		20,000
SCADA and Control Interface		40,000
Fuses/Switches		40,000
Transformer - 69/4.16-kV, 5 MVA, Relaying, LA, etc.		120,000
Voltage Regulators/Bypass Switches		46,000
Recloser/Disconnect Switch		34,000
Relaying PT		36,000
SS and Battery		40,000
Shunt Reactor		180,000
Installation Labor		80,000
Subtotal	$	827,000
Total Direct Costs	$	21,156,110
Indirect Costs		
Alignment Definition and Prelim. Engineering	$	100,000
Alignment Survey		220,000
Final Engineering		975,000
Permitting		735,000
Structure Staking		90,000
Geotechnical Surveys - Overhead		50,000
Geotechnical Surveys - Cable		200,000
Material and Equipment Delivery		4,000,000
Mobilization (6% of Direct Costs less Sub. Cable)		409,000
Construction Management (7% of Direct Costs)		1,481,000
Owners Administration (7% of Direct Costs)		1,481,000
Subtotal - Indirect Costs	$	9,741,000
Contingency - 20%		6,179,000
Total Project Cost	$	37,076,110

As shown in Table 5-1, the total estimated cost of SEI-1 is $37.1 million. This is somewhat higher than AEL&P's estimated cost of approximately $35 million but includes a larger allowance for permitting and various contingencies. A significant cost item in the table above is the estimated cost of material delivery. The amount shown is based on the estimated cost of loading the 25-mile long submarine cable on the cable laying ship and transportation from Europe to the project site.

Kake – Petersburg Intertie (SEI-2)

A cost estimate for the Southern Route Alternative of SEI-2 was been prepared as part of the Phase 1 study and is described in the Phase 1 report. The total estimated costs for SEI-2 are shown in Table 5-2.

TABLE 5-2 (Page 1 of 2)
Estimated Cost of Project Development and Construction
Kake - Petersburg Transmission Line

		Estimated Cost
Overhead Line		
Poles	$	2,255,600
Framing		1,740,600
Guys and Anchors		547,600
Conductor		2,188,700
Fiber Optic Systems		653,400
Foundations and work pads		1,331,400
Distribution transfer		140,000
Special Helicopter Assistance		976,500
Staging area, Duncan Canal		65,000
Subtotal	$	9,898,800
Clearing		
Heavy Timber, Clearing w/Timber Credit	$	1,668,000
Light Clearing		120,000
Subtotal	$	1,788,000
Submarine Cable		
Cable - 3Φ bundled, Single Armor, 120mm^2	$	522,100
Fiber Optic System		26,400
Installation		458,400
Cathodic Protection		120,000
Mob/Demob		610,000
Subtotal	$	1,736,900
Petersburg Tap Switchyard		
Civil Site Prep & Foundations	$	80,000
Ground Grid and Fencing		30,000
Bus Works		34,000
Control Cable and Conduit		36,000
SCADA and Control Interface		35,000
Sectionalizing Switch (2)		63,000
Breaker & CT		100,000
Relaying, PT		36,000
Revenue Metering		40,000
Shunt Reactor and Disc SW		-
Subtotal	$	454,000
Submarine Cable Termination Yards (4)		
Support Structures, Foundations	$	160,000
Cable Terminations		96,000
Lightning Arresters		120,000
Subtotal	$	376,000

TABLE 5-2 (Page 2 of 2)
Estimated Cost of Project Development and Construction
Kake - Petersburg Transmission Line

Kake Substation		
Civil Site Prep & Foundations	$	120,000
Ground Grid and Fencing		45,000
Bus Works		34,000
Control Cable and Conduit		36,000
SCADA and Control Interface		40,000
Fuses/Switches		40,000
Transformer -69/12.5-kV, 2.5 MVA, Relaying, LA, etc		110,000
Voltage Regulators/Bypass Switches		34,000
Recloser/Disconnect Switch		34,000
Relaying PT		36,000
Installation Labor		80,000
SS and Battery		40,000
Subtotal	$	649,000
Total Direct Costs	$	14,902,700
Indirect Costs		
Alignment Definition and Prelim. Engineering	$	200,000
Alignment Survey		125,000
Final Engineering		600,000
Permitting		1,300,000
Structure Staking		125,000
Geotechnical Surveys		90,000
Mobilization (3% of Direct Costs less Sub. Cable)		395,000
Construction Management (5% of Direct Costs)		745,000
Owners Administration (5% of Direct Costs)		745,000
Subtotal - Indirect Costs	$	4,325,000
Contingency - 20%		3,846,000
Total Project Cost	$	23,073,700

