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Appendix D

to

COMPREHENSIVE RENEWABLE ENERGY FEASIBILITY STUDY FOR SEALASKA CORPORATION

EVALUATION OF THE HYDROELECTRIC POTENTIAL NEAR SELECTED SEALASKA COMMUNITIES

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For
Sealaska Corporation

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EVALUATION OF THE HYDROELECTRIC POTENTIAL
NEAR SELECTED SEALASKA COMMUNITIES

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I. SUMMARY

This report documents the results of our effort to update previous feasibility studies for hydroelectric projects that would provide power to Sealaska communities that currently rely on diesel generation. The following indicates the communities and hydroelectric projects that are addressed in this report.

Communities and Hydroelectric Projects

Community	Potential Hydroelectric Projects
Angoon	Thayer Creek (1,000 kW)
Hoonah	Gartina Creek (600 kW) Water Supply Creek (600 kW)
Hydaburg	Reynolds Creek (5,000 kW)
Kake	Cathedral Falls Creek (800 kW)
Klukwan	Walker Lake (1,900 kW)
Yakutat	Chicago Harbor (1,400 kW)

For each of these projects, we reviewed and modified the project arrangements as appropriate, estimated construction costs, conducted a standardized economic analysis, made a preliminary evaluation of the likely environmental issues, and commented on the likely regulatory framework. The following table indicates the results of these tasks. It should be noted that the regulatory framework for most of the projects listed above is in flux, since the Energy Act of 2000 requires that the State of Alaska institute a program to replace that of the Federal Energy Regulatory Commission (FERC) for projects of 5,000 kW capacity or less.

Table 1
Project Feasibility Summary

Community	Project	Construction Cost ($2003)	Economic Feasibility	Environmental Feasibility
Angoon	Thayer Creek (1,000 kW)	$8,700,000	Low	Moderate
Hoonah	Gartina Creek (600 kW) Water Supply Creek (600 kW)	$3,750,000 $3,330,000	Moderate Moderate	Moderate High
Hydaburg	Reynolds Creek (5,000 kW)	$9,400,000	Low	High
Kake	Cathedral Falls Creek (800 kW)	$5,300,000	Moderate	Moderate
Klukwan	Walker Lake (1,900 kW)	$9,400,000	Low	Unknown
Yakutat	Chicago Harbor (1,400 kW)	$9,300,000	Moderate	Unknown

Interconnection to another utility is possible for most of these communities, and may be a viable alternative to either diesel or hydroelectric generation. Because of this potential, we have also commented on the possible transmission interconnections to the various communities, as summarized in the following table.

Table 2
Interconnection Potential Summary

Community	Interconnection Potential
Angoon	Low
Hoonah	Moderate
Hydaburg	High (expected in 2005)
Kake	Moderate
Klukwan	High (expected in 2006)
Yakutat	Very low

II. OVERVIEW

A. Purpose

Southeast Alaska is blessed with high rates of precipitation and mountainous terrain, which makes for outstanding hydroelectric generation potential. Over the years, many communities have sought to develop some of the hydroelectric potential to meet the electric loads of their citizens and businesses. Those communities that have managed to develop hydroelectric projects generally have relatively low power rates, whereas the communities without hydroelectric generation rely almost exclusively on diesel generators and have comparatively high power rates. Because of the rugged terrain and generally long distances between communities, transmission interconnections are few.

The purpose of this study was to update previous studies on hydroelectric projects for the communities that currently rely on diesel generation for most of their power supply. The communities considered are those for which Sealaska Corporation is designated as the Regional Corporation.

The scope of work for the studies comprises the following tasks:

1. Collect previous feasibility reports
2. Review the previous reports and evaluate whether new technology or construction methods could result in cost savings.
3. Update the economic assessments.
4. Conduct a preliminary environmental assessment to determine if there are major issues that would likely preclude development.
5. Conduct a regulatory assessment to determine and describe the regulatory processes that would need to be completed.
6. Document the results in a report.

B. Sealaska Communities

Sealaska communities can be categorized by their power supply as follows:

1. Locally interconnected communities

Many of the larger communities in Southeast Alaska are locally interconnected to smaller communities or to each other, and these larger communities generate most of their electricity from hydroelectric projects. They are served by municipal or investor-owned electric utilities, which can be expected to continue development of additional hydroelectric projects to meet load growth. The following table lists these larger communities, their interconnected smaller communities, their serving utilities, their existing hydroelectric projects, and previously identified potential hydroelectric projects.

Table 3
Locally-Interconnected Larger Communities

Larger Communities	Interconnected Smaller Communities	Electric Utility	Existing Hydroelectric Projects	Potential Hydroelectric Projects
Juneau	Douglas, Auke Bay	Alaska Electric Light & Power (AELP)	Snettisham Annex – Salmon Gold Creek	Lake Dorothy
Ketchikan	Saxman	Ketchikan Public Utilities (KPU)	Swan Lake Beaver Falls – Lake Silvis Ketchikan Lakes	Whitman Lake Mahoney Lake (1)
Sitka		Sitka Electric Department	Blue Lake Green Lake	Takatz Lake Lake Diana Medvejie Lake
Haines – Skagway		Alaska Power & Telephone	Goat Lake Dewey Lakes Lutak	Kasidaya Creek Dayebas Creek Connelly Lake
Petersburg – Wrangell		Petersburg Municipal Power & Light Wrangell Municipal Power & Light	Tyee Lake Blind Slough	Scenery Lake Swan Lake
Metlakatla	Annette	Metlakatla Power & Light	Purple Lake Chester Lake	
Craig – Klawock – Kasaan		Alaska Power & Telephone	Black Bear Lake	South Fork

(1) Mahoney Lake is a proposed development by Ketchikan Electric Company, which is a joint venture of Alaska Power & Telephone and Cape Fox Corporation.

2. Isolated Communities

The remaining communities in Southeast Alaska are electrically isolated, and rely primarily on diesel power for electricity generation. This study focuses on the communities which are associated with Sealaska Corporation, and nearly all of them have had at least an assessment of hydroelectric potential, and a few have had feasibility studies of potential hydroelectric projects. These communities, their existing utilities, and identified potential hydroelectric projects are shown in the following table.

Table 4
Isolated Sealaska Communities

Community	Existing Utility	Potential Hydroelectric Projects
Angoon	Inside Passage Electric Cooperative (IPEC) (1)	Thayer Creek
Hoonah	IPEC	Gartina Creek Water Supply Creek
Hydaburg	Alaska Power & Telephone	Reynolds Creek
Kake	IPEC	Cathedral Falls Creek
Klukwan	IPEC	Walker Lake
Yakutat	Yakutat Power	Chicago Harbor

(1) Previously known as Tlingit and Haida Regional Electric Authority

The hydroelectric potential of these six communities are discussed further in the remaining sections of this report. Each community section also discusses the potential for interconnection to other utilities in more detail. The following subsections of this section discuss the current status of the Southeast Intertie and the regulatory framework and economic analysis methods that are common to all six communities.

C. Southeast Intertie

As noted earlier, there are a number of communities that are locally interconnected electrically, but there is no regional interconnection grid. The Southeast Conference, an association of Southeast communities and organizations, has for years been championing such a regional interconnection, known as the Southeast Intertie. In 1998, a report by Acres International Corporation for the Southeast Conference was published that updated a 1987 study and laid out a schedule for connecting the various communities. The cost of the entire Southeast Intertie was estimated at $436 million. A Congressional authorization was subsequently obtained for $384 million in federal subsidy. The first segment of the Southeast Intertie is now under construction, linking the Ketchikan system with the Petersburg-Wrangell system. It will allow excess energy currently available from the Tyee Lake Project to be used to meet load growth on the Ketchikan system. The cost of the Tyee-Swan intertie is now expected to be significantly more than estimated in the Acres report.

In 2003, a study was conducted by the Southeast Conference for two additional sections of the Southeast Intertie, namely a link between Kake and the Petersburg-Wrangell-Ketchikan system, and links connecting Hoonah and Greens Creek to the Juneau system. The Kake-Petersburg link was estimated to cost $23.1 million (vs. $19.7 million in the Acres report), and the Hoonah-Green Creek-Juneau was estimated to cost $37.1 million (no comparable estimate presented in the Acres report). The Hoonah-Greens Creek-Juneau intertie is being championed by Alaska Electric Light & Power, as it will provide load for its proposed Lake Dorothy Hydroelectric Project.

D. Regulatory Framework

As noted above, the scope of work for the current study requires a regulatory assessment to determine and describe the regulatory processes applicable to development of the potential hydroelectric projects. It must be emphasized that the regulatory framework for development of hydroelectric projects in Alaska is in a state of flux, as discussed below.

1. State of Alaska Regulatory Authority

The main area of uncertainty is that the State of Alaska is directed by federal legislation (the Energy Act of 2000) to take over licensing and regulatory authority from the Federal Energy Regulatory Commission (FERC) for new projects 5,000 kW or less in capacity that would otherwise be subject to FERC authority. The State will start exercising its authority once FERC certifies that the State program protects the public interest and the environment to the same extent as FERC jurisdiction.

The State of Alaska has enacted the necessary legislation to begin the regulatory process, but it is just now starting to draft its regulations, and therefore no details are available. State jurisdiction will not make developing a hydroelectric project less expensive or time-consuming unless it can somehow avoid the drawbacks of the current FERC licensing process. The main drawback with the FERC process is that certain federal agencies have the ability to impose mandatory conditions on a license issued by FERC - - the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS) may prescribe measures for fish protection, and if any part of a project is on federal land, then the agency administering that land may also prescribe conditions. FERC cannot change or even challenge these mandatory conditions.

According to the Energy Act of 2000, a developer of a new project will not be able to elect FERC jurisdiction over a qualifying project unless they have already filed and FERC has accepted an application for a preliminary permit, exemption, or license. If a party decides to try to develop one of the projects discussed later in this report, it may be wise to file for a FERC preliminary permit prior to the State finalizing its regulations. That way, the developer may choose which agency its wants to have jurisdiction.

2. FERC Regulations

FERC now has in place three processes that can be used for obtaining a license. The newest process, known as the Integrated Licensing Process (ILP), was made effective on October 23, 2003. Its intent is to speed up licensing, but it does so by requiring more work and cost early in the process, and therefore it may not be desirable for small and/or non-contentious projects. Nevertheless, on July 23, 2005, the ILP will become the default process unless a developer can show good cause why one of the other two processes should be used (Traditional or Alternative). The three licensing processes are described in more detail in Appendix A.

The ILP includes deadlines for most of the tasks in the process, which are supposed to be adhered to by the developer, the agencies, and FERC. FERC has indicated they are committed to make the ILP work; however, it remains to be seen whether real work circumstances will cause the deadlines to slip, as has historically happened with FERC licensing.

3. ADF&G/ADNR Authority

In 2003, Governor Murkowski altered the authorities of some of the state agencies involved in hydroelectric regulation. In particular, the Habitat Division of the Department of Fish and Game was eliminated, and some of its functions were transferred to the Department of Natural Resources. Many of the individuals in the ADFG Habitat Division transferred to ADNR, but a key hydro-related position was eliminated.

It may be too early to tell whether the transfer of authority to ADNR will have a major impact on the State's position on hydro projects. For the Lake Dorothy Project currently being developed by Alaska Electric Light and Power, it seemed to resolve some issues in the developer's favor, as the State agreed to $70,000 in offsite mitigation instead of some much more expensive measures that they had been demanding.

4. Pending National Energy Bill

In 2003, a national energy bill was considered in Congress that would amend the Federal Power Act to let developers offer alternatives to mandatory conditions imposed by federal agencies. The alternatives would be adopted if the agencies determine that the alternative measures offer no less resource protection and would cost less or increase generation. The bill also requires the agencies to provide an appeal procedure regarding mandatory conditions and to develop a record of their decisions showing they gave equal consideration to energy and non-energy values. The bill also allows FERC to implement a non-binding dispute resolution process if it finds a mandatory condition is inconsistent with the Federal Power Act.

The national energy bill did not pass Congress in 2003 due to issues unrelated to the hydro licensing reform. Its backers have indicated that it will be reintroduced in 2004; however, action is uncertain in an election year. If it is eventually passed and signed into law, then the bill provisions could provide some needed balance to the environmental review process. However, a project that would have a significant detrimental impact to a fish resource would still be nearly impossible to develop.

E. Economic Analysis Method

Economic analysis of a potential hydroelectric project involves comparison of the cost of power from the proposed project to that of the most likely alternative source of power. For the purposes of this report, continuation of the current source of power (diesel generation) is considered to be the most likely alternative for all of the communities considered in this report. Other generation methods such as wind, tides, ocean waves, and fuel cells may be applicable in isolated circumstances. However, the technology for all of these methods (except wind) is not sufficiently mature at this time for them to be considered reliable and cost-effective alternatives.

Devising a definitive method of comparing diesel generation to hydro generation is problematic because hydro has a high initial cost, long life, and relatively low operating cost, whereas diesel has a low initial cost, relatively short life, and relatively high operating cost. Thus, for an economic analysis to be fair, it must extend for a long period of time (the life of a hydro project is generally considered to be at least 50 years). The three main factors affecting an economic analysis are load growth, financing terms, and diesel fuel costs, and all of those can be very volatile, even in the short term.

The typical way to deal with this issue is to vary the key parameters of an analysis to show the sensitivity of the economic feasibility. Sensitivity analyses produce more information, but not more clarity, and are not considered appropriate for this study. The economic analysis method used for this study is outlined below:

1. **Load Growth**

   Load growth in a community or interconnected system is important in analyzing a hydro project only if the potential project energy cannot always be used to meet load. Note that both load and potential generation vary seasonally. For the six communities considered by this study, load growth is considered in the analyses only for Angoon, Hydaburg, and Yakutat. In Hoonah and Kake, the potential projects are small compared to the load, and thus all or nearly all of the generation can be used. For Klukwan, the potential hydro project would feed into a larger interconnected system that has sufficient hydro generation for many years; accordingly there is little need for the project and little value in engaging in a speculative long-term load growth forecast.

   For Angoon, Hydaburg, and Yakutat, load growth has been projected from current loads at a relatively modest rate of 1.5% per year for 10 years, at 1.0% for an additional 10 years, and then at 0.5%. This would reflect a modest rise in population in those communities or a modest increase in usage per customer. A large change in load that may accompany the addition or demise of industrial or large commercial loads is not considered.

2. **Generation**

   The potential generation of each project has been based on the results of previous studies for those projects where the author was directly involved in the work (Thayer Creek near Angoon, Gartina Creek and Water Supply Creek near Hoonah, and Reynolds Creek near Hydaburg). For the other projects, generation has been calculated using a computer model of a run-of-river operation, with streamflows based on factoring of USGS gage records of nearby streams.

3. **Hydro Capital Costs**

   The basic construction cost for each project was determined by varying methods. For those projects where the author was directly involved in the previous work (Thayer Creek near Angoon, Gartina Creek and Water Supply Creek near Hoonah, and Reynolds Creek near Hydaburg), the cost estimates were updated based on increases in the Consumer Price Index between the date of the previous cost estimate and 2003. For the Cathedral Falls and Walker Lake sites, where previous studies were at least 20 years old, the cost estimates were based on new unit prices applied to the quantities from the previous study. For some items, new quantities were also calculated to reflect proposed changes in the project arrangement. For the Chicago Harbor site where no previous applicable study existed, the cost estimate is entirely original.

Engineering and contingency allowances were estimated based on judgment regarding the complexities of the various sites and the thoroughness of the underlying studies. Contingencies allowances vary between 13% and 30%, and engineering costs vary between 12% and 27%.

The investment cost (i.e., the construction cost plus engineering and contingencies) was then escalated to the estimated earliest possible bid date for the project, which is a function of the current status of the permitting and design and the estimated complexity of the environmental issues. Escalation was calculated at 2.5% per year, which is comparable to the inflation rate for the past several years.

The escalated investment costs were then converted to capital costs by adding in amounts for interest during construction and financing costs. For simplicity, interest during construction was calculated as 55% of the interest rate of the construction financing times the duration of the construction period in years. Financing costs were estimated to be zero, which assumes the projects are financed with grants and loans secured from government sources rather than commercial lenders.

Many recent hydro projects in Southeast Alaska have been partially funded to various degrees with grants from the federal and/or state government. For illustrative purposes, we have considered for each project grant funding at levels of 0%, 25%, 50%, 75%, and 100%.

4. Hydro Annual Costs

Annual costs for a hydro project consist of debt service and various operating costs. Debt service has been based on the various assumed levels of grant funding, and loan funding of the balance with an interest rate of 5.5% and a term of 30 years. These loan terms are similar to terms of recent loans by the Alaska Industrial Development and Export Authority (AIDEA) and the Rural Utility Service (RUS).

