A COMPARATIVE ECONOMIC ANALYSIS OF ELECTRIC ENERGY ALTERNATIVES FOR ANGOON, ALASKA

PREPARED BY

ACRES

FEBRUARY, 1984

ALASKA POWER AUTHORITY

ALASKA POWER AUTHORITY

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March 22, 1984

To Interested Agencies and Organizations, and to the Public at Large:

Enclosed is the final report of A comparative Economic Analysis of Electric Energy Alternatives for Angoon, Alaska. This report is very similar to the draft report circulated during the fall. It puts the cost estimates of a number of earlier reports on a common economic base (1983 dollars) so that the economics of the proposed hydro facility can be compared with continued dependence upon diesel-produced electricity. It also examines how the economics of the associated salmon hatchery affects the costs of the hydro facility.

This final report incorporates comments on the draft received from various agencies, organizations, and from the Alaska Power Authority's own review. The most important change is the use of 1983 salmon prices in analysis of the hatchery economics. Other somewhat less evident changes were also made throughout the report.

The conclusions and recommendations that appear in this report are those of the consulting engineer, not those of the Power Authority. Assumptions concerning pricing and financing mechanisms were made in order to calculate economic benefits and costs; they do not represent existing State policy. The Power Authority's Findings and Recommendations will be circulated separately and will use the information in this report.

Thank you for your interest, and if you have any comments or questions, please do not hesitate to write or call.

Sincerely,

Larry D. Crawford

Larry D. Crawford
Executive Director

BL/LDC/sc

Enclosure: Angoon Distribution List

290/140

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March 22, 1984

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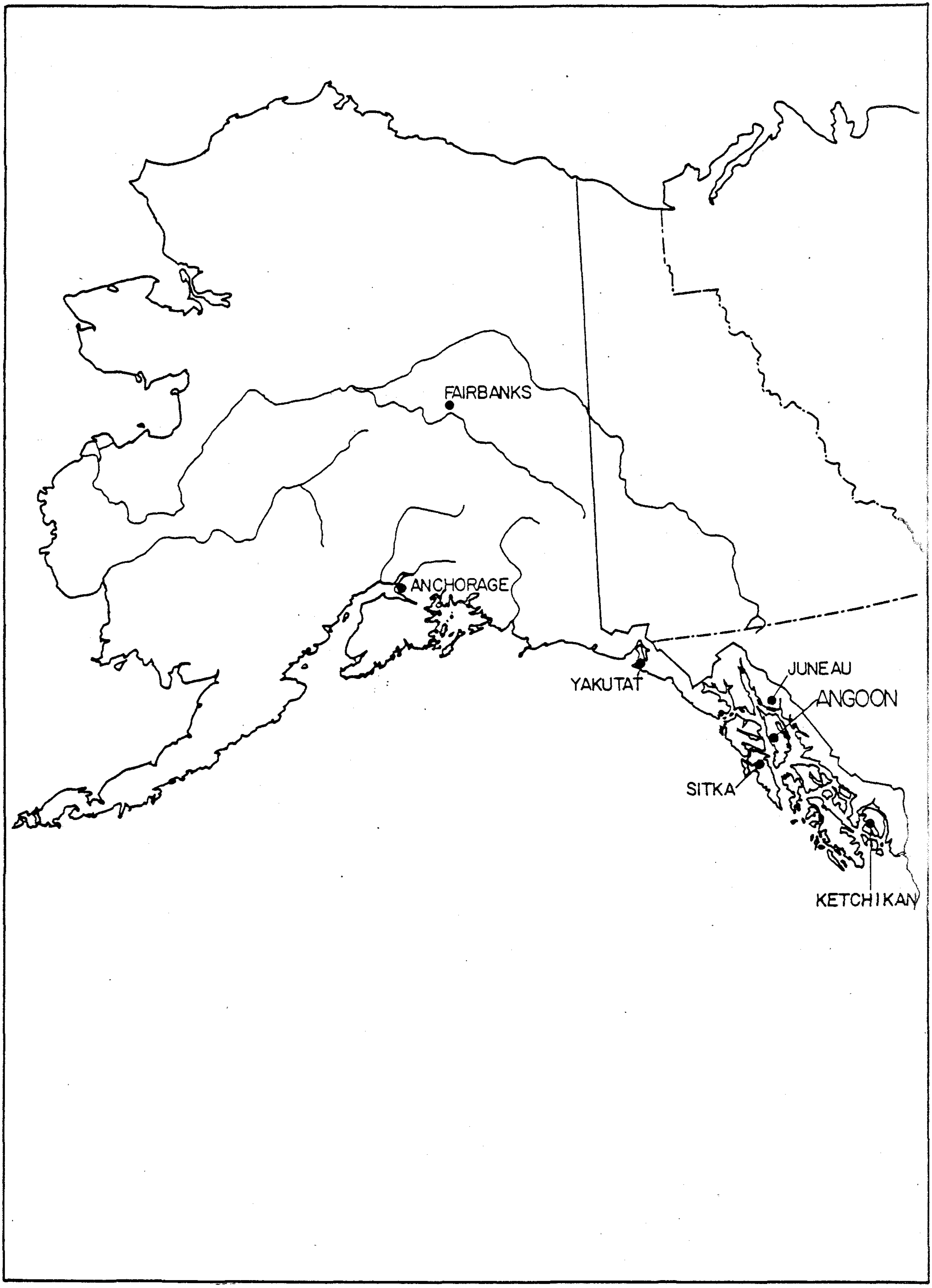

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A - INTRODUCTION

This report is the result of work performed by the Anchorage office of Acres American Incorporated in 1983 at the request of the Alaska Power Authority.

As a result of a number of reconnaissance-level and other studies done for APA, there is a good deal of interest in the development of a small hydroelectric site near Angoon. Because these earlier works were done over a span of years, their cost estimates cannot be compared directly from one report to another. Thus, an old report's estimate may not have much relevance in light of current costs of operating the diesel generating system in Angoon. It is the goal of this report to put the cost estimates of the earlier works on a common economic base (1983 dollars) so that the value of the hydro plant(s) proposed can be compared to the costs of continued dependence upon diesel-produced electricity.

This report examines the economics of a salmon hatchery in concert with the costs of the hydro facility. Since a hatchery would likely be "required" if a hydro plant and its dam were to be built near Angoon, this is considered to be a reasonable approach. Current Alaska Division of Fish and Game policy seeks to protect salmon habitat where possible, and the inclusion of a hatchery in a hydro project would mitigate the loss of spawning habitat.

B - SUMMARY AND RECOMMENDATIONS

It is the general finding of this report that the development of a small hydroelectric facility on Favorite Bay Creek may have economic advantages for the community of Angoon when compared to the present system which uses diesel fuel for power generation.

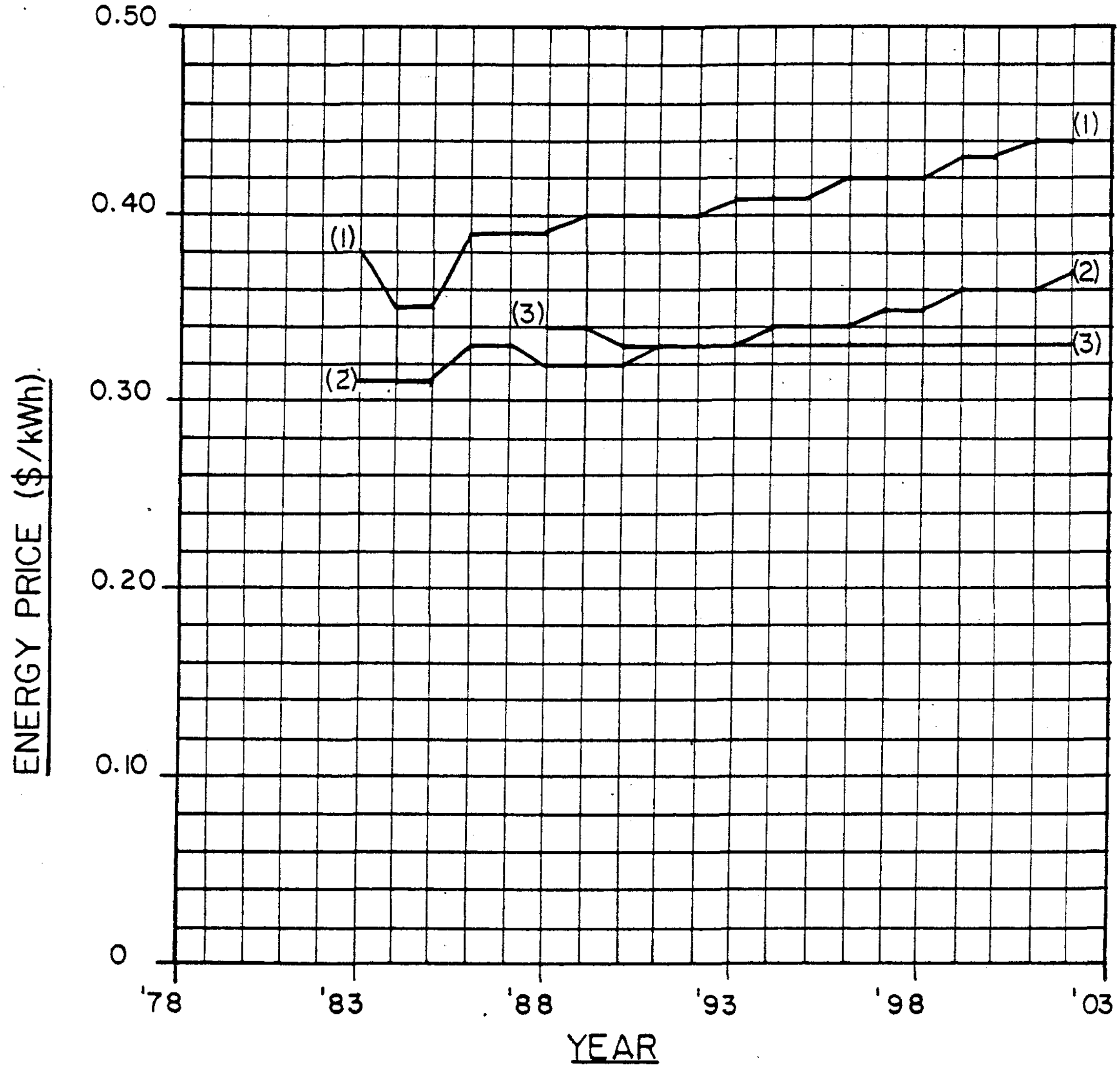
In the eight months between the issuance of the draft version of this report and the final, State agencies have had an opportunity to compile data on the value of salmon harvested from Southeast Alaska waters in 1983. Many of the assumptions used in the draft report regarding the value of fish to be taken by the Angoon Aquaculture Association have been significantly altered by using this more recent data. In contrast to the support given to the Falls Creek project in the draft, it now appears that such an enthusiastic endorsement should not be given without further investigation of the volatility of the salmon market and its possible future trends. The Monte Carlo techniques introduced in Appendix A attempt to probe the implications of varying salmon prices and load growths. The reader is cautioned to interpret the results given in Appendix A as tenative.

There is no available source of energy which can produce "cheap" electricity for the Angoon. Electricity produced at a Favorite Bay site and distributed through the existing Tlingit-Haida Rural Electric Association system will cost about $0.34 per kilowatthour. This is about the same as would be paid for diesel power in 1988, the first year that a Favorite Bay hydro plant is assumed to be available. The advantage of the hydro energy is that it will not escallate as the price of fuel oil rises. The cost of electricity to the consumer would be expected to remain stable at the $0.34/kWh level over the lifetime of the project. Diesel-generated power, on the other hand could be expected to rise to $0.37 to $0.44 per kWh (in 1983 dollars) by the end of the 20th century (see Figure 1).

Other alternatives, including another hydroelectric site, were not found to have any economic advantage for Angoon.

The economic advantage of the Favorite Bay hydro site disappears at low energy use rates because of the high fixed costs involved in such a plant.

If a hydro plant were to be built at Favorite Bay, it is probable that a hatchery would be required by ADF&G to mitigate salmon habitat losses. An application has been made to ADF&G by the Angoon Aquaculture Association for a permit to build a salmon hatchery at Favorite Bay. A permit will not be granted without provision for an impoundment area (dam and reservoir) to ensure adequate water supplies during times of low water or during the winter when the stream is frozen.



Notes:

1. Curve (1) - (1) shows energy prices under the assumptions given in low-growth case if THREA diesel generation is continued.
2. Curve (2) - (2) shows energy prices under the assumptions given in high-growth case if THREA diesel generation is continued.
3. Curve (3) - (3) shows energy prices with a Favorite Bay hydro plant coming on-line in 1988 under the assumptions given in the high-growth case. Energy prices with low consumption are off the top of this graph.
4. No consideration is given to any state subsidy programs.

FIGURE 1 - ANGOON ELECTRICITY PRICES

This report assumes that electric utility customers would not be willing to pay any more for electricity generated by a hydro plant than they do for a diesel plant. It is further assumed that there are no available "subsidies" and that the hydro plant and hatchery must "pay their own way." This constraint limits the revenue generated by the power plant to a level adequate to pay for those structures directly associated with power generation (powerhouse, generators, transmission line, etc.) and 25 percent of the cost of the dam and intake structure, which is "shared" with the hatchery. Later, the report shows that salmon harvest revenues to the Aquaculture Association may not be sufficient to pay for 75 percent of the dam and intake structure costs.

Hatchery operation and increased production at the Angoon cold storage plant would drive up energy use, reducing the per-unit cost of electricity for all consumers in the village.

It should be kept in mind while reviewing this report that the introduction of a hydroelectric plant and salmon hatchery at Angoon has implications far beyond the supply of electricity at a stable price. The improvement in the area's salmon fishery may be able to provide a significant improvement in the general standard of living for many of Angoon's residents.

Before construction can be started on a Favorite Bay hydro plant, detailed studies are needed to verify many of the assumptions used in this study. It is conceded that much of the work presented in this report (and no doubt in reports by others) is rough. This report serves to guide others to focus their attention on the Favorite Bay hydro project, as it seems to provide the most benefits to the village of Angoon for the forseeable future. The studies listed below are recommended. It is the opinion of Acres' staff that they should be commenced in the near future so that unforseen circumstances do not unnecessarily delay the completion of the project:

1. A continuous stream gaging station should be established in the vicinity of the proposed dam site. Existing streamflow data are largely synthesized from USGS data taken at other locations and verified, where possible, by occasional measurements taken at the site.

2. Geotechnical explorations should be undertaken at the dam site to establish foundation conditions.

3. Area geology should be thoroughly explored to identify candidate sites for quarries which would be needed for a rock- or earth-fill dam. Quantities on the order of 100,000 to 150,000 cubic yards of rock would be needed for a Favorite Bay dam. An unknown, but lesser, quantity of aggregate would also be needed for the construction of the hatchery and powerhouse.

4. The implications of the use of National Monument land should be explored. Initial reports indicate that the US Forest Service may be favorably disposed toward a Favorite Bay project, but this needs to be clarified. The involvement of federal lands and a project of this magnitude will likely require the production of a formal environmental impact statement. The preparation of an EIS is typically a very involved process, sometimes taking a number of years. The requirements of the Federal Energy Regulatory Commission (FERC) should also be investigated.

5. Alternative designs for the dam need to be explored. Techniques such as using siphon intakes (which could minimize the cost of intake structures) could simplify the dam design. The use of centrifugal pumps (which are available as off-the-shelf units) instead of limited-production or custom built water turbines can also sometimes represent significant savings.

6. The construction permit for the hatchery needs to be expedited as much as possible. Hatchery construction goes hand-in-hand with the hydro plant.

7. Attention must be given to the details of sharing capital costs between the hatchery and the hydro plant. A study should be initiated to examine the financing of these separate, but related, projects. The alternative methods of financing the projects should be addressed, including the availability of private capital to construct the hydro plant.

The course taken by this report generally follows that taken by other reports prepared by Acres American for the Alaska Power Authority to evaluate the economics of various energy alternatives.

First, forecasts are developed to provide some understanding of the need for energy in future years. To the extent possible, the forecasts take into account potential new users of energy within the community being studied. The effect these new users may have on the population growth and economic activity of the community is then considered.

In the case of Angoon, it is not considered likely that major industrial or commercial development will take place any time in the study period (20 years into the future). The only "significant" developments forseeable are the new cold storage facility and perhaps a hatchery. It does not seem likely that the introduction of these facilities will cause the development of other energy-consuming facilities. Thus, we would expect that the growth of energy use in Angoon would increase very slowly through the end of this century.

The next step in the analysis of energy economics for a small community involves the examination of those energy resources readily available. In the case of Angoon, that would include diesel generation (as currently provided by the Tlingit & Haida Regional Electrical Authority, or "THREA"), hydroelectric power from a proposed site on Falls Creek, and perhaps wind energy.

Finally, the cost of supplying the forecast energy demands with the available alternatives is studied. The life-cycle (or "present worth") costs of the alternatives are compared to establish the most economical means of providing energy to the community.

