PROJECT REPORT

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Supplemental Information

May 2007

Alaska Energy Authority
AK-BC Intertie Feasibility Study

DRAFT Final Report

Supplemental Information
Regional Resource Planning Model
And
Avoided GHG Emissions

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Introduction

NOTE to reader:

In the Draft Final Report reference was made to the Regional Resource Planning Model (RRPM) and the plan was to provide the RRPM with the Final Report. Hatch Acres was requested by AEA to provide the RRPM in advance of the May 8, 2007, meeting of the AK-BC Intertie Work Group meeting being held in Craig, Alaska.

The following text is excerpted from Section 8 of the Draft Final Report provided to AEA on April 5, 2007, and posted on the AEA Website. Section 8 provides information regarding the development and use of the RRPM in preparing the Draft Final Report.

The actual computer files for the Base, Low, and High growth scenarios are being provided for posting along with this explanatory text to AEA on May 2, 2007.

We developed an economic model, the "Regional Resource Planning Model" (RRPM) to assist in our analyses and will provide the RRPM to AEA at the conclusion of this phase of the study.

Two key inter-related questions posed by AEA[1] are addressed:

- "*If the State of Alaska provides funds to construct new transmission segments, will development of the segments discussed in this report provide the incentive for the private sector to invest in new generation, including associated infrastructure to connect with the transmission grid; and*
- *Will the new generation projects use of the state-funded transmission, including the proposed AK-BC Intertie, result in revenues sufficient to cover O&M costs to maintain the transmission system over the long term?*"

The accuracy of the generation, transmission and market information used in performing analyses during Phase I of this study is, in most cases, below a "pre-feasibility" level and both confidence ratings and more accurate information should be developed during Phase II.

Development Scenarios Evaluated

Section 8 of the report describes the work carried out to prepare alternative development scenarios and assess their economic attractiveness. This work is based on the load forecasts prepared for the major load centers of SE Alaska (Section 3), the market price analyses for external markets (Section 4), the cost estimates for new transmission line segments to connect load centers in SE Alaska and to connect SE Alaska with external markets (Section 6) and estimates of the outputs of existing hydro plants and capital and O&M costs of potential hydro plant developments (Section 7).

The approach followed was to first identify the development scenario that would serve the SE Alaska electricity load forecast requirements at the least cost in economic terms. This involved defining three currently non-connected regions within SE Alaska and in a step-wise fashion

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[1] Often stated as "If we build it, will they come?" Questions were developed in consultation with AEA and members of the AK-BC Intertie Work Group.

assessing the economics of connecting load centers within each region, connecting the regions and adding alternative types and sizes of new generation. This process resulted in identification of the least cost development scenario for the study area as a whole identifying the transmission segments and hydro plant developments that would be economic to implement, by year of the planning period. Starting with this scenario, additional hydro plants (the Thomas Bay plants) and the transmission segments needed to export power were assessed to identify the economic benefits of exports based on the projected market prices in the external markets. The analysis was carried out using levelized costs calculated by assuming that hydro plants would have operating lives of 50 years and that their estimated capital costs would be recovered over 50 years of output with the estimated levels of production held constant over the operating period.

A computer-based model in Microsoft Excel was developed to assist with the analysis described above. This model will be provided for future use by the AEA and interested stakeholders.

Avoided GHG Emissions

A section including information prepared by Hatch Acres for AEA regarding GHG emissions following provision of the Draft Final Report delivered on April 5, 2007, is provided at the end of this Supplemental Information.

Recommendations Regarding the RRPM Model – Phase II

The following text is excerpted from the Draft Final Report and presents recommendations for consideration by AEA and the AK-BC Intertie Work Group regarding the Regional Resource Planning Model being provided with this text section to AEA to be posted on the website and provided in advance of the May 8, 2007, meeting.

Excerpt from Section 9 of the Draft Final Report

9.3 Recommendations

9.3.1.8 Computer Model

- Enhance the Regional Resource Planning Model (RRPM) developed during Phase I to include constraints of transmission line capacity.
- Develop and provide detailed user manual and conduct training seminars on the use of the planning tool developed during Phase I.
- Develop a method to quantify other benefits not included in the present analysis.
- Rerun the RRPM as updated energy and cost data becomes available from project proponents.
- Investigate additional scenarios and update the economic analysis performed on the scenarios developed in Phase II.

8. COMPARATIVE ANALYSIS OF DEVELOPMENT

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8.1 Overview

This section of the report identifies and describes a range of potential development scenarios to supply the increasing demand in SE Alaska in a least cost way and examines the effects on the overall economics of developing projects for export power to British Columbia or the Lower 48.

The section provides a brief overview of the methodology used including the approach of dividing the study area into three regions and addressing the individual requirements of each region as well connecting the individual regions. As part of the approach used, a brief description of the special purpose model (referred to as a Regional Resource Planning Model – RRPM) developed for the present study is given.

A brief outlook of the existing generation and transmission facilities is presented together with the planning parameters used in the evaluation to arrive at the least cost plans. The planning parameters include both technical and economic criteria and address such items as generating reserve and fuel costs.

To meet the increased system requirements, the system can count on hydroelectric resources, diesel plants and transmission facilities to bring these resources to the load centres. Several individual projects were identified and included in the overall analysis.

Studies were carried out to determine the capacity and energy balance for each of the load centers in SE Alaska under study to obtain the system needs under a range of conditions regarding existing and committed generation.

Generation expansion plans were formulated, developed, analyzed and evaluation with the assistance of the RRPM in order to arrive at a least cost plan to supply SE Alaska with electrical energy. These plans included scenarios without exports and with exports.

Finally, sensitivity studies were carried out to determine the sensitivity of the generation expansion sequences results to changes in the parameters used in the analysis.

8.2 Description of the Economic Analysis Methodology

The SE part of the State of Alaska is composed of several load centers with few of these being connected to each other which would allow sharing of resources and participating in economies of scale. One of the key objectives of this study is to determine the least cost and environmentally sustainable way to provide energy to meet the region's requirements.

Electricity is presently being generated by hydro plants and diesel generating units. With increasing cost of fuels, the supply cost of diesel generation in SE Alaska is not conducive to economic development but the region has hydro resources that could be developed to supply its own load and possibly for export to the Lower 48 or to British Columbia. The principal obstacle, at this time, to the development of the hydro resources is the lack of a transmission system between the major load centers as well as stagnant load growth in the region. In order to determine the most appropriate way of supplying these load centers, an integrated generation/transmission plan is required.

For study purposes SE Alaska was divided into three main regions, namely:

- Tyee Region composed of the load centers of Petersburg, Wrangell and Kake;
- Swan Region composed of the load centers of Ketchikan and Metlakatla; and
- Prince of Wales (POW) Region composed of the load centers of Craig, Klawock, Thorne Bay, Kassan, Hollis, Hydaburg, Coffman Cove, Naukati and Whale Pass.

At this time the regions remain isolated from each other and load centers within the regions are also isolated, except for Petersburg and Wrangell in the Tyee Region and in the POW Region where only Coffman Cove, Naukati and Whale Pass remain isolated. For the present study, and due to the distances from the other load centres and its relatively small electrical energy requirements, the community of Whale Pass was considered to be supplied in an isolated mode throughout the study period and as such was not considered in the analytical studies.

Keeping the above background in perspective and the fact that the electricity demand requirements are likely to increase in the near future, a study to determine the least cost integrated system (generation and transmission) expansion for SE Alaska was carried out in order to best allocate the resources available to the power sector.

Given the physical structure and topology of the power system, and the fact that the Terms of Reference require that “in-state” (meaning SE Alaska) requirements for energy supply and delivery be met first, this part of the work was carried out in two steps:

- The first step determined the least cost plan to supply the electrical demand in the Southeast part of Alaska without exports; and
- The second step determined the least cost plan to supply the electrical demand in the Southeast part of Alaska taking into account possible export of electricity under long term commitments.

The approach used in each of these two steps is described below.

8.2.1 Least Cost Plan without Exports

The development of the least cost plan without exports followed a series of coordinated steps which included:

- Review of existing studies
- Review of the existing system
- Definition of candidates for future installation
- Analysis of capacity and energy balances for individual load centres
- Formulation of generation alternatives
- Estimation of costs for transmission segments
- Modeling of generation alternatives
- Evaluation of generation alternatives

The first task undertaken was to review the existing studies for both the supply of SE Alaska and for the export cases. Several studies were reviewed and the results of these reviews summarized in the December 2006 Draft Report. Valuable lessons were learned from these reports which also assisted in providing input to the criteria to the used in the present study.