Annual operating costs for a hydro project include labor for operation, maintenance, and administration; parts and supplies; interim replacement of major components; insurance; taxes (if any); land use fees (if any), and environmental mitigation. For most of these small projects, there may be little additional labor cost, as the existing diesel plant personnel will be able to operate the hydro units. There may be some additional transportation costs because the hydro projects are typically located some distance from the communities. For these two items, the costs have been estimated by judgment. The total of the other operating costs have been estimated by the following formula:

Operating cost ($1000, 2003) = $45*MW^{0.55}$, where MW is the generating capacity

The operating costs are assumed to increase at the general rate of inflation (2.5% per year).

5. Diesel Annual Costs

Diesel annual costs include the costs for fuel, consumable parts and supplies, and interim overhauls and replacements. The biggest portion of the cost is the fuel cost, which has been based on values for fuel price and diesel efficiencies listed in AEA's 2003 Statistical Report of the Power Cost Equalization Program, as shown below:

Table 5
Basis for Diesel Costs

Community	Fuel Price, $/gal	Efficiency, kWh/gal
Angoon	1.03	13.06
Hoonah	1.15	14.36
Hydaburg (1)	1.11	13.05
Kake	1.10	13.85
Klukwan/Chilkat Valley	0.98	13.00 (2)
Yakutat	1.15	15.09

(1) Based on Craig/Klawock information

(2) Estimated value

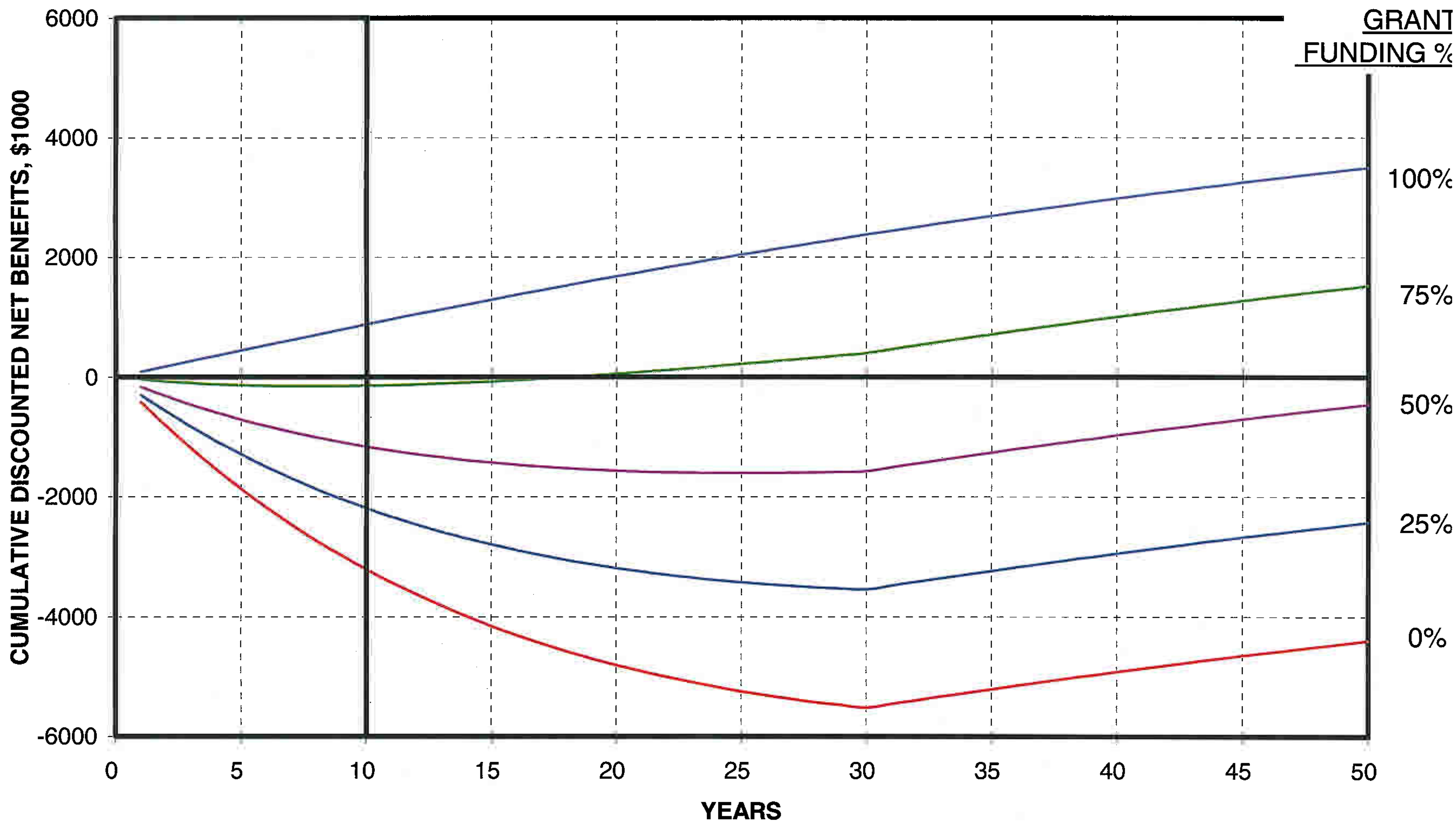
Consumable parts and supplies have been assumed to cost 6.4 mills/kWh, and overhauls and replacement cost on the average 5.3 mills/kWh. Note that all of these costs are at a 2003 cost level, and will vary from year to year. These operating costs are assumed to increase at the assumed general rate of inflation (2.5% per year), except for the price of diesel fuel, which is assumed to increase at a rate of 3.5% per year, reflecting its relative scarcity and recent trends.

6. Cost Comparison

For each of the hydro projects, the economic feasibility has been evaluated by calculating the cumulative discounted net benefits over a typical 50-year life. The net benefit in any one year is the annual cost of the diesel alternative minus the annual cost of the hydro alternative; the benefits may be negative if the hydro project is more costly than continuing with diesel generation. The annual net benefits in each year is calculated, and then discounted back to 2003 using a discount rate of 5.5% (discounting accounts for the lesser real value of future amounts). The cumulative discounted net benefits for each year are then calculated as the sum of the discounted net benefit from the first year of operation to the year in question. As noted above, five levels of grant funding have been assumed, resulting in five discounted net benefit streams for each project, which were then plotted over time (see Figure 1 as an example).

Theoretically, a project that shows a positive cumulative discounted net benefit within its expected 50-year life would be considered economically feasible. As a practical matter, it would be extremely difficult to obtain financing if the crossover to positive net benefits occurs relatively late. For the purposes of this evaluation, we have used a 10-year time frame for crossover to positive cumulative discounted net benefits as an indication of project economic and financial feasibility. In the example shown in Figure 1, the project would be feasible if it is able to obtain grants totaling about 80% of the capital cost of the project.

FIGURE 1
EXAMPLE PROJECT



III. ANGOON

A. Community Overview

Angoon is located on the west side of Admiralty Island, 55 miles southwest of Juneau and 41 miles northeast of Sitka. It is located on a peninsula of land between Chatham Strait and Kootznahoo Inlet, a scenic complex of bays and islands. It is accessible only by floatplane or boat. Freight arrives by barge and ferry.

Angoon has a population of about 540. Commercial fishing is a major source of income, primarily hand-trolling for king and coho salmon. Subsistence remains an important part of the citizen's lifestyle; local resources include deer, salmon, bear, halibut, shellfish, geese, seaweed, and berries. Timberland owned by the Village Corporation (Kootznoowoo, Inc.) has been nearly all logged, and timber-related income has sharply declined. Low salmon prices have also depressed the local economy.

Nearly all of Admiralty Island is included in the Admiralty Island National Monument and Wilderness, administered by the United States Forest Service and established in 1980 by the Alaska National Interest Lands Conservation Act (ANILCA). According to ANILCA, Kootznoowoo Inc. has the right to develop hydroelectric resources on approximately 24 square miles of land north of the community.

B. Existing Power Supply

IPEC currently supplies electric power to Angoon, which is generated at a plant in town with three diesel generators. The power plant capacity is 1,260 kW, and the cost of power to Angoon citizens in 2003 was 14.54 ¢/kWh for up to 500 kWh per month (after PCE subsidy of 18.21 ¢/kWh). Power is distributed by an overhead system. Peak loads have been about 425 kW, and the annual energy requirement has been about 2,000 MWh. There has been little to no load growth recently because of the stagnant economy in Angoon.

C. Hydroelectric Potential

Hydroelectric power for Angoon has been the subject of numerous studies, including:

- Preliminary Appraisal Report on the Hydroelectric Potential for the Villages of Angoon, Craig, Hoonah, Hydaburg, Kake, Kasaan, Klawock, Klukwan, Pelican, and Yakutat; September 1977 by R. W. Retherford Associates.
- Thayer Creek Project, A Reconnaissance Report; October 1979 by Harza Engineering
- Angoon Tidal Power & Comparative Analysis; February 1981 by Harza Engineering
- Angoon Water Supply Alternatives; July 1981 by Trick, Nyman, & Hayes
- A Comparative Economic Analysis of Electric Energy Alternatives for Angoon, Alaska; February 1984 by Acres International
- Angoon Hydro Study; August 1989 by Polarconsult Alaska, Inc.
- Angoon Hydroelectric Project, Feasibility Evaluation Report; March 2000 by HDR Alaska.

1. Thayer Creek

Most of the previous analyses have focused on developing the hydroelectric potential of Thayer Creek, which drains a large lake (Thayer Lake) at about El 365, and flows in a westerly direction to Chatham Strait. The stream gradient is rather gentle for about 6 miles, but 1.7 miles from the mouth at about El 260, the stream begins a series of rapids and falls, including one falls about 0.4 miles from the mouth that is a barrier to upstream movement of anadromous fish. This combination of naturally regulated flows, high stream gradient, and paucity of anadromous fish habitat makes Thayer Creek a good site for hydroelectric development. The main impediments are the length of transmission line (about 7 miles) and wilderness designation of the area. Thayer Creek is in the area reserved to Kootznoowoo, Inc. for hydroelectric development, but that development is still subject to environmental protection stipulations by the Forest Service and possibly litigation by environmental organizations.

Each study of the Thayer Creek site has produced a different recommended configuration for the project:

- Retherford suggested a staged development, with the first stage comprising a 50 feet high concrete arch dam at the head of the anadromous barrier, a 350 feet long tunnel, a 1,000 kW power plant at the base of the anadromous barrier, and six miles of 12.5 kV transmission line. If more power was needed, then the second stage could be developed, comprising a dam at the head of the steep stream gradient, an 800 foot long tunnel, and a second power plant near the head of the Stage I reservoir.
- Harza suggested a similar development to Retherford's first stage, except the dam would be a concrete gravity structure of somewhat lesser height, and the capacity would be only 400 kW.
- Polarconsult considered two options. One would pump water directly from Thayer Lake through a pipeline running generally south, and then generate at a power plant near Kootznahoo Inlet. The net capacity gain would be about 600 kW. The second option was to divert water from Thayer Creek at about El 200 through a tunnel and penstock to a 600 kW power plant that would discharge into Chatham Strait.
- HDR also considered several options. The preferred option included a diversion on Thayer Creek at about El 260, a 6,100 feet long HDPE pipeline, a surge tank, a 510 feet long steel penstock, and a 1,000 kW power plant located on the south side of the stream near the base of the anadromous barrier. Transmission would be a 6.1-mile-long overhead line and 0.9-mile-long submarine cable through Kootznahoo Inlet. A port facility would be located about 2 miles south of Thayer Creek. Note that the author of this current study was also the principal author of the HDR study.

Although all of these various project arrangements have some merit, only the Retherford Stage I and HDR arrangements have been reevaluated herein. Reservations about the other arrangements include the following:

- The Harza arrangement would not provide sufficient generation to meet current loads.

- The Retherford Stage II power plant would be in a very narrow gorge, and access would be extremely difficult.
- The diversion out of Thayer Lake (Polarconsult's first option) is not in the area reserved for hydroelectric development.
- The tunnel and power plant discharging into Chatham Strait (Polarconsult's second option) would cause substantial impact to the salmon runs in the section of stream between tidewater and the anadromous barrier falls.

a. Potential Modifications to the HDR Project Arrangement

The HDR study was completed in 2000, and the technology proposed is quite current. The HDR arrangement features a diversion dam and long pipeline rather than a high dam, since the cost of concrete is usually very high in Southeast Alaska.

One potential modification of the project arrangement that could reduce the estimated cost by about $200,000 is elimination of the surge tank. The surge tank was included as a passive means of reducing pressure surges in the long pipeline that could result from rapid flow changes. However, the arrangement also includes flywheels on the generating units and a load bank, both of which allow for slow variation of the flow rate in the pipeline. Elimination would also decrease the visual impact of the development, but would be possible only if impulse-type turbines were used instead of reaction-type turbines as proposed by HDR.

One other potential modification of the HDR arrangement would be moving the load bank from the powerhouse to somewhere in Angoon. The load bank is basically a large, variable-rate water heater. There would be no savings in construction cost, but locating it in town would allow for utilization of the waste heat produced by the load bank, such as for radiant heating of municipal buildings.

b. Potential Modifications to the Retherford Stage I Arrangement

The Retherford Stage I arrangement includes a 50 feet high arch dam, which was estimated to have a concrete volume of 1700 cy. Since the date of the Retherford study (1979), one technology that has developed is roller compacted concrete (RCC). RCC is a type of concrete that is mixed with a minimum amount of water, then compacted using vibratory roller compactors. In recent years it has become the predominant method of constructing concrete dams because the cost savings can be substantial - - in large structures the unit cost may be as little as $75/cy. It may make sense for the Thayer Creek site because there are substantial deposits of sand and gravel near the mouth of Thayer Creek that could be used in the RCC.

A dam upstream of the anadromous barrier falls would replace the diversion dam, pipeline and penstock, surge tank, and diversion access road of the HDR arrangement. Those items have a combined cost of $1.9 million in direct construction cost, which represents 31% of the total project cost. An analysis was conducted to find the height of dam that would have a cost equal to $1.9 million in construction cost, based on the following assumptions:

- An access road would be required from the power plant to the top of the dam at a slope of 20% and a unit cost of $50/ft.

- A tunnel would be constructed from the power plant area to the dam site, a distance of about 350 feet. The tunnel would be used initially for diverting the creek during construction of the dam, and later for the water conduit from the dam to the power plant. The tunnel would have a unit cost of $600/ft plus $30,000 for mobilization and $20,000 for each of the portals.
- Diversion of the stream during construction of the dam would have a fixed cost of $110,000, including $100,000 for 400 feet of steel pipe that would be the water conduit from the dam, through the tunnel, and to the powerhouse.
- The intake at the dam would have a fixed cost of $25,000 plus incremental costs of $250/ft of dam height
- No foundation excavation would be required at the dam site (rock is exposed, but may be somewhat weathered).
- The unit cost for RCC would vary with the volume as follows: 5,000 cy - - $200/cy; 20,000 cy - - $150/cy, 50,000 cy - - $125/cy. Note that these costs are relatively high for RCC because of the small volume of the dam and the inclement weather at the site.
- The upstream face of the dam would be a vertical formed surface, and would be made watertight by vibrating grout into the placed RCC. The downstream face would be unformed, with a slope of 0.75H:1V.
- The entire crest length would be used for the spillway.
- The crest width of the dam would be 12 feet.

This analysis determined that $1.9 million would provide for a 65-foot-high dam, with the normal water surface at El 105. The gross head would be about 85 feet vs. 200 feet for the HDR arrangement. To provide the same 1,000 kW capacity, the flow rate would need to be greater (approximately 200 cfs at maximum capacity). To avoid the cost increase for the generating equipment associated with this higher flow, it might be more appropriate to use four 250 kW unregulated machines and rely on the load bank to match generation with the load.

It would also be necessary to modify the method of discharging from the power plant to minimize fish attraction to the discharge. HDR assumed a method known as a "perched" tailrace, wherein the water falls at least 10 feet from the power plant to the natural stream. A perched tailrace makes sense with the higher generating head afforded by the HDR arrangement, but with the Modified Retherford arrangement, the 10 foot minimum loss of head would decrease the generation significantly. An alternate method would be to screen the tailrace, which should be possible for about the same cost as the perched tailrace.

Generation by this modification of the Retherford Stage I arrangement would be somewhat less than with the HDR arrangement because of the lesser head. However, because there is usually an excess of flow available, and because the Angoon loads are currently much less than the 1,000 kW capacity, the difference in generation would not be significant unless loads grow substantially.

If Angoon loads were to increase significantly or if Angoon were to become interconnected and able to sell surplus power, then the HDR arrangement would provide for significantly greater generation and revenue than the Retherford Stage I arrangement.