In the study of energy economics at Angoon, an interesting case develops as a result of the availability of the Falls Creek hydro site. If the hydro site is not developed, it is possible that the village could move into a future of very low energy growth. Under most circumstances, a conservative approach to take when evaluating a hydro plant is to assume a low energy growth rate. This makes the electricity from such a plant considerably more expensive. However, in the case of Angoon, such an approach is inappropriate. If a hydro plant is built, a hatchery must be built to mitigate the loss of a salmon spawning stream. The hatchery will, by itself, provide a large increase in the energy used in the community. The higher load forecast which results from the existence of the hatchery will cause the economic calculations to show less expensive electricity from the hydro site. For this reason, the Falls Creek hydro plant will not be evaluated using the lowest-growth forecasts.

The economics of the Falls Creek hydro facility will be evaluated under two assumptions of energy growth: (1) The dam and hatchery will be in place, but the cold storage plant (the other "large" load in Angoon) will operate only 3 months out of the year and (2) same as 1 except that the cold storage plant will operate 10 months of the year as a result of the increase in the area's bottomfish industry.

C - FUTURE LOADS

A key element in the cost of electricity to the consumer from a particular power system is the amount of energy purchased from that system. In general, the more energy consumed or purchased, the less each unit of energy should cost.

Studies done by Harza (1979), Retherford (1981), and Tryck, Nyman & Hayes (1981) have all based their load growth projections on forecast work done by the Tlingit & Haida Regional Electrical Authority (THREA) in 1979. Since that time, THREA has developed a revised forecast of energy use and demand growth (1983). The new forecast anticipates less growth of the Angoon load than did the old one. The differences are shown in the table below:

TABLE 1 -- THREA ENERGY FORECASTS

	ENERGY USE			POWER DEMAND		
YEAR	OLD FORECAST	NEW FORECAST	PCT. CHANGE	OLD FORECAST	NEW FORECAST	PCT. CHANGE
1978	680 MWh	680 MWh	--	171 kW	171 kW	--
1983	1,200	1,050	-12.5	304	295	-3.0
1988	1,290	1,200	- 7.0	327	327	--
1993	1,390	1,200	-13.7	353	340	-3.7

The approach used by THREA to produce their forecasts was to examine the historic trend of energy use (and power demand) for several years prior to the forecast. These trends were then used to develop mathematical descriptions of future load growth rates. This method has been used for a number of years by utilities which are financed by the Rural Electrification Administration (REA).

The REA method is limited in its ability to anticipate the effect of possible capital developments or political actions which may cause alterations in the trend of energy growth rates. Any "adjustment" to the forecast must be made "by hand" by the REA investigators. To the extent possible, THREA has made these adjustments. However, they have not considered the impact which the cold storage plant or the hatchery would have on energy use growth. One reason the cold storage plant was not included in THREA forecasts is that the nearest power line to the plant is about three miles away. Although the construction of a new power line to the cold storage plant may be expensive for the plant, it is probable that, over it's lifetime, power purchased from THREA may be less expensive than self-generated power. Additionally, the new THREA forecasts do not take into account the effect which the elimination of the state's Power Cost Assistance Program would have on energy use in Angoon.

PCAP effectively reduces the cost of electricity to the consumer as much as 50 percent and has greatly influenced recent growth of electricity consumption in rural communities. As an example, in Angoon during 1982 (the first full year the subsidy was available), 1,000,354 kWh were sold. This represents an increase of about 18 percent over 1981 energy sales, which were themselves a decrease from 1980 Angoon sales. Even with PCAP available, it is our understanding that electric bills in Angoon are frequently over $100. Without PCAP, this same bill (for about 700 kWh) would be about $200. Such an expenditure would take a very significant part of a family's disposable income. It would be likely that the discontinuance of the PCAP subsidies would lead to a reduction in residential energy consumption.

Public consumers (schools, community buildings, street lighting systems, etc.) also benefit from PCAP. They are eligible for PCAP support for an amount of electricity which is dependent upon their village's population. The elimination of PCAP would undoubtedly cause significant hardship for many rural governments.

Presently (for fiscal year 1983, which ended July 1, 1983), the PCAP subsidy is set up to cover 95 percent of a residential customer's electricity cost over 14 cents/kWh for the first 600 kWh of their consumption. Funding for PCAP in fiscal year 1984 was not made available by the legislature to the extent that is has been in previous years. It is likely that the program's administrator, the Alaska Power Authority will raise the cost ceiling from 14 cents/kWh to some higher level (as yet unknown) to make their available funding go farther. There is some sentiment in the legislature to do away with this program entirely, something which becomes more probable as state oil revenues continue to fall off.

For purposes of this report, it will be assumed that PCAP subsidies will be available (although is diminishing amounts) through the end of calendar year 1986. Since the 1983 legislature has left the program intact and 1984 is an election year, it is unlikely that the 1984 legislature will eliminate the program. This report will assume that the 1985 legislature will terminate PCAP altogether with funding to end at the end of calendar year 1985 (a simplifying assumption, since funds will likely not continue past June 1985, the end of the fiscal year). In 1986, there will be an immediate 20 percent reduction in residential consumption. As oil prices continue to rise, there will be little to no growth in that sector throughout the remainder of the forecast period (1983 - 2002). Public and commercial users will continue to use the same amount of energy they would have if the program had continued.

An unfortunate effect of this reduced energy use is that each unit of energy (kWh) will have to cost the consumer more to pay for the utilities' fixed costs (equipment capitalization, administration, fixed maintenance, etc). This will have the effect of reducing consumption further, driving kWh prices up more, reducing consumption, etc, etc.

We will use the THREA 1983 forecast as an upper limit for Angoon energy consumption and load (after appropriate changes have been made to take into account the cold-storage plant). The lower limit forecast will take THREA's forecast and modify it to show a 40 percent reduction in residential consumption occurring in 1986 with growth thereafter due only to new housing units. We will assume that 2 new homes will be built in Angoon each year from 1983 through 1987, 1 home per year from 1988 through 1997, with no new homes added for 1998 - 2002. In 1982, the "average" Angoon residential customer used about 4,370 kWh (360 kWh per month). This will be considered to remain constant from 1983 to 1986 when the annual residential consumption will fall to 3,311 kWh (276 kWh per month).

It is assumed that: (1) the new cold-storage facility will become fully operational in 1985; (2) if it is used only for the salmon season, it will only be used for three months each year; (3) if a bottomfish industry develops in the area, the cold-storage plant could be operated for 10 months out of the year. The new cold-storage plant load is calculated as follows:

TABLE 2 -- COLD STORAGE PLANT LOADS

Load	Power Demand	Load Factor	MWh/month	3 month MWh	10 month MWh
100 hp Air compr.	76 kW	0.6	33	99	330
25 hp Ice maker	20	0.3	4	12	40
15 hp Process equip.	12	1.0	9	27	90
15 hp Refrigeration	12	0.6	5	15	50
Lights & Misc.	5	1.0	4	12	40
TOTALS	125 kW		55	165	550

Note: 1 MWh = 1,000 kWh

In addition to this cold-storage plant, there is some possibility of a fish hatchery being constructed in Angoon. It will be assumed to begin operation in 1988, with the following loads:

TABLE 3 -- HATCHERY PLANT LOADS

Load	Power Demand	Load Factor	MWh/month	MWh/year
3 20 hp Pumps	40 kW	0.6	17	204
Lights & Misc.	5	0.7	2	24
TOTALS	45 kW		19	228

From the above, three distincly different load forecasts were developed. The assumptions under which these three forecasts were made are as follows:

1. A "low-growth" forecast was developed wherein no hatchery was constructed and the cold storage plant operated only three months each year.

2. A "moderate-growth" forecast was developed in which the Falls Creek hatchery and hydro plant are included and the cold storage plant operates only three months each year.

3. A "high-growth" forecast is virtually the same as "2" with the exception that the cold storage plant operates ten months of the year.

The economics of the hydro plant are evaluated only under the growth conditions described by "2" and "3." A year-by-year forecast for 1983 through 2002 is given on Table 4 on the following page for each of these conditions.

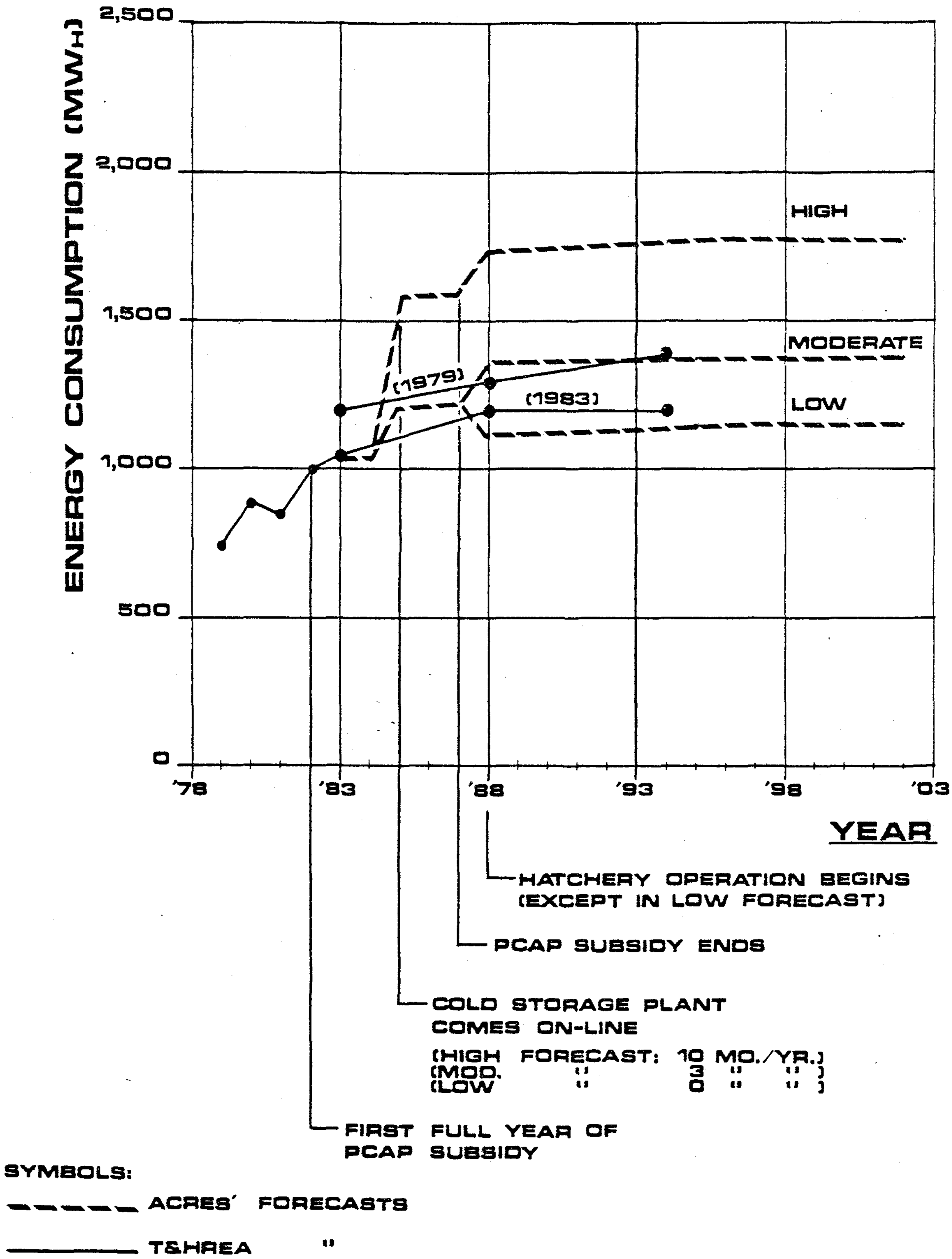
TABLE 4

ENERGY USE AND POWER DEMAND FORECASTS FOR ANGOON, ALASKA

1983 - 2003

YEAR	1979 THREA FORECAST		1983 THREA FORECAST		ACRES' FORECASTS HIGH-GROWTH FORECAST		ACRES' FORECASTS MODERATE-GROWTH FORECAST		ACRES' FORECASTS LOW-GROWTH FORECAST		REMARKS
	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	
1983	304	1,200	290	1,060	289	1,020	289	1,020	289	1,020	
1984					292	1,577	292	1,028	292	1,028	2 new homes
1985					419	1,587	419	1,202	419	1,202	cold storage plant on-line; 2 new homes
1986					424	1,596	424	1,211	424	1,211	2 new homes
1987					429	1,605	429	1,220	429	1,220	last year of PCAP; 2 new homes
1988	327	1,290	330	1,200	477	1,735	477	1,350	432	1,122	hatchery/dam in moderate & high; 1 new home
1989					479	1,739	479	1,354	434	1,126	1 new home
1990					481	1,743	481	1,358	436	1,130	" " "
1991					484	1,746	484	1,361	439	1,133	" " "
1992					487	1,749	487	1,364	442	1,136	" " "
1993	353	1,390	340	1,200	489	1,753	489	1,368	444	1,140	" " "
1994					491	1,757	491	1,372	446	1,144	" " "
1995					494	1,762	494	1,375	449	1,147	" " "
1996					497	1,763	497	1,378	452	1,150	" " "
1997					499	1,767	499	1,382	454	1,154	" " "
1998					499	1,767	499	1,382	454	1,154	no additional homes through study period
1999					499	1,767	499	1,382	454	1,154	
2000					499	1,767	499	1,382	454	1,154	
2001					499	1,767	499	1,382	454	1,154	
2002					499	1,767	499	1,382	454	1,154	

Notes: The differences in Acres' "Low," "Moderate," and "High" growth forecasts result from: (1) cold storage plant operaged only 3 months per year, no hatchery in the "Low" forecast; (2) cold storage plant operates 3 months, hatchery in operation in the "Moderate" forecast; (3) cold storage plant operates 10 months per year, hatchery in operation in "High" growth forecast.



ACRES

FIGURE 2

FORECASTS OF ENERGY
CONSUMPTION IN ANGOON

D - FUTURE COST OF POWER PROVIDED BY THREA DIESEL SYSTEM

The existing power system at Angoon, owned by the Tlingit and Haida Regional Electrical Authority (THREA) consists of three diesel units rated at 250, 300, and 400 kW for a firm capacity of 550 kW (250 + 300 kW, assuming that the largest of the machines may be unavailable for service). Since the greatest load anticipated in Angoon for the next 20 years is only about 360 kW (see Part C), it can be seen that the generating capacity will not have to be increased. This report will assume that, when the existing units are replaced at the end of their service lives, they will be replaced with identical units.

Because electric utilities are capital-intensive, they have very large annual costs which are fixed. That is to say that even if THREA were to stop generating power altogether, they would have ongoing financial obligations to cover such items as financing of their equipment, administrative charges, maintenance of equipment and power lines, insurance, taxes, etc. In 1982, of THREA's expenditures of $2.25 million, just less than half (about $1.1 million) were fixed expenses. Because of these high fixed charges, utility systems which sell relatively small amounts of energy (such as THREA) have cost structures which are sensitive to changes in sales levels: the more energy which is sold, the less its per-kWh price becomes. Conversely, if less energy is sold, each unit of energy must be sold at a higher price.

Using information obtained from THREA's 1982 Annual Report to the Alaska Public Utilities commission, Acres has broken expense data into categories of fixed and variable costs. These are summarized on Table 5 on the following page.

Total fixed costs for the system in 1982 were $1,108,704; variable costs were $1,140,107. Since not all of the fixed costs can be reasonably charged to any one of the five THREA villages, they have been allocated on a per-customer basis. In 1982, THREA reported that they had a total of 779 customers, with 144 in Angoon. Therefore, the fixed costs allocated to Angoon for 1982 were:

$$\$1,108,704 \times (144 \div 779) = \$204,946$$

Variable costs were allocated equally throughout the system on a per-kWh basis. These variable cost rate was calculated to be:

$$\$1,140,107 \div 6,562,000 \text{ kWh} = \$0.1737/\text{kWh}$$

Part of these variable costs are due to fuel ($780,475 in 1982, or 68.46 percent of the total variable costs), the remainder are due to maintenance and bad debt expenses ($333,862 and $25,770 respectively). The per-kWh cost of fuel can be expected to escallate in real terms (1983 dollars) at a rate greater than general inflation. Calculations which follow assume that fuel prices will increase 2.5 percent faster (on an annual basis) than general inflation. All other costs are assumed to remain constant relative to the general inflation rate.

TABLE 5

ALLOCATION OF FIXED AND VARIABLE COSTS IN THE THREA SYSTEM

(Based upon data taken from THREA's 1982 Annual Report to APUC)

VARIABLE COSTS

Item	Amount
** * Fuel	$ 780,475
* Generation Expenses	276,615
* Miscellaneous Other Power Generation Expenses	57,247
Uncollectible Accounts	25,770
TOTAL VARIABLE COSTS:	$1,140,107

FIXED COSTS

Item	Amount
Operation Supervision and Engineering	$ 22
Rents	29,876
Maintenance Supervision and Engineering (Generation)	5,729
Maintenance of Structures	1,039
Maintenance of Generating and Electric Plant	150,111
Maintenance of Miscellaneous Other Power Generation Plant	773
Operation Supervision and Engineering	1,247
Overhead Line Expenses	25,116
Street Lighting and Signal System Expenses	132
Meter Expenses	7,360
Miscellaneous Distribution Expenses	18,817
Maintenance Supervision and Engineering (Distribution)	1,303
Maintenance of Overhead Lines	7,746
Maintenance of Underground Lines	75
Maintenance of Street Lighting and Signal Systems	1,558
Maintenance of Meters	357
Supervision (Customer Accounts)	7,120
Meter Reading Expenses	5,144
Customer Records and Collection Expenses	60,389
Administrative and General Salaries	129,099
Office Supplies and Expenses	50,908
Outside Services Employed	17,559
Property Insurance	13,592
Injuries and Damages	32,265
Employee Pensions and Benefits	110,326
Franchise Requirements	45,156
Regulatory Commission Expenses	9,913

(continued on next page)

*Cost of these items may be eliminated by alternative energy sources.
**Cost of fuel is expected to rise relative to inflation.