As shown in Table 5-2, the total estimated cost of SEI-2 is $23.1 million.

Metlakatla – Ketchikan Intertie (SEI-3)

The estimated cost of SEI-3, provided in Table 5-3 below, is based primarily on the estimate prepared by R.W. Beck in early 2000. Costs provided in the 2000 estimate were adjusted to present price levels using standard construction cost indices. The 2000 estimate was also adjusted to include the estimated cost of KPU and MP&L substation improvements and submarine termination yards. The 2000 cost estimate included the costs of permitting,

engineering, owner's administration and construction management under the Engineering and Administration line item.

TABLE 5-3
Estimated Cost of Project Development and Construction
Metlakatla - Ketchikan Transmission Line

Overhead Line		
Materials and Labor	$	454,000
Helicopter Assistance		436,000
Subtotal	$	890,000
Clearing	$	103,000
Submarine Cable		
Material and Installation	$	973,000
Other		-
Subtotal	$	973,000
Cable Termination Yards		
Mountain Point	$	94,000
Annette Island		94,000
Subtotal	$	188,000
Fiber Optic System		224,400
Substation Improvements		
KPU	$	60,000
MP&L		600,000
Subtotal	$	660,000
Total Direct Costs	$	3,038,400
Indirect Costs		
Engineering and Administration	$	1,218,000
Construction Management		-
Other		-
Subtotal - Indirect Costs	$	1,218,000
Contingency		1,706,000
Total Project Cost	$	5,962,400

The total project cost of SEI-3 is $5.96 million as shown in Table 5-3. The cost estimate provided in the 2000 R.W. Beck report was $3.5 million, which was considerably lower than a $6.5 million cost estimate prepared as part of a 1996 KPU study. The 1998 Southeast Alaska Electrical Intertie System Plan indicated a cost estimate of $8.8 million in 1996 dollars.

Ketchikan – Prince of Wales Intertie (SEI-4)

The 1987 Harza report estimated the cost of the Ketchikan to Prince of Wales transmission line to be $42.7 million. This line was somewhat longer than presently anticipated and included a DC submarine cable system and converter stations. The 1997 Southeast Alaska Electrical Intertie System Plan estimated the cost of the line at $39.1 million. Table 5-4 provides the estimated cost of SEI-4 as presently configured and described in Section 4 of this report.

TABLE 5-4
Estimated Cost of Project Development and Construction
Ketchikan – Prince of Wales Transmission Line

Overhead Lines			
69-kV Along Roads		$	1,433,000
69-kV Roadless Areas			3,750,000
Subtotal		$	5,183,000
Clearing			1,375,000
Submarine Cable			7,127,000
Cable Termination Facilities			800,000
Substation Improvements and Additions			1,300,000
Fiber Optic Systems			601,000
Total Direct Costs		$	16,386,000
Engineering, Permitting, Admin.	30%		4,916,000
Special Mobilization (Cable Delivery)			4,000,000
Contingency	30%		6,391,000
Total Project Cost		$	31,693,000

As shown in Table 5-4, the total estimated cost of SEI-4 is $31.7 million. This cost includes 30% contingency.

Kake - Sitka Intertie (SEI-5)

Table 5-5 provides the estimated cost of SEI-5 as presently configured and described in Section 4 of this report.