However, the Retherford Stage I arrangement could be expanded more easily than the HDR arrangement to provide even greater generation.

c. Potential Generation

HDR estimated the potential generation of the Thayer Creek Project to be about 8,400 MWh if not limited by load and about 2,000 MWh with current loads (about 99% of the Angoon requirements). With the Modified Retherford Stage I arrangement, the potential generation would be about 7,700 MWh if not limited by load and about 2,000 MWh with current loads.

d. Environmental Assessment

The major environmental issues associated with the HDR arrangement are likely to be:

- Development of a hydroelectric project in a National Monument and wilderness area. Even though the right to develop the project is unquestionable, the issue will undoubtedly be raised, as hydro development in wilderness areas is anathema to many environmental organizations.
- Visibility of the corridor for the transmission line, and possibly of the surge tank and penstock.
- Instream flows in the bypassed reach of stream between the diversion dam and the powerhouse. HDR assumed a constant instream flow of 20 cfs, based on the assumption that there is a population of resident fish in the bypassed reach that ADF&G and the Forest Service would want to protect. Since the HDR study was concluded, ADF&G's role in instream flow matters has been transferred to ADNR; however, it is unclear whether this change will result in the state placing less emphasis on protecting resident fish populations.

The major environmental issues associated with the Retherford Stage I arrangement of the Thayer Creek Project are likely to be:

- Development of a hydroelectric project in a National Monument and wilderness area.
- Visibility of the corridor for the transmission line, and possibly the dam.

The environmental feasibility of either arrangement is judged to be moderate because of the likely opposition to construction in a National Monument and Wilderness, even though the right to develop the project is undeniable.

e. Economic Assessment

The estimated construction costs of the original and modified HDR arrangements as described above are shown in Table 7, adjusted to a 2003 cost level. Also shown are the estimated annual operating costs. Costs for the modified Retherford Stage I arrangement are not shown, as they would be nearly identical to the modified HDR arrangement. The earliest possible on-line date is estimated to be 2010, considering the current status of the development effort and the likely environmental opposition to the project.

The results of the economic analysis for the modified HDR arrangement of the Thayer Creek Project are shown in Figure 2 (see Section 1.D for a discussion of the methods and assumptions of the economic analysis). As can be seen from Figure 2, the Thayer Creek

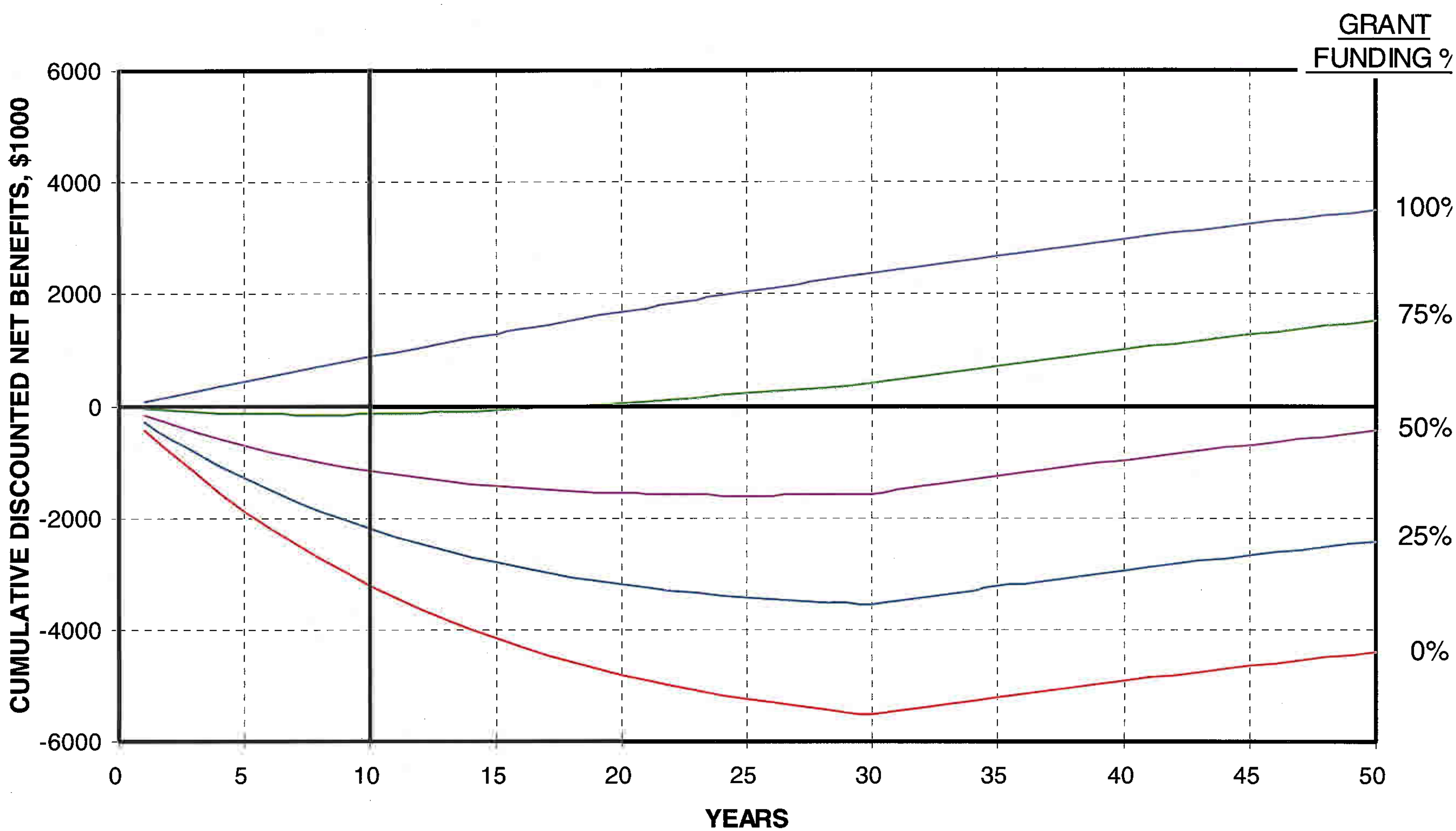
Table 6
Thayer Creek Hydroelectric Project (Angoon)
Summary of Project Costs

CONSTRUCTION COST (1999 Cost Level)		Project Arrangement	
		HDR	Modified HDR
FERC Account	Description	Amount	Amount
330	Land and Land Rights	$ -	$ -
330.5	Mobilization and Logistics	$ 741,000	$ 741,000
331	Structures and Improvements	$ 543,000	$ 543,000
332	Reservoirs, Dams, and Waterways	$ 1,587,000	$ 1,453,000
333	Turbines and Generators	$ 715,000	$ 715,000
334	Accessory Electrical Equipment	$ 366,000	$ 366,000
335	Miscellaneous Mechanical Equipment	$ 110,000	$ 110,000
336	Roads and Bridges	$ 789,000	$ 773,000
353	Substation Equipment and Structures	$ 48,000	$ 48,000
355	Transmission Line	$ 1,173,000	$ 1,173,000
SUBTOTAL		$ 6,072,000	$ 5,922,000
	Contingencies	$ 800,000	$ 780,000
TOTAL DIRECT CONSTRUCTION COST		$ 6,872,000	$ 6,702,000
	Permitting and Engineering	$ 1,228,000	$ 1,198,000
TOTAL INVESTMENT COST (1999 Cost Level)		$ 8,100,000	$ 7,900,000
	Escalation		$ 800,000
TOTAL INVESTMENT COST (2003 Cost Level)			$ 8,700,000

		Project Arrangement	
		HDR	Modified HDR
	Cost level	1999	2003
OPERATING COSTS		Amount	Amount
	Incremental Labor	$ 25,000	$ 35,000
	Transportation	$ 5,000	$ 10,000
	Other Operating Costs (1)	$ 55,000	$ 45,000
TOTAL OPERATING COSTS		$ 85,000	$ 90,000
	Escalation	$ 9,000	$ -
TOTAL OPERATING COSTS (2003 Cost Level)		$ 94,000	$ 90,000

(1) Includes administration, insurance, taxes, land use feed, interima replacements, and environmental mitigation.

FIGURE 2
THAYER CREEK PROJECT (Angoon)
ECONOMICS SUMMARY



Project appears to be economical only if approximately 80% of its cost can be funded with grants (i.e. $7,000,000 in grants). The same conclusion would apply to the modified Retherford Stage I arrangement. The Thayer Creek Project is judged to have a low potential for economic and financial feasibility.

Development of the Thayer Creek Project could be viewed as an alternative to construction of the Angoon branch of the Southeast Intertie. If viewed in that context, the economics are much more favorable, since the Angoon branch of the Southeast Intertie is likely to be much more expensive than the Thayer Creek Project. Note that 80% federal funding has been authorized for construction of the Southeast Intertie, the same rate as required for economic feasibility for the Thayer Creek Project.

f. Regulatory Assessment

On January 23, 2001, the Federal Energy Regulatory Commission (FERC) ruled that it did not have jurisdiction over the Thayer Creek Project because it cannot license projects located in National Monuments within the national Forest System. The effect of this ruling is that the primary federal permitting authority will be the Forest Service, presumably by a Special Use Permit. The Forest Service acknowledges Kootznoowoo's rights to develop the project, but they may be strict in their prescriptions to protect the "water, fishery, wildlife, recreational, and scenic values of Admiralty Island." They may also require an Environmental Impact Statement (EIS) rather than the less comprehensive Environmental Assessment (EA) that FERC would normally require for this size project. Note that the Thayer Creek Project may not be regulated under the new state program (see Section 1.C.1), as the legislation authorizing the state program specifically excludes project in ANILCA-created reservations.

Other permits that would likely be required include

- Wetlands Permit from the Corps of Engineers
- Water rights from the Alaska Department of Natural Resources (ADNR)
- Section 401 Water Quality Certification from the Alaska Department of Environmental Quality (ADEQ)
- Coastal Zone Management Consistency Determination by the Alaska Division of Governmental Coordination (ADGC). As noted earlier, the State of Alaska has recently transferred much of the responsibility for hydroelectric project review from ADF&G to ADNR.

2. Other Potential Hydroelectric Developments

Other potential hydroelectric developments in the Angoon area that have been considered in the past include:

- Development of a small hydroelectric facility in conjunction with a water supply and hatchery development on Favorite Bay Creek south of Angoon.
- Development of a tidal power station on Kootznahoo Inlet at Turn Point, where tidal currents are very strong.
- Development of a small hydroelectric facility in conjunction with a water supply development of two lakes and an unnamed creek approximately 2 miles north of Angoon in the area reserved for hydroelectric development.

With regard to the tidal development, a conventional large-scale development involving closure of the inlet at Turn Point is technically possible, but would only be economically feasible if were connected to much larger loads than Angoon. It would more than likely be unacceptable from an environmental standpoint however. A small tidal current generator installation may be possible, but that technology is untested at this time. UEK Corporation, a manufacturer of tidal current generators, has indicated they have done some preliminary work on a tidal development at Turn Point.

With regard to the water supply developments, concurrent hydroelectric generation is frequently feasible and should be considered if a new water supply system is developed. The development of the two lakes and unnamed stream north of Angoon is intriguing because it could be developed as a first phase of the Thayer Creek development if funds cannot be secured for the entire project.

D. Interconnection Potential by the Southeast Intertie

The 1998 Acres report on the Southeast Intertie included an interconnection to Angoon in the third phase, which is the 2015-2020 timeframe. Phase III was to include interconnection of Sitka, Tenakee Springs, Angoon, Hoonah, Greens Creek, and Juneau, and was estimated to cost $173.8 million. It is important to note that the interconnection of Angoon is shown as a side branch rather than on the main intertie. Furthermore, if AEL&P is successful in interconnecting Hoonah, Greens Creek, and Juneau, there may be less incentive for completion of the link between Hoonah and Tenakee Springs/Angoon/Sitka as envisaged by the Acres report. Thus, it is very possible that interconnection of Angoon may be delayed well beyond the 2015-2020 timeframe.

Development of a hydroelectric project to serve Angoon could also delay interconnection. If the interconnection were to occur, it would allow marketing of any excess energy to the interconnected utilities.

IV. HOONAH

A. Community Overview

Hoonah is a Tlingit community located on the northeast shore of Chichagof Island, 40 miles west of Juneau. It is accessible only by aircraft or boat; however, there is an extensive logging road system. Freight arrives by barge year-round and by ferry, and there is scheduled air service between Hoonah and Juneau.

Hoonah is incorporated as a 1st Class City, with a population of about 870. Fishing, timber harvesting, and local government are mainstays of the economy. An old cannery site north of town (Point Sophia) is being converted into a tourist destination, and cruise ships will begin to stop at Hoonah in 2004, which should provide a boost to the economy. Subsistence remains an important part of the citizen's lifestyle.

Hoonah has a maritime climate characterized by cool summers and mild winters. Precipitation averages about 100 inches annually, with 71 inches of snowfall.

B. Existing Power Supply

IPEC currently supplies electric power to Hoonah, which is generated at a plant in town with diesel generators. The power plant capacity is 2,455 kW, and the cost of power to Hoonah citizens in 2003 was 14.54 ¢/kWh for up to 500 kWh per month (after PCE subsidy of 18.21 ¢/kWh). Power is distributed by an overhead system. The annual energy requirement has been about 4,500 MWh. There has been little to no load growth recently, but the Point Sophia development may add significantly to the loads as it enters operation.

C. Hydroelectric Potential

Hydroelectric potential in the Hoonah area has been the subject of at least three studies, as follows:

- Preliminary Appraisal Report on the Hydroelectric Potential for the Villages of Angoon, Craig, Hoonah, Hydaburg, Kake, Kasaan, Klawock, Klukwan, Pelican, and Yakutat; September 1977 by R. W. Retherford Associates.
- Gartina Creek Project, A Reconnaissance Report; October 1979 by Harza Engineering Company
- Reconnaissance of Three Potential Hydroelectric Sites Near Hoonah, Alaska; June 2002 by HydroWest Group, LLC. (HydroWest Group was a wholly-owned subsidiary of Alaska Power & Telephone, and the author of the current study was the principal author of the Hoonah study)

1. Game Creek

Game Creek flows into Port Frederick near Hoonah, and was initially considered by Retherford as a potential hydroelectric site because of its relatively large size and the good topography for developing a storage project. However, Retherford dropped consideration of Game Creek when it was determined to be a major anadromous fish stream. Because of the probable environmental impacts, Game Creek has not been reviewed for the current study.

2. Gartina Creek

a. Project Arrangements of Previous Studies

Retherford also considered Gartina Creek as a hydroelectric site because of the existence of a moderate height waterfall. Interestingly, Retherford indicates that the City of Hoonah made an early attempt to develop hydroelectric generation at Gartina Falls, going so far as building a log crib dam at the head of the falls and ordering a turbine and generator. Retherford reported that the generator was destroyed in the fire that burned much of Hoonah in 1944, but that they found the turbine in the remains of a timber building near the falls.

Retherford suggested a run-of-river project at Gartina Falls, with a 20-foot-high concrete dam at the head of the falls, a short penstock, and a powerhouse at the base of the falls with a capacity of 750 kW and an annual generation of 2.1 GWh. The cost for a 1979 bid date was estimated to be about $1.25 million.

Harza conducted a more detailed study in 1979 for the Gartina Falls site, and selected an arrangement quite similar to Retherford. It included a 27-foot-high concrete dam about 150 feet upstream of the head of the falls, a 210-foot-long, 57-inch diameter penstock, and a 2-unit 450-kW power plant at the base of the falls, with provisions for adding two additional units in the future. Harza estimated the construction cost to be $4.9 million, and the annual generation to be about 2.2 GWh. The large difference in cost between the Retherford and Harza studies can be attributed mostly to the greater detail of the Harza study.

HydroWest proposed a similar arrangement for the Gartina Falls site, but with a few significant differences:

- The diversion dam was proposed to have a concrete core wall and grouted rockfill slopes, and would be about 15 feet high and located at the head of the falls.
- The intake structure includes a means for sluicing sediment past the diversion dam.
- The powerhouse would be located about 150' below the falls to allow more economical access and to provide greater protection from rockfalls.
- The powerhouse would contain a single impulse-type turbine rated at 600 kW.
- The tailrace would include a diffuser structure to prevent fish from entering the tailrace.

HydroWest estimated the construction cost would be $3.75 million and the annual generation would be 1.88 GWh. Note that the City of Hoonah began collecting streamflow data just upstream of Gartina Falls in spring 2003 as the first step in a more serious consideration of developing the site.

b. Potential Modifications of Previous Project Arrangements

The HydroWest study was conducted by the author of this study, and is considered to be a reasonable evaluation of the site potential. The arrangement is believed to be suitable for the site, with one reservation - - the location of the powerhouse downstream of the falls may not be acceptable from a fisheries standpoint because the pools at the base of the falls would be deprived of any inflow during certain times of the year. The pools at the base of the falls may be considered by fisheries agency personnel to be critical habitat, and therefore the powerhouse may need to be located at the base of the falls. If that is the case, the cost of access to the powerhouse would probably increase because a rock outcrop below the falls would need to be removed. Alternately, the powerhouse at the base of the falls could be accessed for construction and operation by a tramway. For the purposes of this study, no modification of the powerhouse location is suggested.

c. Potential Generation

The potential generation of the Gartina Falls Project was estimated by HydroWest to be about 1,900 MWh per year, which is approximately 40% of the current Hoonah load. HydroWest did not estimate the amount of that potential generation that would actually be usable. There should be little problem absorbing all or nearly all of the potential generation into the Hoonah system, particularly if the Point Sophia development increases loads substantially.

d. Environmental Assessment

Potential environmental issues with the Gartina Falls Project are considered to be:

- Loss of anadromous fish habitat between the base of the falls and the powerhouse, including deep pools at the base of the falls.
- Diminished aesthetic value of Gartina Falls.
- Disruption of brown bear feeding patterns due to the powerhouse location.