FIXED COSTS (continued)

Item	Amount
General Advertising Expenses	$ 19,872
Miscellaneous General Expenses	27,826
Depreciation	206,436
Taxes	9,793
Interest on Long-Term Debt	126,926
Interest and Dividend Income	(14,881)
TOTAL FIXED COSTS:	$1,108,704

It is important to keep in mind that under varying circumstances, many of the costs called "fixed" or "variable" here may switch categories. Different utilities have developed their own method of differentiating between fixed and variable costs.

It is also important to note that the fixed costs are "fixed" only over a relatively narrow range of energy production and power demand. The retention of the allocation of fixed and variable costs in the manner discussed here is done for simplification of the report calculations.

There are only a few of these costs which would be decreased or eliminated with the construction of a hydroelectric plant (or other alternative energy source) at Angoon. These are:

- Fuel ($780,475 in 1982)
- Generation Expenses ($276,615 in 1982)
- Miscellaneous Other Power Generation Expenses ($ 57,247 in 1982)

The total of these "displaceable" costs ($1,114,337) represents almost 50 percent of THREA's costs which we have allocated to Angoon.

The "benchmark" against which other alternatives must be compared is the existing THREA diesel system. Throughout this report, this benchmark system is called the "base case" plan. The costs associated with operating this system on into the future are calculated for each year of the study. In this case, our study must extend for the entire 50 year life of the proposed hydroelectric plant which will be assumed to be put "on-line" in 1988. Therefore, the study period will be 1983 - 2037. Load growth and fuel price escallation are both assumed to stop after 2002. The "net present worth" of all of the future years' is calculated using a 3.5 percent annual rate.

The calculations used to produce the net present worth of the Angoon are shown on Tables 6 and 7. Note that the "Approximate Energy Sales Price" shown does not include any subsidy discounts.

The construction of a waste heat recovery system on the THREA generators by the Alaska Power Authority complicates the calculation of utility system economics in Angoon. The heat energy recovered by that system is being used by the sewage treatment plant, the grade school, the high school gym, and the teachers' quarters. It is estimated that this recovered waste heat eliminates the need for about 14,600 gallons of heating oil in these buildings each year. At current prices of $1.98 per gallon (delivered), this heat is "worth" about $28,900 per year. The Alaska Power Authority has no plans to charge for the heat, so the affected building owners realize a combined "benefit" of $28,900 each year. This is treated as a savings against the annual cost of power production in Angoon, even though the village residents will never see a recduction in their electric bills as a result of the waste heat system installation. The installation and annual maintenance costs must be added to the system costs as well. These calculations are shown separately, on Table 8 so that the energy costs shown on Tables 6 and 7 will not be distorted by the economics of the waste heat system.

Present worth calculations of the system operation for the years 1983 through 2037 (50 years after the assumed on-line date for a Favorite Bay hydro plant) assuming an interest rate of 3.5 percent shows a lowgrowth plan to have a present worth of $11,657,000. Similarly, the high-growth plan has a present worth of $15,049,000. When the benefits of the waste heat system are considered (which will reduce each of these costs by $604,000), we reach net present worths of:

LOW-GROWTH BASE CASE:	$11,053,000
HIGH-GROWTH BASE CASE:	$14,445,000

The "net present worth" of a plan is the amount of money which would have to be invested in January of 1983 to cover all future expenses of that plan while earning a particular rate of return (in this case 3.5% annually).

TABLE 6

COSTS OF BASE CASE PLAN FOR ANGOON UNDER LOW-GROWTH FORECAST

1983 - 2037

YEAR	LOW-GROWTH FORECAST (MWh)	VARIABLE COSTS: DISPLACEABLE: ESCALATING (Fuel) ($/kWh)	VARIABLE COSTS: DISPLACEABLE: NON-ESCALATING (O&M, etc.) ($/kWh)	VARIABLE COSTS: NON-DISPLACEABLE: NON-ESCALATING (Uncoll. Accts.) ($/kWh)	TOTAL VARIABLE COSTS ($1,000)	FIXED COSTS: TOTAL ($1,000)	TOTAL SYSTEM COSTS ($1,000)	APPROX. ENERGY SALES PRICE ($/kWh)	PRESENT WORTH OF TOTAL SYSTEM COSTS ($1,000)
1983	1,020	0.119	0.051	0.004	177	205	382	.375	369
1984	1,028	0.122	0.051	0.004	182	205	387	.376	361
1985	1,202	0.125	0.051	0.004	216	205	421	.351	380
1986	1,211	0.128	0.051	0.004	222	205	427	.352	372
1987	1,220	0.131	0.051	0.004	227	205	432	.354	364
1988	1,122	0.135	0.051	0.004	213	205	418	.373	340
1989	1,126	0.138	0.051	0.004	217	205	422	.375	332
1990	1,130	0.141	0.051	0.004	221	205	426	.377	324
1991	1,133	0.145	0.051	0.004	227	205	432	.381	317
1992	1,136	0.149	0.051	0.004	232	205	437	.384	310
1993	1,140	0.152	0.051	0.004	236	205	441	.387	302
1994	1,144	0.156	0.051	0.004	241	205	446	.390	295
1995	1,147	0.160	0.051	0.004	247	205	452	.394	289
1996	1,150	0.164	0.051	0.004	252	205	457	.397	282
1997	1,154	0.168	0.051	0.004	257	205	462	.401	276
1998	1,154	0.172	0.051	0.004	262	205	467	.405	269
1999	1,154	0.176	0.051	0.004	267	205	472	.409	263
2000	1,154	0.181	0.051	0.004	272	205	477	.414	257
2001	1,154	0.186	0.051	0.004	278	205	483	.419	251
2002	1,154	0.190	0.051	0.004	283	205	488	.423	245
'03 - '37	1,154	0.190	0.051	0.004	283	205	488	.423	4,669

TOTAL: 10,867

TABLE 7

COSTS OF BASE CASE PLAN FOR ANGOON UNDER MODERATE-GROWTH FORECAST

1983 - 2037

YEAR	MODERATE GROWTH FORECAST (MWh)	VARIABLE COSTS DISPLACEABLE ESCALATING (Fuel) ($/kWh)	DISPLACEABLE NON-ESCALATING (O&M, etc.) ($/kWh)	NON-DISPLACEABLE NON-ESCALATING (Uncoll. Accts.) ($/kWh)	TOTAL VARIABLE COSTS ($1,000)	FIXED COSTS TOTAL ($1,000)	TOTAL SYSTEM COSTS ($1,000)	APPROX. ENERGY SALES PRICE ($/kWh)	PRESENT WORTH OF TOTAL SYSTEM COSTS ($1,000)
1983	1,020	0.119	0.051	0.004	177	205	382	.375	369
1984	1,028	0.122	0.051	0.004	182	205	387	.376	361
1985	1,202	0.125	0.051	0.004	216	205	421	.351	380
1986	1,211	0.128	0.051	0.004	222	205	427	.352	372
1987	1,220	0.131	0.051	0.004	227	205	432	.354	364
1988	1,350	0.135	0.051	0.004	257	205	462	.342	376
1989	1,354	0.138	0.051	0.004	261	205	466	.344	366
1990	1,358	0.141	0.051	0.004	266	205	471	.347	358
1991	1,361	0.145	0.051	0.004	272	205	477	.351	350
1992	1,364	0.149	0.051	0.004	278	205	483	.354	342
1993	1,368	0.152	0.051	0.004	283	205	488	.357	334
1994	1,372	0.156	0.051	0.004	289	205	494	.360	327
1995	1,375	0.160	0.051	0.004	296	205	501	.364	320
1996	1,378	0.164	0.051	0.004	302	205	507	.368	313
1997	1,382	0.168	0.051	0.004	308	205	513	.371	306
1998	1,382	0.172	0.051	0.004	314	205	519	.375	299
1999	1,382	0.176	0.051	0.004	319	205	524	.379	292
2000	1,382	0.181	0.051	0.004	326	205	531	.384	286
2001	1,382	0.186	0.051	0.004	333	205	538	.389	280
2002	1,382	0.190	0.051	0.004	339	205	544	.393	273
'03 - '37	1,382	0.190	0.051	0.004	339	205	544	.393	5,204
								TOTAL:	11,872

TABLE 8

COSTS OF BASE CASE PLAN FOR ANGOON UNDER HIGH-GROWTH FORECAST

1983 - 2037

YEAR	HIGH GROWTH FORECAST (MWh)	VARIABLE COSTS: DISPLACEABLE: ESCALATING (Fuel) ($/kWh)	VARIABLE COSTS: DISPLACEABLE: NON-ESCALATING (O&M, etc.) ($/kWh)	VARIABLE COSTS: NON-DISPLACEABLE: NON-ESCALATING (Uncoll. Accts.) ($/kWh)	TOTAL VARIABLE COSTS ($1,000)	FIXED COSTS: TOTAL ($1,000)	TOTAL SYSTEM COSTS ($1,000)	APPROX. ENERGY SALES PRICE ($/kWh)	PRESENT WORTH OF TOTAL SYSTEM COSTS ($1,000)
1983	1,020	0.119	0.051	0.004	177	205	382	.375	369
1984	1,577	0.122	0.051	0.004	279	205	484	.307	452
1985	1,587	0.125	0.051	0.004	286	205	491	.309	443
1986	1,596	0.128	0.051	0.004	292	205	497	.311	433
1987	1,605	0.131	0.051	0.004	299	205	504	.314	424
1988	1,735	0.135	0.051	0.004	330	205	535	.308	435
1989	1,739	0.138	0.051	0.004	336	205	541	.311	425
1990	1,743	0.141	0.051	0.004	342	205	547	.314	415
1991	1,746	0.145	0.051	0.004	349	205	554	.317	406
1992	1,749	0.149	0.051	0.004	357	205	562	.321	398
1993	1,753	0.152	0.051	0.004	363	205	568	.324	389
1994	1,757	0.156	0.051	0.004	371	205	576	.328	381
1995	1,742	0.160	0.051	0.004	375	205	580	.333	371
1996	1,763	0.164	0.051	0.004	386	205	591	.335	365
1997	1,767	0.168	0.051	0.004	394	205	599	.339	358
1998	1,767	0.172	0.051	0.004	401	205	606	.343	349
1999	1,767	0.176	0.051	0.004	408	205	613	.347	342
2000	1,767	0.181	0.051	0.004	417	205	622	.352	335
2001	1,767	0.186	0.051	0.004	426	205	631	.357	328
2002	1,767	0.190	0.051	0.004	433	205	638	.361	321
'03 - '37	1,767	0.190	0.051	0.004	433	205	638	.361	6,104

TOTAL: $ 13,843

TABLE 9

VALUE OF HEAT DELIVERED BY ANGOON WASTE HEAT RECOVERY SYSTEM

YEAR	CAPITAL COSTS ($185,000 at 3.5 pct for 15 yrs) ($1,000)	MAINTENANCE COSTS ($1,000)	VALUE OF DISPLACED HEATING OIL (escl. @ 2.5%) ($1,000)	NET BENEFITS ($1,000)	PRESENT WORTH OF NET BENEFITS ($1,000)
1983	16.1	2.6	29.0	10.3	10.0
1984	16.1	2.6	29.7	11.0	10.3
1985	16.1	2.6	30.5	11.8	10.6
1986	16.1	2.6	31.2	12.5	10.9
1987	16.1	2.6	32.0	13.3	11.2
1988	16.1	2.6	32.8	14.1	11.5
1989	16.1	2.6	33.6	14.9	11.7
1990	16.1	2.6	34.5	15.8	12.0
1991	16.1	2.6	35.3	16.6	12.2
1992	16.1	2.6	36.2	17.5	12.4
1993	16.1	2.6	37.1	18.4	12.6
1994	16.1	2.6	38.0	19.3	12.8
1995	16.1	2.6	39.0	20.3	13.0
1996	16.1	2.6	40.0	21.3	13.2
1997	16.1	2.6	41.0	22.3	13.3
1998	16.1	2.6	42.0	23.3	13.4
1999	16.1	2.6	43.0	24.3	13.5
2000	16.1	2.6	44.1	25.4	13.7
2001	16.1	2.6	45.2	26.5	13.8
2002	16.1	2.6	46.3	27.6	13.9
'03-'37	16.1	2.6	46.3	27.6	264.0

NET PRESENT WORTH OF HEAT: $ 510.0

Since not all of the costs of the THREA system would "go away" with the introduction of an alternative source of power (such as a Favorite Bay hydro plant), it is important to determine just how much money would be saved if all possible costs were eliminated. Table 10 shows the calculations of the annual "displaceable" costs of the THREA system in Angoon.

The calculations given show the savings which would result from a shut-down of the THREA diesels completely for both the low- and the high-growth plans. In 1990, for example, $217,000 would be saved in the low-growth instance; $335,000 in the high-growth case. The present worths of these annual savings are summed for the years 1983 - 2037 with a resulting savings of $5,880,000, $6,870,000, and $8,807,000 for the low, moderate, and high energy growth rates.

If the Falls Creek hydro plant is put into operation and the THREA diesels were shut down, the waste heat system would be "out of business." The loss of the heating system's benefits are counted as an added cost to the hydro project. The present worth of the waste heat system benefits for the years 1988 through 1997 must be added to the present worth of the hydro project costs. Note that the entire $510,000 of benefits from the waste heat system is not added. This is because the benefit from the waste heat system over the period 1983 through 1987 is subtracted from the present worth of the THREA system.

From the above discussion, it can be seen that the net present worth of the Falls Creek hydro plant (or any similar alternative investigated for Angoon) must have a net present worth of no more than about $6.4 million if our "moderate" growth rate is assumed or $8.3 million if a higher forecast is used.

Of course, it is entirely possible that a particular alternative to the THREA diesel system would not completely eliminate the fuel use. There may be times in the future when the alternative could not produce sufficient power to meet Angoon's needs (for example, if a generator were down for maintenance). The numbers given above are general guidelines by which a particular alternative may be measured.

TABLE 10

CALCULATION OF PRESENT WORTH OF DISPLACEABLE COSTS FOR BASE CASE PLAN
1983 - 2037

YEAR	DISPLACEABLE COST ITEMS ESCALATING (Fuel) ($/kWh)	NON-ESCALATING (O&M, etc.) ($/kWh)	LOW-GROWTH FORECAST (MWh)	TOTAL DISPL. COSTS ($1,000)	PRESENT WORTH OF DISPLACEABLE COSTS ($1,000)	MODERATE GROWTH FORECAST (MWh)	TOTAL DISPL. COSTS ($1,000)	PRESENT WORTH OF DISPLACEABLE COSTS ($1,000)	HIGH-GROWTH FORECAST (MWh)	TOTAL ($1,000)	PRESENT WORTH OF DISPLACEABLE COSTS ($1,000)
1983	0.119	0.051	1,020	173	167	1,020	173	167	1,020	173	167
1984	0.122	0.051	1,028	178	166	1,028	178	166	1,577	273	255
1985	0.125	0.051	1,202	212	191	1,202	212	191	1,587	279	252
1986	0.128	0.051	1,211	217	189	1,211	217	189	1,596	286	249
1987	0.131	0.051	1,220	222	187	1,220	222	187	1,605	292	246
1988	0.135	0.051	1,122	209	170	1,350	251	204	1,735	323	263
1989	0.138	0.051	1,126	213	167	1,354	256	201	1,739	329	259
1990	0.141	0.051	1,130	217	165	1,358	261	198	1,743	335	254
1991	0.145	0.051	1,133	222	163	1,361	267	196	1,746	342	251
1992	0.149	0.051	1,136	227	161	1,364	273	194	1,749	350	248
1993	0.152	0.051	1,140	231	158	1,368	278	190	1,753	356	244
1994	0.156	0.051	1,144	237	157	1,372	284	188	1,757	364	241
1995	0.160	0.051	1,147	242	155	1,375	290	185	1,742	368	235
1996	0.164	0.051	1,150	247	153	1,378	296	183	1,763	379	234
1997	0.168	0.051	1,154	253	151	1,382	303	181	1,767	387	231
1998	0.172	0.051	1,154	257	148	1,382	308	178	1,767	394	227
1999	0.176	0.051	1,154	262	146	1,382	314	175	1,767	401	223
2000	0.181	0.051	1,154	268	144	1,382	321	173	1,767	410	221
2001	0.186	0.051	1,154	273	142	1,382	328	171	1,767	419	218
2002	0.190	0.051	1,154	278	140	1,382	333	167	1,767	426	214
'03-'37	0.190	0.051	1,154	278	2,660	1,382	333	3,186	1,767	426	4,075

LOW-GROWTH TOTAL: $ 5,880.0 MODERATE-GROWTH TOTAL: $ 6,870.0 HIGH-GROWTH TOTAL: $ 8,807.0

E - THE ECONOMICS OF A FAVORITE BAY HYDROELECTRIC PLANT

The design (at a conceptual level) of a small hydroelectric plant on an unnamed creek (Favorite Bay Creek?) about 4 miles south of the village has been under study by the Anchorage firm of Tryck, Nyman, and Hayes (TN&H) since 1980. The major thrust of their work has been in the direction of the development of a fish hatchery to provide a renewable income-producing resource. The operation of a fish hatchery on Favorite Bay Creek would necessitate the construction of a water impoundment so that fresh water would be available year-round, even when the creek was frozen, as it normally does in the winter months.