The second step was to obtain data for the existing generation and transmission facilities for each of the three regions. A list of diesel units and hydro plants along with their respective technical and cost characteristics was developed based on the information received. Of particular importance within the data received for the existing diesel units was the price of diesel oil which allowed the delivery cost and other costs to be determined for each diesel plant in SE Alaska.

Hydro plant generation by month was also received from other project team members for three hydrological conditions: minimum, average and maximum. The variation of the hydro generation capability throughout the year plays an important role in the supply of the demand and as such one has to ensure that the appropriate values are utilized.

Candidate projects for future installation were analyzed. These consisted of thermal and hydroelectric projects. No project-specific information regarding other renewable energy facilities is available at this time. Therefore, other renewable energy sources were not included in Phase I of this study, but should be considered when project-specific information is made available in following phases.

For new thermal generation only diesel technology was considered suitable for the load centers of SE Alaska using diesel oil (No. 2) as fuel. The use of heavy fuel oil (HFO) was not considered for large units because it is not presently being used and its use could probably require especial handling facilities. Should generation by diesel units be significant at a particular load centre to warrant possible use of HFO, then the proper studies should be undertaken to verify the overall economics of switching to that fuel.

For the hydroelectric candidates capital cost estimates were developed and the unit price of energy determined taking into account an annuity to pay off the capital investment (determined at an agreed upon discount rate and project life), the annual operation and maintenance costs and the expected energy to be produced by the plant (on an average basis). The unit price of energy at the plant's capacity factor was compared to that of equivalent diesel plant to determine its cost advantage and care was exercised in the interpretation of these values since many times the hydroelectric plants produce energy that could not be absorbed immediately by the load. In order to avoid this issue, an amount of generation from a particular new project was determined that could be sufficient to offset its costs by replacing diesel generation (break even amount of generation).

Capacity and energy balances based on annual values were carried out for each individual load center to assist in determining the need for system additions. This simple exercise provided input as to when and how much new capacity and/or energy additions are required in a particular load center.

Once the above steps were carried out, generation alternatives were formulated as described below.

8.2.1.1 Formulation of Generation Alternatives

For the least cost plan to supply the electrical demand in SE Alaska without exports, two main scenarios for generation alternatives were examined.

The first considered the development of the generation requirements for each of the three regions without taking into account possible future connections between regions. Also within this scenario, the economics of connecting isolated load centres within a region was examined and this entailed the analysis of such connections such as Kake with Petersburg and Metlakatla with Ketchikan.

The second generation alternative scenario considered the connection of the three regions to each other to form a SE Alaska electrical system. It should be noted that the connection of the POW Region could pose some technical challenges due to its relatively small demand and distance from the two other regions.

8.2.1.2 Modeling of Generation Alternatives

Once the generation alternatives were formulated they were developed, analyzed and costed using a specially built model in MS Excel described in the next section. Basically, the model considers the load's peak demand and energy requirements as well as the existing and committed generation. From these it determines the reserve and when this reserve falls below a certain level new generation has to be added manually. The model determines the overall cost of supplying a given number of load centers with the supply entered by the user.

In order to capture the variations throughout the year in the capacity and energy components of the demand and the fluctuation of capacity and energy generation by the hydroelectric plants, the model used monthly simulations of all supply and demand components.

The model can simulate various load centers connected through a series of "transmission lines" and determine the costs for the various generation sources and transmission lines required to meet the overall demand.

Should the generation within a load centre or within a region not be sufficient to meet the demand, the model treats the unsupplied energy as unserved energy and costs this energy at a value specified by the user.

8.2.1.3 Evaluation of Generation Alternatives

By comparing the total annual supply costs of the alternatives examined one can determine the most economic way to supply a given load center or a region. One can also determine the most appropriate year for a load center to be supplied from outside its own boundaries or the most appropriate timing for a given diesel or hydro plant.

8.2.2 Least Cost Plan with Exports

The approach used to determine the least cost plan to supply the electrical demand in SE Alaska taking into account exports of electricity under long term commitments is described herein.

The studies carried out for the case without exports developed a comprehensive list of resources available for power generation, and since thermal generation is expected to be more expensive in SE Alaska then anywhere else in the Lower 48 or in BC, this type of generation was not be considered to support exports.

The export case could allow for faster resource development as large hydroelectric projects can be considered earlier since the deemed load to be met will be much larger.

The potential energy available for export was determined by considering the existing and future reasonably priced hydro projects and the total energy requirements in SE Alaska.

Once the energy available for export was known, one followed with formulating generation alternatives and modeling these generation alternatives using an approach similar to that outlined for the case without exports. However, the modeling of these alternatives required some interaction between the analyst and the model since the energy available for export was available only in blocks through times that increase through time as new hydro projects are built and decreases as the SE Alaska load increases.

In the model, the exports were considered as the surplus hydro energy that was not required to serve the demand in SE Alaska. The exports generate revenues which were subtracted from the overall costs. In this case the capital costs of building the transmission facilities to allow export of power were considered to be funded through a grant and only the O&M costs of the transmission facilities were considered in the economic analysis.

8.2.3 Sensitivity Analysis

Sensitivity analyses were carried out to determine the least cost expansion plan's robustness to changes of principal parameters used in the analysis. Meaningful variations of these parameters were selected to demonstrate the robustness of the planning results under conditions that could be reasonably expected. This analysis investigated the following parameters:

- Fuel prices;
- Capital cost of thermal and hydro projects;
- Operation and maintenance costs of transmission projects;
- Discount rate.

8.2.4 Outline of the Planning Tool Used

A special purpose model was developed to analyse the development alternatives in SE Alaska for generation alternatives without exports and generation alternatives with exports. This model was developed on an MS Excel platform and makes uses of several macros programmed using Basic.

The model was designed to accommodate up to 20 load centers, 30 buses (a bus can either be a load center or a generating plant), 30 hydro plants, 20 diesel plants with up to 10 units at each plant and 40 transmission lines to interconnect any of the buses. The model divides a year into 12 months and three of the months (June, July and August) are further subdivided into 4 weekly intervals to allow the model to be able to represent transmission line maintenance or generating unit maintenance. Up to 35 years can be simulated individually and up to 15 years of extended simulation can be carried out (load, generation and expenditures are kept constant during this period).

The model was designed to determine system costs under any one of up to three hydrological conditions and for the present study these include the minimum, average and maximum hydro generation conditions.

The model consists of 5 input pages, 1 information page and 3 output pages. There are 11 macros written in Basic which read each of the input pages and carry out data validation, deal with the availability of transmission between the individual load centres, dispatch the hydro and diesel generation, calculate the annual costs and write the respective output of the calculations.

NOTE to the reader:

The following paragraphs, excerpted from the Draft Final Report, provide introductory information regarding the model. The two figures referenced here have been replaced with the model information provided in the Supplemental Information – Regional Resource Planning Model. The reader can refer to the Draft Final Report pages 181 and 182 for the referred to Figures.

Figure 8.2-1 provides a snapshot of the scenario input page in the program. In this definition page, the load centres are defined and they are linked with the data provided in the "load page", the reserves for individual load centres can be entered in either percentage of the peak demand or absolute MWs. The next columns identify the supply priority for each load centre. Each load centre dispatches hydro resources connected to itself first and taking Ketchikan as an example, the hydro plants connected to the Ketchikan bus would be dispatched first. The exhibit shows that for Ketchikan (bus 1000), the first priority, after its own hydro, is the Swan Lake Hydro (bus 1100) followed by new hydro plants in Ketchikan (bus 1200) and then by hydro plants connected to the Metlakatla bus(1500). In this case, the Swan-Tyee Intertie (STI) was assumed to not be in place, and thus its bus (bus 2000) does not appear in the priority list for Ketchikan. However, should the STI be in place, then the priority list would contain bus 2000 after bus 1100 in order for the dispatch to comply with the "Long-Term Power Sales Agreement Four Dam Pool – Initial Project of the Alaska Power Authority".

Continuing with Figure 8.2-1, the next block of information addresses the "Renewable Generation Resources" where the proposed on line date is defined for each project. Data for each project is given in the "renewable page". The project Numbers, Names, Bus ID and Earliest On-Line are linked with the values in the "renewable page". The block to the right addresses "Transmission Links" and contains similar information to the previous block and in this case it is linked with the "transmission page". The input page also shows information for diesel units that is similar to that contained in the previous blocks.

The scenario input page also contains information dealing with escalation of several inputs, the discount rate and the price for exports.

The renewable energy page is used to enter information related to each hydro project either existing or future. This information is comprised of capacity and energy capability for each simulation interval in a year (21 composed of 9 months plus 12 intervals for June, July and August), the capital cost, the project life, the earliest in-service year, the variable and fixed operation and maintenance (O&M). Maintenance of individual units is easily simulated by manually adjusting a particular unit's interval capacity value.