Only the first of these potential issues is considered to be significant. The project is judged to have a moderate potential for environmental feasibility.

e. Economic Assessment

The estimated construction annual operating costs of the Gartina Falls Project as described above are shown in Table 8. The construction costs are based on a review and adjustment of the HydroWest cost estimate to a 2003 cost level. The earliest possible on-line date is estimated to be 2008, considering the current status of the development effort.

The results of the economic analysis for the Gartina Falls Project are shown in Figure 3 (see Section 1.D for a discussion of the methods and assumptions of the economic analysis). As can be seen from Figure 3, the Gartina Falls Project appears to be economical if approximately 45% of its cost can be funded with grants (i.e. $1,700,000 in grants). This indicates a moderate potential for economic and financial feasibility.

f. Regulatory Assessment

In December 1998, Alaska Power & Telephone filed a Declaration of Intention with FERC on behalf of Sealaska Corporation to determine whether FERC had jurisdiction over a proposed development at the Gartina Falls site. On August 16, 2001, FERC issued a notice that it did not have jurisdiction. ADF&G and NMFS requested rehearing on the basis of a possible impact to anadromous fish, but on November 21, 2001, FERC affirmed that FERC licensing is not required.

As noted earlier, the State of Alaska will assume regulatory authority over hydroelectric projects of 5 MW capacity or less once they develop an adequate program. It is reasonable to assume that the State will apply its regulatory process to all small projects, even those like Gartina Falls where FERC does not have jurisdiction. It is not clear how complicated the state process will be, and therefore there could by some advantage to proceeding with the project permitting under the current process for non-jurisdictional projects. The South Fork Project currently being developed on Prince of Wales Island by Alaska Power & Telephone can be considered a model for the regulatory process for a project that is non-jurisdictional. For South Fork, the following permits have been required:

- Wetlands Permit from the Corps of Engineers
- Water rights from the Alaska Department of Natural Resources (ADNR)
- Section 401 Water Quality Certification from the Alaska Department of Environmental Conservation (ADEC)
- Coastal Zone Management Consistency Determination (ADNR). Only part of the transmission line would be in the Hoonah coastal zone, which may limit the complexity of that consistency determination.

Based on AP&T's experience with the South Fork Project, obtaining the necessary permits for construction would probably require 18 to 24 months once a definite project arrangement is developed, assuming one summer season of field studies is necessary.

3. Water Supply Creek

a. Project Arrangements of Previous Studies

HydroWest also considered a hydroelectric development on a tributary of Gartina Creek, referred to in their study as Water Supply Creek. Water Supply Creek flows north and northeast into Gartina Creek a few hundred feet above Gartina Falls. About 2,500 feet above that confluence, the City of Hoonah diverts water for a municipal water supply. The land is entirely Sealaska Corporation land.

The arrangement proposed by HydroWest includes the following:

- A concrete and rockfill diversion dam at about El 800 that raises the water surface about 8 feet. An intake structure would be located on the east abutment.
- A power conduit consisting of 4,000 feet of 24-inch diameter HDPE pipe and 1,500 feet of 20-inch diameter steel pipe. The power conduit would be located adjacent to an existing logging road for much of its length.
- A powerhouse located just below the existing water supply diversion. The powerhouse would have a single 600-kW generating unit. The power plant would discharge back to the pond behind the water supply diversion dam.
- A transmission line about 4.1 miles long to connect to the existing IPEC system near the airport. Note that if both the Gartina Falls and Water Supply Creek projects are developed, the cost of most of the transmission line would be shared.
- An access road about 1300 feet long from the end of existing logging road to the diversion structure.

The construction cost for the HydroWest arrangement was estimated to be $3.1 million. Note that the City of Hoonah began collecting streamflow data just upstream of the water supply diversion in spring 2003 as the first step in a more serious consideration of developing the site.

Table 7

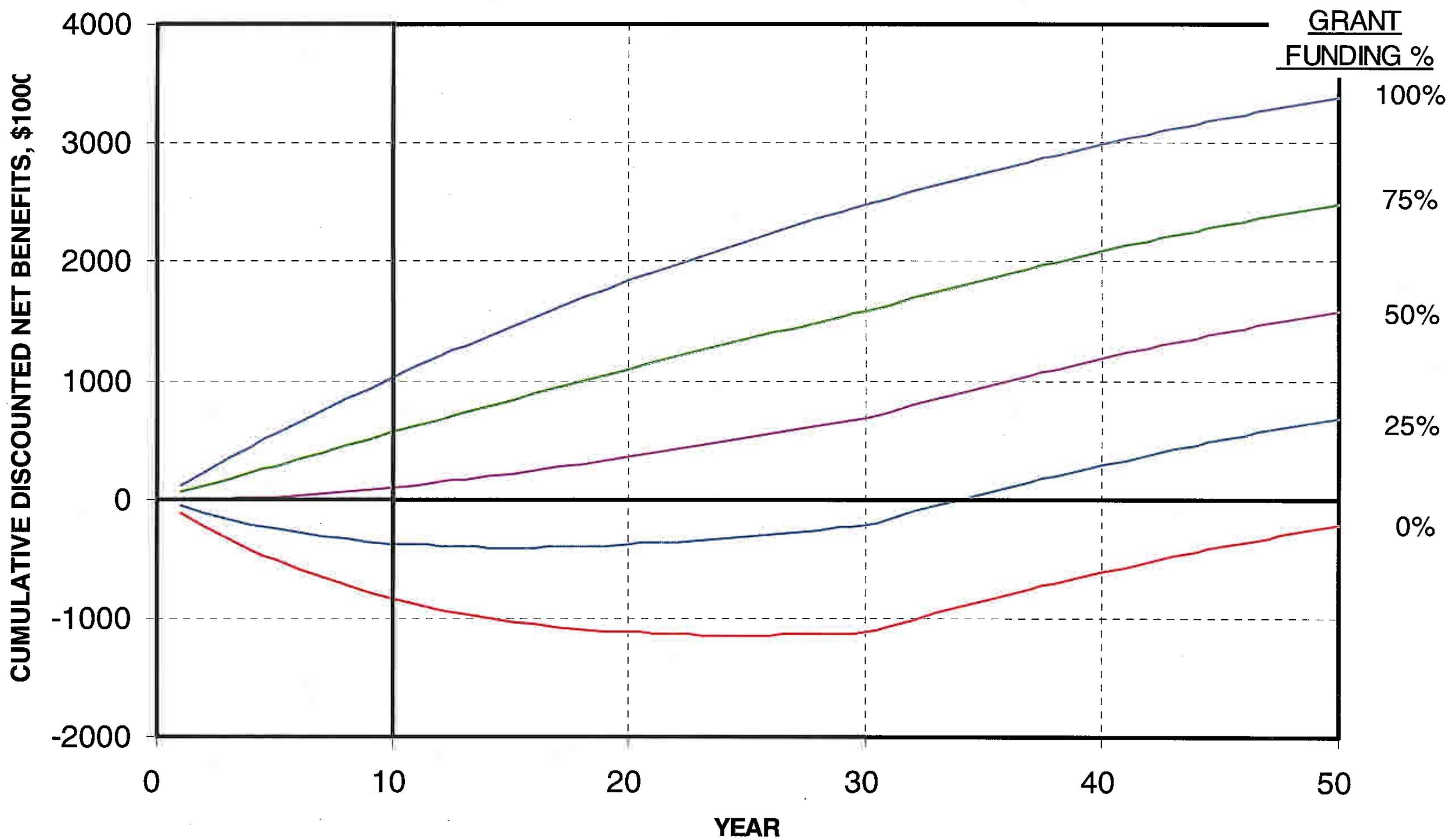
Gartina Falls and Water Supply Creek Hydro Projects (Hoonah)
Summary of Project Costs

CONSTRUCTION COST (2002 Cost Level)		Project Arrangement	
		Gartina Falls	Water Supply Creek
FERC Account	Description	Amount	Amount
330	Land and Land Rights	$ -	$ -
330.5	Mobilization and Logistics	$ 76,000	$ 67,000
331	Structures and Improvements	$ 330,000	$ 178,000
332	Reservoirs, Dams, and Waterways	$ 836,000	$ 814,000
333	Turbines and Generators	$ 325,000	$ 299,000
334	Accessory Electrical Equipment	$ 215,000	$ 215,000
335	Miscellaneous Mechanical Equipment	$ 75,000	$ 75,000
336	Roads and Bridges	$ 73,000	$ 61,000
353	Substation Equipment and Structures	$ 100,000	$ 100,000
355	Transmission Line	$ 280,000	$ 287,000
SUBTOTAL		$ 2,310,000	$ 2,096,000
	Contingencies	$ 578,000	$ 524,000
TOTAL DIRECT CONSTRUCTION COST		$ 2,888,000	$ 2,620,000
	Permitting and Engineering	$ 775,000	$ 625,000
TOTAL INVESTMENT COST (2002 Cost Level)		$ 3,663,000	$ 3,245,000
	Escalation (Approx. 2.3%)	$ 87,000	$ 75,000
TOTAL INVESTMENT COST (2003 Cost Level)		$ 3,750,000	$ 3,320,000

OPERATING COSTS (2002 Cost Level)	Project Arrangement	
	Gartina Falls Amount	Water Supply Creek Amount
Incremental Labor	$ -	$ -
Transportation	$ -	$ -
Other Operating Costs (1)	$34,000	$34,000
TOTAL OPERATING COSTS (2002 Cost Level)	$ 34,000	$ 34,000
Escalation (Approx. 2.3%)	$ 1,000	$ 1,000
TOTAL OPERATING COSTS (2003 Cost Level)	$ 35,000	$ 35,000

(1) Includes administration, insurance, taxes, land use feed, interima replacements, and environmental mitigation.

FIGURE 3
GARTINA FALLS PROJECT (Hoonah)
ECONOMICS SUMMARY



b. Potential Modification to the Previous Arrangement

If the project proceeds to design, some modifications of the project arrangement can be expected based on the availability of more detailed information and a more thorough evaluation. However for the purposes of this study, the arrangement proposed in the HydroWest study is considered to be reasonable and appropriate for the site.

c. Potential Generation

The potential generation of the Water Supply Creek Project was estimated by HydroWest to be about 1,800 MWh per year, which is approximately 40% of the current Hoonah load. HydroWest did not estimate the amount of that potential generation that would actually be usable. There should be little problem absorbing all or nearly all of the potential generation into the Hoonah system.

d. Environmental Assessment

There are no issues known at this time that would prevent the development of the Water Supply Creek project. If subsequent surveys determine that there is a significant population of resident fish in the creek between the diversion and the powerhouse, then some regulatory agencies want to impose an instream flow requirement, which would seriously jeopardize the project's feasibility. The project is judged to have a high potential for environmental feasibility.

e. Economic Assessment

The estimated construction and annual operating costs of the Water Supply Creek Project as described above are shown in Table 8. The construction costs are based on a review and adjustment of the HydroWest cost estimate to a 2003 cost level. The earliest possible on-line date is estimated to be 2008, considering the current status of the development effort.

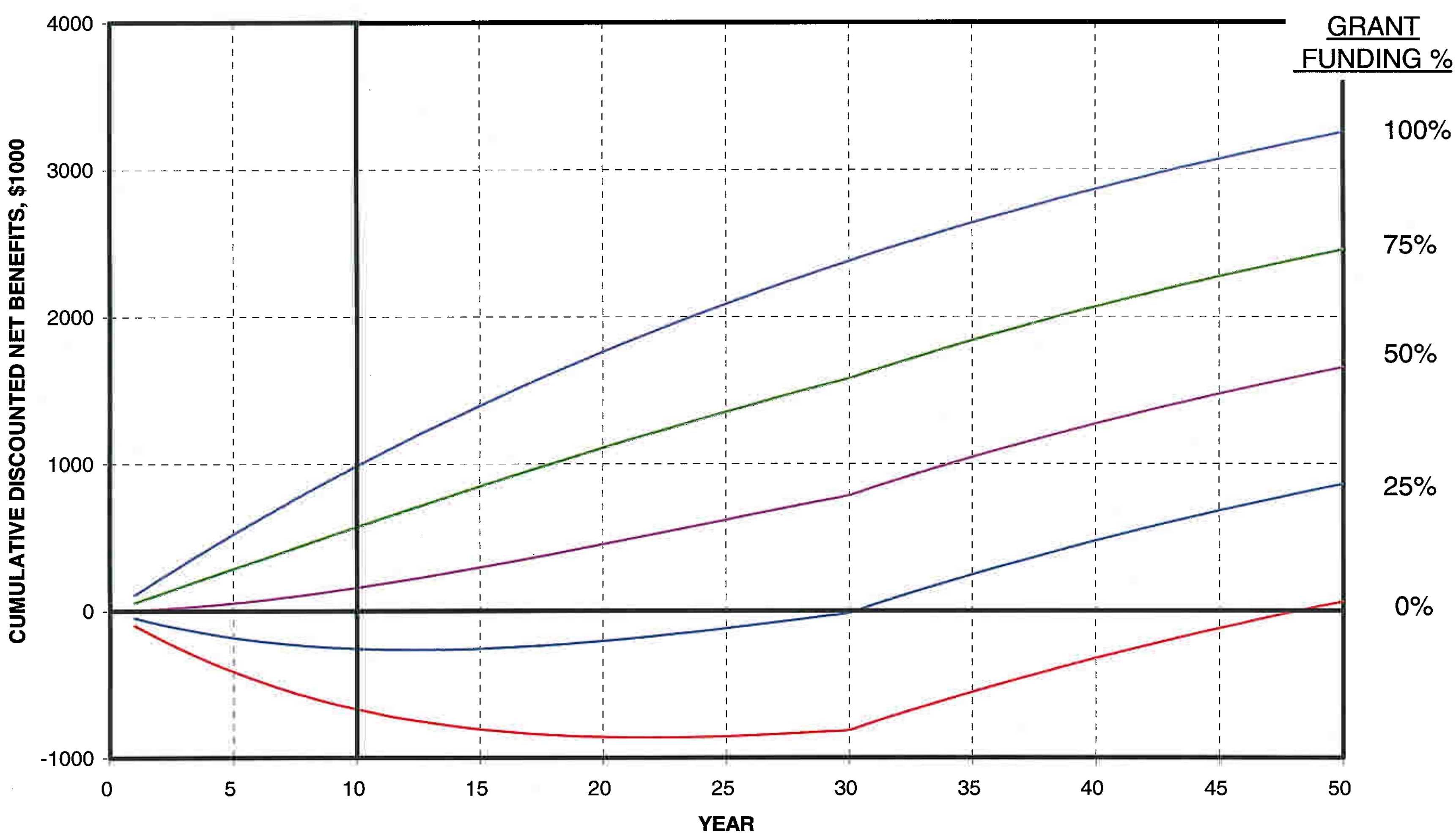
The results of the economic analysis for the Water Supply Creek Project are shown in Figure 4 (see Section 1.D for a discussion of the methods and assumptions of the economic analysis). As can be seen from Figure 4, the Water Supply Creek Project appears to be economical if approximately 40% of its cost can be funded with grants (i.e. $1,300,000 in grants). This indicates a moderate potential for economic feasibility.

f. Regulatory Assessment

Since Water Supply Creek is entirely on Sealaska land and flows into Gartina Creek above Gartina Falls, it is unquestionable that FERC lacks jurisdiction, since FERC determined it did not have jurisdiction over the Gartina Falls site. It may nevertheless take a formal proceeding by FERC to confirm the issue.

As noted earlier, the State of Alaska will assume regulatory authority over hydroelectric projects of 5 MW capacity or less once they develop an adequate program. It is reasonable to assume that the State will apply its regulatory process to all small projects, even those like Water Supply Creek where FERC does not have jurisdiction. It is not clear how complicated the state process will be, and therefore there could by some advantage to proceeding with the project permitting under the current process for non-jurisdictional projects.

FIGURE 4
WATER SUPPLY CREEK PROJECT (Hoonah)
ECONOMICS SUMMARY



4. Joint Development

The HydroWest study concluded that only one of the two projects should be developed, as there was insufficient load in Hoonah to justify both. That conclusion did not take into consideration the Point Sophia development, which is expected to add considerable load. It is quite possible that development of both projects can be justified when the Point Sophia load is considered, but more detailed study of the timing of the loads and generation would be required. Joint development would decrease the construction cost somewhat, and if the projects were developed sequentially, could provide construction employment for a number of Hoonah residents for 3-4 years.