TABLE 5-5
Estimated Cost of Project Development and Construction
Kake - Sitka Transmission Line

Overhead Lines			
69-kV Along Roads		$	2,084,000
69-kV Roadless Areas			6,000,000
Subtotal		$	8,084,000
Clearing			3,600,000
Submarine Cable			13,184,000
Cable Termination Facilities			1,000,000
Substation Improvements and Additions			500,000
Fiber Optic Systems			1,055,800
Total Direct Costs		$	27,423,800
Engineering, Permitting, Admin.	30%		8,227,000
Special Mobilization (Cable Delivery)			4,000,000
Contingency	30%		10,695,000
Total Project Cost		$	50,345,800

The estimated cost of SEI-5 is $50.3 million as shown in Table 5-5. The 1997 Southeast Alaska Electrical Intertie System Plan indicated the cost of this connection to be $45.5 million whereas the 1987 Harza study estimated the cost at $34.2 million.

Hawk Inlet – Angoon – Sitka Intertie (SEI-6)

The proposed route of SEI-6 involves the long submarine cables between Hawk Inlet and Angoon and between Angoon and Warm Springs Bay. For the purpose of the cost estimate, it is assumed that both submarine cables would be installed at the same time. This would save considerable mobilization and delivery cost over two separate installations. The estimated cost for SEI-6 also includes the cost of the overhead section of the line between Warm Springs Bay and the Blue Lake powerhouse. If SEI-5 were installed prior to SEI-6, this overhead section of the line would not to be duplicated as part of SEI-6. Table 5-6 provides the estimated cost of SEI-6 as presently configured and described in Section 4 of this report.

TABLE 5-6
Estimated Cost of Project Development and Construction
Hawk Inlet - Angoon - Sitka Transmission Line

Overhead Lines			
69-kV Along Roads		$	1,563,000
69-kV Roadless Areas			6,000,000
Subtotal		$	7,563,000
Clearing			3,000,000
Submarine Cable			29,708,000
Cable Termination Facilities			1,300,000
Substation Improvements and Additions			900,000
Fiber Optic Systems			2,022,400
Total Direct Costs		$	44,493,400
Engineering, Permitting, Admin.	30%		13,348,000
Special Mobilization (Cable Delivery)			6,000,000
Contingency	30%		17,352,000
Total Project Cost		$	81,193,400

The estimated cost of SEI-6 is $81.2 million as shown in Table 5-6. Neither the 1987 Harza study nor the 1997 Southeast Alaska Electrical Intertie System Plan estimated the cost of this transmission segment.

The estimated cost of a transmission system between Hawk Inlet and Angoon (i.e. excluding the additional connection to Sitka) is $39.5 million as shown in Table 5-7. This system would be comprised primarily of a 48-mile long submarine cable from the Hawk Inlet cable termination facility on Admiralty Island to Angoon.

TABLE 5-7
Estimated Cost of Project Development and Construction
Hawk Inlet - Angoon Transmission Line

Overhead Lines			
69-kV Along Roads		$	521,000
69-kV Roadless Areas			-
Subtotal		$	521,000
Clearing			220,000
Submarine Cable			17,756,000
Cable Termination Facilities			800,000
Substation Improvements and Additions			650,000
Fiber Optic Systems			1,040,400
Total Direct Costs		$	20,987,400
Engineering, Permitting, Admin.	30%		6,296,000
Special Mobilization (Cable Delivery)			4,000,000
Contingency	30%		8,185,000
Total Project Cost		$	39,468,400

Table 5-8 provides the estimated cost of the alternative routing of SEI-6 between Hoonah, Tenakee Springs, Angoon and Sitka which is primarily an overhead land-based system.

TABLE 5-8
Estimated Cost of Project Development and Construction
Hoonah – Tenakee Springs - Angoon - Sitka Transmission Line (Alternative SEI-6)

Overhead Lines			
69-kV Along Roads		$	17,922,000
69-kV Roadless Areas			6,600,000
Subtotal		$	24,522,000
Clearing			13,620,000
Submarine Cable			8,285,000
Cable Termination Facilities			750,000
Substation Improvements and Additions			1,350,000
Fiber Optic Systems			1,561,560
Total Direct Costs		$	50,088,560
Engineering, Permitting, Admin.	30%		15,027,000
Special Mobilization (Cable Delivery)			-
Contingency	30%		19,535,000
Total Project Cost		$	84,650,560

As shown in Table 5-8, the estimated cost of the Hoonah – Angoon – Sitka line is $84.7 million, approximately $2.6 million more than the submarine cable route.