On the diesel information page one can provide the information for individual diesel plants with up to 10 units each. If more units exist, an additional bus can be created and connected to the load bus through a transmission line. The input required includes the on-line year, the year of retirement (if known), the capital cost, plant life, heat rate, fuel cost, variable O&M cost, fixed O&M cost and monthly capability. Once again maintenance can easily be simulated by derating individual unit capability in an appropriate month or interval.

The transmission page provides information relative to the transmission lines between the different buses. The input required includes the buses to which the line is to connect, the capacity of the line in terms of MW, the capital cost, the life, the fixed costs, the expected losses and the monthly capability. Maintenance is simulated during one or more of the 21 annual intervals by forcing the capacity of the line to 0 MW.

Once given the request to start calculations, in the scenario page, the model reads, verifies and validates the data. The model then determines how the load at each load centre should be supplied under the hydrological condition being simulated. As previously mentioned, the hydro generated energy is dispatched first from its own generation (the load centre being studied) and then from the hydro plants in the priority list as well as those beyond the priority list if such generation exists and the transmission links allow it to be brought into the load centre. After all hydro energy is exhausted, the model considers diesel generation in a similar way as it considered hydro generation. Should the supply be less than the demand, the model considers the difference as unserved energy.

The model considers capital, fuel and operation and maintenance costs for each of the hydrological conditions. The capital costs are based on annuities for each new generation addition with existing and committed units assumed to have sunk costs. The fuel costs are calculated for each thermal unit by multiplying the respective heat rates by the fuel cost and energy generated at particular locations while the operation and maintenance (O&M) costs considered both fixed and variable costs for all units. The transmission line costs can include annuities for the capital costs (these would be zero if grant funding is assumed), as determined by the model, as well as fixed O&M costs.

The model also determines, on an interval basis, the amount of energy available for export and this can be valued using a selling price entered by the user. This can be treated as potential revenue and subtracted from the overall costs of supply. Figure 8.2-2 presents a sample output from the model under average hydrological conditions and only one load, one hydro plant and one diesel plant are shown as this is for illustrative purposes only and the total costs do not match those presented. In this case the simulation was carried out up to 2031 but this is not shown due to limited space on the page.

8.3 Existing Generation and Transmission Infrastructure

SE Alaska has a number of existing hydroelectric plants and diesel plants. Each load center has enough local generation to meet the peak load with its own local generation and some load centers are served by energy generated at remote hydro plants that is delivered by a transmission line. The existing hydro, diesel and transmission facilities are described below.

8.3.1 Hydro Generation

In SE Alaska there are 10 hydroelectric plants. The power plants in each of the regions outlined in Section 8.2 can be summarized as:

REGION	PLANT	CAPACITY (MW)
Tyee	Tyee Lake	22.5
	Blind Slough	2.0
Swan	Swan Lake	22.5
	Ketchikan	4.2
	Beaver Falls	6.0
	Silvis	2.1
	Purple Lake	3.9
	Chester	1.0
POW*	Black Bear	4.5
	South Fork	2.0
Total		**70.7**

* POW – Prince of Wales

The total hydro capability in SE Alaska amounts to 70.7 MW with 39.7 MW in the Swan Region, 24.5 MW in the Tyee Region, and 6.5 MW in the POW region.

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-1 (reproduced with all other tables at the end of this section) presents the capability of each of the hydro plants on a monthly and annual basis for three hydrological conditions; average, minimum and maximum. Under the average condition the hydro plants annual energy capability amounts to 326.7 GWh. The largest monthly capability is in December and January while the smallest is in April and May (for the three regions as a whole the lowest monthly amount is over 80% of that for the maximum month) but it should be noted that these values do not necessarily reflect the monthly inflows as storage capability at some of the plants was used to derive the monthly energy capability.

Under average hydro conditions the annual capacity factors range from 36.6% for Swan to 73.1% for Beaver Falls. The overall system capacity factor is close to 53%.

Table 8-1 also presents the annual operation and maintenance costs for each hydroelectric plant and these range from $127,000 for Blind Slough to $1,275,000 for Tyee Lake and the same amount for Swan Lake.

8.3.2 Diesel Generation

In SE Alaska there are many diesel plants with units ranging in size from a few kWs to 10.5 MW. The total capability of these units amounts to 56.65 MW of which 26.0 MW are available in the Swan region, 23.19 MW in the Tyee region and 10.76 MW in the POW region. In Ketchikan one of the Worthington units is out of service and it has not been included in the total capability.

The capability of the existing units by load center is:

REGION	LOAD CENTER	CAPACITY (MW)
Tyee	Wrangell	8.50
	Petersburg	8.80
	Kake	2.59
Swan	Ketchikan	22.70
	Metlakatla	3.30
POW	POW South*	2.10
	Coffman Cove	0.74
	Naukati	0.48
	Whale Pass	0.30
Total		**56.65**

* POW South includes the communities of Craig, Hollis, Hydaburg, Klawock, Kasaan and Thorne Bay

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-2 (at the end of this section) presents information relative to the characteristics of all the diesel units in South Southeast Alaska. Most of the information presented in Table 8-2 was obtained directly from the utilities in Southeast Alaska. The present study defined the values for fixed and variable O&M based on information available in our databank. The annual fixed O&M for the larger plants was taken as 40 $/kW while for the smaller plants the fixed O&M was taken at 60 $/kW and the variable O&M was taken as 20 $/MWh for the larger plants and 25 $/MWh for the smaller plants.

For the Swan and Tyee Regions, the units presented in the table were commissioned between 1971 and 2001 and this represents a wide range in the age of the units. The earliest commissioned units have been in operation over 35 years but also of importance is the hours of operation of each of the units and as can be seen from the values presented in Table 8-2 these are somewhat low for the age of the units. It should be noted that the duty cycle of most of these units is of the back up and emergency type (with exception of units at Kake and isolate load centers on POW) and therefore these units operated very few hours in the past.

The condition of the units in the Swan and Tyee Regions ranges from fair to excellent with most units being reported as being in good condition. The fuel consumption ranges from 8.8 kWh per gallon to 150 kWh per gallon of Diesel Oil (No. 2) fuel with the best efficiency being obtained by the largest unit in the system (10.5 MW) located in Ketchikan.

Table 8-2 presents information by plant for the POW units. Table 8-3 presents individual unit information for all the units in POW. The total diesel capability in POW amounts to 10.73 MW with individual unit sizes ranging from 70 kW to 1,285 kW for a unit at Craig. The Craig diesel plant accounts for over 53% of the total diesel capability in POW. The second largest plant is the Thorne Bay plant with 1,075 kW. The information received did not include the commissioning year for several of the units but it included the operating hours for each of the plants and six of the units have already reached at least 50,000 operating hours with a unit in Hydaburg having operated more than 100,000 hours.

Since all of the communities in POW South are now connected, it is expected that diesel operation will be reduced from that in the past as hydro energy is now available to meet the demand. The fuel consumption ranges from 10.00 kWh per gallon to 15.79 kWh per gallon with the highest value being achieved by the largest diesel unit in POW.

It is recognized that several diesel units in SE Alaska have been service close to 30 years and in some cases longer and that some time in the future some of the units will be taken out of service and probably be replaced by larger more efficient units. For the present study it was decided to keep all units throughout the study period since the decision to retire individual units is based on economics and several operating factors and requires an in depth study that is considered beyond the scope of this study.

8.3.3 Existing Transmission

There are only two high voltages transmission lines in SE Alaska. One high voltage transmission line (115kV) connects the output of the Swan Lake hydroelectric plant to the Ketchikan load center at the Bailey Substation.

The other high voltage transmission line is used to supply the communities of Wrangell and Petersburg with electricity generated at the Tyee Lake hydroelectric plant. This line is presently operated at 69 kV. However, the transmission line was designed and built with a capability of operating at 138 kV. The step up transformers at Tyee Lake and the step down transformers at Wrangell and Petersburg are dual voltage (69 and 138 kV) and the switchgear is rated at 138 kV. Switchover to the higher voltage can be carried out with a minimum cost and disruption of supply.

Lower voltages are used in the regions to connect the hydro and diesel plants to the load centers. In POW, the principal communities in the southern part are all interconnected via 34.5 kV transmission lines.

8.4 Planning Parameters

The planning parameters used in the analysis are presented and discussed in this subsection. These parameters include technical and economic parameters such as discount rate, escalation rates, fuel prices and O&M costs of transmission lines.

8.4.1 Planning Horizon

The planning horizon covers a period of 25 years from 2007 to 2031.

At the end of the Planning horizon, the various expansion scenarios could have different plant mixes with different remaining lives and different operation and maintenance costs as well as different investment costs.