D. Interconnection Potential

Alaska Electric Light & Power (AELP), the utility serving Juneau, has proposed to construct an intertie between Juneau and Hoonah through Greens Creek. AELP is also proposing to develop the Lake Dorothy Hydroelectric Project, which would produce the power needed to supply the Greens Creek mine and Hoonah. In 2003, D. Hittle & Associates evaluated the feasibility of such an intertie. That report determined that the cost of power to Hoonah would be about 9.6 ¢/kWh in 2007, based on the following key assumptions:

- The construction cost of the intertie ($37.1) million would be funded by grants.
- The interconnection to Hoonah would be complete in 2007.
- The allocated operating costs of the intertie would be about $61,000 in 2007, including operation and maintenance, administrative and general, and reserves and replacement fund expenses.
- The busbar cost of power from Lake Dorothy would be about 8.5 ¢/kWh in 2007.

It is impossible at this time to determine whether these assumptions are realistic. If they are, then the interconnection would provide power to Hoonah at a rate that is substantially cheaper than diesel generation. However, the following circumstances should be noted:

- Power from Lake Dorothy may not be firm in the long term, as AEL&P's first priority may be to supply Juneau loads.
- Hoonah's loads are small compared to the Greens Creek mine loads, but the cost of the line from Greens Creek to Hoonah is relatively high. Thus, there is less economic incentive for the Greens Creek-to-Hoonah segment than there is for the Juneau-to-Greens Creek segment. If funding is difficult to obtain, the Greens Creek-to-Hoonah segment could be sacrificed.
- Hoonah's cost of power with the intertie could go up substantially when the Greens Creek mine ceases operation, since Hoonah would need to pay the O&M cost for the entire intertie.
- If the Hoonah hydroelectric projects were evaluated on the same basis (i.e. 100% grant funding), then their cost of power would be even less than the intertie.
- Construction of the Hoonah hydroelectric projects does not necessarily preclude the construction of the intertie.
- Development of the projects could be viewed as an alternative to construction of the Greens Creek-Hoonah link of the Southeast Intertie. If viewed in that context, the economics of the hydro projects are highly favorable. However, there would still be a need for a substantial amount of diesel generation in Hoonah.

V. HYDABURG

A. Community Overview

Hydaburg is located on the southwest coast of Prince of Wales Island, 45 air miles northwest of Ketchikan. It is connected by road to most of the other communities on Prince of Wales Island, including the ferry landing in Hollis and airport in Klawock. The ferry has one or two sailings per day from Ketchikan, and barge service is available to Craig.

Prince of Wales Island is dominated by a cool, moist, maritime climate. Average annual precipitation is about 120 inches, including 40 inches of snow.

Hydaburg has a population of about 360. The economy is dependent on commercial fishing and timber. Subsistence remains an important part of the citizen's lifestyle.

B. Existing Power Supply

AP&T currently supplies electric power to Hydaburg, which is generated at a plant in town with diesel generators. The power plant capacity is 1,085 kW, and the cost of power to Hydaburg citizens in 2003 was 13.49 ¢/kWh for up to 500 kWh per month (after PCE subsidy of 4.81 ¢/kWh). Power is distributed by an overhead system. The annual energy requirement has been about 1,500 MWh.

AP&T has started construction of a transmission line linking Hydaburg to the Craig/Klawock system. Once that line is complete (expected to be in 2005), the Hydaburg loads will be served primarily by AP&T's hydroelectric projects (Black Bear Lake and the soon-to-be-constructed South Fork project). The existing Hydaburg diesel plant will be kept in reserve for use in the event the transmission line needs repair.

C. Hydroelectric Potential

1. General

In October 2000, Haida Corporation, the village corporation for Hydaburg received a FERC license to construct and operate the Reynolds Creek Hydroelectric Project, located approximately 8 miles east of Hydaburg. As currently planned and licensed, the Reynolds Creek Project will be constructed in two phases. The first phase is planned for a capacity of 1.5 MW, and the second phase will add 3.5 MW. The intent of the first phase was to supply the local Hydaburg loads, and the second phase would be to supply load growth on the remainder of Prince of Wales Island.

Because of the imminent interconnection of Hydaburg, and because growth on Prince of Wales Island has leveled off dramatically in the last few years, there will be no need for the energy from the Reynolds Creek Project for several years at least. Therefore, Hydaburg is attempting to obtain a legislative remedy to avoid losing the FERC license (which typically requires completion of construction within a few years of the license issuance).

Note that the primary author of this report worked on the licensing of the Reynolds Creek Project while employed by HDR Engineering, consultant for Haida Corporation.

2. Potential Modifications to the Project Arrangement

Assuming that Haida Corporation. is successful in preserving its FERC license, and assuming that load growth picks up on Prince of Wales Island, then the Reynolds Creek

Project is the next logical addition to the Prince of Wales hydro system. However, it may be more economical to develop the entire 5 MW capacity at once rather than the two-phased arrangement as licensed. That change should not require an extensive revision of the license, since the FERC environmental analysis evaluated the effects of the entire project. Constructing the entire 5 MW capacity could be accomplished with a single generating unit, which would decrease the cost somewhat.

3. Environmental Assessment

The major environmental issues of the Reynolds Creek Project as evaluated in the FERC licensing are the potential impacts to:

- Arctic grayling in Lake Mellen.
- Resident fish in the bypassed reach between Lake Mellen and the powerhouse.
- Anadromous fish in the stream reach below the powerhouse (the powerhouse is located at the anadromous barrier).

Mitigation measures for these potentials impacts included in the license are as follows:

- Restrictions on use of Lake Mellen for storage to preserve grayling spawning in tributary streams.
- Screens at the power intake to prevent grayling from being entrained in the diversion to the power plant.
- Instream flow requirements for the bypassed reach (10 cfs).
- Instream flow requirements for the anadromous reach (varying from 25 to 50 cfs).
- Restrictions on rate of change of flow by the power plant (also known as the ramping rate).

These mitigation measures were developed at a time when ADF&G was extraordinarily protective of both resident and anadromous fish resources. Since then, there has been some transfer of authority from ADF&G to ADNR, which may not apply the same protection criteria to resident fish. For example, on the Lake Dorothy Project licensed by FERC in December 2003, ADF&G accepted $70,000 in off-site mitigation for impacts to an introduced population of brook trout. The arctic grayling in Lake Mellen, like the Lake Dorothy brook trout, are an introduced population, and therefore the State may now accept a one-time off-site mitigation payment in lieu of the screens and operating restrictions to protect the Lake Mellen grayling. Likewise, the State may be willing to accept a lower instream flow requirement for the bypassed reach. Easing of the protection measures for the anadromous reach is unlikely, but they do not unduly restrict the generating capability or increase the cost of the project.

Modification of any of the mitigation measures would require an amendment to the license, including renegotiation with the state and federal fish agencies. The Reynolds Creek Project is nevertheless judged to have a high potential for environmental feasibility because the issues have all been resolved through the FERC licensing process, and there is the potential for reducing economic impact of the environmental mitigation measures.

4. Potential Generation

HDR calculated the potential generation of the Reynolds Creek Project to be 11,500 MWh with the 1500 kW Stage I development, and 23,500 MWh with the both the Stage I and Stage II developments. Changes in the instream flow requirements may change the values somewhat, but 23,000 MWh is considered to be a reasonable estimate of the generation if the Reynolds Creek Project is constructed in a single phase, as described above.

5. Economic Assessment

The estimated construction and annual operating costs of the Reynolds Creek Project as described above are shown in Table 10. The construction costs are based on a review and adjustment of the HDR cost estimate to a 2003 cost level, and to eliminate the staged construction, as described above. The economic analysis is based on an on-line date of 2015, which assumes Haida Corporation receives a 12-year extension to the required start of construction. Delaying the construction is necessary because of the current low loads on Prince of Wales Island.

Haida Corporation has been allocated approximately $4,000,000 in federal grant funds to help defray the cost of construction. Even with that amount of grant funding, the Reynolds Creek Project will not be economical if there is little load to be served. AP&T's interconnected load on Prince of Wales Island (including the planned interconnections to Hydaburg and Hollis) is currently about 26.0 GWh. AP&T's hydroelectric generation capability from the Black Bear Lake Project and the planned South Fork Project is about 30 GWh. Load growth has been very limited in the last few years; however, for purposes of this economic analysis, load growth has been forecast as follows:

Table 8
Prince of Wales Island Forecast Loads

	Craig/Klawock/Viking/ Thorne Bay	Kasaan/Hollis/Hydaburg
2003 Load	24.0 GWh	2.0 GWh
2004 to 2015	1.5%	0.5%
2016 to 2025	1.0%	0.5%
2036 to 2035	0.5%	0.5%
2036 to 2065	0.5%	0.5%

The results of the economic analysis for the Reynolds Creek Project are shown in Figure 5 (see Section 1.D for a discussion of the methods and assumptions of the economic analysis). As can be seen from Figure 5, the Reynolds Creek Project appears to be economical only if 100% of its cost can be funded with grants, or if there is substantial load growth on Prince of Wales Island, such as from a new industrial development. Thus, the Reynolds Creek Project is judged to have a low potential for economic and financial feasibility.

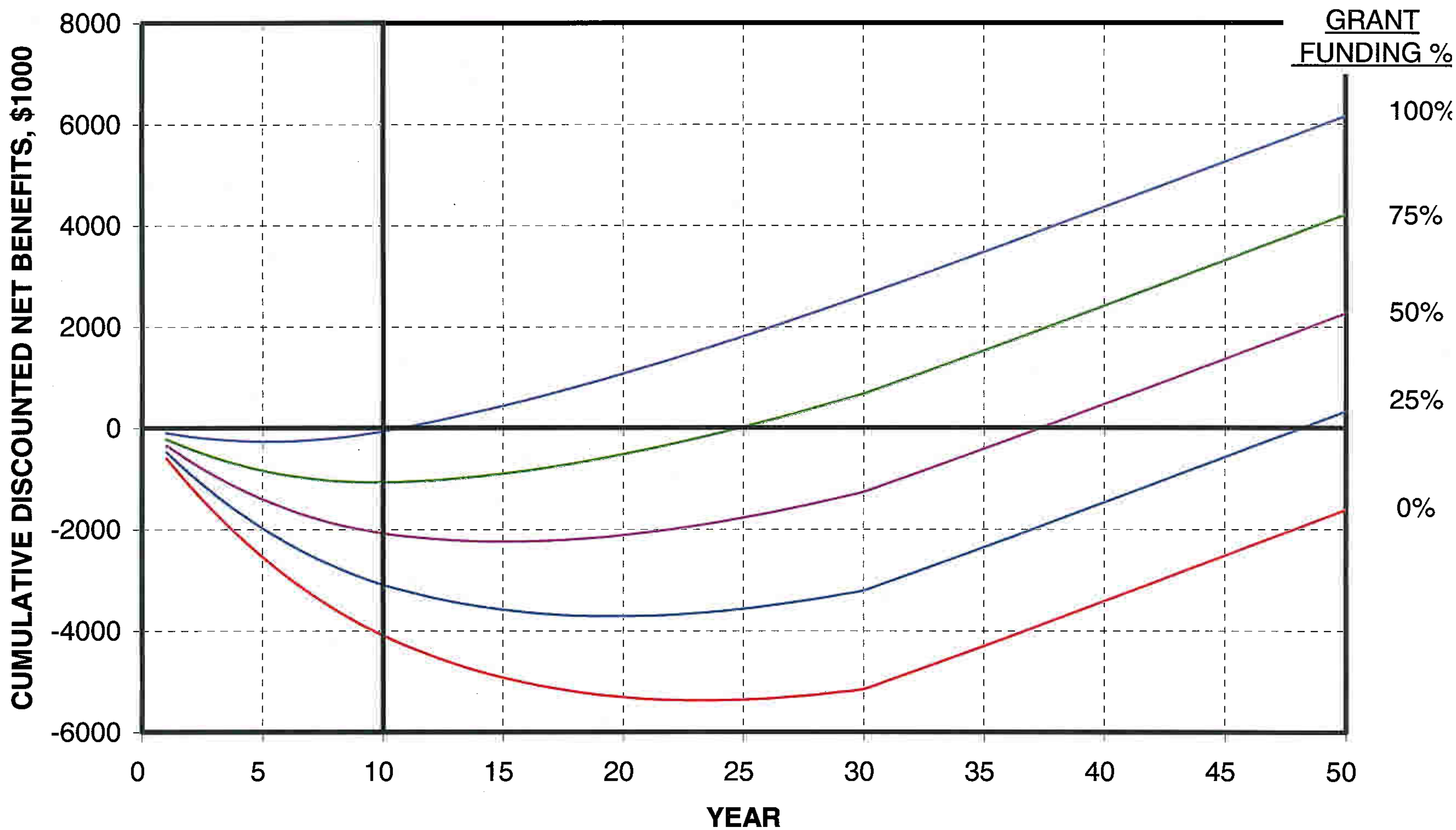
Table 9
Reynolds Creek Hydro Project (Hydaburg)
Summary of Project Costs

	Project Arrangement	
	HDR Stage I	Revised
CONSTRUCTION COST (Cost Level 1999)	(1500 kW)	(5000 kW)
FERC		
Account Description	Amount	Amount
330 Land and Land Rights	$ -	$ -
330.5 Mobilization and Logistics	$ 500,000	$ 500,000
331 Structures and Improvements	$ 400,000	$ 570,000
332 Reservoirs, Dams, and Waterways	$ 827,000	$ 827,000
333 Turbines and Generators	$ 1,100,000	$ 1,500,000
334 Accessory Electrical Equipment	$ 15,000	$ 315,000
335 Miscellaneous Mechanical Equipment	$ 20,000	$ 50,000
336 Roads and Bridges	$ 200,000	$ 200,000
353 Substation Equipment and Structures	$ 72,000	$ 202,000
355 Transmission Line	$ 2,045,000	$ 2,045,000
SUBTOTAL	$ 5,179,000	$ 6,209,000
Contingencies	$ 817,000	$ 943,000
TOTAL DIRECT CONSTRUCTION COST	$ 5,996,000	$ 7,152,000
Permitting and Engineering	$ 1,400,000	$ 1,400,000
TOTAL INVESTMENT COST (1999 Cost Level	$ 7,396,000	$ 8,552,000
Escalation (Approx. 10.4%)	$ 804,000	$ 848,000
TOTAL INVESTMENT COST (2003 Cost Level	$ 8,200,000	$ 9,400,000

	Project Arrangement	
	HDR Stage I	Revised
	(1500 kW)	(5000 kW)
Cost level	2003	2003
OPERATING COSTS	Amount	Amount
Incremental Labor		$ 36,000
Transportation		$ 18,000
Other Operating Costs (1)		$ 109,000
TOTAL OPERATING COSTS (2003 Cost Level)	$ -	$ 163,000

(1) Includes administration, insurance, taxes, land use feed, interima replacements, and environmental miti

FIGURE 5
REYNOLDS CREEK PROJECT (Hydaburg)
ECONOMICS SUMMARY



6. Regulatory Assessment

The Reynolds Creek Project has already received a FERC license and various State permits. If Haida Corporation proceeds with the project in the future, it could elect for regulation by the State rather than FERC in accordance with the Energy Act of 2000, which transfers regulatory authority from FERC to the State for projects of 5 MW capacity or less. Should Haida Corporation wish to try to modify any of the license conditions, it could also be either under FERC regulation or State regulation, assuming the amendment process is started after the State institutes its regulatory program.

D. Interconnection Potential

As noted earlier, Hydaburg will soon be interconnected to the Alaska Power & Telephone's system on Prince of Wales Island. Also, the 1998 Acres update study for the Southeast Intertie suggested that a link between Ketchikan and Prince of Wales Island should occur in the 2025 timeframe. If this link were constructed, it would need hydro projects on Prince of Wales Island to generate power to meet loads in the interconnected Southeast system. The construction cost was estimated to be about $39 million in 1996 dollars.

VI. KAKE

A. Community Overview

Kake is located on the northwest coast of Kupreanof Island, 38 air miles northwest of Petersburg and 95 air miles southwest of Juneau. It is accessible only by aircraft or boat. There is scheduled air taxi service between Kake and Juneau, Petersburg, and Sitka. Freight arrives year-round by barge and by ferry.

Kake has a maritime climate characterized by cool summers and mild winters. It receives much less precipitation than is typical of Southeast Alaska, averaging 54 inches a year, with 44 inches of snow.

Kake has a population of about 700. The economy is dependent on commercial fishing, fish processing, and timber harvesting. Subsistence is an important part of the citizen's lifestyle.

B. Existing Power Supply

IPEC currently supplies electric power to Kake, which is generated at a plant in town with diesel generators. The power plant capacity is 2,585 kW, and the cost of power to Kake citizens in 2003 was 14.54 ¢/kWh for up to 500 kWh per month (after PCE subsidy of 18.21 ¢/kWh). Power is distributed by an overhead system. The annual energy requirement has been about 4,200 MWh.