The availability of the head developed behind an impoundment dam would provide an attractive hydroelectric resource. Any dam would be an expensive proposition, but the incremental cost associated with building a dam large enough to provide a water supply adequate for both the hatchery <u>and</u> a hydroelectric plant could be fairly low. It may well be that if a hatchery and its dam were constructed, it wouldn't make sense <u>not</u> to include a hydro plant to make use of the energy stored behind the dam before the water was released for hatchery use. Naturally, some minimum streamflow would have to be maintained at all times.

From the standpoint of hydroelectric development at Angoon, the construction of a hatchery is practically a given condition. If Favorite Bay Creek were to be developed, a dam would be necessary. Favorite Bay Creek is a salmon spawning creek (although a fairly poor one) and the Alaska Department of Fish and Game's (ADF&G) prevailing stance is that salmon habitat must be protected. If a dam were built on the stream, it would destroy the existing habitat. In such a case, ADF&G would likely require some mitigative measure such as a hatchery to make up for the loss of the salmon.

This study will examine the economics of the hatchery/hydro plant system at three levels:

1. First, an investigation is made of the hydro plant in isolation from the hatchery and its costs and revenues.

   This approach assumes that the hydro plant pays for <u>all</u> costs which are identified as being unique to that facility; the hatchery funding "pays" for 75 percent of the dam, access road, and intake structure.

   The ratio of the benefits (savings in displaceable costs) to the costs of operating the "base case" diesels is calculated for the moderate and high growth energy forecasts. It is not considered appropriate to carry out this calculation for the low-growth forecast, because one of the load components of the two higher forecasts is the hatchery.

2. An investigation is made of the hydro plant plus the hatchery. This will examine the impact to the benefit:cost ratio of the revenues and costs due to the hatchery operation and salmon harvests.

3. The final investigation carried out is identical to that performed under "2" above, except that the extra revenues which are realized by the local fishing fleet as a result of the hatchery's operation are included.

In 1982 the Angoon Aquaculture Association filed an application with ADF&G to be granted a permit to construct a fish hatchery at a site along Favorite Bay Creek. Their permit application describes a "...newly created reservoir of 4,500 acre feet... behind a one hundred foot dam." This dam is also featured in a TN&H report done in 1981 to explore various options available to Angoon for a new water supply. That report explored the dam as a multi-use facility, providing the village with drinking water, hydroelectric power, and water for their hatchery.

In their 1981 report describing the multi-purpose facility (hatchery/hydro/water supply), TN&H gave cost estimates for the various facility components as follows:

Dam and Intake Structure		$ 5,088,750
Power Generating System		2,784,210
Water Supply System		2,628,188
Access Road		1,308,413
	TOTAL:	$11,809,561

Using an 8 percent escallation rate to yield 1982 dollars and another 4.3 percent to give current costs, this estimate is revised to $13.3 million in 1983 dollars. It is Acres' opinion that, for the most part, estimates provided by TN&H are quite reasonable for the level of detail required at this stage of project evaluation.

There are a couple of changes to this cost estimate which will be made before proceeding.

The most significant of these changes is in the cost of the dam itself. Acres carried out calculations based on an earth- or rock-filled dam. At a dam volume of 132,000 cubic yards, with a price of $37 per cubic yard, Acres calculates a dam cost of $4.9 million ($ 1983) compared to the $2.5 million ($2.85 million in $ 1983) given by TN&H. Their work was based upon a dam volume of 110,000 cubic yards of rock with a price of $23 per cubic yard. Acres does not believe that rock fill will be available in Angoon for that price.

We do believe that suitable rock will be available in Angoon for the $37 per cubic yard mentioned above. Rock and earth placed at Tyee ranged from $8 per cubic yard for "Common Backfill" to $48 per cubic yard for "Select Bedding and Backfill". In that bid, the fairly coarse rock "Riprap" was priced at $20 per cubic yard. While not identifying riprap as a bid item, the Swan Lake low bid priced "Compacted Backfill, Type A" at $15 per cubic yard and "Compacted Backfill, Type B" at $25 per yard (not including some special purpose Type B backfill priced at $310 per yard for a small quantity). A Tryck, Nyman, and Hayes staff member told Acres personnel that rock fill in the Craig/Klawock/ Hydaburg area was presently costing about $25 per ton (or about $37 per cubic yard).

This adjustment would mean that the line item "Dam and Intake Structure" would be $7,782,278 (in 1983 dollars), an increase of about $2 million over the TN&H estimate of $5,088,750 ($5.73 million in 1983 dollars).

The second adjustment to be made in Acres' analysis is the "removal" of the costs associated with the water supply system. The existing water supply for Angoon is in such disrepair that it is likely that the construction of a new source will be of such priority that it will be constructed before the hatchery/dam is begun. This change will decrease the project cost estimate by $2,960,496 (1983 dollars).

Thirdly, in their cost estimate for the hatchery (total cost $6.09 million in 1983 dollars), TN&H had allocated $392,370 (1982 dollars) for the construction of an access road. This estimate was based upon the idea that the hatchery would share the cost of an access road built to serve the hatchery, the dam, and the water supply system. The preliminary cost of the complete road was $1,473,849 in 1983 dollars. Since it is likely that most (perhaps as much as 2/3) of this road will be built to serve the new water supply before a Falls Creek hydro site is built, only one third of its cost, or $491,283, needs to be allocated to the hydro plant/hatchery.

Thus, the cost estimate used in this report (expressed in 1983 dollars) is as follows:

Dam and Intake Structure	$ 7,782,278
Power Generating System	3,136,246
Water Supply System	-0-
Access Road	491,283
TOTAL:	$11,409,807

The first examination of the Favorite Bay hydro plant economics assumes that the hatchery will pay for 75 percent of the dam and intake structure (and 75 percent of the access road). This makes the incremental cost of the hydro plant:

Dam and Intake Structure (0.25 x $7.782 M)	$1,946,000
Power Generating System	3,136,000
Water Supply System	-0-
Access Road (0.25 x $0.491 M)	123,000
TOTAL:	$5,205,000

Since this report assumes an on-line date of 1988 (Year 6 of the economic analysis), this dam capital cost has a present worth of $4,234,000 (when calculated at 3.5%).

The 1981 cost estimate for maintaining a Favorite Bay hydro plant was $102,500 per year (not counting the cost of maintaining the water supply). This represents an annual cost of $115,460 in today's dollars. The present worth of 50 years of this O&M (calculated at 3-1/2%, assuming an on-line date of 1988) is $2,203,000. Therefore, the total present worth of a Favorite Bay hydro plant is $6.437 M.

As discussed in Part D of this report, some components of the THREA system will continue to cost Angoon customers money even though THREA may not be generating any power. Items such as the diesel generators (which would be maintained to act as backups to the hydro plant) and the power distribution lines must be kept in good working order; the cost of the REA loans used to finance the THREA equipment must be paid off; THREA administrative work will continue and must be financed.

Again referring to Part D, it may be remembered that there was some discussion of "displaceable" costs associated with the THREA system. Those were costs which would no longer be realized if some other generation facility came along which could replace the energy produced by THREA's diesels. The "displaceable" costs are used in determining the economic impact of a Favorite Bay hydroelectric project on the Angoon power system.

TABLE 11 - PRESENT WORTH OF POWER SYSTEM WITH FAVORITE BAY PLANT
(Moderate - Growth Forecasts)

1.	Present worth of THREA system operation (low - growth forecast, 55 years, 3.5%)	$11,872,000
2.	Present worth of "displaceable" THREA costs (low - growth forecast, Year 6 - 55, 3.5%)	6,870,000
3.	Savings due to operation of APA waste heat system from 1983 through 1987	53,000
4.	Potential savings from waste heat system which are lost due to the shutdown of the system from 1988 through 2037	457,000
5.	Present worth of Favorite Bay hydro plant	6,437,000
	TOTAL (1 - 2 - 3 + 4 + 5)	$11,843,000

This total should be compared to the present worth of the continued operation of the existing THREA system which is $11,872,000. The difference, $29,000 in 1983 dollars shows that if the Angoon load growth follows the moderate forecast, the system with the dam would be about the same price as continued operation of THREA's diesel system.

In terms of incremental benefit:cost ratios, we can easily take the cost data from the previous page and develop the following:

BENEFITS

1. "Displaceable" THREA costs	$ 6.87 million

COSTS

1. Favorite Bay hydro plant	$ 6.78 million
2. Lost benefits from APA waste heat system	.46 million
TOTAL COSTS	$ 6.89 million

Benefit:Cost Ratio 0.997 = 6.87 ÷ 6.89

It should be noted that these first calculations were done using the moderate-growth scenario. Below are the same calculations carried out using the high growth forecasts.

TABLE 12 - PRESENT WORTH OF THREA - FAVORITE BAY HYDRO SYSTEM
(High - Growth Forecasts)

1.	Present worth of THREA system operation (high-growth forecasts, 55 years, 3.5%)	$13,843,000
2.	Present worth of "displaceable" THREA costs (high-growth forecasts, Year 6 - 55, 3%)	8,807,000
3.	Savings due to operation of APA waste heat system from 1983 through 1987	53,000
4.	Potential savings from waste heat system which are lost due to the shutdown of the system from 1988 through 2037	457,000
5.	Present worth of Favorite Bay hydro plant (see calculations above)	6,780,000
	TOTAL (1 - 2 - 3 + 4 + 5)	$ 12,220,000

Under this load assumption, it can be seen that the THREA-Favorite Bay Hydro system is about $1.6 million (11%) less expensive (present worth) than the diesel-fueled THREA system.

The incremental benefit:cost ratio of the Favorite Bay hydro plant under this set of assumptions is:

Benefit:Cost Ratio 1.22 = 8.81 ÷ 7.24

This is significantly different from the 0.99 B:C ratio which was calculated using the moderate-growth assumptions.

It is not so obvious what effect the hydro plant will have on individual consumers' electric bills. This is the next topic to be explored.

The incremental capital costs of the Favorite Bay hydro plant were calculated to be $5,205,000. By APA project evaluation rules, the period over which these hydro plants are financed is 35 years. At an interest rate of 3.5%, the annual costs associated with the dam construction are $260,250. Again, the O&M costs are $102,500. Thus, the total annual cost of the hydro plant is about $363,000. These costs are fixed and will not change over the 35 years of the dam financing period.

Additionally, there are costs associated with the THREA system which are not eliminated with the operation of the hydro plant and must be considered. As has been shown on Table 5 and discussed in Part D, THREA incurs fixed costs of about $205,000 per year. These costs do not change with energy use. There are also some "non-displaceable" costs which vary with energy use, but these are so small that they may be ignored in this analysis (these costs were estimated at $0.004 per kWh).

Thus, the total annual charges associated with operating a power sytem which makes use of the existing THREA distribution system and a new Favorite Bay hydro plant are:

$363,000 + $205,000 = $568,000

At the highest energy uses anticipated, this works out to a per kilowatt hour charge of about $0.32, which is currently a "typical" price level for a diesel-powered system in the bush. For the later years of the moderate forecast, the energy price from such a system would be about $0.41/kWh, an unreasonably high price for electricity.

Calculations performed in Part D (Tables 7 and 8) showed THREA prices of $0.38 and $0.34 per kilowatthour for the moderate and high growth cases, respectively in 1998. A comparison of projected electricity prices both with and without a Favorite Bay site in operation are shown below:

TABLE 13

	MODERATE GROWTH		HIGH GROWTH	
YEAR	NO HYDRO	WITH HYDRO	NO HYDRO	WITH HYDRO
1988	$ 0.34	$ 0.42	$ 0.31	$ 0.33
1990	0.35	0.42	0.31	0.33
1992	0.35	0.42	0.32	0.32
1994	0.36	0.41	0.33	0.32
1996	0.37	0.41	0.34	0.32
1998	0.38	0.41	0.34	0.32
2000	0.38	0.41	0.35	0.32
2002	0.39	0.41	0.36	0.32

The "catch" to all of these calculations is that 75 percent of the cost of the dam, intake structure, and that part of the access road not built as part of the water supply are allocated to the hatchery. The hydro plant then is charged with 25 percent of the cost of these items plus all parts of the project which are unique to the generation and transmission of electricity.

This rather arbitrary split in costs was made because it is felt that the major beneficiary of the project will be the hatchery and the commercial fishery which will be enhanced by its existence. It is only a coincidence that the energy prices realized in the high-growth forecast are as competitive with the THREA system as they are.

Recent experience in Southeast Alaska has shown that utility customers are almost universally opposed to the purchase of energy from a hydro project which is more expensive than that available from their existing diesel system. In order to make the Falls Creek hydro system attractive, it may be necessary to allocate an even greater fraction of the project costs to the hatchery.

Some calculations regarding the economics of the hatchery operation are now in order.

Tryck, Nyman, and Hayes has carried out an economic analysis of the hatchery's operation which shows that it would be able to turn a profit once its design production levels were reached and the full potential of the returning fish runs was realized. [It should be kept in mind that the hatchery's operator, the Angoon Aquaculture Association is organized as a nonprofit corporation.] The TN&H calculations, assume that "someone else" would provide the dam and its impoundment. Under the calculations just presented, we assumed that the Angoon Aquaculture Association would pay for 75 percent of the dam and intake structure and access road. This would add another $6.02 M to the capital cost of their project (0.75 x $8.27 M).

The TN&H report gave a cost estimate for the fish hatchery of $5.84 million (as explained in a supplemental letter) in 1982 dollars. Applying an escallation rate of 4.3 percent to bring this to January 1983 dollars, we get an "updated" cost estimate of $6.09 million.

Adding the $6.02 M to the $6.09 M derived above, the capital cost of the hatchery and its 75 percent share of the dam is $12.11 million.

The terms of the loan by which the Angoon Aquaculture Association plans to finance this project require no payback of the loan's principal for six to ten years. At the end of that period, the loan is repaid over a ten-year period. For the purposes of this study, we will make the following assumptions regarding the intial financing of the dam and hatchery:

Initial hatchery cost.	$ 12.11 million
Loan deferral period	10 years
Interest rate (net of inflation)	3.5 percent
Loan payback period.	10 years
Annual payment (year 11-20).	$ 1.46 million

Additionally, for the calculation of present worths, we will treat the total investment as occurring in Year 1 of the project's existence, which is assumed to be 1988. The life of the hatchery will be assumed to be 20 years, after which the analysis will presume that a second hatchery is "built", and a third 20 years after the second one. These "replacement" hatcheries, costing $6.09 million, will be financed with 20-year loans at 3.5 percent, for an annual cost of $428,000.

The dam will be assumed to have a lifetime of 50 years and will only be "built" once.

The last hatchery will not be replaced at the end of the economic life of the dam. Since it will then be in the middle of a "lifetime" it will be credited with a salvage value of 50 perecent ($3,045,000).

Tryck, Nyman, and Hayes has estimated the operating costs of the hatchery to be on the order of $428,000 per year (1982 dollars). In terms of 1983 dollars, this figure is $446,400.

In response to ADF&G requests for supplemental information on the hatchery permit, TN&H provided details of their assumptions regarding the economic viability of a hatchery at Angoon. In their permit application and in their supplemental letter, they provided data regarding the number of salmon to be released from the hatchery and the number expected to return to the area to complete their life cycle.

The Angoon hatchery is designed to operate at maximum egg production levels of :

Coho Salmon	1.5 million green eggs
Pink Salmon	7.5 " " "
Chum Salmon	50.0 " " "

In their revenue assumptions, TN&H "operated" the chum salmon portion of the hatchery at a 20 million egg level, which is consistent with the terms of their existing permit. A summary of the hatchery release and return levels (as stated by TN&H) is given on the next page.