In order to measure all substantive benefits of the plants that are commissioned during the planning horizon and take into account different plant lives, it is a common practice to extend the period of analysis by 10 to 15 or more years. For the extended period, demand and supply are maintained at the same level as at the end of the simulation period. An extended period of analysis of 15 years was used in this study.

8.4.2 Reserve

A deterministic criteria was selected to determine the generation reserve that should be in place at each load center. For the present study, the reserve criterion adopted was that each load center should have sufficient local generation to be able to meet the expected peak demand. For the purposes of the study, local generation is defined as the diesel and hydroelectric generation connected directly to each load centre. Thus the generation available at the Swan Lake and Tyee Lake hydroelectric plants is not included in the capability of any load center. However, for example, the output of the Silvis and Beaver Falls hydroelectric plants is taken into account when determining the :local" generation for Ketchikan.

8.4.3 Unserved Energy

It is possible that during some time periods some of the load centers may not have sufficient supply available to meet the entire demand requirement. In this case, the deficit is referred to as "unserved" energy. To evaluate the impact of the unserved energy on the overall cost of the generation alternative being evaluated it is customary to place a relatively high value on this type of energy to reflect the deemed cost to society of the shortfall. For this study a value of 1,000 $/MWh was assumed as the cost of unserved energy.

8.4.4 Energy Losses

The transmission lines connecting the various generating centers with the load centers have inherent losses that are dependent upon the power being transmitted. For this study, a simplified approach has been taken by assuming that all transmission segments would encounter losses of the order of 2%. This value can be refined once detailed load flow studies are carried out.

8.4.5 Discount Rate

Following the practice in previous power sector studies performed for SE Alaska, a discount rate of 6% was used in the study. For the sensitivity analysis, discount rates of 8% and 10% were used to test the robustness of selected generation alternatives to the discount rate.

8.4.6 Escalation

An assumed annual inflation rate of 2.5% was used on all items except the energy being generated and sold by the Swan Lake and Tyee Lake hydroelectric plants.

8.4.7 Reference Year for Present Value Analysis

The reference point for the present value analysis is January 1, 2007. This implies that all costs are discounted to the beginning of 2007. It should be noted that the model used for the analysis assumes that all costs are incurred at the middle of the year.

8.4.8 Capital and O&M Costs of Transmission Lines

Capital costs of the future transmission lines required to connect the various load centers and regions and to export surplus power were assumed to be grant funded implying that there will be no capital recovery associated with the future transmission lines. The costs of transmission lines to connect new generation projects to the system are assumed to be included in the project's capital cost. The exception to this is the transmission segment from Thomas Bay to Petersburg where potential state grant-funding is being considered and a preliminary cost estimate is available.

For the transmission line to connect the Coffman Cove and Naukati load centers to the other load centers in POW South, two alternatives were considered; one with grant funds and another with a capital recovery component for the $5.1 million which corresponds to the estimated cost to build the transmission lines.

The annual O&M costs for the existing lines was not used in the study as they were considered to be common to all alternatives. The annual O&M costs for the new transmission segments considered in the analysis are:

TRANSMISSION SEGMENT	O&M COST ($)
Tyee – BC Border	360,000
AK-BC Border to Connection in BC	450,000
Swan – Tyee	500,000
Thomas Bay – Petersburg	810,000
Petersburg – Kake	210,000
Kake – Takatz	1,200,000
Ketchikan – Metlakatla	125,000
Coffman Cove – Wrangell	1,300,000
Coffman Cove – Naukati – POW South [*]	40,000

* Assumed value

8.4.9 Fuel Prices

The present fuel prices at each load center were obtained from the respective utilities and are presented in Table 8-4. The fuel prices vary by load center and they range from 220.00 ¢/gallon (Ketchikan) to 268.00 ¢/gallon (Wrangell). These fuel prices were assumed to reflect a crude price in the NIMEX market of the order to 61.00 $ per barrel which could be translated to a base value (reference price) for diesel Oil (No. 2) of 176.20 ¢/gallon. This base value was used to calculate the additional costs to bring the fuel to each community.

The future price of fuel is an important determinant of the overall outcome of the economic analysis. Thus the fuel price forecast is of significant importance. For this study, several sources were consulted regarding fuel forecasts and the forecast produced by the Energy Information Administration (EIA) of the U.S. Department of Energy in its Annual Energy Outlook dated March 2007 was selected.

When the values shown in the EIA forecast are converted to 2007 prices, the average price for low sulphur light sweet crude oil amounts to 57.12 $ per barrel. By using the appropriate conversion factors this is equivalent to 165.25 ¢/gallon for diesel oil (No. 2). To this value, the additional costs calculated with the existing prices were added to arrive at the future delivered price for diesel oil (No. 2).

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-4 also presents the future price at each load center for diesel oil (No.2).

8.4.10 Cost of Energy from Swan Lake and Tyee Lake Hydros

Energy sales from Swan Lake and Tyee Lake were attributed an average cost of 64.00 $/MWh for the scenarios where the STI would not be commissioned. In the scenario where the STI would be commissioned early during the study period, an average cost of 53.00 $/MWh was used in the study. It should be noted that annual revenues for the two scenarios would be the same but since in the case of the STI the current surplus energy at Tyee Lake could be delivered to the loads, the unit cost of energy would decrease.

8.4.11 Cost to Society of Greenhouse Gas and Other Emissions

No cost was included although it is recognized that some of the alternatives include significant amounts of generation by diesel plants using No. 2 fuel oil.

8.5 Development Projects Considered

As shown in Section 3 of this Report, the load in SE Alaska is expected to grow during the study period. To meet the increased requirements, the system will rely on hydroelectric projects, diesel plants and transmission facilities to serve these load centers. Only diesel plants were considered as thermal resources since they were considered to be the most appropriate technology to supply the demand given its requirements and the resources available at each load center.

8.5.1 Hydro Projects

There are several hydroelectric projects that could be developed to meet the growing demand in SE Alaska and possibly to export energy to BC and the Lower 48 states. This phase of the study considers the 15 projects listed in Table 8-5 as candidates projects. These candidate projects are located in the 3 regions under study: 1 project located in POW, 5 projects in the Swan region, and the remaining 9 in the Tyee region.

The candidate hydroelectric projects range in capability from 0.8 MW to 45 MW and their capacity factors range, under average hydrological conditions, from 13.9% to 71.5%. Table 8-5 also presents the monthly energy distribution for each candidate hydroelectric project as well as the corresponding annual values. It should be noted that the values shown for the Tyee project are for the total project but when this project was considered in the study only the incremental values were used.

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

The monthly energy values presented in Table 8-5 indicate that most projects are run of river without storage facilities, the exception being the Takatz and Tyee projects.

Table 8-6 presents cost data for the candidate hydroelectric projects including capital costs and O&M cost. Assuming a discount rate of 6% and an economic life of 50 years, the annual capital charges were determined and are presented in Table 8-6. The unit cost of energy was determined taking into account the annual capital charges plus the annual O&M charges divided by the annual average energy. For purposes of this analysis, we used levelized as opposed to nominal costs. Levelized costs spread the costs over the 50-year term of the FERC license as opposed to nominal costs that reflect the initial term of financing for a project developed in the private sector.

As can be seen from the values presented in Table 8-6, the levelized unit cost of energy varies between 45.42 $/MWh and 374.80 $/MWh. The levelized unit cost of energy for the most promising projects is summarized below:

PROJECT	**LEVELIZED** **UNIT COST OF ENERGY ($/MWh)**
Whitman Lake	45.42
Mahoney Lake	54.02
Scenery Lake	54.80
Connell Lake	56.63
Cascade (Swan)	58.01
Carlanna Lake	70.71
Delta (Ruth)	70.36
Tyee Lake Extension	90.96
Triangle	91.44
Triangle	91.44

Table 8-6 also presents the earliest in-service date for each project. Whitman Lake and Mahoney Lake could be in-service by 2010 whereas the Tyee extension project could be in-service by 2012. Absent current information regarding the development schedule, all other projects were considered have the potential to be in-service by 2015.

It is noted that the "Levelized Unit Cost of Energy" derived in this section (as shown in the above table) is defined on a different basis from the "Cost of Power" shown in Section 7.2.3. The two calculations each use the same assumptions on the total estimated capital investment and annual operating and maintenance costs for each of the potential new hydropower developments. The calculation methods used for each calculation are described in the respective sections.

8.5.2 Diesel Units

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-7 presents the characteristics of candidate diesel units to meet the increasing demand in South Southeast Alaska. Several unit sizes were selected since there are several unit sizes in operation and each load center would have its own size requirements.

The technical and cost data were obtained from our in-house data base. High speed diesel technology was selected for the smaller sizes. The fuel consumption values shown are typical and reflect life cycle values and are for mid range duty which implies that these could be higher when operating only a few hours per week.