C. Hydroelectric Potential

Hydroelectric potential in the Kake area has been the subject of at least two studies, as follows:

- Preliminary Appraisal Report on the Hydroelectric Potential for the Villages of Angoon, Craig, Hoonah, Hydaburg, Kake, Kasaan, Klawock, Klukwan, Pelican, and Yakutat; September 1977 by R. W. Retherford Associates.
- Cathedral Falls Project, A Reconnaissance Report; October 1979 by Harza Engineering Company

1. Gunnock Creek

a. Project Arrangements of Previous Studies

Gunnock Creek flows through Kake into Keku Strait, and has a drainage area of about 11.5 sq. miles. Retherford reports that a small hydro project was constructed on Gunnock Creek in the 1920s, but there is little current evidence of its existence. The City of Kake constructed a timber crib dam about 3000 feet upstream from the mouth of the creek, and used the dam and reservoir to supply water to the town and to a hatchery near the mouth of the creek. In July 2000, the dam failed during a flood. An emergency system was built to continue the municipal and hatchery water supply while the Corps of Engineers designs and constructs a new dam (construction is expected in 2004). The City recently constructed a diversion from Alpine Lake in the Gunnock Creek basin to provide reserve storage for the water supply system.

Retherford considered Gunnock Creek as a potential hydroelectric site, and developed a project arrangement with two dams, 14,500 acre-foot storage reservoir, 2800-foot long pipeline, and 1800 kW power plant. On the basis of the Retherford study, the Alaska Power Authority contracted with Harza Engineering to study the Gunnock Creek site. Harza's initial studies of the site concluded that the cost of the Gunnock Creek project would be much more than estimated by Retherford. The Gunnock Creek site was then dropped in favor of the Cathedral Falls site, which had also been identified by Retherford.

b. Potential Modifications of Previous Project Arrangements

Harza's evaluation of the Gunnock Creek development as proposed by Retherford undoubtedly holds true today. However, we understand that the Corps of Engineers will include an outlet in the new water supply dam that could be used for the addition of a generating plant, but they are not planning on pursuing power development as part of the dam. Much of the water available at the dam is piped downstream for the hatchery, and therefore the greatest generation would be obtained if a power plant were constructed near the hatchery that would make use of the additional head and flow. Assuming a hydraulic capacity of 60 cfs and a generating head of 125 feet, the capacity of a power plant at the hatchery would be about 500 kW.

Salmon are reported to spawn in Gunnock Creek as far upstream as the water supply dam. Development of the power plant at the hatchery could have a detrimental impact on natural spawning and rearing in Gunnock Creek if the diversion rate is greater than the current hatchery withdrawal. Also, the hatchery may not be agreeable to a power plant since it could result in a colder water supply to the hatchery.

Consequently, the most practicable use of Gunnock Creek for generation is likely to be a small generator at the water supply dam, discharging to the stream directly below the dam. The capacity would be quite small (perhaps 25-50 kW), but the installation cost should be small as well. The feasibility of such an installation has not been evaluated herein because it will depend to a great degree on the arrangement of the facilities in the dam, and that information is not currently available. Once the details of the dam design are known, we recommend a detailed feasibility study, as there is likely to be a high potential for it being cost-effective.

2. Cathedral Falls Creek

a. Project Arrangements of Previous Studies

Cathedral Falls Creek flows into Hamilton Bay about 10 miles south of Kake. Retherford considered Cathedral Falls Creek as a hydroelectric site because of the existence of a moderate height waterfall. Retherford suggested a project with a 70-foot-high concrete dam, a 2000-foot long penstock, and a powerhouse at the base of the falls with a capacity of around 2000 kW. However, Retherford did not prepare a cost estimate of cost of power analysis, as they focused on the Gunnock Creek site.

Harza's arrangement for the Cathedral Falls site included a 27-foot-high concrete dam at the head of the falls, a 210-foot-long, a 9-foot-diameter tunnel 360 feet long, a 78-inch diameter penstock 470 feet long, and a 2-unit 750-kW power plant at the base of the falls. Harza estimated the construction cost to be $7.1 million. Harza's plan provided for future expansion of the powerhouse to include 2 additional generating units for an ultimate capacity of 1,500 kW.

b. Potential Modifications of Previous Project Arrangement

The following modifications to the Harza project arrangement are likely to result in a more economical project:

- Minimize the height of the diversion dam.
- Construct the dam with a concrete core wall and grouted rockfill rather than all concrete. Incorporate a sluice gate for removing accumulated sediment.
- Construct the tunnel and penstock with a microtunnel boring machine, and decrease the diameter to 4 feet.
- Utilize Ossberger-type generating units in the power plant to allow more efficient use of the available flow.

The generating capacity of this modified arrangement would be 1,000 kW, with no future expansion potential. The intake would probably need to be screened if there are resident fish above the falls. Likewise, a screened tailrace would probably be needed to protect anadromous fish below the falls.

The drainage basin above the falls appears to be relatively flat, but the stream appears to be somewhat incised. Harza indicated storage could not be developed at the damsite, however, they did not indicate if storage could be developed elsewhere in the basin. One intriguing possibility is to develop a reservoir in the Goose March area on Slo Duc Creek, with a diversion from Cathedral Falls Creek. Water from Cathedral Falls Creek and Slo Duc Creek could be stored during high flow periods, and then released to Cathedral Falls Creek for generation, possibly through a second power plant. This concept has not been reviewed in detail, as the available topographic mapping is not sufficiently detailed. If development of the Cathedral Falls site is pursued, we recommend that this storage option be explored in more detail.

c. Potential Generation

Harza estimated the annual generation with their arrangement to be about 3.45 GWh. With the revised arrangement as described above, the average annual energy potential is estimated to be 3,300 MWh, assuming no requirement for instream flows in the bypassed reach.

d. Environmental Assessment

Anadromous fish utilize Cathedral Falls Creek extensively below the fall. Because the project will operate in a run-of-river mode and return flow at the base of the falls, impacts to the anadromous fish population would be insignificant. However, it is reasonable to expect regulatory agency concern for the anadromous population and adoption of several measures to ensure minimal impact. The measures could include:

- Screened tailrace design
- Immediate release of flow at the diversion site whenever the power plant trips offline.
- Rate-of-change restrictions on the power plant discharge.

The Harza report does not indicate if there are resident fish in Cathedral Falls Creek above the falls. Based on the topography, it is reasonable to expect the stream to be capable of supporting a sizable resident population. Screening of the power intakes is likely to be required to prevent losses to any resident population.

It is unknown whether there are significant aesthetic or cultural issues that would be associated with diminishing flow over the falls.

There do not appear to be any environmental issues that would prevent development of a run-of-river project at Cathedral Falls, but a moderate amount of environmental mitigation would be required. Therefore, the Cathedral Falls Project is judged to have a moderate potential for environmental feasibility.

e. Economic Assessment

The estimated construction and annual operating costs of the Cathedral Falls Project as described above are shown in Table 11. The construction costs are based on a review and adjustment of the Harza cost estimate. The earliest possible on-line date is estimated to be 2009, considering the current status of the development effort.

The results of the economic analysis for the Cathedral Falls Project are shown in Figure 6 (see Section 1.D for a discussion of the methods and assumptions of the economic analysis). As can be seen from Figure 6, the Cathedral Falls Project appears to be economical if approximately 55% of its cost can be funded with grants (i.e. grants totaling about $2,900,000 would be required). This indicates a moderate potential for economic and financial feasibility.

f. Regulatory Assessment

Some or all of the land occupied by the Cathedral Falls site is in the Tongass National Forest. In other states, occupying US land automatically results in jurisdiction by the Federal Energy Regulatory Commission. However, as described in Section I.C.1, the State of Alaska will begin regulation of small hydro projects in the state once it develops and receives approval of its own regulatory program. The state has just begun developing its program, so it is too early to tell how complicated or expensive it will be.

D. Interconnection Potential

The 1998 Acres update study for the Southeast Intertie suggested that the link between Petersburg and Kake should occur in the 2011 to 2015 timeframe. The transmission link would allow sale of surplus power from the Tyee Lake hydro project to IPEC to serve Kake loads. The construction cost was estimated to be about $19.7 million in 1996 dollars.

In 2003, D. Hittle & Associates evaluated the feasibility of the Petersburg-Kake transmission line. Their report concluded that the cost of power to Kake would be about 9.6 ¢/kWh in 2007, based on the following key assumptions:

- The construction cost of the intertie ($23.1 million) would be funded entirely by grants.
- The interconnection to Kake would be complete in 2007.
- The operating costs of the intertie would be about $255,000 in 2007, including operation and maintenance, administrative and general, and reserves and replacement fund expenses.
- The busbar cost of power from the Tyee Lake Project would be about 4.0 ¢/kWh in 2007.

Table 10

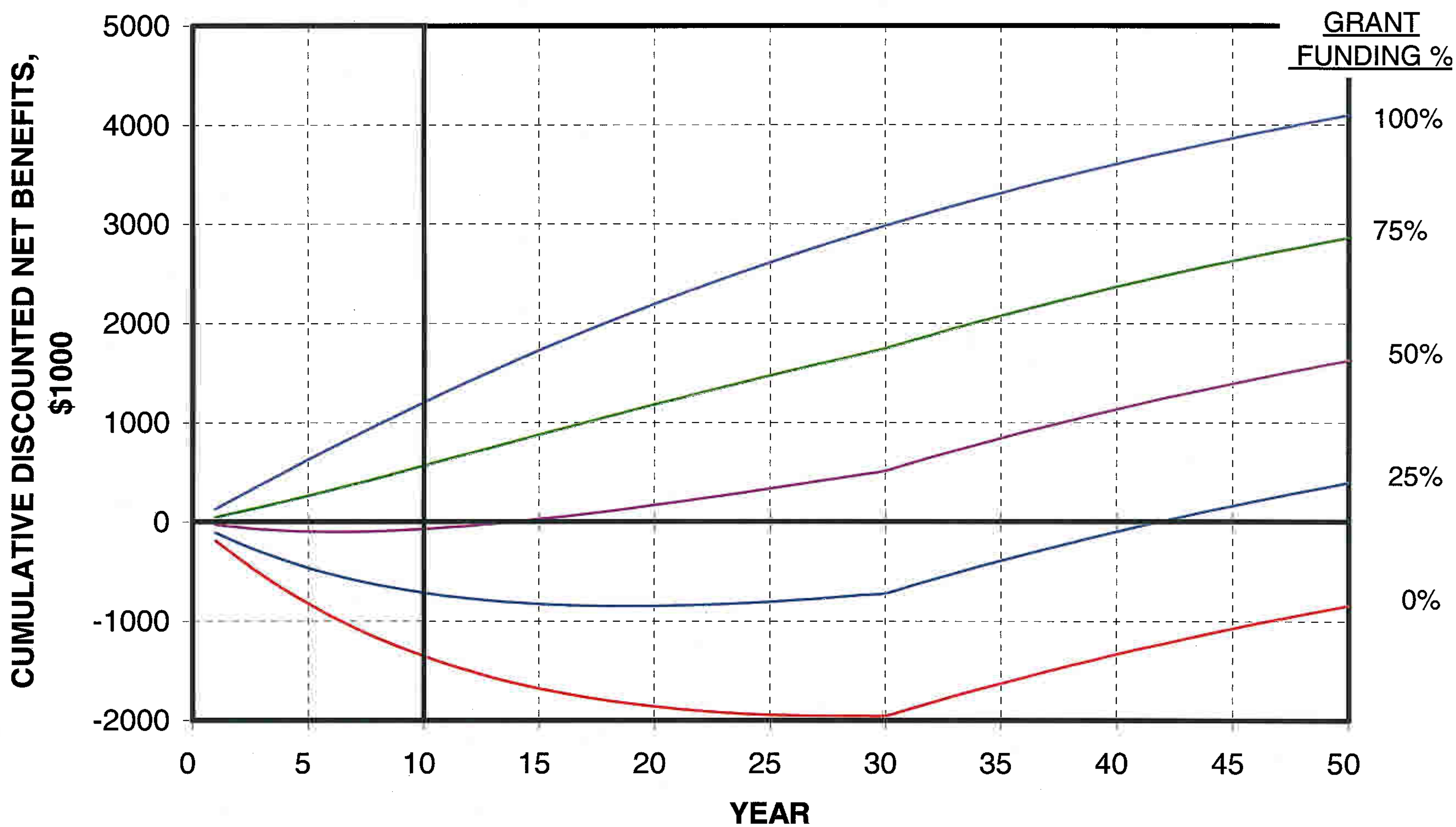
Cathedral Falls Hydroelectric Project (Kake)
Summary of Project Costs

		Project Arrangement	
CONSTRUCTION COST		Harza	Modified Harza
	Cost level	1979	2003
FERC			
Account	Description	Amount	Amount
330	Land and Land Rights	$ 17,000	$ -
330.5	Mobilization and Logistics	$ 500,000	$ 126,000
331	Structures and Improvements	$ 126,000	$ 204,000
332	Reservoirs, Dams, and Waterways	$ 2,800,000	$ 1,500,000
333	Turbines and Generators	$ 320,000	$ 600,000
334	Accessory Electrical Equipment	$ -	$ 295,000
335	Miscellaneous Mechanical Equipment	$ 82,000	$ 70,000
336	Roads and Bridges	$ 444,000	$ 90,000
353	Substation Equipment and Structures	$ -	$ 65,000
355	Poles and Fixtures	$ 497,000	$ 720,000
SUBTOTAL		$ 4,786,000	$ 3,670,000
	Contingencies	$ 1,197,000	$ 918,000
TOTAL DIRECT CONSTRUCTION COST		$ 5,983,000	$ 4,588,000
	Permitting and Engineering	$ 1,117,000	$ 712,000
TOTAL CONSTRUCTION COST		$ 7,100,000	$ 5,300,000

		Project Arrangement	
		Harza	Modified Harza
	Cost level	1979	2003
OPERATING COSTS		Amount	Amount
	Incremental Labor		$ -
	Transportation		$ 10,000
	Other Operating Costs (1)	$ 40,000	$ 40,000
TOTAL OPERATING COSTS		$ 40,000	$ 50,000

(1) Includes administration, insurance, taxes, land use feed, interima replacements, and environmental mitigation.

FIGURE 6
CATHEDRAL FALLS PROJECT (Kake)
ECONOMICS SUMMARY



It is impossible at this time to determine whether these assumptions are realistic. If they are, then the interconnection would provide power to Kake at a rate that is substantially cheaper than diesel generation. However, the following circumstances should be noted:

- Power from Tyee Lake may not be firm in the long term, as the first priority will be to supply Petersburg & Wrangell loads, and then Ketchikan loads as a second priority.
- The preferred route of the transmission line is overland and away from the coast. However, there is a separate proposal to construct a road linking Kake to Petersburg that would follow the coastline. If the road were constructed, there would be some environmental incentive to route the transmission line along the road, even though that might not be the most economical route. This interface with the road complicates and probably delays the transmission line development.
- If the Cathedral Falls hydro project was evaluated on the same basis (i.e. 100% grant funding), then their cost of power would be even less than the intertie.
- Construction of the Cathedral Falls hydro project would not necessarily preclude the construction of the intertie.
- Development of the project could be viewed as an alternative to construction of the Petersburg-Kake link of the Southeast Intertie. If viewed in that context, the economics of the hydro projects are highly favorable. However, there would still be a need for a substantial amount of diesel generation in Kake.

VII. KLUKWAN / CHILKAT VALLEY

A. Community Overview

Klukwan is located on the north bank of the Chilkat River, about 22 miles north of Haines. It lies at the junction of the Kleheni and Tsirku Rivers, about 100 miles northwest of Juneau. It is the only sizable community in Southeast Alaska not located on tidewater. It is accessible by road to Canada and Southcentral Alaska via the Haines Highway and Alcan Highway. Residents also utilize the barge, ferry, and air service in Haines.

Klukwan and the Chilkat Valley have a maritime climate characterized by cool summers and mild winters. The area receives much less precipitation than is typical for Southeast Alaska, averaging 23 inches a year, with 104 inches of snow.

Klukwan has a population of about 110. It is a traditional Tlingit village, and subsistence is a major part of the lifestyle. Fishing, logging, and traditional crafts are also components of the local economy. Klukwan borders the Chilkat Bald Eagle Preserve, which provides some tourism activity.

The population in the Chilkat Valley outside of Klukwan is approximately 230.

B. Existing Power Supply

IPEC currently supplies electric power to Klukwan and the Chilkat Valley. Most of the generation is from hydro, which is purchased from an independent developer. The cost of power to Klukwan residents in 2003 was 14.54 ¢/kWh for up to 500 kWh per month (after PCE subsidy of 18.21 ¢/kWh). For Chilkat Valley residents, the 2003 cost of power was 16.29 ¢/kWh for up to 500 kWh per month (after PCE subsidy of 18.21 ¢/kWh). The annual energy requirement for Klukwan and the Chilkat Valley has been about 1,600 MWh.