TABLE 14 - ECONOMICS OF HATCHERY OPERATION
(Based on Data from Tryck, Nyman, and Hayes)

HATCHERY PRODUCTION

1. COHO SALMON (see note 1)

a.	Hatchery release	1,000,000	per	year
b.	Returning fish (assuming that 5 percent survive in the ocean). . .	50,000	"	"
c.	Catch by local fleet (70 percent). . .	35,000	"	"
d.	Fish returned to hatchery (b - c). . .	15,000	"	"
e.	Fish used for brood stock.	1,072	"	"
f.	Fish remaining for sale by Aquaculture Association (d - e). . .	13,928	"	"

2. PINK SALMON (see note 1)

a.	Hatchery release	6,000,000	per	year
b.	Returning fish (assuming that 2 percent survive in the ocean). . .	120,000	"	"
c.	Catch by local fleet (40 percent). . .	48,000	"	"
d.	Fish returned to hatchery (b - c). . .	72,000	"	"
e.	Fish used for brood stock.	8,824	"	"
f.	Fish remaining for sale by Aquaculture Association (d - e). . .	63,176	"	"

3. CHUM SALMON (see note 2)

a.	Hatchery release	16,000,000	per	year
b.	Returning fish (assuming that 2 percent survive in the ocean). . .	320,000	"	"
c.	Catch by local fleet (40 percent). . .	128,000	"	"
d.	Fish returned to hatchery (b - c). . .	192,000	"	"
e.	Fish used for brood stock.	20,000	"	"
f.	Fish remaining for sale by Aquaculture Association (d - e). . .	172,000	"	"

Notes:

1. Release data taken from permit application.
2. Release taken from supplemental letter. Hatchery was apparently expanded from the conceptual design in the permit application to make this chum production possible.

The Alaska Department of Fish and Game (Limited Entry Permit Section) has provided data giving preliminary 1983 catch price levels for the various fish species by gear type in the Juneau area (which includes Angoon). These figures are as follows:

TABLE 15--SALMON PRICES BY GEAR TYPE (FROM 1983 DATA)

SPECIES	GEAR TYPE TROLL	 PURSE SEINE	 DRIFT NET
Pink Salmon	$ 0.35/lb	$ 0.23/lb	$ 0.26/lb
Chum Salmon	0.55	0.30	0.41
Coho Salmon	0.75	0.40	0.55

ADF&G has also provided data on the "average" weight of the various species. These are:

SPECIES	AVG. WEIGHT
Pink Salmon	4 lb
Chum Salmon	10
Coho Salmon	7

Because the troll harvest is relatively small, this report will use the drift net price for each species as the "average" price paid the fishermen for their catch. Given the average weights as listed above, we can calculate a per-fish value of $1.04 for pink salmon; $4.10 for chum salmon; and $3.85 for coho. These figures contrast greatly with the per-fish values assumed by Tryck, Nyman, and Hayes in their economic assessment of the hatchery operation. Their work, which used data from earlier years, assumed the following per-fish values: $1.36 for pink salmon; $6.90 for chum; and $10.50 for coho salmon.

From the discussion on pages 30 and 31 regarding the terms of the Aquaculture Association's loan, it can be seen that the annual costs associated with loan repayment will be $1.46 million (assuming that the complete hatchery/dam package can be financed under the same terms). Added to this is the $0.446 million in annual operating costs for a total of $1.90 million per year during those years when the hatchery loan will come due.

From the catch data given in Table 14, and the per-fish values as developed above, we can see that the hatchery revenue of all three species is about $824,000 per year. This assumes a maximum production of coho and pink salmon and a 40 percent (20 million green eggs ÷ 50 million green eggs) production level of chum salmon.

The logical question would be "Can increased chum production make up the $1.08 million shortfall in revenues?" To determine the chum egg levels needed to bring the hatchery an extra $1.08 million these simplifying assumptions will be made:

1. Of each million chum salmon eggs produced, 8,600 adult fish will return to be harvested by the Aquaculture Association.

2. The allocation of variable costs will be based upon the number of eggs produced of each species, with coho being charged more (since they cost more to raise)

   Coho Variable Costs = $ 44,900
   = $ 29,200 per million eggs

   Pink Variable Costs = $109,700
   = $ 14,600 per million eggs

   Chum Variable Costs = $292,400
   = $ 14,600 per million eggs

3. Returning chum salmon will be worth $4.10 per fish to the Aquaculture Association

A simple calculation is all that is necessary to determine the chum production level needed to make the hatchery break even:

$$\$\ 1{,}080{,}000 = \$4.10 \times (8{,}600\ n) - \$14{,}600 \times (n)$$
$$52.3 = n$$

where "n" is in millions of additional chum salmon eggs needed to make up the shortfall

This represents a chum salmon production level of about 72 million eggs, or about 22 million eggs (44 percent) beyond the design level.

Given recent salmon prices, we can see that if the Aquaculture Association were required to pay for 75 percent of the dam costs, it would be unable to adjust production levels to cover all costs. Further analysis in this report will presume that chum egg production will be raised to 50 million, the hatchery's maximum design level.

These results are in stark contrast to those presented in the draft version of this report. There, using per-fish values developed by TN&H (as shown on the previous page), it was found that the hatchery could generate sufficient revenue to cover both its operating costs and the capital costs of 75 percent of the dam by raising chum production to 32 million green eggs. It is obvious that the economics of the Falls Creek hatchery and hydro plant are influenced by salmon prices which are much more volatile than were previously recognized.

The economic analyses presented in the draft edition of this report showed that the Favorite Bay hatchery's production could easily be adujsted to make up for the funding shortfall realized when operating under those circumstances. It now appears that there may be times when salmon prices are depressed to the point where the proposed hatchery cannot produce enough fish to generate revenue sufficient to meet all needs. Raising the price of electricity from a Falls Creek hydro plant to generate additional revenue is not an available alternative. This is because diesel power is alreayd available to Angoon residents. Earlier analysis work assumed that the selling price of Falls Creek energy would be set to cover just the "displaceable" costs of THREA diesel generation. Any increase in Falls Creek energy prices beyond this level would prompt a shift back to diesel generation.

Although it appears that the economics of the hatchery are unattractive at recent salmon prices, this study will proceed to develop Benefit: Cost rations for its operation.

Table 14 on page 32 gave production and harvest levels for the three species of salmon to be raised at the Favorite Bay hatchery. On the previous page, we "adjusted" the chum salmon production in an attempt to enable the Aquaculture Association to pay for 75 percent of the dam. This resulted in a chum salmon production of 50 million green eggs, which is the design production maximum. Even so, the Aquaculture Association revenue was inadequate to support the hatchery operation and the loan payback for the construction of the dam.

TABLE 16 - ASSUMPTIONS REGARDING HATCHERY OPERATION

1. COHO SALMON

a.	Hatchery release	1,000,000	per	year
b.	Catch by local fleet (70% of return)	35,000	"	"
c.	Fish available for sale by Aquaculture Assn.	13,928	"	"
d.	Aquaculture Assn. revenue ($3.85 per fish)	$ 53,623	"	"

2. PINK SALMON

a.	Hatchery release	6,000,000	per	year
b.	Catch by local fleet (40% of return)	48,000	"	"
c.	Fish available for sale by Aquaculture Assn.	63,176	"	"
d.	Aquaculture Assn. revenue ($1.04 per fish) .	$ 65,703	"	"

TABLE 16 (cont'd)

3. CHUM SALMON

a.	Hatchery release	40,000,000	"	"
b.	Catch by local fleet (40% of return)	320,000	"	"
c.	Fish available for sale by Aquaculture Assn.	430,000	"	"
d.	Aquaculture Assn. revenue ($4.10 per fish)	$1,763,000	"	"

It is not expected that hatchery production will begin at the levels shown above. Data taken from the hatchery permit application and later verified in conversations with TN&H personnel yield the following production schedule:

YEAR OF HATCHERY OPERATION (Year 1 - 1988)	HATCHERY RELEASE BY SPECIES (percent of ultimate production) COHO	PINK	CHUM
1	0	0	0
2	10	7	3
3	33	27	12
4	33	34	31
5	100	60	63
6 and later	100	100	100

There is a delay between the time when the salmon are released and the time they return. Again, based upon data from Tryck, Nyman, and Hayes, we have derived the following fish return schedule from which annual revenue levels may be computed:

TABLE 17 - SALMON RETURNS AND AQUACULTURE ASSOCIATION REVENUES

YEAR OF HATCHERY OPERATION	SALMON RETURNS BY SPECIES (percent of ultimate returns)			REVENUES			
	COHO	PINK	CHUM	COHO	PINK	CHUM	TOTAL
1	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0
4	0	7	3	0	4.6	52.9	57.5
5	10	27	12	5.4	17.7	211.6	234.7
6	33	34	31	17.7	22.3	546.5	586.5
7	33	60	63	17.7	39.4	1110.7	1167.8
8 and later	100	100	100	53.6	65.7	1763.0	1882.3

(Year 1 = 1988, revenues shown are in $1,000)

The total revenues, if continued for 50 years, can be shown to have a total present worth (1983 dollars, calculated at 3.5%) of $28.2 million.

As discussed before, the share of the dam and intake structure allocated to the Aquaculture Association (75 percent of the total) had a cost of $6.02 million (1983 dollars, spent in 1988). This would have a present worth of $5.05 million. The hatchery capital cost of $6.09 million, plus "rebuilding" in years 21 and 41 and a 50 percent salvage in year 50 have a total present worth of $8.3 million.

The annual operating costs to the Aquaculture Association are $884,000 (including an extra $438,000 due to the expanded chum salmon production). Over 50 years beginning in 1988, these expenditures would have a present worth of $16.9 million.

Thus, the total costs of the hatchery are $30.2 million, the total revenues (benefits) are $28.2 million, for a benefit:cost ratio of 0.93 over the term of the project.

When considering the hydro plant/hatchery "system" as a whole, the following incremental benefit:cost calculations may be made:

BENEFITS

1. Displaceable THREA costs		$ 8.8 M
2. Hatchery Revenue		28.2
	TOTAL	$ 37.0 M

COSTS

1. Favorite Bay Hydro Plant		$ 6.8 M
2. Hatchery (capital plus O&M costs)		30.2
3. Lost Benefits from APA Waste Heat System		0.5
	TOTAL	$37.5 M

Benefit:Cost Ratio 0.99 = 37.0 ÷ 37.5

This number may be compared to the B:C ratio of 1.22 calculated for the THREA - Favorite Bay power system standing on their own. The reader's attention is directed to our use in this case of the displaceable benefits from the high-growth case. This approach is believed to be correct because the hatchery was included in the high- and moderate-growth forecasts, but not in the low-growth forecast. Additionally, the increased salmon production which would accompany the hatchery operation would likely increase the ice consumption (therefore the energy use) of the Angoon cold storage plant. That increased demand was also a high-forecast component. Under the moderate-growth forecast, the B:C ratio is 0.94.

With regard to both of these calculations, it is appropriate to emphasize that the Angoon Aquaculture Association is chartered as a non-profit organization. It very well may be that they would "schedule" their salmon production levels to meet cash flow requirements of future years so that they would have small annual surpluses. If this were the case, the B:C ratios for both high and low forecasts would be much closer to unity.

The sensitivity of the system's B:C ratio to changes in the capital costs of the hydro plant or the costs of the THREA system is diminished by the overwhelming influence of the hatchery costs and revenues. The B:C ratio is considerably more sensitive to the performance of the Angoon Aquaculture Association's fishery.

This completes the second of our three analyses, showing in this case that a Favorite Bay hydroelectric plant may not be an economically sound venture.

The final approach taken in the analysis of the economics of the Favorite Bay hydro plant is to include the benefits realized by the local fishing fleet as a result of the hatchery operation.

In their revenue estimates, Tryck, Nyman, and Hayes assumed that the operators of the local fishing fleet would catch 70 percent of the returning coho salmon and 40 percent of both pink and chum salmon. Referring to Table 13, this amounts to 35,000 coho, 48,000 pink, and 320,000 chum salmon annually if the hatchery has reached its maximum assumed production levels. In terms of revenue, these catch levels represent $135,000 for coho, $50,000 for pink, and $1.31 million for chum salmon. For purposes of this study, it will be assumed that no capital additions (e.g. boats) will be required to harvest these extra fish. However, we will assume that 25 percent of the revenue will be used to purchase extra fuel needed to capture the fish. This will make the ultimate net revenues $101,000 of coho, $37,500 for pink, and $0.98 million for chum salmon.

The local fishing fleet will be faced with the same schedule of returning fish as is the Aquaculture Association. As shown in Table 18, we have derived the following fish return schedule showing revenues to the local fleet:

TABLE 18 - SALMON RETURNS AND LOCAL FISHING FLEET REVENUES

YEAR OF HATCHERY OPERATION	SALMON RETURNS BY SPECIES (percent of ultimate returns) COHO	PINK	CHUM	REVENUES COHO	PINK	CHUM	TOTAL
1	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0
4	0	7	3	0	2.6	29.4	32.0
5	10	27	12	10.1	10.1	117.6	127.7
6	33	34	31	33.3	12.8	303.8	316.6
7	33	60	63	33.3	22.5	617.4	639.9
8 and later	100	100	100	101.0	37.5	980.0	1118.5

(Year 1 = 1988, revenues shown are in $1,000)

The total revenues, if continued for 50 years, can be shown to have a total present worth (1983 dollars, calculated at 3.5%) of $16.5 million.

Now considering the benefit:cost ratio of the hydro plant/Aquaculture Association/local fishing fleet "system" we see:

BENEFITS

1. Displaceable THREA costs	$ 8.8 M
2. Hatchery Revenue	28.2
3. Local Fishing Fleet Revenues	16.5
TOTAL:	$53.5 M

COSTS

1. Favorite Bay Hydro Plant	$ 6.8 M
2. Hatchery (capital plus O&M costs)	30.2
3. Lost Benefits from APA Waste Heat System	0.5
TOTAL:	$37.7 M

Benefit:Cost Ratio 1.43 = 53.5 ÷ 37.7

When considered as a complete "system", the construction of an impoundment dam and its attendant hatchery at Favorite Bay, becomes a more attractive proposition.

There are a number of other benefits which can be ascribed to this system. Some of these have measurable economic benefits to the system. These "extra" benefits have not been included in any of the above analyses because of their somewhat esoteric nature. They are considered here and left for each reader to draw their own conclusions as to the appropriateness of their inclusion in the analyses.

There is a non-trivial market for salmon eggs, considered a delicacy in Japan and gaining popularity in the US. The harvesting and processing of salmon eggs is done by special teams of Japanese "technicians" who travel from fishing village to fishing village throughout the salmon season to package them to meet the exacting standards of Japanese consumers. Data gathered by TN&H personnel on the economics of the salmon egg market yields the following information:

1. Salmon egg prices are now at a very depressed level, their lowest in many years. Coho eggs sell for $5.80 per pound wholesale; pink for $4.00; and chum for $4.50.

2. The cost of the Japanese technicians to carry out the processing work at the village is about $0.75 per pound of eggs regardless of species of fish. This does not include travel expenses to the village nor housing expenses in the village.

3. About 7 percent of the body weight of a female salmon is eggs. Roughly 50 percent of the returning salmon are females. The average weight of the harvested fish by species are: coho 7 pounds; pink 4 pounds; chum salmon 10 pounds.

Since it is very important to the Japanese to have their salmon eggs harvested from the females as soon after they are taken from the water as possible, our analysis will concentrate on the fish harvested by the Aquaculture Association.

Referring to Table 16, the ultimate harvest by the Aquaculture Association is assumed to be: 13,928 coho, 63,176 pink, and 430,000 chum salmon. This means that there will ultimately be 6,964 female coho, 31,588 female pink, and 215,000 female coho salmon harvested by the Aquaculture Association. This harvest will yield 3,400 pounds of coho eggs; 8,800 pounds of pink eggs; 150,000 pounds of chum salmon eggs. By species, these eggs would bring the following revenues (under present depressed prices):

Coho:	$17,170 =	3,400 lb x	($5.80/lb - $0.75/lb)
Pink:	$28,600 =	8,800 lb x	($4.00/lb - $0.75/lb)
Chum:	$562,500 =	150,000 lb x	($4.50/lb - $0.75/lb)

This total revenue of $339,000 per year would be reached following much the same schedule as the harvest of the salmon themselves. Table 19 on the following page was prepared to show the development of the egg revenues to the Aquaculture Association:

TABLE 19-- AQUACULTURE ASSOCIATION EGG REVENUES

YEAR OF HATCHERY OPERATION	SALMON RETURNS BY SPECIES (percent of ultimate returns) COHO	PINK	CHUM	REVENUES COHO	PINK	CHUM	TOTAL
1	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0
4	0	7	3	0	2.0	16.9	18.9
5	10	27	12	1.7	7.7	67.5	76.9
6	33	34	31	5.7	9.7	174.4	189.8
7	33	60	63	5.7	17.2	354.4	377.3
8 and later	100	100	100	17.2	28.6	562.5	608.3

(Year 1 = 1988, revenues shown are in $1,000)

These revenues, if continued for 50 years, can be shown to have a total present worth (1983 dollars, calculated at 3.5%) of $9.0 million.

Another benefit which may be attributed to the existence of an impoundment behind a Favorite Bay dam is that the Angoon cold storage plant would not have to construct a water filtration plant. The existing water supply to the village of Angoon produces water which is yellowish in color and has a definite taste and odor. Buyers would almost certainly object to fish which were sold packed in ice made from untreated Angoon water. The water from Favorite Bay Creek however, is very clear with no objectionable taste or odor. Without the dam, the cold storage plant would be forced to build a filtration plant capable of removing the minerals or organic matter responsible for the taste, odor, and color now in the water. While no firm data for the costs of such a plant are available (without knowing specifically what contaminants must be removed, it is not possible to develop meaningful estimates), it is conceivable that they could run to the hundreds of thousands of dollars over the 50 year economic analysis period of this study. The water from an impoundment would only need to be chlorinated to make it acceptable for use at the cold storage plant.