The capital costs consider North American supply with units to be installed within a building with all controls and required equipment.

8.5.3 Transmission

The transmission lines to be considered for the present study can be divided into two groups: those required to connect new generation to the load centers and those to connect load centers.

In the first group one finds only two transmission lines. The first would be necessary to connect the output of the Thomas Bay projects to Petersburg and the timing of this line should coincide with the in-service date of those projects. The second transmission line would be necessary to connect the Takatz hydroelectric project to Kake and due to the distances between the two locations, geography and topology, this connection would require a submarine cable as well the use of HVDC technology.

The second group includes several transmission lines. The proposed Swan-Tyee Intertie (STI) would connect the Tyee Lake Project near Wrangell with the Swan Lake Project near Ketchikan. The STI is partially constructed and a proposal to secure grant funds to complete this segment is pending. The STI would transfer power between Tyee and Swan in both directions.

The Kake to Petersburg transmission line (KPTL) has been recommended by several studies to be built as a 69 kV transmission line, however, this voltage could limit or hinder a future connection with other electrical systems in the northern sector of SE Alaska. This voltage is used in this study, but serious consideration should be given to higher voltages for the KPTL.

The Metlakatla to Ketchikan 34.5 kV transmission line could allow the transfer of power between these two load centers and encourage development of hydro projects in both load centers for mutual assistance.

A proposed 34.5 kV transmission line would connect the load centers of Coffman Cove and Naukati with POW South. This line segment would transmit lower cost power generated by the hydro plants in POW South to supply Coffman Cove and Naukati.

A connection between POW and the Tyee region in SE Alaska via a submarine cable connecting Coffman Cove and Wrangell is under consideration. This would be an HVDC connection.

The final transmission line under consideration is the AK-BC Intertie, a line from the Tyee Lake plant to the BC border to transmit power generated by hydroelectric facilities in SE Alaska to BC and the Lower 48.

8.6 Capacity and Energy Balances

Studies were performed to determine the capacity and energy balance for each of the SE Alaska load centers under study to obtain the system needs under a range of conditions regarding existing and committed generation. Since many load centers in SE Alaska are heavily dependant on energy produced by hydroelectric plants, the balance for the energy component was calculated using the minimum generation capability of the hydro plants.

In carrying out the capacity and energy balances, the only resources taken into account were the deemed local generation and as such the Swan and Tyee hydro plants capabilities were not considered. The capacity and energy balances were carried out based on annual values. The capacity reserve required for different load centers was based on the loss of the largest diesel unit if the load center was not connected to any major hydro plant or the capacity reserve was neglected if the load center was connected to a major hydro plant.

8.6.1 Kake

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-8 presents the capacity and energy balance for Kake as if this load center was to remain isolated from Petersburg and Wrangell. As can be seen, there is a capacity excess up to 2020 and further investigation showed this capacity excess to occur until the end of the study period.

The current generation in Kake is capable of meeting the load center's projected energy needs well past 2020.

8.6.2 Petersburg and Wrangell

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-9 presents the capacity and energy balance for Petersburg. Under the reference load growth forecast, there could be a capacity deficit by 2017 and this deficit could increase to about 2.1 MW by 2031. There are no energy deficits during the study period.

Table 8-9 also shows the capacity and energy balance for Wrangell. There are no capacity or energy deficits during the study period.

8.6.3 Ketchikan and Metlakatla

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-10 presents the capacity and energy balance for Ketchikan. As can be seen, under the reference growth load forecast, a capacity deficit is expected by 2010. This deficit is expected to grow to 9 MW by 2020 and could reach 15.5 MW by 2031. Thus the Ketchikan load center requires generation capacity additions amounting to at least 15.5 MW during the study period and should some of the existing diesel generation be retired during the study period then additional units would have to be commissioned.

As shown in Table 8-10, the Ketchikan load center is expected to have an energy deficit by 2019 and this deficit could increase to about 35,000 MWh by the end of the study period but as new units are commissioned to meet the capacity deficit, this energy deficit is expected to be reduced significantly.

Table 8-10 also shows the capacity and energy balance for Metlakatla. There are no capacity or energy deficits during the study period.

8.6.4 POW

NOTE to Reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

Table 8-11 presents the capacity and energy balance for the POW South communities as well as Coffman Cove and Naukati. Under the reference growth load forecast, there are capacity and energy excesses up to 2020. The excesses continue during the study period.

8.6.5 SE Intertie Development Scenarios Considered to Date

Proposals and investigations with the goal of interconnecting the communities of SE Alaska with an electrical transmission grid (SE Intertie) have been considered for decades. In 1997 a group of utilities and communities formed a committee under the leadership of the Southeast Conference and engaged Acres International to perform a study and propose a long-term plan, including phased development and estimated costs in support of a proposed electrical intertie system to interconnect isolated load centers; increase system reliability; reduce or avoid diesel dependence; encourage economic development; and stabilize and equalize rates. The Acres study provided recommendations for implementing a reliable Intertie system in five phases. The Southeast Conference and its members, working closely with the Alaskan Congressional delegation in Washington, D.C., secured passage in 2000 of a bill authorizing the intertie project that included Federal expenditures in the amount of $384,000,000, equal to 80 percent of the system cost, and requiring a 20 percent local match requirement..

The Five Phases investigated in 1997 included potential development scenarios presented in this report. Since 2000 two segments of the SE Intertie have received federal funding as authorized by S.2439.

8.6.6 SE Intertie Segments Currently Under Development with Federal Funds to Date

The Swan-Tyee Intertie (STI) segment has been designed, permits secured, and the project is partially constructed. Completion of the STI is dependent on funding by the State of Alaska. The STI is an integral element to the Development Scenarios discussed in this section of the report.

The Juneau to Hoonah Intertie segment is under construction by the Kwaan Electric Transmission Intertie Cooperative, Inc. (KWETICO). This segment will connect Alaska Electric Light & Power Company's (AEL&P) transmission infrastructure to Inside Passage Electric Cooperative, Inc.'s (IPEC) distribution system serving Hoonah on Chichagof Island, replacing current high-cost diesel generation with low-cost hydro-generated power

The second proposed segment under consideration by KWETICO is the Kake-Petersburg transmission segment that would interconnect IPEC's system on Kupreanof Island with the FDPPA existing transmission segment between Petersburg/Wrangell and the Tyee Lake Project and provide low-cost hydro power to an area solely dependent on high-cost diesel-generated power[2].

8.7 Development Scenarios in SE Alaska without Exports

As mentioned in Section 8.2 SE Alaska was divided into three main regions and generation expansion scenarios for each of these regions were formulated, developed, analyzed and evaluated. In addition, scenarios considering regional connections were also investigated.

8.7.1 Generation Expansion Scenarios for the Tyee Region

The Tyee region is composed of the Petersburg, Wrangell and Kake load centers. Kake's demand is being supplied by local diesel generation. Petersburg's demand is supplied by local hydro, local diesel and electrical energy from the Tyee Lake hydro plant. Wrangell's demand is supplied by local diesel and electrical energy from the Tyee Lake hydro plant. A transmission line operated at 69 kV but designed and constructed for 138 kV operation connects the Tyee Lake hydro plant to Wrangell and from there to Petersburg.

As identified in the previous section, Petersburg is the only load center in the Tyee region that requires capacity additions during the study period and in order to meet the reserve criterion it was decided to install a 2 MW diesel unit by 2017 at that load center.

The RRPM was used to determine the costs associated with supplying the Tyee region load centers demand assuming continuing supply from existing resources.

The next step taken was to estimate the year that a connection between Kake and Petersburg could be economic. This was done by dividing the estimated annual O&M cost of the transmission line to connect these load centers by the variable cost of diesel generation minus the cost of Tyee Lake energy. The resulting value indicated that if about 1,450 MWh of diesel generation could be displaced by Tyee Lake generated energy, the connection would be economic and since the load at Kake is greater that that value, such a connection would be economic as soon as it would be operational. However, considering the lead time to place this line in operation, it was decided that the first in service date would be January 1, 2011.

The RRPM was rerun considering a transmission line between Kake and Petersburg starting in 2011. The present value of costs of supplying the Tyee region demand, from 2007 to 2031 and a further evaluation period of 15 years, under the two alternatives described above can be summarized as:

Scenario	**C.P.V. of Costs to January 2007 ($, million)**		
	6%	**8%**	**10%**
Wrangell + Petersburg & Kake Isolated	117.0	90.1	72.1
Wrangell + Petersburg + Kake Connected in 2011	109.4	84.9	68.3
Benefits of Connection of Kake	7.5	5.2	3.8

Note: C.P.V. stands for Cumulative Present Value

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[2] KWETICO included the Kake-Petersburg Transmission Intertie in its Application for New Certificate of Public Convenience and Necessity; and Request for Public Interest Exemption filed with the RCA under U-05-100 on December 21, 2005.