C. Interconnection Potential

AP&T is planning construction of a transmission line linking IPEC's Chilkat Valley system and Klukwan to the Haines/Skagway system. Once that line is complete (expected to be in 2006), the Klukwan loads will be served primarily by hydroelectric projects (AP&T's Goat Lake and the soon-to-be-constructed Kasidaya Creek projects, and the Lutak Hydro project near Haines). The existing Klukwan diesel plant will be kept in reserve for use in the event the transmission line needs repair.

D. Hydroelectric Potential

1. Previous Studies

In 1988, Ott Water Engineers conducted a reconnaissance-level feasibility study of a Walker Lake hydroelectric project for the Alaska Power Authority. Walker Lake is located 8 miles west of Klukwan at about El 1180. It has a surface area of about 120 acres. Its depth is unknown, but based on the area topography it is probably fairly shallow. The outlet stream, Walker Creek, flows into the Little Salmon River, which then flows into the Tsirku River at about El 250.

Ott considered five alternative configurations for the Walker Lake project, three of which were for supplying power to Klukwan only, and two of which were for supplying power to Klukwan and Haines. Because Klukwan will be interconnected the Haines-Skagway system soon, any future development of the Walker Lake site would be as a regional resource. Only one of the five alternatives studied by Ott showed any potential for feasibility (designated Alternative 3B by Ott). Coincidentally, it is the alternative with the greatest generation potential, and therefore the one most suited for development as a regional resource. Accordingly, this study has concentrated on that one alternative, as described below.

Alternative 3B included the following major features:

- A diversion dam on the Little Salmon River at about El 1250 feet.
- A 5,900-foot long 18-inch diameter buried HDPE pipeline from the Salmon River diversion to Walker Lake
- Two small rockfill dams on Walker Lake to provide storage. One of the dams would include an intake structure.
- A 9,700-foot long 30-inch diameter low-pressure buried steel pipeline from Walker Lake along the hillside to a point above the powerhouse.
- A 2,200-foot long 30-inch diameter exposed steel penstock from the end of the low-pressure pipeline to the powerhouse.
- A powerhouse containing a single generating unit with a capacity of 1900 kW. The generating unit would have a 3-jet impulse turbine, operating under a gross head of about 780 feet and a maximum discharge of 37 cfs. A field trip report included in Ott's report seems to indicate the powerhouse location is near the existing bridge over the Little Salmon River; however, the estimated gross head at the site seems to indicate the powerhouse location is a bit farther upstream.
- A 20-mile long 34.5 kV transmission line linking the powerhouse to Klukwan and Haines.
- A switchyard at the powerhouse and a substation in Klukwan.

The construction cost was estimated to be about $10.8 million.

2. Potential Modifications of Previous Project Arrangements

The Ott report did not include any drawings showing the locations of the various structures; therefore, it is difficult to reliably evaluate alternatives. Nevertheless, there do appear to be some modifications that could lessen the cost:

- Instead of diverting the flow of the Little Salmon River in a separate pipeline to Walker Lake, the diversion pipeline could join directly to the larger pipeline from Walker Lake to the powerhouse. This would shorten the length from 5900 feet to about 4900 feet.
- Use a siphon intake at the lake rather than a dam (this may not be practical if the lake is shallow near the intake site). AP&T has used siphon intakes at both its Black Bear Lake and Goat Lake projects with good success.
- Use of HDPE instead of steel for the low-pressure pipe from Walker Lake.

Of course, the transmission line would only need to be 8 miles long from the powerhouse to Klukwan, as the Klukwan-Haines link will be in existence soon. For purposes of this report, we have assumed the line would be buried construction since it will pass through or near the Chilkat Bald Eagle Preserve.

3. Potential Generation

The energy potential of the Walker Lake site was estimated by Ott to be 5430 MWh for Alternative 3B. Generation would be similar with the suggested modifications.

4. Environmental Assessment

Ott did not address environmental issues, other than to indicate that the overhead transmission line they proposed might not be allowed. The revised project as described above would bypass all of Walker Creek and about two miles of the Little Salmon River. If there are significant fish resources in either of those streams, then development of the Walker Lake site would be difficult. The ADNR Catalog of Waters Important for Spawning, Rearing or Migration of Anadromous Fishes indicates that the Little Salmon River has fish in its lower reach, but not in the bypassed reach. However, fish surveys would be necessary to determine the actual extent of fish usage. Because of the lack of any specific information, the environmental feasibility is considered to be unknown.

5. Economic Assessment

The estimated construction and annual operating costs of the Walker Lake Project as described above are shown in Table 12. The construction costs are based on a review and adjustment of the Ott cost estimate to a 2003 cost level. Note that it appears Ott was quite conservative in its estimate. The earliest possible on-line date is estimated to be 2010 considering the current status of the development effort. However, unless loads grow at an unexpectedly high rate, the interconnected system will have sufficient hydro generation until at least 2020. Because additional hydro generation will not be needed any time soon, an economic analysis has not been conducted for this study, and the economic feasibility is considered to be low.

As noted earlier, any future development of the Walker Lake site will be as a regional resource. Therefore, it will also need to be compared to other potential hydro projects in the region. There are at least three other projects, which have been considered in the past, West Creek, Dayebas Creek and Connelly Lake (aka Upper Chilkoot Lake). The Walker Lake site has storage potential, which is an advantage compared to Dayebas Creek, which is strictly a run-of-river site. The generating potential of the Walker Lake site is substantially less than the Connelly Lake site, which could be advantageous if the load growth rate is expected to be moderate. However, more work has been done on the Connelly Lake site. In all likelihood, the choice between the Connelly Lake and Walker Lake sites would be decided by environmental issues and cost. In 1995, the construction cost for Upper Chilkoot site was estimated to be about $15,000,000, comparable to about $20,000,000 in 2003.

6. Regulatory Assessment

The land occupied by the Walker Lake site is in the Haines State Forest Resource Management Area. It is unlikely that the Federal Energy Regulatory Commission (FERC) would currently have jurisdiction. As noted earlier, the State of Alaska will assume regulatory authority over hydroelectric projects of 5 MW capacity or less once they develop an adequate program. It is reasonable to assume that the State will apply its regulatory process to all small projects, even those like Walker Lake where FERC would ordinarily not have jurisdiction.

Table 11
Walker Lake Hydro Project (Klukwan)
Summary of Project Costs

		Project Arrangement			
CONSTRUCTION COST			OTT		Modified OTT
	Cost level		1988		2003
FERC					
Account	Description		Amount		Amount
330	Land and Land Rights	$	-	$	-
330.5	Mobilization and Logistics	$	193,000	$	180,000
331	Structures and Improvements	$	304,000	$	256,000
332	Reservoirs, Dams, and Waterways	$	3,093,000	$	2,572,000
333	Turbines and Generators	$	920,000	$	610,000
334	Accessory Electrical Equipment	$	420,000	$	295,000
335	Miscellaneous Mechanical Equipment	$	40,000	$	60,000
336	Roads and Bridges	$	603,000	$	648,000
353	Substation Equipment and Structures	$	205,000	$	90,000
355	Poles and Fixtures	$	787,000	$	-
356	Conductors and Devices	$	715,000	$	-
358	Underground Conductor & Devices			$	1,921,000
359	Line Clearing, Mob. And Demob	$	60,000	$	60,000
SUBTOTAL		$	7,340,000	$	6,692,000
	Contingencies	$	1,835,000	$	1,673,000
TOTAL DIRECT CONSTRUCTION COST		$	9,175,000	$	8,365,000
	Permitting and Engineering	$	1,625,000	$	1,035,000
TOTAL CONSTRUCTION COST)		$	10,800,000	$	9,400,000

	Project Arrangement		
	OTT		Modified OTT
OPERATING COSTS (2003 Cost Level)	Amount		Amount
Incremental Labor	NOT SHOWN IN REPORT	$	-
Transportation		$	16,000
Other Operating Costs (1)		$	64,000
TOTAL OPERATING COSTS (2003 Cost Level)		$	80,000

(1) Includes administration, insurance, taxes, land use feed, interima replacements, and environmental mitigation.

VIII. YAKUTAT

A. Community Overview

Yakutat is located along the lowlands of the Gulf of Alaska, 225 miles northwest of Juneau and 220 miles southeast of Cordova. It is at the mouth of Yakutat Bay, one of the few refuges for vessels along this stretch of coast. It is accessible only by aircraft or boat. Freight arrives by barge year-round and by ferry in the summer.

Yakutat receives some of the heaviest precipitation in Alaska, averaging 132 inches, including 220 inches of snowfall. The heavy precipitation combined with high mountains to the north results in some of the largest glaciers in the world being located near Yakutat.

Yakutat has a population of about 810. Yakutat's economy is dependent on fishing, fish processing, and government. Exploitation of world-class recreational fishing opportunities near Yakutat, particularly the Situk River, contributes substantially to the local economy. North Pacific Processors is the major private employer. Subsistence remains an important part of the citizen's lifestyle.

B. Existing Power Supply

Yakutat Power, a division of the City and Borough of Yakutat, generates and distributes all power in Yakutat. All generation is by diesel engines, with a combined capacity of 2,880 kW. Peak loads are about 1,500 kW, and annual generation is about 7 GWh. Much of the load is from supplying power to two fish processing plants. The cost of power to Yakutat citizens in 2003 was 20.35 ¢/kWh for up to 500 kWh per month (after PCE subsidy of 8.98 ¢/kWh.

C. Hydroelectric Potential

The only previous studies of the hydroelectric potential in the Yakutat area was Retherford (1977), which considered only a tidal development at Ankau, a complex of bays about 3 miles west of town. Retherford concluded that a tidal development would not be economical because of the relatively low tide range in Yakutat (about 13 feet maximum).

Information on Yakutat produced by the Alaska Department of Community and Economic Development indicated that Yakutat was interested in exploring the hydroelectric potential of the Chicago Harbor area about 15 miles north of town. In a conversation, Mr. Scott Newlun, Yakutat's Power Manager, indicated they were interested in any generation method that could replace the current diesel generation. A tidal development at Ankau is still under consideration, and some work is being done in that regard by Arctic Pacific Enterprises.

1. Ankau Tidal Development

The Ankau area would appear to lend itself to any of three types of tidal development:

- A conventional tidal development, where the Ankau channel is closed by a dike and power plant. The turbines would be reversible so generation would occur both on filling and draining of the Ankau basin, but it would be intermittent and variable.
- A two-basin tidal development, where the Ankau/Kardy Lake basin is divided into two pools by a number of dikes, with a power plant located between the two pools. During high tide periods, water would flow from the Gulf of Alaska into

the Kardy Lake pool through a sluiceway constructed on the southwest side of the lake; the sluiceway gates would close on the receding tide once the Kardy Lake water level rose to sea level. As the water level in Kardy Lake rises, water would flow through the power plant into the Ankau basin, generating power. Once the water level in the Ankau basin rises above the sea level, a sluiceway in the Ankau channel would open to drain it. With this type of development, a continuous generation pattern can be obtained although it would vary somewhat throughout the day and from day to day. However, the generation would be less than with the conventional development, and the cost would be higher because of the greater number of structures. Preliminary calculations indicate the average output from tidal energy would be around 250 kW, generating about 2.2 GWh per year. The runoff into the Kardy Lake basin would provide some additional generation, perhaps 0.5-1.0 GWh per year.

- A tidal current development, where a number of turbines are anchored in the Ankau channel to make use of the energy of the moving water. This type of development would cause the least impact to the Ankau basin, but would also have the least generation.

Because of the low tide range, power from any conventional tidal development will be very expensive unless substantially subsidized. A tidal current development may be the most practicable, although the generating equipment for such an application is still rather experimental, and environmental impacts are largely unknown. Note that AP&T is participating in a pilot program to place a similar turbine in the Yukon River near Eagle. Permitting for that pilot program is nearly complete, and installation may take place in 2004.

ADNR's Catalog of Waters Important for Spawning, Rearing or Migration of Anadromous Fishes indicates that the Ankau-Kardy Lake system is utilized by anadromous fish. It may be very difficult to obtain the necessary permits for any project that could have negative impacts to anadromous fish.

2. Conventional Hydroelectric Projects

No previous studies have located small conventional hydroelectric projects near Yakutat, although an Alaska Energy Authority database indicates some analysis of a 300 MW development on the Alsek River. For the current study, a search was made using USGS topographic maps to look for sites that might have hydroelectric potential, generally focusing on the Chicago Harbor area, as that area was identified by Yakutat Power as having potential. Two sites were located, as discussed below. Note that neither of these sites has been visited and the USGS maps have a 100' contour interval; therefore, the analyses should be viewed with caution.

a. Chicago Harbor

An unnamed stream drains the western slopes of Mt. Tebenkof and flows into Yakutat Bay at Chicago Harbor, approximately 15 miles north of Yakutat. A relatively broad basin occurs at about the 500' elevation, and the stream below that basin is quite steep. It is impossible to tell from the mapping if there is storage potential in the basin; therefore, a run-of-river project has been assumed. The drainage area is estimated to be 4.2 square miles.

The selected project arrangement includes the following features:

- A low diversion dam at about El 450.
- A 36-inch diameter low pressure pipeline about 3400 feet long traversing the hillside from the diversion dam to the west.
- A 30-inch diameter high-pressure penstock about 1200 feet long dropping down the hillside from the end of the low-pressure pipeline to the power plant.
- A power plant near the mouth of the creek, containing a single impulse turbine and generator rated 1400 kW at a flow of 50 cfs and a net head of 410 feet.
- A boat ramp for construction and operation access.
- An access road about 1.6 miles long from the boat ramp to the power plant and diversion dam.
- A transmission line consisting of 12.5 miles of submarine cable from the power plant to the Sawmill Cove northeast of Yakutat, and 2.5 miles of overhead line from Sawmill Cove to Yakutat.

The hydraulic capacity of the project is estimated to be 50 cfs, which would be exceeded about 20% of the time, based on factoring of flow records for the Situk River. Note that actual flows may be greater than estimated for the subject stream because its drainage basin is relatively higher in elevation than the Situk River. On the other hand, the subject stream may be flashier than estimated, because the Situk River drainage includes a large lake and many ponds, which tend to even out the flows. Installation of a stream gage and developing more detailed topographic mapping would be important first steps in evaluating this site.

b. Lake Redfield

Lake Redfield is a lake located about 9 miles northeast of Yakutat and about 4.5 miles south of Chicago Harbor. The lake has a surface area of about 800 acres, and the surface is at about El 150. The surrounding area is quite flat and very marshy. The outlet stream from the lake flows through a series of ponds for about 4000 feet before dropping to Yakutat Bay. The USGS map indicates the last 600 feet of stream drops 100 feet, which could make for a decent small hydroelectric site. The site is particularly appealing because of the possibility of utilizing and/or developing storage at the lake.

Because of the wide contour spacing and flat terrain, it is not possible to accurately determine the drainage area or storage potential. For this study, the drainage area has been estimated to be 7 square miles, which would provide an average flow of about 60 cfs. Good regulation of the stream flow could be accomplished with storage of about 15,000 acre-feet, which could be gained by raising the lake level about 15 feet. If the plant were sized to provide a generating capacity of 1500 kW, the hydraulic capacity would be about 180 cfs. For purposes of this assessment, the following components have been assumed:

- An earthfill storage dam 500 feet long and 25 feet high.
- A 60-inch diameter low pressure pipeline about 2000 feet long parallel the stream from the dam to the west.

- A 48-inch diameter penstock about 200 feet long dropping down the hillside from the end of the low-pressure pipeline to the power plant.
- A power plant near the mouth of the creek, containing two generating units, each rated 750 kW at a flow of 90 cfs and a net head of 125 feet.
- A boat ramp for construction and operation access.
- An access road about 0.5 miles long from the boat ramp to the power plant and diversion dam.

No transmission line would be required if developed in conjunction with the Chicago Harbor project, as the submarine cable from that project could be conveniently brought ashore in the Lake Redfield area.

c. Potential Generation

The potential annual generation of the Chicago Harbor site is estimated to be 7,500 MWh; however, not all of that generation is likely to be usable, as some of it would occur when loads are low. For purposes of this study, it has been assumed that 60%, or 4,500 MWh would be usable.

The potential annual generation of the Lake Redfield site is estimated on a preliminary basis to be about 3,700 MWh. If the Lake Redfield site was developed as described above, all of the generation would be usable because of the ability to store excess water in the lake.

d. Environmental Assessment

The topographic maps indicate the land occupied by both projects is in the Tongass National Forest. ADNR's Catalog of Waters Important for Spawning, Rearing or Migration of Anadromous Fishes does not indicate anadromous fish usage of the Chicago Harbor stream. If there is a barrier falls near the mouth of the stream, then fish usage may not be much of an issue. If the anadromous barrier is further upstream, then it may be necessary to move the power plant upstream to the barrier to minimize impacts to fish. Such a move would decrease the generating head and power output. Resident fish populations are often found upstream of barriers falls, and can also be problematic.