Other benefits, which are difficult or impossible to quantify, but which would nonetheless exist if an impoundment were available, include a larger and more reliable water supply for the village (important from a fire fighting viewpoint); the possiblility of the development of an improved sport fishery above the dam (dolly varden, trout, landlocked salmon, etc); the possibility of local employment in the construction trades (during dam and hatchery construction) and in the local fishery; and an increase in tourism revenues due to the plentiful salmon run which would result from the hatchery operation.

F - THE THAYER CREEK HYDROELECTRIC PROJECT

At first glance, the development of a hydroelectric plant on Thayer Creek (6 miles north of Angoon) seems to be an ideal opportunity. The sites which have been investigated by at least two earlier reports are simply ideal places to put dams. The creek has sufficient flows (mean annual flows on the order of 400 cubic feet per second) to generate all the energy Angoon could possibly use; the lower end of the creek passes through a gorge no wider than 100 feet in some places, with solid rock walls on either side (although some shales and slates are present in places); the creek is regulated by Thayer Lake; and salmon do not migrate above the falls which mark a proposed damsite.

In their 1979 report, the Harza Engineering Company estimated the cost of a Thayer Creek hydro project (complete with access roads and transmission lines) to be $9.4 million. To escallate this price to 1983 dollars, we apply increases of 10.7 percent for the periods 1979-1980, 10.5 percent for 1980-1981, 8 percent for 1981-1982, and 4.3 percent for 1982-1983, a total of 37.8 percent. This yields a 1983 capital cost estimate for the project of $13.0 million. With an assumption that Year 1 of the project is 1988, such an expenditure would have a present value of $10.8 million.

Harza provided a cost estimate of $40,000 per year in operation and maintenance costs ($55,100 per year in 1983 dollars). Over a 50 year period (Year 1 = 1988) this would represent a net worth of $1.2 million in 1983 dollars. Note that this annual O&M cost is less than half that given by Tryck, Nyman, and Hayes (and used in our analysis) for the Favorite Bay plant.

Together, the capital cost and the O&M costs have a present worth of $12.0 million. This value exceeds by more than $2 million (22 percent) the fuel and O&M costs of the THREA system which would be saved by the operation of a hydro plant, even under the assumption of the high energy forecast.

The low-forecast benefit:cost ratio for this project under the above assumptions is 0.44. Using the high energy use forecast, the ratio becomes 0.69.

Another disadvantage of the Thayer Creek site is that it would not be practical to develop as a multi-use facility. The site is too innaccessable to construct a hatchery; it is too far from the village to run water lines for a new water source. Further, the transmission line to the village would be run through Admiralty Island National Monument land for virtually its entire distance. It is likely that the environmentalist coalition would work against allowing such a line's construction. The Favorite Bay site, by contrast is located such that its transmission lines are routed through village lands for most or all of their distance.

It is the opinon of Acres' staff that the development of a Thayer Creek site is inappropriate at this time. Further consideration may be given to the site in the event that Angoon's energy needs grow beyond the capacity of a Favorite Bay development. By the forecasts developed in this report, there is little possibility that this could happen at any time in the 20th century.

G - OTHER ENERGY TECHNOLOGIES

Previous reports[1,2] discussed in varying detail other technologies which were felt to be worthy of study for Angoon. For the most part these technologies were believed to be too expensive or to experimental in nature. Ideas for power generation which were examined and then discarded included solar, wind, wood waste, interconnection to other power systems, other hydro projects (Hasselborg Creek, Jim's Creek, Kathleen Creek), and coal. It is the opinion of Acres' staff that the earlier reports were correct in dismissing those technologies from detailed consideration.

One report[2] put forth the idea of constructing a tidal power plant at Angoon which would make use of the relatively high tidal velocities in Kootznahoo Inlet. It is the opinion of Acres' staff that the assumptions used in that report to arrive at the favorible analysis of tidal power at Angoon are basically flawed. It is beyond the scope of this document to provide a detailed analysis of the tidal power scheme as it was proposed, but we do not believe that proper consideration was given to many of the problems associated with such a scheme. Areas such as anchoring of the units, maintenance, power transmission, corrosion protection, protection of the units from rocks moved by the tides, and environmental effects are dismissed with what appears to be little serious consideration.

Due to the prototypical nature of such a tidal power unit, any serious consideration of its implementation at Angoon is considered inappropriate at this time.

1. "Thayer Creek Project, A Reconnaissance Report," by Harza Engineering Co., Chicago, for the Alaska Power Authority, 1979.
2. "Angoon Tidal Power and Comparative Analysis, Angoon, Alaska" by Robert W. Retherford Div., IECO, for the Alaska Division of Energy and Power Development, 1981.

PART H

COMMENTS RECEIVED FROM REVIEW AGENCIES

comments were received from:
Alaska Department of Fish & Game
US Army Corps of Engineers
US Fish & Wildlife Service

STATE OF ALASKA

Bill Sheffield, Governor

DEPARTMENT OF FISH AND GAME

Habitat Division

230 S. Franklin Street
Room 307
Juneau, Alaska 99801
Phone: (907) 465-4290

RECEIVED

NOV 10 1983

ALAS... ...THORITY

November 7, 1983

Loeffler

Mr. Bob ~~Leftler~~
Project Manager
Alaska Power Authority
334 West 5th Avenue
Anchorage, Alaska 99501

RE: Angoon Energy Alternatives

Dear Mr. Leftler:

The Department of Fish and Game has reviewed the report prepared by Acres American entitled "A Comparative Economic Analysis of Electric Energy Alternatives for Angoon, Alaska." First of all, we wish to express our appreciation for your extension of the response time. We do feel that our comments will help to correct some deficiencies in the report.

Page 2, paragraph 5: It is stated that "an application has been made to ADF&G by the Angoon Aquaculture Association for a permit to build a salmon hatchery at Favorite Bay." Actually, the permit was issued on August 15, 1982.

Page 21, paragraph 1: Again, the hatchery permit has been issued for a hatchery capacity of 7.5 million pink salmon eggs, 20 million chum salmon eggs, and 1.5 million coho salmon eggs.

Page 26, paragraph 3: It is our understanding that if the Angoon Aquaculture Association plans to finance the project with loans from the Aquaculture Loan Fund, (1) they probably would be limited to 1 million dollars, or 6 million if they received the official approval of the Northern Southeast Regional Aquaculture Association and (2) the provisions of these State loans call for payback after 6-10 years with interest, rather than 10 years and interest-free, as stated in the report.

Page 26, paragraph 5: The estimated operating costs of the hatchery ($446,000/year) appear rather high considering other PNP hatcheries of similar size in the region. A more appropriate range might be $200,000 - 250,000/year. However, we cannot completely evaluate the total costs, as no breakdown of operational costs is included.

Page 27, Table 12: Prices listed for fish appear to be considerably higher than the current (1982 Juneau area purse seine) prices of $0.84/lb for coho; $0.20/lb. for pinks; and $0.47/lb for chums. The 1983 prices may be even lower.

Page 30, Table 14: Our estimates indicate, assuming a 32 million egg capacity, that the hatchery would not have excess chum returns for sale in excess of brood stock needs until the sixth year of production. Table 14 indicates excess production in the fourth year.

Page 33, paragraph 7: The average weight for coho is listed as 12 pounds, this is more likely to be 7-9 pounds. Average weights for Southeast Alaska based upon catch statistics are 7.0 lb (coho), 3.8 lb (pink) and 9.9 lb (chum).

Thank you for the opportunity to review the report. While we realize our corrections primarily related to the facility as permitted, we feel the most current information should be used.

If you have any questions please feel free to contact us.

Sincerely,

Richard Reed

Richard Rèed
Regional Supervisor

cc: D. Hardy

ACRES RESPONSE TO LETTER FROM ALASKA DEPARTMENT OF FISH & GAME

1. Comment: ". . .the hatchery permit has been issued for a hatchery capacity of 7.5 million pink salmon eggs, 20 million chum salmon eggs, and 1.5 million coho salmon eggs."

   Acres' Response: The hatchery is designed to operate at production levels of up to 50 million chum salmon green eggs in addition to the 7.5 million pink and 1.5 million coho eggs as noted. This "reserve" was included by the hatchery's designers in order that the Aquaculture Association could adjust salmon production as needed to meet their financial requirements. No change in the text is needed.

2. Comment: ". . .if the Angoon Aquaculture Association plans to finance the project with loans from the Aquaculture Loan Fund,. . .they are probably limited to . . . 6 million dollars. ."

   Acres' Response: As a study exercise, this analysis is not required to study the intricacies of loan programs available to the Aquaculture Association. Any loan available to the Association would, because of the long lead time involved in bringing the hatchery "on-line," defer repayment for some time into the future. Whether this deferral is 10 years or some other time is of little significance to the outcome of this study. It is assumed that funding needed beyond that available from the Aquaculture Loan Fund will be provided with similar terms. What is important is the study of the project without outright grants from the state. Such an approach tests the ability of a project to "stand on its own." No change in the text is needed.

3. Comment: ". . .the provisions of these State loans cal for payback after 6-10 years with interest, rather than 10 years and interest-free. . ."

   Acres' Response: The text will be changed as required to show a payment deferral for 10 years and a 10-year payback period, with interest calculated at 3.5 percent.

4. Comment: "Prices listed for fish appear to be considerably higher than the current (1982 Juneau area purse seine) prices of \$0.84/lb for coho; \$0.20/lb. for pinks; and \$0.47/lb for chums. The 1983 prices may be even lower."

   Acres' Response: The draft report used salmon prices from the 1980 or 1981 seasons. The final report uses prices from 1983, which as suggested by the comment, are <u>considerably</u> less than they were in 1982. 1983 Juneau purse seine prices were as follows: pink salmon \$0.23/lb; chum salmon \$0.30/lb; coho salmon \$0.40/lb. These data were given by Elaine Dinneford of the Limited Entry Section of ADF&G in Juneau.

The price of salmon has a tremendous impact on the economics of the Falls Creek project. As the report shows, the hatchery is called upon to "subsidize" the hydro plant. Since Angoon residents have an alternative to electricity generated by the Falls Creek plant (namely THREA's diesels), they would be disinclined to purchase electricity at anything but the lowest available price. Thus, in order to make any sales of energy from Falls Creek, the price of that energy must be such that the bill to the consumers does not rise above the levels experienced if all the energy was supplied by THREA.

The text has been changed to make use of 1983 Juneau-area catch prices.

5. Comment: ". . .a 32 million egg . . . hatchery would not have excess chum returns for sale in excess of brood stock needs until the sixth year of production. Table 14 indicates excess production in the fourth year."

Acres' Response: The return schedule was developed with the assistance of the designers of the hatchery. If there is any error in this assumption, its impact on the economic analyses will be minimal because of the small numbers of fish harvested in the early years of hatchery operation. No change in the text is needed.

6. Comment: "The average weight for coho is listed as 12 pounds, this is more likely to be 7-9 pounds. Average weights for Southeast Alaska based upon catch statistics are 7.0 lb (coho), 3.8 lb (pink), and 9.9 lb (chum)."

Acres' Response: These numbers will be incorporated in the final version of the report.

DEPARTMENT OF THE ARMY
ALASKA DISTRICT. CORPS OF ENGINEERS
POUCH 898
ANCHORAGE, ALASKA 99506

October 27, 1983

RECEIVED
OCT 31 1983
ALASKA POWER AUTHORITY

REPLY TO
ATTENTION OF:

Hydropower and Comprehensive
Planning Section

Mr. Raymond J. Benish
Alaska Power Authority
334 West Fifth Avenue
Anchorage, Alaska 99501

Dear Mr. Benish:

Thank you for the opportunity to review your draft report "A Comparative Economic Analysis of Electric Energy Alternatives for Angoon, Alaska." In general, we found the report both interesting and informative. ACRES appeared to be quite resourceful, although somewhat arbitrary, in their proposed cost sharing plan with the Angoon Aquaculture Association.

Several rational cost allocation methods are available for use on multipurpose projects such as Angoon. It is important to separate these costs in a consistent manner to ascertain if each use is in fact "paying its way." This prevents feasible projects from carrying infeasible ones. We suggest use of the separable costs remaining benefits method of cost allocation for the Angoon project.

The "simple calculation" pg. 28, which increases the hatchery's chum production by 11.2 million to cover the additional $8.59 million in dam, intake, and access road costs assigned to the hatchery by ACRES appears to be rather simplistic. However, without the benefit of reviewing the Aquaculture Association's report, it is difficult to determine if the assumptions made regarding expansion, profit, etc. are reasonable.

We did find the Monte Carlo approach to the sensitivity analysis refreshing. This approach should aid you in decision making. It may be useful to expand the possible salmon price and catch variations in the program to more realistically reflect possible changes in this very volatile industry.

If you have any questions regarding our comments please contact Mr. Loran Baxter of our Hydropower and Comprehensive Planning Section, at 552-3461.

Sincerely,

Harlan E. Moore
Chief, Engineering Division

ACRES RESPONSE TO LETTER FROM US ARMY CORPS OF ENGINEERS

1. Comment: "Acres appeared to be . . . somewhat arbitrary, in their proposed cost sharing plan with the Angoon Aquaculture Association."

   Acres' Response: The 25:75 cost split between the hydro plant and the hatchery for "common" facilities (access road, dam, intake structure, etc) was indeed arbitrary.

   It will not likely be possible to sell electricity to Angoon consumers at a cost higher than it is presently sold by THREA. With this constraint, it works out that the hydro plant can absorb just about 25 percent of the "common" project costs and all of the "hydro plant only" costs (power house, turbines and generators, transmission line, and O&M).

   To a point, the hatchery can adjust its production levels to meet varying fiscal needs. The initial operating plan calls for the hatchery to operate at green-egg levels of 1.5 million coho eggs; 7.5 million pink eggs; and 20 million chum salmon eggs. These figures represent the maximum design levels for coho and pink salmon eggs, but the hatchery is designed to be operated at as many as 50 million chum salmon eggs.

   With this arrangement, it is understood that the hatchery will be "subsidizing" the hydroelectric plant. However, as the final version of the report shows, with salmon prices as low as they were in 1983, it is unlikely that the hatchery/hydro plant will be able to generate adequate levels of revenue.

2. Comment: "The 'simple calculation' pg. 28, which increases the hatchery's chum production by 11.2 million to cover the additional $8.59 million in dam, intake, and access road costs assigned to the hatchery by ACRES appears to be rather simplistic. However, without the benefit of reviewing the Aquaculture Association's report, it is difficult to determine if the assumptions made regarding expansion, profit, etc. are reasonable."

   Acres' Response: The calculations are indeed simplistic. They are intended to be so. The objective of this report is to examine the potential at Angoon for the development of a hydroelectric plant which can provide economic benefits for the community. Until feasibility-level work is done, more sophisticated analysis techniques will be unable to provide "better" results.

3. Comment: "We did find the Monte Carlo approach to the sensitivity analysis refreshing. . . .It may be useful to expand the possible salmon price and catch variations in the program to more realistically reflect possible changes in this very volatile industry."

Acres' Response: The compliment on the use of the Monte Carlo technique is very much appreciated.

In the final version of the report, the range is expanded considerably. As the main body of the text indicates, there is a significant probability that the B:C ratio of the hydro plant/hatchery could be less than unity.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
P. O. Box 1287
Juneau, Alaska 99802

IN REPLY REFER TO:

RECEIVED
OCT 3 1 1983
ALASKA POWER AUTHORITY

October 26, 1983

Mr. Ray Benish
Acting Executive Director
Alaska Power Authority
334 West 5th Avenue
Anchorage, Alaska 99501

Re: Favorite Bay Creek
Hydro Project

Dear Mr. Benish:

We have reviewed the subject draft report and offer the following comments:

General Comments

Our review of pertinent fisheries related sections of the report suggests that more work would be required to fully assess the proposed hatchery operation. We are particularly disturbed with the statement on page 2 indicating that many assumptions used in this study need verification. The validity of conclusions in the report, therefore, seems unclear.

Although the project is still in its early planning stage, it should be recognized that a hatchery does not mitigate all project impacts. A range of project impacts can be expected. We, therefore, recommend that an environmental analysis be initiated in coordination with resource agencies.

Specific Comments

Page 4. Summary and Recommendations. A stream survey should be conducted to update escapement counts (pink, chum and coho salmon).

Page 25, seventh paragraph. The Economics of a Favorite Bay Hydroelectric Plant. This paragraph should be expanded to discuss the basis for assuming that the Angoon Aquaculture Association would pay for 75 percent of the dam, intake structure and access road.

Page 26, last paragraph, same section. The basis for various assumptions used in deriving the economics of the hatchery operation should be discussed. We further suggest that the economics of the proposed hatchery be compared with existing hatchery operations in southeast Alaska.

Page 30, second paragraph, same section. Since the hatchery operation would displace a major part of the existing salmon runs, loss of the natural run should be subtracted from the hatchery revenue.

Thank you for the opportunity to comment.

Sincerely yours,

Field Supervisor

ACRES RESPONSE TO LETTER FROM US FISH AND WILDLIFE SERVICE

1. Comment: "We are particularly disturbed with the statement on page 2 indicating that many of this study need verification. The validity of conclusions in the report, therefore, seems unclear."