Hoonah - Gustavus Intertie (SEI-7)

The estimated cost of the transmission line between Hoonah and Gustavus, primarily a submarine cable system, is shown in Table 5-9.

TABLE 5-9
Estimated Cost of Project Development and Construction
Hoonah - Gustavus Transmission Line

Overhead Lines			
69-kV Along Roads		$	261,000
69-kV Roadless Areas			-
Subtotal		$	261,000
Clearing			110,000
Submarine Cable			10,992,000
Cable Termination Facilities			400,000
Substation Improvements and Additions			850,000
Fiber Optic Systems			625,200
Total Direct Costs		$	13,238,200
Engineering, Permitting, Admin.	30%		3,971,000
Special Mobilization (Cable Delivery)			4,000,000
Contingency	30%		5,163,000
Total Project Cost		$	26,372,200

Juneau - Haines Intertie (SEI-8)

The estimated cost of the transmission line between Juneau and Haines, is shown in Table 5-10.

TABLE 5-10
Estimated Cost of Project Development and Construction
Juneau - Haines Transmission Line

Overhead Lines			
69-kV Along Roads		$	5,601,000
69-kV Roadless Areas			18,300,000
Subtotal		$	23,901,000
Clearing			12,375,000
Submarine Cable			1,724,000
Cable Termination Facilities			500,000
Substation Improvements and Additions			1,050,000
Fiber Optic Systems			1,148,000
Total Direct Costs		$	40,698,000
Engineering, Permitting, Admin.	30%		12,209,000
Special Mobilization (Cable Delivery)			1,000,000
Contingency	30%		15,872,000
Total Project Cost		$	69,779,000

As shown in Table 5-10, the estimated cost of SEI-8 is $69.8 million. The cost estimate included in the 1997 Southeast Alaska Electrical Intertie Plan for this line was $79.2 million, however, at the time of the 1997 study, AP&T had not installed the submarine cable connecting the Haines and Skagway systems.

Total System

The estimated cost of the total Southeast Intertie system is shown in Table 5-11. For the most part, the costs included in Table 5-10 do not acknowledge any cost savings that could possibly occur if several components of the system were to be constructed concurrently. Significant savings could potentially be realized if multiple submarine cable crossing systems were installed at the same time.

TABLE 5-11
Estimated Cost of Project Development and Construction
Southeast Alaska Intertie System

SEI - 1	Juneau - KMCGC - Hoonah	$	37,076,000
SEI - 2	Kake - Petersburg		23,073,700
SEI - 3	Metlakatla - Ketchikan		5,962,400
SEI - 4	Ketchikan - Prince of Wales		31,693,000
SEI - 5	Kake - Sitka		50,345,800
SEI - 6	Hawk Inlet - Angoon - Sitka		81,193,400
	Less: SEI-6 costs common to SEI-5		(9,506,000)
SEI - 7	Hoonah - Gustavus		26,372,200
SEI - 8	Juneau - Haines		69,779,000
	Total System	$	315,989,500

The total estimated cost of the system is $316.0 million. Of this amount, approximately $7.0 million is for inclusion of fiber optic systems in both the submarine and overhead portions of the transmission lines.

The total estimated cost is significantly less than the $435.8 million indicated in the 1997 Southeast Alaska Electrical Intertie System Plan. The 1997 Plan amount included $69.8 million for the Tyee – Swan Intertie that is not included in Table 5-11. The 1997 Plan also included approximately $55.5 million more for the interconnection between Juneau, Hoonah and Sitka than is indicated for SEI-1 and SEI-6 in total in Table 5-11, above.