The above results indicate that the connection of Kake to Petersburg is economic from its first possible in service year, delay in the connection would decrease the benefits.

The transmission voltage for this connection is being mentioned elsewhere in the report as being 69 kV. Serious consideration has to be given to this voltage level for this transmission segment as this voltage could jeopardize future development in Southeast Alaska, namely the connection of the Tyee region to regions to the North.

8.7.2 Generation Expansion Scenarios for the Swan Region

NOTE to reader:

Tables referenced below are provided in the files containing the RRPM model runs for the base, low and high scenarios posted with this narrative section. These tables are also presented in the Draft Final Report provided on April 5, 2007 and posted on the AEA website.

The Swan region is composed of the Ketchikan and Metlakatla load centers. Ketchikan's demand is being supplied by local hydro, local diesel and electrical energy from the Swan Lake hydro plant. Metlakatla's demand is supplied by local hydro and local diesel. A transmission line operated at 115 kV connects the Swan Lake hydro plant to Ketchikan.

As identified in the previous section, Ketchikan requires capacity additions by 2010 and this rises to a need for new capacity of 15.5 MW by 2031. This new capacity could be obtained either from diesel generation or the hydro resources available in the region. As diesel generation is relatively more expensive than hydro generation and the hydro projects available to be brought into service are not much larger than the load requirements it was decided to meet Ketchikan capacity and energy requirements with new hydroelectric resources.

Item 3 in Table 8-12 presents the development sequence of new hydro projects to meet Ketchikan's capacity and energy requirements when supplied in an isolated fashion. Four hydro projects were considered to be developed during the study period to meet both capacity and energy requirements. Even though only one hydro plant would be needed in the earlier years, it was decided to have both Whitman Lake and Mahoney Lake on line in order to displace expensive diesel generation. With both Whitman Lake and Mahoney Lake in place, further capacity additions would only be required by 2029 but since the diesel generators at Ketchikan would be producing close to 20,000 MWh by 2015 it was decided to advance Connell Lake to its earliest in service date. The in service date of Carlanna Lake was determined by its costs and capability to displace diesel generation.

Item 4 in Table 8-12 presents the generation additions to meet Metlakatla's capacity and energy requirements when supplied in an isolated way. According to the capacity and energy balances, Metlakatla does not need generation additions to meet capacity and energy requirements. However, when carrying out preliminary system simulations it was noticed that significant amounts of diesel generation were required past 2020. In order to curtail diesel generation and decrease cost, the Triangle hydro project was assumed to be commissioned by 2022.

A generation expansion scenario was developed whereby the load centers of Ketchikan and Metlakatla would be connected. The resulting expansion scenario is shown in item 5 of Table 8-12 and as can be seen the Triangle hydro project was advanced because it could supply energy to Ketchikan that would compensate for its advancement.

The most economic in-service date for the connection of Ketchikan and Metlakatla was 2013. This connection was beneficial to both load centers in terms of displaced diesel energy. From 2013 to 2031 some 21,600 MWh of diesel energy was displaced in Ketchikan when compared to the isolated scenario and some 7,800 MWh in Metlakatla.

The present value of costs for supplying the Swan region's demand, from 2007 to 2031 and a further evaluation period of 15 years, under the two alternatives described above can be summarized as:

Scenario	**C.P.V. of Costs to January 2007 ($, million)**		
	6%	**8%**	**10%**
Ketchikan Isolated	271.9	212.9	173.2
Metlakatla Isolated	25.3	19.8	15.8
Ketchikan + Metlakatla Connected in 2013	294.0	230.9	188.2
Benefits of Connecting Ketchikan & Metlakatla	3.2	1.8	0.8

The above results indicate that the connection of Ketchikan and Metlakatla is economic from 2013 and delay in the connection would decrease the benefits.

8.7.3 Generation Expansion Scenarios for the POW Region

The energy and capacity balance section shows that during the study period there are no deficits in the POW region. For study purposes, the region has been divided into POW South and the load centers of Coffman Cove and Naukati. The POW South load centers are all connected via 34.5 transmission lines and are supplied from the Black Bear and South Fork hydro plants as well as from diesel units located at each load center. Coffman Cove and Naukati are relatively small load centers supplied by local diesel generation.

During preliminary system simulations with the RRPM it was noticed that the load centers in POW South during certain periods of the year were absorbing all the hydro generation and producing some diesel generation. To reduce costs and displace the diesel generation, it was decided to include the Reynolds Creek hydro project and the most economic in-service date for this project was found to be 2021.

Following the development of the generation expansion scenarios for the case where the load centers would continue to be isolated, two additional generation expansion scenarios were evaluated; one considering the capital cost and O&M cost of a 34.5 kV transmission line to connect Coffman Cove and Naukati to the POW South load centers and another considering only the O&M cost of the transmission line. The transmission line would be in service by 2011.

The present value of costs for supplying the POW region's demand, from 2007 to 2031 and a further evaluation period of 15 years, under the three scenarios described above can be summarized as:

Scenario	**C.P.V. of Costs to January 2007 ($, million)**		
	6%	**8%**	**10%**
POW South + Coffman Cove &	58.3	44.4	35.1

Naukati			
POW Connected in 2011 & with Capital & O&M	60.5	46.9	37.7
POW Connected in 2011 & with O&M Costs Only	55.8	42.6	33.8
Benefit of Connecting 2 centers with O&M Costs Only	2.5	1.8	1.4

The above results indicate that the connection of the Coffman Cove and Naukati load centers to the load centers of POW South is not economic if both the capital cost and O&M cost of the transmission line required for the connection is included in the calculations. However, the connection is economic if only the O&M of the transmission line is included in the costs.

8.7.4 Connection of the Swan and Tyee Regions

The connection of the Swan and Tyee regions requires that a transmission line be in place between the Tyee Lake hydro plant and the Swan Lake hydro plant, the Swan Tyee Intertie (STI). Significant work has been already done on the STI (see Section 6.2 of this Report for a detailed discussion). The Four Dam Pool Power Agency (FDPPA) has a request pending before the State decision-makers to authorize funds to complete the STI. The Governor's budget proposal includes some of the requested additional funding. The STI will enable the FDPPA to optimize generation at Tyee Lake and decrease spilling as the existing surplus could be used to meet Ketchikan's energy needs.

The STI is approximately 57 miles long with no submarine crossings. It would be constructed for 138-kV nominal voltage but would be operated initially at 69-kV.

Generation expansion plans were developed for the Swan and Tyee regions considering that the STI would be in place by 2010. Item 6 in Table 8-12 presents the generation additions as well as their timing. It should be noted that since the STI would be bringing energy into the Ketchikan area, some of the local hydro plant additions should be delayed as utilization of their generation would be curtailed. The analysis indicated that Mahoney Lake should be delayed 4 years, Triangle Lake should be delayed by 6 years and the Carlanna Lake hydro project should be delayed beyond the study period.

The present value of costs for supplying the Swan and Tyee regions' demand, from 2007 to 2031 and a further evaluation period of 15 years, either individually or in a connected way can be summarized as:

Scenario	**C.P.V. of Costs to January 2007 ($, million)**		
	6%	**8%**	**10%**
Isolated Supply of Swan and Tyee Demand	403.4	315.8	256.5
Swan and Tyee Connected in 2010	370.2	288.8	233.7
Benefit of STI	33.2	27.0	22.8

The above results indicate that the STI is economic from its first possible in service year. Delay in the connection would decrease the benefits.

The utilization of the energy that could be produced by individual hydro plants in the scenario without the STI and in the scenario with the STI is shown in Figures 8-1 and 8-2 respectively. The figures are provided at the end of this Section 8.

8.7.5 Connection of the POW Region to Other Regions

Studies were undertaken to verify the economic viability of connecting the POW load centers to the Wrangell substation. The connection of the POW load centers would involve the construction of a submarine cable link, 50 miles long utilizing HVDC technology. The capital cost of this link is quite high and the annual O&M charges have been estimated at $ 1,300,000.

In order for the link to be economically viable, the annual O&M charges would have to be offset with gains from displaced diesel energy. The diesel generation is expected to cost about 164 $/MWh and hydro energy from either Swan Lake or Tyee Lake would cost about 53 $/MWh and this would result in an overall net savings of 111 $/MWh.

Dividing the annual O&M cost of the connection between POW and Wrangell by the overall net savings ($1,300,000 /111$/MWh) provides the amount of energy that would have to imported into POW for the connection to be economic and in this case this energy amounts to about 11,700 MWh.