   Acres' Response: The report is valid within constraints imposed by the lack of detailed data on project costs and operations. The prudent reader should not be "disturbed" by the report's recommendation that assumptions used in the analyses be verified by futher study. Indeed, a prudent reader should be more disturbed by works which profess no flaws.

   The scope of the report was to establish the economic viability of the proposed Falls Creek project before detailed studies were commenced. Taken in this light, it is our opinion that the validity of the report is quite clear.

2. Comment: ". . .an environmental analysis [should] be initiated in coordination with resource agencies."

   Acres' Response: It is entirely likely that the construction of a dam at the Falls Creek site would require the completion of an Environmental Impact Statement. Under federal law, an EIS must be included ". . .in every recommendation or report on proposals for . . . major Federal actions significantly affecting the quality of the human environment."

   A project at Falls Creek would require a "major Federal action" in the form of the permits needed to back water up into the Admiralty Island National Monument. The project would also "significantly affect the human environment."

   In addition to the EIS, it is likely that a FERC license would be required if the dam were used to generate power.

3. Comment: "A stream survey should be conducted to update escapement counts. . ."

   Acres' Response: No doubt such a survey would be one of the undertakings necessary to produce an Environmental Impact Statement (see Comment No. 2).

4. Comment: ". . .discuss the basis for assuming that the Angoon Aquaculture Association would pay for 75 percent of the dam, intake structure and access road."

   Acres' Response: See response to US Army Corps of Engineers Comment No. 1 on page 52.

APPENDIX A

BENEFIT:COST RATIO SENSITIVITY ANALYSES

APPENDIX A - BENEFIT:COST SENSITIVITY ANALYSES

Throughout the study of the economics of the Favorite Bay hydro project and the Aquaculture Association's hatchery, no consideration was given to the range over which project cost components could vary.

It is sometimes easy to lose sight of the point that all of the costs put forth in a report of this type are estimates. These estimates may be very carefully thought out, but the fact remains that it is not possible for a forecaster to dictate future energy growth rates, costs, or revenues.

There are a number of approaches available to give the reader some idea of the range over which the economics of a project may vary. A common method is to identify the lowest and highest costs (or revenues) which a particular project component could achieve. All of the the low-cost (or low-revenue) values are then added up. This yields the absolute lowest cost (or revenue) for the project. Summing the high-cost values similarly yields the upper bound for project costs (or revenues).

In real life, it is rare that all components of a project will come in at their lowest (or highest) possible cost. Thus, the upper and lower boundaries established by the technique described above are normally of very limited value to decision makers. Cost estimates could be made more useful if some means were at hand to allow the individual cost components to vary independently (and randomly) over their available ranges. To carry out such a task by hand with more than a very small number of cost components is virtually impossible. The wide availability of computers makes a technique known as Monte Carlo analysis attractive in this type of work.

Simply put, a Monte Carlo program makes random choices of cost (or revenue) values for each of the components of the project under study. These values are then summed to produce the total project cost. One "pass" through such a procedure would provide no more insight into the project cost than to show one possible cost. Thus, it is standard practice to repeat the process a great number of times to generate a "cost distribution" which is representative of the project.

When investigating a system which is to be studied over a number of years (such as our power system), it is reasonable to allow each cost component to vary through its range in each year of the study. An appropriate discount rate is applied to the total costs incurred in future years to provide a "real dollar" value for that year's cost. The individual years' costs are summed to provide a net present worth of the project over its lifetime. The program runs through a large number of "lifetimes" to develop a cost distribution for the project.

The approach taken in the sensitivity analysis of the Favorite Bay project paralells that taken in the original economic analysis. That is, the project was first examined on its own merits, with no consideration given to the costs or revenues attributed to the hatchery. A second analysis was carried out which tested the B:C ratio of the hydro plant plus the hatchery costs and revenues. Thirdly, the B:C ratio of the hydro plant, the hatchery, and the local fishing fleet (which would catch fish released by the hatchery) was examined.

The base values assumed and the ranges over which they were allowed to vary are given for each case on Tables A-1 through A-3. These base values are the same as those developed in the text of this report. The ranges over which individual parameters are allowed to vary were determined in cooperation with staff of Tryck, Nyman & Hayes (for fish catch and price data) and the Alaska Power Authority (all other data).

Following Table A-3 is a rudimentary flow diagram of the computational process used in the Monte Carlo run. Space limitations prevent the inclusion of significant detail. The diagram is included only to provide the reader with a graphic representation of the process involved. The program "SPSS" mentioned in that figure is a widelyavailable package of stastical routines which is installed on most large computer systems. All computations carried out for this project were done on CDC equipment owned by Boeing Computer Services.

Following the flow chart is a graphic representation of the output of the SPSS work. The cumulative probabilities of a Favorite Bay project having lifetime B:C ratios below particular values are given for each of our three analysis approaches. A broad pen was used deliberately to give the reader the idea that these plots were to be used as representative values only.

It is interesting and instructive to compare the results of the Monte Carlo program with the manual calculations presented in the text (Part E of the report).

In the first analysis (Favorite Bay's B:C ratio calculated in isolation), the manual calculations gave B:C ratios of 0.997 and 1.22 when using the moderate- and high-growth forecasts, repspectively. The Monte Carlo routine gives B:C ratios ranging from 0.82 to 1.45, with a mean ratio of about 1.11. Fifty percent of the B:C ratios calculated by the Monte Carlo routine were below 1.13. This would imply some sensitivity to load, since this was virtually the only variable in the manual approach to this analysis.

The second analysis (Favorite Bay plus the Angoon Aquaculture hatchery) manual methods produced B:C ratios of 0.94 and 0.99 for the moderate- and high-growth cases. The Monte Carlo routine developed B:C ratios ranging from 0.95 to 1.47, with a mean ratio of 1.17. This "improvement" in the ratios is due in most part to the variation in price which was available to the salmon prices.

The third analysis (similar to the second, but including the revenues of the local fleet due to hatchery-produced salmon) yielded a high-growth B:C ratio of 1.43. No moderate-growth ratio was calculated manually as it was believed the load growth due to income earned by the local fleet operators would push energy use to <u>at least</u> high-growth levels. The Monte Carlo analysis for this scenario produced B:C ratios ranging from 1.66 to 2.56, with a mean of about 2.07.

We can see that as the economic impact of the hatchery production is given greater consideration, the sensitivity of the B:C ratio to energy use is reduced. While such a result may be expected intuitively, it is always comforting to be able to see some confirmation of one's expectations.

TABLE A - 1 -- PARAMATERS USED FOR B:C SENSITIVITY ANALYSIS
(Case 1: Favorite Bay Hydro Plant)

PARAMETER	RANGE OF VARIABILITY
Energy Use	40 percent probability of using the Acres low-growth projection; 40 percent probability of using Acres' high-growth projection; 20 percent probability of using 110% of Acres' high growth projection. Energy use choices are assumed to remain constant after 20 years into the study.
Fuel Cost	Fuel is assumed to cost $0.119 per kWh in 1983, with escallation rates of 2.00%, 2.25%, 2.50%, 2.75% and 3.00% available each year. Each escallation rate is assumed to be equally likely (20 percent probability each). Fuel price is assumed to remain constant after 20 years into the study.
Generation-Dependent O&M	Base cost assumed to be $0.051 per kWh, with equally probable costs at -10, -5, + 5, and +10 percent. No escallation is involved in this cost.
Hydro Plant Capital Costs	Base cost assumed to be $5,205,000, with equally probable costs of -10, -5, +10 and +20 percent. This expenditure is assumed to occur in Year 6 (1988) of the study.
Hydro Plant O&M	Base cost assumed to be $115,000 per year. Equally probable costs of -10, -5, +5, and +10 percent are available each year. This cost is not subject to escallation.
Number of Iterations	10,000
Discount rate	3.5 percent

TABLE A - 2 -- PARAMATERS USED FOR B:C SENSITIVITY ANALYSIS
(Case 2: Favorite Bay Hydro Plant Plus Hatchery)

PARAMETER	RANGE OF VARIABILITY
Energy Use	See Case 1
Fuel Cost	See Case 1
Generation-Dependent O&M	See Case 1
Hydro Plant Capital Costs	Base cost assumed to be $11,410,000, with equally probable costs of -10, -5, +10, and +20 percent. This expenditure is assumed to occur in year 6 (1988) of the study.
Hydro Plant O&M	See Case 1
Hatchery Capital Costs	Base cost assumed to be $6,090,000, with equally probable costs of -10, -5, +7.5, and +15 percent. This expenditure is assumed to occur in Years 6, 26, and 46 (1988, 2008, and 2028) of the study. Hatchery salvalge of 50 percent in Year 55 (2037).
Hatchery O&M	Base cost assumed to be $824,000, with equally probable costs of -10, -5, +5, and +10 percent. These costs are not subject to escallation
Number of Coho Caught by AAA	Base number assumed to be as shown in text discussion of hatchery economics. Equally probable catch level variations of -10, -5, +5, and +10 percent are available to the program.
Price of Coho	Base price assumed to be $3.85 per fish. Price variations of -25, -10, +100, and +200 percent were available. These prices are not subject to escallation.
Number of Pinks Caught by AAA	Set in a manner similar to that used for coho.
Price of Pinks	Base price assumed to be $1.04 per fish. Price variations of -25, -10, +50, and +100 percent were available. These prices are not subject to escallation.
Number of Chum Caught by AAA	Set in a manner similar to that used for coho and pinks.
Price of Chum	Base price assumed to be $4.10 per fish. Price variations of -25, -10, +50, and +100 percent were available. These prices are not subject to escallation.
Iterations	10,000
Discount rate	3.5 percent

TABLE A - 3 -- PARAMATERS USED FOR B:C SENSITIVITY ANALYSIS
(Case 3: Favorite Bay Hydro Plant Plus Hatchery and Local Fishing Fleet)

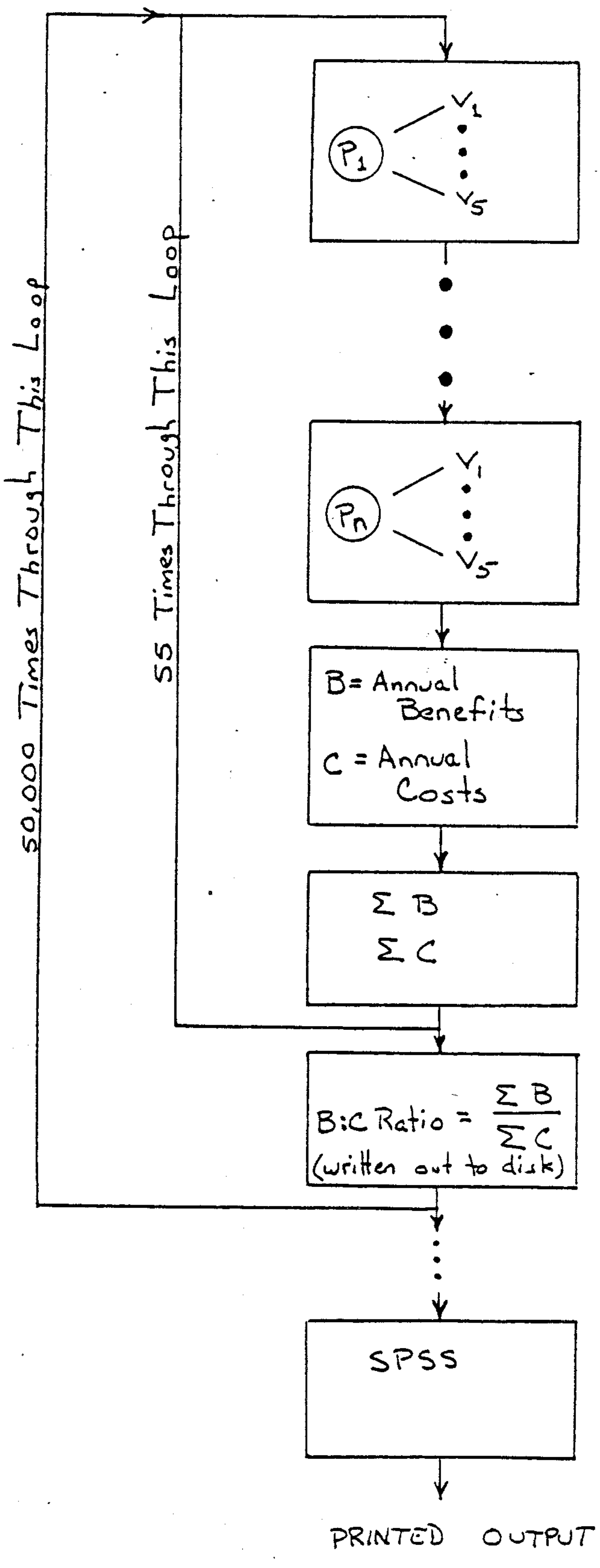
PARAMETER	RANGE OF VARIABILITY
Energy Use	See Cases 1 and 2
Fuel Cost	See Cases 1 and 2
Generation-Dependent O&M	See Cases 1 and 2
Hydro Plant Capital Costs	See Cases 1 and 2
Hydro Plant O&M	See Cases 1 and 2
Hatchery Capital Costs	See Cases 1 and 2
Hatchery O&M	See Case 2
Number of Coho Caught by AAA	See Case 2
Number of Coho Caught by LFF	LFF catch calculated as discussed in text. Catch variations were assumed to be the same as AAA catch.
Price of Coho	See Case 2
Number of Pinks Caught by AAA	See Case 2
Number of Pinks Caught by LFF	LFF pink catch set in the same manner as its coho catch.
Price of Pinks	See Case 2
Number of Chum Caught by AAA	See Case 2
Number of Chum Caught by LFF	LFF chum catch set in the same manner as its coho and pink catches.
Price of Chum	See Case 2
Iterations	10,000
Discount Rate	3.5 percent

ACRES

Calculations

SUBJECT:

JOB NUMBER P6409.01
FILE NUMBER
SHEET 1 OF 1
BY J LANDMAN DATE 9-3-83
APP DATE



In each year of the study, each cost (and benefit) parameter (energy use, maintenance costs, dam capital costs, fish revenues etc.), is allowed to select one value from among five choices. The selection is made randomly and independently from one parameter to another.

The fuel price for each year is calculated from the price of the previous year multiplied by a randomly selected escalation rate.

At the end of eaoh study year, the cost and benefit parameters are summed independently and the total costs and benefits are added to those calculated in previous years.

At the end of the 55-year study period, the present worth of the plan's benefits are divided by the PW of the plan's costs. This yields a B:C ratio for that particular "lifetime". Each lifetime B:C ratio is written out to a storage file for future processing. The program then repeats the calculation of the lifetime B:C ratio, a process that is repeated 50,000 times.

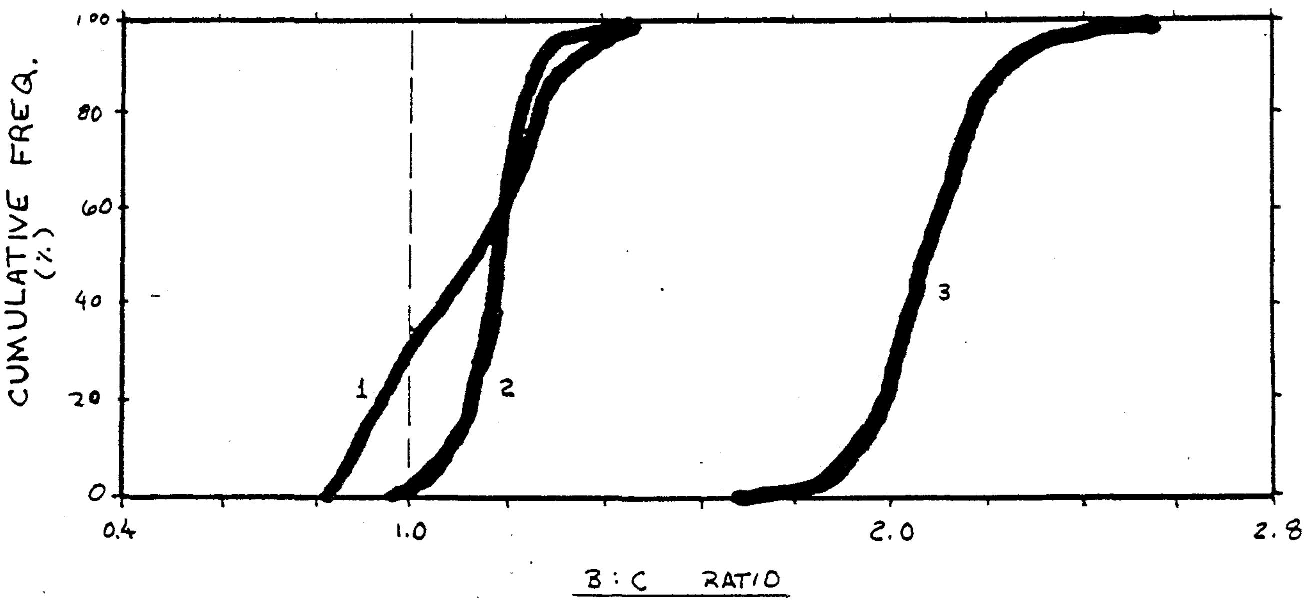
When all 50,000 lifetime B:C ratios have been calculated, the program "SPSS" is used to provide a statistical analysis of the results. This analysis includes an identification of the maximum and minimum B:C ratios identified, the mean of the population generated, and the number of times each B:C ratio was encountered. These data were used to plot the graphs provided on the following page.