Other Issues

Telecommunication Cable Integration

The Intertie systems can be used to help expand telecommunication capabilities and services in the Southeast Alaska communities. This is most often accomplished by including fiber optic delivery systems with the transmission lines. Fiber optic conductors are typically bundled in submarine transmission cables and can be supported from transmission poles and towers on overland components of the system. Discussion with telecommunication providers in Southeast Alaska indicate that fiber optic delivery systems are considered to be the preferable choice for many years to come, i.e. the likelihood of near-term technical obsolescence is remote.

Many electric utilities around the country have investigated or installed fiber optic communication systems. Typically, these systems are initially comprised of the fiber optic "backbone" delivery components. The systems are used for internal utility voice, data and SCADA communications. The fiber backbones are generally much larger than needed for these purposes and excess fiber capacity is leased to telecommunication service providers. Alaska Communication Systems (ACS) has indicated that it is presently leasing fiber capacity from Homer Electric Association in Homer.

AP&T included fiber optic strands in the submarine cable between Skagway and Haines at a relatively minor additional cost. The fiber optic system is used for internal company communication and control and fibers are leased to other telecommunication service providers. AEL&P has included plans for fiber optic strands to be included in the Juneau – KMCGC – Hoonah Intertie. Including the fiber strands in the submarine cable is estimated to add approximately 4% to the material cost of the cable.

AP&T has also investigated the possibility of installing fiber optic cable systems on overhead transmission poles. The costs of fiber optic cables have dropped extensively in recent years, as reported by AP&T. The Four Dam Pool Power Agency recently concluded that it would not include fiber optic cables with the Tyee – Swan Intertie. The initial design of this Intertie had not included fiber optic cables and the cost of retrofit, $3 - $5 million, at the current stage of construction was considered too expensive.

A fiber optic network throughout the communities of Southeast Alaska would provide a number of benefits to the residents and businesses in the region. At this stage of Intertie evaluation, it should be considered almost essential to factor in fiber optic systems to any plans for further development of the regional electric transmission system. Estimating the costs and benefits of a fiber optic telecommunication system were not a part of this Intertie study. Future studies should include this component.

Alternative Organizational Structures

A number of different entities presently own, manage, operate and regulate the electric generation, transmission and distribution systems in Southeast Alaska. The existing transmission lines are owned by the utilities, the Four Dam Pool Power Agency and the State. Except for the relatively small Craig-Klawock line owned by the State, the ownership and operation of existing transmission lines are integrated with generation and distribution systems. This means that the transmission lines are not separate business operations and the revenues and expenses associated with their use are bundled with other elements of electric utility operation. A difficulty with transmission systems on a standalone basis is that they can be expensive to construct and repair if damaged and generally can't be insured. Further, their operating costs are primarily fixed and usage can vary significantly from year to year leading to difficulty in unit pricing for transmission services.

Elsewhere in the country, transmission lines are primarily owned by utilities, joint operating organizations and government agencies. In the Pacific Northwest, the Bonneville Power Administration (BPA), a federal power marketing agency, owns and operates a large transmission system. BPA's system allows for the transmission of power from federal generation projects to BPA's customers and is integrated with the rest of the transmission system owned by the utilities in the region. BPA's customers all pay a portion of the cost of transmission system through rates tied to their power deliveries. Although BPA must recover its costs, including debt repayment, an advantage is ready access to federal capital funding sources. The former Alaska Power Administration (APA) was a federal power marketing agency similar to BPA.

At the present time, it is not known exactly how ownership and operation of the Southeast Interties would be structured. Most likely, the operation and maintenance of the Interties would be contracted out to the local utilities or other entities with ongoing operating experience. As with other generation and transmission systems in Alaska, the owner of the system can be a different entity than the operator and the user. The Four Dam Pool Power Agency is owner of the Four Dam Pool hydroelectric and transmission systems and contracts project operation and maintenance to the utilities that purchase the output of the projects. Prior to divestiture of the Four Dam Pool, the State owned the projects through the Alaska Energy Authority and contractually procured operation and maintenance services.

Ownership, however, is more difficult because of the various entities involved and the overall objectives of the owning entity and the communities of Southeast Alaska. The objectives of the owner would be expected to include:

- Coordinate the planning, permitting, design and construction of the Interties.
- Arrange for and administer grant funding for the initial Intertie investments, in conjunction with other government and utility agencies.