The diesel energy generated in POW by 2031 amounts to only 7,000 MWh and in this case the connection would not be economic.

8.8 Development Scenarios in SE Alaska with Exports

Generation expansion scenarios considering sales of energy generated within SE Alaska to entities either in BC or in the Lower 48 states were developed. Under this arrangement hydro projects would be developed in SE Alaska and their energy would be able to meet the demand in SE Alaska first with the remaining surplus available for sale to entities outside SE Alaska.

Under this scenario, a transmission line (AK-BC Intertie) would be built from the Tyee Lake hydro plant to the AK/BC border to make the sales of the surplus energy possible. Losses on this line were assumed to be 2% with a further 6% to be encountered from the border to the final buyer. The sales at the border were valued at 60 $/MWh.

From the list of projects presented in Section 8.5 it was determined that the most economic projects available for export were the Thomas Bay projects. The transmission line would originate at the power house of the closest project, the Cascade Creek powerhouse and substation, located near tidewater. The other two projects at Thomas Bay would include infrastructure to connect and transmit their generated energy to the substation at Cascade Creek. Power from Thomas Bay projects would be transmitted from Thomas Bay across Frederick Sound to a new substation southwest of Petersburg. From there the power would be transmitted on the existing transmission line that connects Petersburg to Wrangell and the Tyee Lake hydro plant. Losses were assumed at 2% for each transmission segment between the collection point and Tyee Lake.

For the generation expansion plan it was decided to start with the plan for the STI scenario and make revisions to it as required. The development of the Thomas Bay plants was considered to be staged. Cascade Creek would be the first plant to be commissioned, followed 2 years later by Scenery Lake and 2 years after that the Delta Creek plant would be commissioned. The Cascade Creek hydro plant was considered to be in service at its earliest possible date, 2015, followed by Scenery Lake in 2017 and Delta Creek in 2019. Study results indicated that Delta Creek would not provide sufficient revenue to cover its costs (capital and O&M) and thus was not considered to be part of the system. Other hydro projects were considered for export but were found to be uneconomical. In addition, under this scenario it was shown to be more economical to delay the Triangle Lake hydro project beyond the study period.

Item 7 in Table 8-12 presents the expansion plan considered for the scenario with exports.

The present value of costs for supplying the Swan and Tyee regions' demand, from 2007 to 2031 and a further evaluation period of 15 years, either in a connected way or in an export mode can be summarized as:

Scenario	**C.P.V. of Costs to January 2007 ($, million)**		
	6%	**8%**	**10%**
Swan Lake and Tyee Lake Connected in 2010	370.2	288.8	233.7
Swan Lake and Tyee Lake Connected in 2010 & Power Exports	337.7	298.4	264.4
Benefit of Power Exports	32.5	-9.6	-30.7

The above results indicate that power exports are economic under the base case discount rate but uneconomic at higher discount rates.

Figure 8-3 presents the potential energy for export by month for three selected years.

8.9 Items Not Included in Economic Analysis

As noted in an earlier section, the economic analysis has been carried out under the assumption that the transmission segments needed to connect load centers and bring power to the BC border for export would be funded through government grants. However, the economic analysis includes the full estimated costs of the annual operation and maintenance costs associated with each transmission segment. The operation and maintenance cost estimates have been prepared to recognize the challenges of the Alaskan climate and terrain and the resulting impacts on costs.

On the other hand, there are a number of benefits to the residents of the region and the State of Alaska as a whole that would likely result from the projects for SE Alaska that have not been quantified as part of the Phase 1 work and thus have not been counted in the economic analysis. These include benefits such as:

- Reduction of GHG from diesel generation;

NOTE to reader: Please see information included following this section for information developed following provision of the Draft Final Report regarding reduction of GHG.

- Reduction in the total amount of spinning reserve;
- More conversions from oil heat to electric heat and the resulting economic and GHG reduction benefits;
- Increased total output from hydro plants by the ability to exploit hydro complementarities through coordinated operation of the plants;

- Assistance during maintenance outages;
- Reduction in PCE subsidy payments; and
- The multiplier effects of increased economic development and increased disposable income resulting from lower energy prices;

Similar un-quantified benefits would generally also result from the investments made to allow the export of power. In this case there would be further un-quantified benefits associated with:

- Earlier development of larger hydro projects allowing further reduction in diesel generation in SE Alaska;
- Increased flexibility of power system operations by virtue of being connected to a larger system; and
- Opportunity for further optimization of system resources.

8.10 Sensitivity Analysis

Sensitivity studies were carried out to determine the sensitivity of the generation/transmission expansion sequences results to changes in the parameters used in the analysis. Meaningful variations of these parameters were selected to demonstrate the robustness of the planning results under conditions that could reasonably be expected. Sensitivity was investigated to variations in the following parameters.

- Low and high load growth
- Capital and O&M Costs
- Fuel prices
- Export price and repayment period
- Discount rate

8.10.1 Low and High Load Growth

The generation expansion scenarios developed for the reference load forecast were examined to obtain indications on how the generating plants added during the study period would be either delayed or advanced depending on the load growth scenario under study; low or high. The capacity and energy balances were also taken into account when developing generation expansion sequences for the load growth under study.

For the low growth load forecast, Petersburg could experience a capacity deficit by 2026 and Ketchikan has a capacity deficit by 2011 with the remaining load centers not encountering capacity deficits. With the assistance of the RRPM, studies were performed to determine the best timing of the hydro plants considered under the reference growth load forecast. The resulting plant addition plan is presented in Table 8-13 and when compared to Table 8-12 it can be seen that for the Swan region expansion plans, the Carlanna Lake and Triangle Lake hydro projects were delayed from 2 to 8 years depending upon the case being studied. For the STI and exports cases Connell Lake was delayed 6 years and Triangle Lake was delayed beyond the study period.

For the high growth load forecast, Petersburg would see a capacity deficit by 2013 and Ketchikan would have a capacity deficit by 2010 with the remaining load centers not encountering capacity deficits. With the assistance of the RRPM, studies were performed to determine the best timing of the hydro plants considered under the reference growth load forecast.

The resulting plant addition plan is presented in Table 8-14 and when compared to Table 8-12 it can be seen that for the Tyee region, diesel additions were commissioned by 2013 and 2017 in Petersburg with a nominal size of 2 MW for each addition. For the Swan region expansion plans, there was a need for a 5 MW diesel unit at Ketchikan to mitigate the capacity deficit in 2026, the Triangle Lake hydro projects was advanced either 3 or 4 years depending upon the scenario being investigated and the Carlanna Lake plant was advanced 4 years in the case of a connection between Ketchikan and Metlakatla. For the high growth load forecast, the Tyee extension hydro project was included in the generation expansion plans, other hydro projects were found to be uneconomical.

The STI and export cases required the advance of all plants when compared to the reference growth load forecast with Cascade Creek and Scenery Lake remaining with the same in-service date as in previous cases.

Table 8-15 summarizes the costs associated with supplying the demand in SE Alaska under the three different load growth forecasts. Generally, the costs associated with supplying the demand of the three regions under study in SE Alaska increase with the high growth load forecast and decrease with the low growth load forecast. The benefits associated with the various connections also increase with load growth and generally have their smallest values under the low load growth case. The exception being the loads in the POW region where the benefits of connecting the Coffman Cove and Naukati load centers decrease with increasing load growth and this may be due to the fact of limited hydro energy availability.

8.10.2 Capital and O&M Costs Increase

Studies were performed to determine the sensitivity of the economic analysis to variations in the capital costs and O&M costs of projects. In this analysis, a 20% increase was assumed in the capital cost and O&M cost estimates for all projects. The results of these studies are presented in Table 8-16 and these results indicate that a 20% increase in capital and O&M costs would not result in significant impacts on the benefits of the connection of Kake to Petersburg, the connection of Ketchikan and Metlakatla and the connection of Swan Lake and Tyee Lake (the STI). However, the economics of the export case would be significantly and adversely affected by a 20% increase in capital and O&M costs of the Thomas Bay projects.

8.10.3 Fuel Prices

Studies were performed to determine the sensitivity of the generation sequences to variations of fuel prices. Studies were performed for a ± 15 % variation in all fuels prices which would correspond to crude price varying from 48 $per barrel to 65 $ per barrel. The results of these studies are presented in Table 8-17 and these results indicate that the higher the fuel price the more costly to supply the load centers and the more benefits one would obtain from the various connection alternatives including the STI and the export cases.

8.10.4 Export Price and Capital Repayment Period

Studies were performed to determine the sensitivity of the generation sequences for the export cases to variations of export price, capital cost of plants for export and numbers of years for capital cost repayment. The results are shown in Table 8-18 and indicate that for a 20 years capital repayment period and an export price of 60 $/MWh, increases in capital cost of the plants built for export would result in negative benefits. However, for export prices of 70 and 80 $/MWh the benefits of exports would remain positive for the range of capital cost increases examined.