Scott Newlun, Manager of Yakutat Power, has indicated that there is a fairly large run of salmon in the Lake Redfield stream. The ADNR catalog does not show anadromous usage of the outlet stream, but it does indicate Lake Redfield is connected to the Situk River system. If that is the case, then development of Lake Redfield would be very difficult and/or uneconomic.

e. Economic Assessment

A combined development of the Chicago Harbor and Lake Redfield sites would be able to provide for all or nearly all of the generation requirements of Yakutat. However, because of the probable environmental impacts from developing Lake Redfield, we have conducted an economic analysis of only the Chicago Harbor site. The estimated construction and annual operating costs are shown in Table 13 for a 2003 cost level. The construction costs are based on the USGS mapping and recent cost estimates for other projects in Southeast Alaska. The earliest possible on-line date is estimated to be 2010 considering the current status of the development effort.

Table 12
Chicago Harbor Hydroelectric Project (Yakutat)
Summary of Project Costs

CONSTRUCTION COST (2003 Cost Level)

FERC Account	Description		Amount
330	Land and Land Rights	$	-
330.5	Mobilization and Logistics	$	300,000
331	Structures and Improvements	$	180,000
332	Reservoirs, Dams, and Waterways	$	1,060,000
333	Turbines and Generators	$	680,000
334	Accessory Electrical Equipment	$	260,000
335	Miscellaneous Mechanical Equipment	$	110,000
336	Roads and Bridges	$	470,000
353	Substation Equipment and Structures	$	140,000
355	Overhead Transmission Line	$	380,000
358	Submarine Transmission Line	$	2,810,000
SUBTOTAL		$	6,390,000
	Contingencies	$	1,920,000
TOTAL DIRECT CONSTRUCTION COST		$	8,310,000
	Permitting and Engineering	$	990,000
TOTAL CONSTRUCTION COST (2003 Cost Level)		$	9,300,000

OPERATING COSTS (2003 Cost Level)		Amount
Incremental Labor	$	30,000
Transportation	$	25,000
Other Operating Costs (1)	$	55,000
TOTAL OPERATING COSTS (2003 Cost Level)	$	110,000

(1) Includes administration, insurance, taxes, land use feed, interima replacements, and environmental mitigation.

The results of the economic analysis for the Chicago Harbor Project are shown in Figure 7 (see Section 1.D for a discussion of the methods and assumptions of the economic analysis). As can be seen from Figure 7, the Chicago Harbor Project appears to be economical if approximately 55% of its cost can be funded with grants (i.e. $5,100,000 in grants). This indicates a moderate potential for economic and financial feasibility.

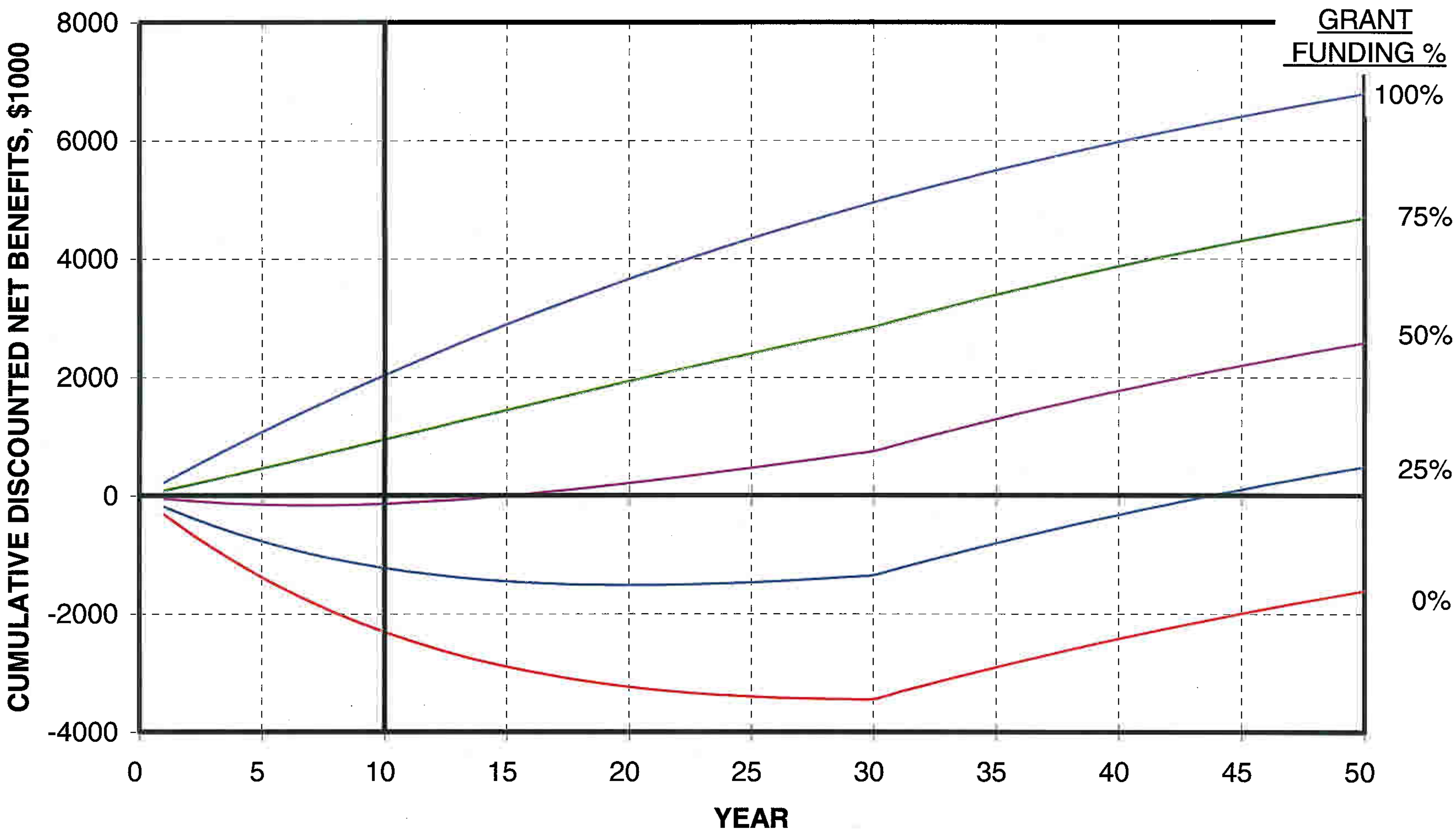
f. Regulatory Assessment

Some or all of the land occupied by the Cathedral Falls site is in the Tongass National Forest. In other states, occupying US land automatically results in jurisdiction by the Federal Energy Regulatory Commission. However, as described in Section I.C.1, the State of Alaska will begin regulation of small hydro projects in the state once it develops and receives approval of its own regulatory program. The state has just begun developing its program, so it is too early to tell how complicated or expensive it will be.

D. Interconnection Potential

Because of its extreme isolation, Yakutat is unlikely to be electrically interconnected to any other community in the foreseeable future.

FIGURE 7
CHICAGO HARBOR PROJECT (Yakutat)
ECONOMICS SUMMARY



IX. APPENDIX A - - FERC REGULATION SUMMARY

A. FERC Jurisdiction

FERC has jurisdiction over hydroelectric development if any of the following four conditions apply:

- Any part of the project is on Federal lands
- The project affects interstate commerce
- The project is on a navigable waterway
- The project would utilize water from a U.S. government dam

For small projects in Alaska, FERC jurisdiction generally arises because Federal lands are involved. The interstate commerce criteria can sometimes apply if the project would have an impact on a major anadromous fish population. There is a formal process by which a project developer can request FERC to determine if it has jurisdiction.

The Energy Act of 2000 stipulates that the State of Alaska rather than FERC will have jurisdiction over projects of 5 MW or less capacity in the state. The State regulation can only be instituted once FERC certifies that the State regulatory program provides at least the same level of protection of the public interest and the environment as FERC regulation. The State is still developing its program, and so has not yet requested certification. It is unclear whether there will be any real advantage to the State regulatory process.

B. Legislative Context

FERC authority is derived from the Federal Power Act of 1920, as amended over the years. Other legislation and court rulings have modified FERC's authority so that other agencies have significant control over the outcome of a FERC license proceeding. In particular:

- **National Environmental Policy Act of 1969 (NEPA)**: Issuance of a license is considered to be a Federal action that requires documentation of the environmental impacts in accordance with NEPA.
- **Fish and Wildlife Coordination Act**: FERC must consult with and give full consideration to recommendations of the U.S. Fish and Wildlife Service and state fish agencies regarding wildlife aspects of a project.
- **Electric Consumers Protection Act (ECPA)**: ECPA amended the FPA. Amendments significant to new projects in Alaska include: 1) FERC must give equal consideration to power and non-power resources (e.g. fish, water quality); 2) FERC must include in a license conditions for the protection of fish and wildlife based on recommendations of FWS, the National Marine Fisheries Service (NMFS) and state fish and wildlife agencies; and 3) FERC must insure consistency with any comprehensive plans issued by a Federal agency or state applicable to the site.
- **Clean Water Act (CWA)**: FERC will not issue a license until the Corps of Engineers issues a permit authorizing that portion of the work located in a waterway or wetland, in accordance with Section 404 of the CWA. In addition, Section 401 of the CWA requires that the state pollution control agency (Alaska Department of Conservation) certify the project will comply with the CWA.

- **Wilderness Act / Wild and Scenic Rivers Act**: FERC is not allowed to issue a license for a project that would be located in a National Park or National Monument, nor in a National Wilderness Area or on a stream that is a component of the National Wild and Scenic River System.
- **Coastal Zone Management Act**: For projects located in a designated coastal zone, FERC is not allowed to issue a license until the State certifies that the project will be consistent with the Coastal Zone Management Act.
- **Magnuson-Stevens Fishery Conservation and Management Act**: FERC is required to consider protection and mitigation measures recommended by fish agencies if a project could adversely affect essential fish habitat (waters and substrate needed by fish for spawning, feeding, or growth to maturity.
- **Endangered Species Act (ESA)**: FERC must prepare a biological assessment as part of NEPA compliance if the FWS or NMFS determine a project is likely to jeopardize the continued existence of any endangered or threatened species or result in critical habitat destruction.

C. FERC Licensing Process

1. General

The general process for obtaining a FERC license is that the developer prepares a license application and submits it to FERC. FERC then prepares the documentation pursuant to NEPA, either an environmental assessment (EA) or environmental impact statement (EIS), and issues an order either approving or disapproving the construction and operation of the project. An original license is generally issued for a 50-year term. FERC has different requirements for the license application for several classes of projects, as follows:

- Major project (capacity greater than 5.0 MW with construction of a dam)
- Major project – existing dam (capacity greater than 5.0 MW without construction of a dam)
- Major project 5.0 MW or less (capacity between 1.5 MW and 5.0 MW, with or without construction of a dam)
- Minor project (capacity 1.5 MW or less, with or without construction of a dam)

The rules are different for these different classes primarily in the amount of engineering and economic information that must be provided by the developer. However, there is actually little difference in the process or the amount of effort required by the developer, since the effort is mostly associated with addressing the environmental impacts, and that effort is the basically the same for all types of projects.

2. Traditional Licensing Process

Until the mid-1990s, there was only one process used in preparing an application and FERC's subsequent consideration of the application. That procedure is now known as the traditional licensing process (TLP), and includes the following major steps:

- The developer provides preliminary information about the proposed project to various Federal and state agencies, the public, and non-governmental organizations (NGOs) and holds a joint agency/public meeting. Note that the inclusion of the public and NGOs in the initial consultation is a new requirement.

- The public/agencies request studies to be conducted to provide the information required to determine the proposed project's environmental impacts.
- The developer prepares study plans in conjunction with the public/agencies, and then conducts the studies in accordance with the study plans. If the developer and public/agencies cannot agree on the scope of the studies, FERC may be requested to assist in resolving the dispute. However, FERC's role is simply advisory. The developer is not obligated to conduct all of the studies requested by the agencies, but FERC may reject an application if the developer has not conducted studies that FERC believes are justified.
- Once the studies are complete, the developer analyzes the results and prepares a draft license application and submits it to the public/agencies for review and comment. Environmental information is contained in Exhibit E of the application. If there are substantive disagreements between the developer and public/agencies, the developer should attempt to resolve the disagreements through further consultation. However, agreement on all issues it is not required.
- The developer modifies the license application based upon the comments received on the draft license application and submits it as a final application to FERC. Copies are also provided to the public/agencies. The application includes the results of the studies, but it is the developer's proposal, and does not require the approval of the agencies.
- At the same time the developer is preparing the final license application, they prepare and submit an application for water quality certification.
- FERC invites requests for additional studies from the agencies and public, which the developer may comment on.
- FERC reviews the application to determine 1) if it meets the statutory requirements, and 2) if additional information is required. If FERC believes additional studies are required, it will request the additional information.
- Once FERC has all the necessary information, it accepts the application and invites protests and interventions.
- FERC then begins the NEPA review process. If the project is deemed to not have significant adverse impacts, then an EA is called for. If the project will have adverse impacts that can be mitigated, then an EIS is called for. If the project will have adverse impacts that cannot be mitigated, then the application will be dismissed.
- FERC will first prepare a scoping document for review by the agencies and public, hold a scoping meeting, and issue a revised scoping document. As a result of the scoping, FERC may request additional information from the developer.
- Once FERC has all the necessary information, it will request the agencies to submit their requirements and/or recommendations for mitigation measures to be included in the license. As noted above, many of these are mandatory conditions

that FERC cannot change, and some are recommendations. The developer is given the opportunity to comment on the agency terms and conditions.

- FERC then prepares a draft environmental document (EA or EIS) based upon the developer's application, site visits, scoping meeting, independent research and analysis, and public and agency comments. The draft environmental document is distributed for review and comment.
- If FERC has modified or not included any of the fish and wildlife recommendations, it attempts to resolve the issues with the appropriate agency through a process known as a 10(j) negotiation.
- The developer, agencies, and public submit comments on the draft environmental document.
- FERC then modifies its analysis, responds to comments, and issues the final environmental document.
- The licensing order is then issued. FERC may deny the application; however, more typically they issue a license with many conditions and requirements for environmental mitigation. It is then up to the developer to determine if it makes economic sense to construct the project. The developer may accept the order or file for rehearing if there are problems. Agencies may also request rehearing.

3. Alternative Licensing Process

As the TLP has evolved, it has become rather cumbersome and time consuming. In the early 1990s, a large number of original licenses expired, which resulted in many applications for new licenses and very slow processing of applications by FERC. As a result, FERC developed a second process, now known as the alternative licensing process (ALP) for use on projects that will require only an EA for the NEPA environmental document. The most significant differences between the TLP and the ALP are:

- The developer prepares a preliminary draft of the NEPA EA instead of the Exhibit E Environmental Report of the license application. This was intended to be a means of speeding up licensing by avoiding some of the duplication involved in the TLP, especially regarding study scoping.
- Agencies file preliminary recommendations and conditions with FERC after review of the preliminary draft of the NEPA EA prepared by the developer. They then file final terms and conditions with FERC after FERC has reviewed and accepted the application.

The ALP only works if the developer and the agencies/NGOs can work together cooperatively and in good faith, and so there is a formal process by which the developer must lay the groundwork with the agencies/NGOs and request approval from FERC to use the ALP.

In recent years, many applications have included settlement agreements, wherein the developer and agencies/NGOs resolve any issues between themselves for review by FERC and incorporation into the license proceeding.

4. Integrated Licensing Process

In response to complaints about the length of time required to obtain a license by either the TLP or ALP, FERC on October 23, 2003, instituted a third process, known as the integrated licensing process (ILP). Until July 23, 2005, a developer may choose any of the three processes. After July 23, 2005, the integrated licensing process will be the default, and the other processes may only be used with FERC approval after a showing of good cause.

The most significant differences with the ILP are:

- There are deadlines for each step in the process that are binding on the developer, the agencies, and FERC.
- The initial scoping document is replaced by a Notification of Intent (NOI) and Pre-Application Document (PAD), which together constitute very preliminary drafts of the application and NEPA document. The PAD is also the basis for the initial scoping document, which is issued by FERC, and the Preliminary Licensing Proposal, which is prepared by the developer.
- FERC is actively involved in the early stages of the process, whereas with the TLP and ALP FERC is usually not active until the application is filed.
- FERC will initiate a binding dispute resolution process if the developer and agencies cannot agree on the studies that need to be conducted. Agencies are also required to clearly justify their study requests.

FERC expects the ILP will result in projects being licensed in 5.5 years, and has indicated a strong commitment to making the process achieve that goal. However, as there is no track record, it is impossible to say whether that goal can actually be achieved.

The ILP is geared primarily towards relicensing of existing projects, but they have indicated that they intend to use the ILP for original licensing as well. This will cause some duplication, as the NOI includes much of the same information as an application for a preliminary permit, which is usually sought by a developer of a new project.