- Provide reliable transmission service to the interconnected utilities at the lowest possible cost while meeting all current cost obligations.
- Limit the financial risk to the owner associated with potential failure of the transmission systems.
- Provide assurance that damaged systems can be repaired.
- Limit the cost obligation and near-term rate impacts associated with potential long-term repair and replacement costs.
- Have the ability to finance certain capital cost obligations with long-term debt at tax-exempt interest rates, if possible.
- Allow for representation of all interconnected and potential interconnected utilities on the governing board of the owning entity.
- Allow for open access of transmission lines to all utilities, non-utility and other agencies involved with electric service in Southeast Alaska.
- Establish fair and equitable rates for transmission service as needed to recover revenues sufficient to pay all costs of transmission system operation, maintenance, repair and administration as well as provide for the establishment of a reserve fund to pay a portion of future repair and replacement costs.
- Coordinate planning efforts, budgeting, service procurement and policy issues related to the Interties.
- Assist with contractual arrangements between the users of the Intertie systems.
- Assist in regional power supply planning efforts in the future, particularly with regard to evaluation of and decisions regarding.

The owning entity is expected to serve as the manager of Intertie system development but could readily contract for almost all necessary services. Policy decisions and oversight would need to be provided by the governing board of the owning entity. A number of different ownership organizations are used in Alaska and elsewhere for owning transmission systems. The Tyee – Swan Intertie, currently under construction, is presently owned by the City of Ketchikan. Efforts are underway, however, to transfer ownership to the Four Dam Pool Power Agency.

Certain options that could potentially be used for ownership of the Southeast Alaska Intertie system are discussed briefly below. Legal, financial and political assessments will be needed to determine the best ownership approach to be taken.

- *Utility ownership* – Existing electric utilities could own and operate the Interties but would not have the ability to allow other entities on to their governing boards. Regulated utilities such as AEL&P and AP&T would need to include the transmission assets in their

ratebase and collect revenues for Intertie use that would assure no negative effect on their existing customers. This would most likely result in high transmission rates for the Interties.

- *State agency ownership* – AIDEA or another State agency could own the transmission system and provide essentially all functions identified above. A management committee could be established to oversee the Intertie systems and work with the State. As exhibited in the recent State acquisition of the Snettisham Hydroelectric Project and the divestiture of the Four Sam Pool, the State would want to contractually assure that long-term repair and replacement obligations would not fall on the State.

- *Generation and Transmission (G&T) Cooperative* – A G&T Cooperative would be a joint operating agency based on a model used in Alaska and throughout the country. Most G&T cooperatives, however, are comprised of electric cooperatives of which Metlakatla Power & Light is the only one in Southeast Alaska.[51] The funding sources of the G&T cooperatives such as CFC and Cobank, would be available only to cooperative organizations.

- *New joint operating agency* – A joint operating agency, similar to the Four Dam Pool Power Agency, could be formed to own the Interties. Usually, these agencies are formed in a manner to preserve, and potentially expand, the ability of the municipal members to obtain or have access to tax-exempt financing. If tax-exempt financing is not an essential requirement of the Intertie owner, a joint operating agency of some sort would most likely be an acceptable owning entity since it could be formed as needed to meet the objectives. The Four Dam Pool Power Agency cannot expand its membership which would, along with a number of other political and operational issues, most likely preclude its consideration as owner of the Southeast Intertie system.

- *Existing joint operating agency* – The Four Dam Pool Power Agency, for example, could potentially own a portion of the Intertie system, particularly those segments interconnected with the Lake Tyee and Swan Lake projects. Other entities could not be on the FDPPA board and the FDPPA would need to limit its long-term risks associated with additional transmission line ownership and would want assurance of positive benefits to its existing members.