ACRES

Calculations

SUBJECT:

JOB NUMBER
FILE NUMBER
SHEET 1 OF 1
BY jkl DATE 2-27-84
APP DATE



Curve 1: Benefit:Cost Ratio of Favorite Bay Hydro Plant vs. THREA Diesel System

Curve 2: Benefit:Cost Ratio of Favorite Bay Hydro Plant <u>and</u> Angoon Aquaculture Association Hatchery vs. THREA Diesel System.

Curve 3: Benefit:Cost Ratio of Favorite Bay Hydro Plant and Angoon Aquaculture Association Hatchery <u>plus</u> Revenues to the Local Fishing Fleet Operators

APPENDIX B

ALASKA POWER AUTHORITY PROJECT EVALUATION PROCEDURES

1 July 80
current 2/17/8

ALASKA POWER AUTHORITY

PROJECT EVALUATION PROCEDURE

The Power Authority's project evaluation procedure reflects the organization's purpose and philosophy. The Power Authority was established as an instrument of the State to intervene for the purpose of bringing to fruition worthy projects that would otherwise be excluded from development by the constraints of financial markets. Most, if not all, Alaskan capital intensive power projects would be precluded from conventional financing due to the perception of added risk inherent in building projects in small, isolated Alaska communities.

Thus, the Authority's approach to project evaluation does not consist, as some have recommended, of using market financial parameters to determine the ability of the project to generate sufficient sales to cover revenue requirements. Instead, the approach entails first assessing a project's "worthiness" apart from the constraints of financial markets, and, second, determining if there is the ability and political will to intervene to establish financing arrangements and terms that permit the project to be financed. To reiterate, the Authority's purpose is to intervene in financial markets to permit worthy projects to be developed. A project evaluation procedure that requires a project to pass a financing test using market conditions would preclude the Authority from acting in keeping with its purpose.

The means that the Authority has adopted to assess a project's worthiness are consistent with traditional federal evaluation methods for public water resource projects. The goal is to maximize net economic benefits from the state's perspective, tempered by environmental, socioeconomic and public preference constraints. The method attempts to identify the real economic resource costs of all options under study; the magnitude of these costs are independent of the entity that finances and implements the options.

The Authority's project evaluation procedure has evolved since 1979 and continues to undergo refinement. Some desired characteristics of the procedures are:

1. Consistency from one study and market area to another.

2. Equity in the treatment of alternatives.

3. Practicality, given data limitations.

4. Responsiveness to statutory direction.

In general terms, the procedure entails (1) forecasting end use requirements on the basis of assumptions regarding economic activity and energy cost trends; (2) formulating various alternative plans to satisfy the forecasted requirements; (3) estimating the capital, operation, maintenance and fuel costs of each plan over its life cycle; (4) discounting the cost of each plan to a common point in time; (5) comparing the total discounted costs of each plan and determining the preferred plan; (6) evaluating the preferred plan's cost of power under a variety of financing arrangements in relation to anticipated power costs without the plan; and (7) identifying those financing arrangements which result in acceptable power costs.

Forecasting Future Requirements.

A planning period is first adopted to define the period of time over which forecasts are developed and energy plans are formulated. The length of the planning period is limited by the practical difficulties of forecasting far into the future. A period of 20 years from the present is normally adopted. End use requirements (space heating, water heating, lights and appliances, and industrial processes) are forecast over the planning period for each of three sectors (residential, commercial/government, and manufacturing). The end use requirement forecasts are initially developed irrespective of the form of energy being used to energize the end use. The forecast for each end use reflects a range of economic activity/population forecasts and a range of overall energy prices. With respect to the former, economic base analysis founded on discreet developmental events is used as the basis of forecasting rather than simple trend projections, whenever possible. With regard to the latter, the end use forecasts reflect situations both where energy prices, overall, rise faster than general prices and where energy prices, overall, rise at a rate in keeping with general price levels. (It can be expected that the actual energy costs of the preferred plan will eventually be shown to fall within that range.) An intermediate forecast is used as the basis for the initial planning steps. For each end use where more than one energy form is available to energize that end use, a mode split analysis is performed. This is accomplished in the course of the following initial screening of alternatives:

1. All reasonable alternative means of providing each end use are identified.

2. The per unit cost of energy is determined for each alternative using the Power Authority's economic evaluation parameters.

3. The amount of energy (or the amount of energy savings) that can be provided by each alternative is estimated.

4. For each end use, cost curves are developed showing relative cost, over time, of providing the end use by each of the reasonable alternatives.

5. The lowest cost means, or combination of means of providing each end use is identified. This determines the mode split after due consideration of the existing mode split and lag time for substitution of energy forms. The results also serve as a tool for formulating energy plans, which is the next step in the analysis.

The forecasts address both energy and peak load requirements.

Plan Formulation.

The first step in formulating energy plans is identifying and screening all reasonable energy supply and conservation options. These include structural and non-structural alternatives and alternatives that provide intermittent as well as firm energy. This is accomplished in the course of the previous step in the analysis.

Existing energy generation facilities and conservation practices are also evaluated for their performance, operation and maintenance costs, condition and remaining economic life.

Given the menu of options available, the relative cost and mode split information developed in the course of forecasting energy requirements, and any additional comparative analysis of the options, two or more energy plans are formulated. Each plan must, with a consistent level of reliability, meet the forecasted energy and peak load requirements over the planning period.

Whether plans are formulated to meet electrical energy requirements only, or both electrical and thermal requirements, depends upon the results of the mode split analysis. If it is shown that thermal needs should be met to a significant extent by electrical energy, then plans are formulated to meet both thermal and electrical requirements. If it is shown, on the other hand, that electricity should not play a significant part in providing thermal needs, then the bounds of the study are limited to electrical energy requirements only.

One plan is termed the "base case plan"; this plan is developed assuming a continuation of existing practice in the study area and is used as a common yard stick for comparison of the other plans.

If opportunities exist, a plan is formulated to improve the base case plan by increasing its efficiency or by other means.

One or more additional plans are formulated incorporating various combinations of options with the objective of identifying the lowest cost plan that is environmentally and socially acceptable.

The sequence and timing of plan components are optimized as an integral part of plan formulation. This is accomplished by a systematic testing of different sequences and project timing in search of the sequence and timing that results in the lowest present value of plan costs.

Discussion:

1. The Authority initially confined the forecasting to electrical energy requirements only. There are two problems with this approach. First, electrical energy supply plans often have associated with them certain amounts of waste heat suitable for space, water or process heating. In such cases, a forecast of thermal energy requirements is needed to determine the possibility of effectively utilizing this heat.

   Second, in forecasting electrical energy alone, the analyst is either explicitly or implicitly assuming a certain mode split in those end uses where more than just electrical energy can provide that end use. It is necessary to make the analysis of mode split explicit, and to do so requires a forecast of end use requirements rather than simply electrical energy needs.

2. In amplification of the procedure for mode split determination, the goal is to determine, based on full economic cost of alternatives and rational economic behavior, the lowest cost way of providing the end use.

<u>Estimating Project Costs.</u>

All costs for all projects are estimated with reference to a base year and in terms of the base year price levels. Costs incurred in future years reflect relative price changes only. Capital cost estimates are "overnight" estimates.

Capital costs (in the year they are incurred) are added to annual operation and maintenance costs and any fuel costs to give the total yearly cost of a plan. The series of yearly costs is discounted to a common point in time, typically the first year of the planning period.

Discussion:

1. A constant dollar approach has been adopted in the economic analysis to keep from having to forecast a long term inflation rate that would always serve as source of dispute, and to ease the computational burden. As reported by the Water and Energy Task Force of the U.S. Water Resources Council in their December 1981 report entitled "Evaluating Hydropower Benefits," the critical element in an analytical approach is the "use of consistent assumptions about interest rates and future prices." The Task Force endorses either "life-cycle analysis" (which includes inflation) or "inflation free analysis". The Power Authority's approach is specifically cited by the Task Force as an example of the latter.

2. Life cycle analysis dictates, state statute requires, and the long term planning horizon of a state government suggests that the relative plan costs be compared over the economic life of the projects under consideration. When hydroelectric and steam plant projects are being addressed, the economic evaluation period exceeds the 20 (or sometimes 30) year planning horizon. Yet, it is inappropriate to forecast load growth or escalation trends beyond the limits of the planning period. Also, project economic lives differ for varying types of facilities. These problems are handled by addressing costs throughout the economic evaluation period, but by assuming no load growth or cost escalation beyond the planning period. Facilities are replaced throughout the economic analysis period as dictated by their economic lives. Salvage values are included in the final year of the period as necessary. The economic evaluation period extends to the year that the longest lived project (that is added during the planning period) reaches the end of its economic life. For instance, if a hydroelectric project with a 50-year economic life is added in the tenth year of the planning period, the economic evaluation period would be 60 years in duration.

Plan Comparison.

Plans are compared in terms of total net benefits. Net benefits are equal to the gross benefits associated with a plan, less plan cost. The benefits are defined as the discounted total cost of the base case plan, supplemented by any subsidiary benefits of a particular plan (see discussion).

The plan offering the greatest net benefits is the preferred plan from an economic perspective. A benefit/cost ratio can also be used as an indicator of a plan's cost effectiveness.

Discussion:

1. In the event a plan provides a beneficial output other than that specifically being addressed in the study, incremental costs required to realize that benefit are subtracted from the benefit in each year, and these annual subsidiary net benefits are discounted to the common base date.

2. Consider the following hypothetical example: All cost and benefit figures are the sum of annual amounts discounted to the base date.

Plan	Cost	Subsidiary Net Benefit
Base Case	100	-
Plan A	120	10
Plan B	90	15

Base Case Evaluation -

benefits: 100
cost: 100
net benefits: 0
benefit/cost ratio: 1

Plan A Evaluation -

benefits: 100 + 10 = 110
cost: 120
net benefits: 110 - 120 = -10
benefit/cost ratio: 110/120 = 0.92

Plan B Evaluation -

benefits: 100 + 15 = 115
cost: 90
net benefits: 115 - 90 = 25
benefit/cost ratio: 115/90 = 1.28

2/17/83

SUMMARY OF RECOMMENDATIONS

Analysis Parameters for the 1983 Fiscal Year

Economic Analysis

Inflation Rate - 0%
Real Discount Rate - 3.5%
Real Oil Distillate Escalation Rate
- 2.5% - First 20 years
- 0% - Thereafter

Cost of Power Analysis

Inflation Rate -7.0%
Project Debt to Equity Ratio - 1:0
Cost of Debt - 12.0%

Economic Life and Term of Financing

Gasification Equipment	10 years
Waste Heat Recapture Equipment	
Under 5 MW	10 years
Over 5 MW	20 years
Solar, Wind Turbines, Geothermal and Organic Rankine Cycle Turbines	15 years
Diesel Generation*	
Units under 300 KW	10 years
Units over 300 KW	20 years
Gas Turbines	20 years
Combined Cycle Turbines	30 years
Steam Turbines (Including Coal and Wood-fired Boilers)	
Under 10 MW	20 years
Over 10 MW	30 years
Hydroelectric Projects	
Economic Life	50 years
Term of Financing	35 years
Transmission Systems	
Transmission Lines w/ Wood Poles	30 years
Transmission Lines w/ Steel Towers	40 years
Submarine Cables	
Oil Filled	30 years
Solid Dielectric	20 years

*Diesel Reserve Units will have longer life depending on use. Also this economic life is by unit and not total plant capacity.

Inflation Rate

For the purpose of the economic analysis there is assumed to be no inflation.

Recommendation: The inflation rate should therefore remain at 0%.

Discount Rate

As previously indicated in the Analysis Parameters of FY 82 the historic inflation free cost of money to the utility industry appears to be approximately 3.0%. Currently national and local economists and financial experts estimate the overall real discount rate to be in the range of 3% to 4% with a likelihood that the real cost of money for utilities is increasing slightly due to the increasing size and cost of electric generation projects currently being undertaken. It is also acknowledged that historically the real cost of money in Alaska contains an "Alaska factor" and is therefore somewhat higher than in the rest of the nation. However, the discount rate is also intended reflect the state opportunity cost of money and reflect long term trends.

Recommendation: In regards to the above analysis and review, the Discount Rate should be set at 3.5%.

Escalation Rate

Based upon a composite research of Energy Consulting Companies, national and local economists, and Investment Brokerage Firms, the forecast of distillate fuels (diesel and fuel oil) are expected to increase at an average real rate of 2.5% per annum for the period from 1982 to 2001. Beyond the year 2001 further increases in fuel are assumed to be zero. This assumption is based upon the belief that although additional increases are expected they are too speculative to quantify.

Recommendation: The escalation rate for diesel and fuel oil be set at 2.5% per annum for the first 20 years of the economic analysis. Thereafter, further increases in the rate are assumed to be zero.

Inflation Rate

For the 1983 Fiscal Year, national and local economists along with Financial Institutions and Energy consulting Firms forecast the National inflation rate between 6 and 8 percent.

Recommendation: The inflation rate should be set at 7% per year.

Debt to Equity Ratio

At the present time and under legislation currently in effect it is difficult to estimate the extent of debt financing for future Power Authority projects. It is also common utility practice to debt finance capital intensive projects.

Recommendation: In spite of the Power Authority's legislation, the debt to equity ratio for power project financing should remain at 1:0.

Cost of Debt

Cost of Debt is largely determined by the interest rate identified by statute for loans from the Power Project Loan fund. That interest rate is equal to the average weekly yield of municipal revenue bonds for the previous 12 month period as determined from the Weekly Bond Buyers 30 year index of revenue bonds. This average is currently approximately 13%. It is anticipated that the average will decrease only slowly during the 1983 fiscal year.

Recommendation: Because of the anticipated slow decrease in the weekly revenue bond index it is recommended that the cost of debt be set at 12% to reflect current long term tax exempt rates with a decreasing participation of the Rural Electrification Administration in providing federal low interest financing.

Economic Life and Term of Loan

Although in certain instances economic lives of up to 100 years may be warranted for hydroelectric projects, both the State Division of Budget and Management and F.E.R.C. recommend the use of 50 year economic lives for new hydroelectric projects. As a result the economic life of a new hydroelectric project is set at 50 years and the term of financing at 35 years. For all other alternative generation sources, the economic life and the term for which financing can be obtained is assumed to be the same even though they vary for each alternative. The following economic lives and loan terms should be used for various power project alternatives.

Economic Life and Term of Financing

Gasification Equipment	10 years
Waste Heat Recapture Equipment	
Under 5 MW	10 years
Over 5 MW	20 years
Solar, Wind Turbines, Geothermal and Organic Rankine Cycle Turbines	15 years
Diesel Generation*	
Units under 300 KW	10 years
Units over 300 KW	20 years
Gas Turbines	20 years
Combined Cycle Turbines	30 years
Steam Turbines (Including Coal and Wood-fired Boilers)	
Under 10 MW	20 years
Over 10 MW	30 years
Hydroelectric Projects	
Economic Life	50 years
Term of Financing	35 years
Transmission Systems	
Transmission Lines w/ Wood Poles	30 years
Transmission Lines w/ Steel Towers	40 years
Submarine Cables	
Oil Filled	30 years
Solid Dielectric	20 years

*Diesel Reserve Units will have longer life depending on use. Also this economic life is by unit and not total plant capacity.

REFERENCE

	Inflation Rate	Discount Rate	Fuel Escalation Rate
Dr. Scott Goldsmith I.S.E.R.	6.0%	3.0%	2.3%
Dr. David Reaume Economic Consultant	7.0%	3.0%	2.6%
Lehman Brothers, Kohn Loeb	5.0 - 6.0%	3.0 - 3.5%	2.8%
Dr. Bradford Tuck University of Alaska	6.0%	3.5%	2.65%
Donald MacFayden Salomon Brothers	6 - 8%	4.0%	3.0 - 4.0%
Peter W. Sugg URS/Cloverdale & Colpitts	6.0 - 7.0%	4.0½%	4.0%
Gary Anderson, Stanford Research Institute	7.0%	4.0 - 4.0½%	3.0%
Dr. Mike Scott Battelle Pacific N.W. Lab.	5.0 - 7.0%	3.0%	2.7%
Mr. Thomas Thurber Data Resources, Inc.	6.5%	3.0%	2.0%
Victor A. Perry III Bechtel Corp.	5.0%	3.0%	2.5%
William L. Randall The First Boston Corp.	7.0 - 8.0%	3.5%	3.0 - 3.5%
Wm. Micheal McHugh Applied Economics Associates	7.0 - 8.0%	3.5%	3.0 - 3.5%
Fredric J. Prager Smith, Barney, Harris Upnam & Company	5.0 - 6.0%	4.0%	2.5%
John Delrocali Wharton Econometric Forcasting Asso.	7.0%	3.5%	2.3%
Michael G. Moroney Peat, Marwick & Mitchell, Inc.	6.5%	3.0%	2.5%
Exxon Corp.	6.0%	3.0% - 4.0%	2.0%