Table 8-18 also shows that for a capital repayment period of 50 years, one would encounter negative benefits if the export price was 60 $/MWh and the capital cost of the plants built for export was increased by 20%. The other export prices and capital cost increases tested resulted in positive benefits.

8.10.5 Discount Rate

The cumulative present value of costs, at different discount rates, of supplying the load centers under study are presented in Sections 8.7 and 8.8. Generally the results show that the higher the discount rate the lower the overall benefits of connecting the load centers. The STI benefits are reduced from $33.2 million for a 6% discount rate to $22.8 million for a 10% discount rate.

The benefits associated with the export case are significantly adversely affected by increases in the discount rate. At 6% discount rate, the export case has a positive benefit of $32.5 million whereas for a discount rate of 10%, the benefit is negative $35.9 million.

ESTIMATED AVOIDED GHG EMISSIONS

ADDITIONAL INFORMATION DEVELOPED POST PROVISION OF THE DRAFT FINAL REPORT REGARDING REDUCTION OF CURRENT LEVELS OF GHG FROM DIESEL GENERATION

Excerpt from Section 9 of the Draft Final Report

9.2.1.5 Un-quantified Benefits Resulting From Interconnected Electric Transmission System

Several benefits to the SE Alaska ratepayers and communities would likely result from an interconnected electric transmission system. They are not quantified in the economic analysis performed to date. These include:

- Reduction of current levels of GHG from diesel generation;

ESTIMATED AVOIDED GHG EMISSIONS

AEA requested Hatch Energy to perform an analyses of avoided emissions that could result when individual load centers and systems are interconnected in southern SE Alaska. Two load growth scenarios were investigated:

- Include conversion of a portion of heating supplied by oil fired heating furnaces to loads supplied by electrical heaters (case with conversion)
- Consider that heating would continue to be supplied by oil fired heating furnaces (case without or no conversion).

This section of this Supplemental Information regarding the RRPM provides results of this analysis.

In the case with conversion of oil fired heating furnaces, the annual expected displaced oil consumption of these furnaces was estimated and the expected amount is discussed in this section.

For each of the two load growth scenarios, the generation for three system development cases was determined in order to calculate the avoided emissions. These cases are::

1) Isolated --	Swan-Tyee Intertie is not implemented and both Kake and Metlakatla remain isolated;
2) Isolated With STI --	Swan-Tyee Intertie is commissioned in 2010 but both Kate and Metlakatla remain isolated;
3) Interconnected With STI --	Swan-Tyee Intertie is commissioned in 2010, Kate is interconnected with Petersburg and Metlakatla is interconnected with Ketchikan.

Emission Factors

Four emission pollutants - CO2, SOx, CO and NOx - were examined in this study. The emission factors used were obtained from AP 42, Volume I, Fifth Edition published by the Environmental Protection Agency (EPA) of the USA in 1995. These factors are summarized as follows:

Pollutant	Diesel Engine	Furnace

Emission Factors in Pounds Per Horsepower-Hour (lb/hp-hr)		
CO2	1.16	
SOx	0.00809	
CO	0.0055	
NOx	0.024	
Emission Factors in Pounds Per Thousand Gallons of Fuel (lb/1000-gal)		
CO2	22,548	22,300
SOx	157	144
CO	107	5
NOx	467	18

It is important to note that the emission factors in lb/hp-hr for diesel engines shown in the table above are the average values for large diesel engines (greater than 600 hp). The factors in lb/1000-gal for the diesel engines are calculated based on the values in lb/hp-hr, heat rate of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb and diesel density 7.05 lb/gal. It is also assumed that the diesel used contains 1% of sulfur.

It can be seen from these emission factors that for the same amount of liquid fuel consumed by the diesel engines and furnaces, the two types of facilities emit similar amounts of CO2 and SOx but diesel engines emit much more CO and NOx than furnaces. CO and NOx emissions from diesel engines are about 21 times and 26 times of those from furnaces.

2 Electricity Required for Conversion of Oil Fired Heating Furnaces

In this analysis, five load centres were considered - Ketchikan, Metlakatla, Wrangell, Petersburg and Kake. The estimated additional annual electrical energy required to supply the loads that would be converted from oil fired heating furnaces assumed as well as the displaced oil consumption in the case with conversion are summarized as follows:

Year	Additional Electricity Required (MWh)	Displaced Oil Consumption (US Gallon)
2007	2,759	108,375
2008	5,433	213,377
2009	8,016	314,846
2010	11,728	453,163
2011	18,962	707,095
2012	28,600	1,039,909
2013	30,889	1,129,792
2014	39,194	1,417,705
2015	41,449	1,506,298
2016	43,641	1,592,398
2017	45,765	1,675,796
2018	47,841	1,757,324
2019	49,874	1,837,193
2020	51,891	1,916,396
2021	53,860	1,993,728
2022	55,781	2,069,190
2023	57,660	2,142,990
2024	59,492	2,214,920

2025	61,286	2,285,395
2026	63,058	2,354,991
2027	64,793	2,423,133
2028	66,496	2,490,028
2029	68,168	2,555,676
2030	69,802	2,619,869
2031	71,425	2,683,600
Total	**1,117,863**	**41,503,183**

With conversion of each MWh of furnace load to electrical load, about 37 gallons of heating oil can be displaced. Based on a heat rate 7,000 Btu/hp-hr, a heating value of 19,300 Btu/lb and a density of 7.05 lb/gal as mentioned earlier, diesel engines would use about 69 gallons of diesel to generate one MWh. This implies that diesel engines have lower efficiency than heating furnaces. If the additional load for heating was produced by diesel engines, there would be more oil consumption and more pollution than in the case of supply from heating furnaces. I important to note that most of the additional or displaced heating furnace load is expected to be produced by unused hydro generation.

3 Estimated Avoided Emissions

The following tables present total and avoided emissions over the periods from 2007 to 2041 and from 2007 to 2031. Tables showing detailed information from which these summary tables were developed is attached at the end of this section of the comments.

Total Emissions

Theme	Case	CO2 (ton)	SOx (ton)	CO (ton)	NOx (ton)
		2007-2046			
No-Conversion	**Isolated**	1,667,754	11,160	3,790	16,381
	Isolated-STI	1,485,993	9,892	2,928	12,620
	IC-STI	1,383,714	9,179	2,443	10,504
Conversion	**Isolated**	1,424,535	9,935	6,754	29,473
	Isolated-STI	956,242	6,669	4,534	19,784
	IC-STI	872,599	6,086	4,137	18,054
		2007-2031			
No-Conversion	**Isolated**	912,198	6,123	2,235	9,672
	Isolated-STI	829,041	5,543	1,840	7,952
	IC-STI	770,639	5,135	1,564	6,743
Conversion	**Isolated**	754,157	5,260	3,576	15,603
	Isolated-STI	471,672	3,290	2,236	9,759
	IC-STI	426,202	2,972	2,021	8,818

Avoided Emissions

Theme	Case	CO2 (ton)	SOx (ton)	CO (ton)	NOx (ton)
2007-2046					
No-Conversion	**Isolated**	--	--	--	--
	Isolated-STI	181,762	1,268	862	3,761
	IC-STI	284,040	1,981	1,347	5,877
Conversion	**Isolated**	243,219	1,225	-2,965	-13,093
	Isolated-STI	711,513	4,491	-744	-3,404
	IC-STI	795,155	5,074	-348	-1,673
2007-2031					
No-Conversion	**Isolated**	--	--	--	--
	Isolated-STI	83,156	580	394	1,720
	IC-STI	141,559	987	671	2,929
Conversion	**Isolated**	158,041	863	-1,341	-5,931
	Isolated-STI	440,525	2,833	-2	-87
	IC-STI	485,996	3,150	214	854

It can be seen from the above table that in the interconnected case with the Swan-Tyee interconnection commissioned in 2010, conversion of a portion of oil fired furnace load could reduce CO2 and SOx emissions by 795,155 and 5,074 tons or some 47.7% and 45.5% respectively over the period from 2007 to 2046 or 485,996 and 3,150 tons or some 53.3% and 51.5% respectively over the period from 2007 to 2031 when compared with the isolated case without conversion. Over the period from 2007 to 2046, emissions of CO and NOx would be increased by 348 and 1673 tons or about 9.2% and 10.2% respectively and this is due to the corresponding high emission factors of diesel engines.

The following Tables 1 and 2 present detailed information regarding the estimated annual emissions in short tons (2000lb/short ton) for each of the two load growths studied.