All potential owners of the Intertie systems would want to limit the risks of long-term cost exposure with the Interties. Some means of mitigating these risks would be needed to sufficiently limit the financial risks to the owning entity. Both the Four Dam Pool and the Snettisham Project have established reserve funds in to which revenues are deposited annually to fund long-range capital needs in advance. In a situation where transmission revenues in the early years of operation could be small, it may be necessary to "seed" possible Intertie reserve funds with grant monies or funds from other sources.

[51] THREA is pursuing formation as an electric cooperative.

Comparison of AC, HVDC and HVDC/VSC Technologies

Introduction

A study was conducted by Northstar Power Engineering and George Karady, Phd. of Arizona State University to evaluate the use of alternative energy transmission technologies for the Interties. Their complete report on the subject is included as Appendix C to this report. Following is an excerpted summary of the report and its findings.

The objective of the present study is the identification of the most advantageous transmission system for the Intertie. The technical problem is that the interconnection is between islands and requires submarine cables. In an alternating current (AC) system, the capacitive current limits the length of a submarine cable to about 40-50 miles. This problem can be eliminated by using direct current (DC) energy transmission. A DC system eliminates the capacitive charging current of the cable and permits long submarine cable routes.

Another advantage is that the DC system capacity is significantly larger than an AC system when cables are used. However, a DC system requires converters at both ends, which increases the initial investment. Another problem is that most operating HVDC systems are designed for point-to-point transmission. Recent development of new high power transistors (IGBTs) and the advancement of voltage source converter (VSC) technology have produced the HVDC with VSC transmission system. This has opened new areas for the use of DC transmission. These developments suggest that DC transmission or the combination of AC and DC transmission could be considered for the Southeast Alaska Intertie.

The available energy transmission methods are:

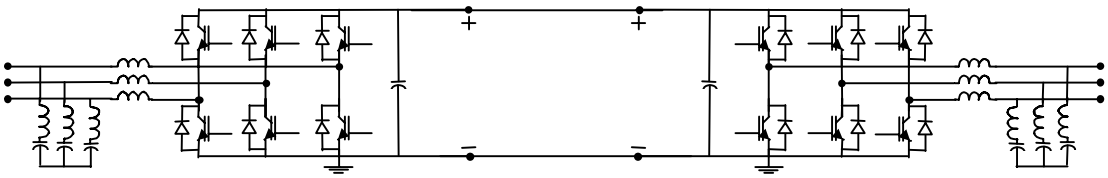
1) AC transmission using 69 kV transmission line
2) Combination of AC and traditional DC transmission
3) DC transmission with VSCs
4) Combination of AC and DC transmission with VSCs

HVDV and HVDC/VDC Options

A HVDC station requires considerable land because the transformers, filters and phase correction capacitors are placed outdoors. The valves and control equipment are placed in a closed air-conditioned/heated building. The completely enclosed system requires a large building and is prohibitively expensive.

A HVDC system with VSCs contains two converters. It can transfer energy in both directions. One of the converters operates as a PWM rectifier the other as an inverter. The rectifier can be controlled to operate close to unity power factor. The inverter can produce AC power with the required power factor. Typical losses claimed by ABB for two converters are 5%. Figure 7-1 shows the concept of a point-to-point energy transmission system.

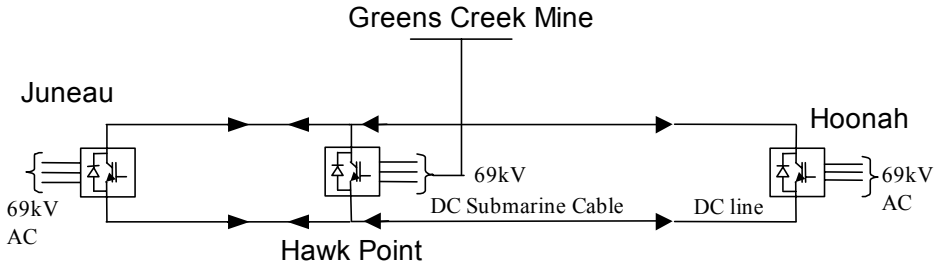
FIGURE 7-1
DC System with Voltage Source Converters (VSC)



The system is very simple and requires only a few components. The major components are the AC filters, DC capacitance, AC reactors, converters and the DC line or cable. The converter can be controlled remotely via a dial up telephone line. The system at the AC side is protected by standard circuit breakers. The converters can be energized separately.

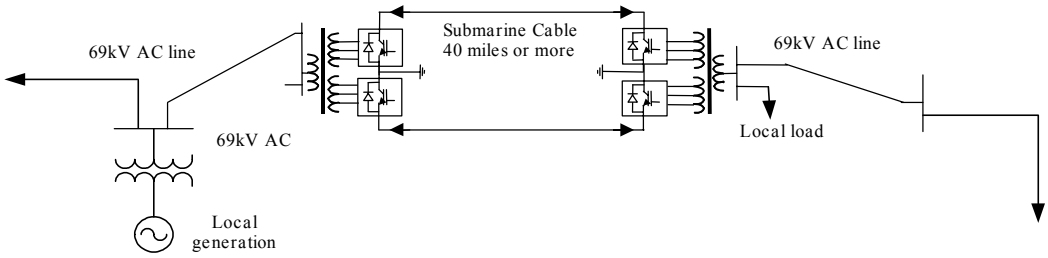
The total DC system with voltage source converters is a viable option. This system requires 3 converters as shown in Figure 7-2.

FIGURE 7-2
Conceptual DC System for SEI-1



The combined AC and DC system is built with standard AC 69-kV transmission lines and point-to-point DC transmission at a long submarine (30 miles or more) crossing. The concept of this system is shown in Figure 7-3.

FIGURE 7-3
Concept of Combined AC and DC System with Voltage Source Converters (VSC)



The preliminary cost estimates show that minimization of the number of converters will reduce the cost of the system. Because of the low level of load, the most advantageous system is the combined AC and DC system. Utilities have extensive operating experience with the existing 69 kV AC system, which suggests the use of a DC system with VSCs only at the long submarine crossing as a point-to-point transmission system.

Cost Issues

The cost of the DC cable would be less than the cost of the bundled 3-phase AC cable on a cost per unit basis. The need for two cables, however, would increase the cost of the DC system. In addition, the DC system would need voltage source converters (VSCs) at each end of the system. Each VSC is estimated to cost $3.2 million. The cost of the VSCs would not be required for a standard AC system.

Cost estimate have been prepared for several Intertie segments for comparison purposes. The cost estimates are based on hybrid systems using HVDC bi-polar submarine cables and AC overhead lines as needed. For the Ketchikan to Hollis interconnection, submarine cables would interconnect directly with AP&T's system in Hollis thereby avoiding the need to build new overhead lines on Prince of Wales Island as has been specified for SEI-4, the AC transmission alternative.

Table 7-1 provides the comparable HVDC cost estimates.

TABLE 7-1
Estimated Costs of Selected HVDC Interconnections

		Hollis - Ketchikan	Hawk Inlet - Angoon	Kake - Sitka- Angoon - Hawk
DC Submarine Cables		$ 12,400,000	$ 15,252,000	$ 35,433,000
Votage Converter Stations		6,500,000	6,500,000	13,000,000
Overhead Lines		1,433,000	547,400	9,506,000
Cable Termination Yards		600,000	600,000	1,200,000
Substation Improvements		1,300,000	650,000	900,000
Total - Direct Costs		$ 22,233,000	$ 23,549,400	$ 60,039,000
Indirect Costs	30%	6,669,900	7,064,800	18,011,700
Contingency	30%	8,670,900	9,184,300	23,415,200
Total - Project Costs		$ 37,573,800	$ 39,798,500	$ 101,465,900

The Hollis – Ketchikan cost estimate of $37.6 million is approximately $5.9 million more than the estimated cost of SEI-4. The estimated cost of the HVDC interconnection between Hawk Inlet and Angoon of $39.8 million is essentially the same as the estimated cost of an AC interconnection. The estimated cost of an HVDC system between Kake, Sitka, Angoon and Hawk Inlet of $101.5 million is $20.5 million than the combined costs of SEI-5 and SEI-6, the comparable AC system components.