wholesale price for Susitna power that was equal to or greater than the cost to produce it. Mr. Chairman, we've heard a lot of talk about cheap and abundant electricity coming from hydropower in Alaska and, sure, it would be abundant and sure, if the someone else pays the bill, it might even be considered inexpensive to the consumer. But, if there are no more cost increases in Susitna, and inflation remains relatively low, and the State puts 2.3 billion 1982 dollars into the project, the consumer price of electricity in Anchorage and Fairbanks in 1994 will be somewhat on the order of 24 cents per kilowatt-hour. My understanding is that this is about twice what consumers in Fairbanks are paying today, and 4-5 times what the costs are in Anchorage. I wonder if the consumer is going to think of these prices as "cheap." Other power projects have similar problems, as we all know from the Tyee experience.

Simply put, Mr. Chairman, the problems associated with the Alaska Power Authority are not, by and large, environmental problems, or problems associated with the historic growth/no growth issue in Alaska, they are basically economic in nature. It is my belief, and I so stated when I was on the Power Authority Board, that there are not major environmental or constructibility problems associated with the Susitna Hydropower project, the problems are economic and financing. The same can be said for most of the rest of the projects on the drawing boards of the Authority. The fact that there are serious, and perhaps fatal, problems with these projects can, in my opinion, be blamed on three major influences: political, institutional and procedural.

As the size of APA projects increased, and as more and more State dollars went into them, the Alaska Power Authority increasingly became a political entity of its own, with its own constituency. A large number of Alaskans became convinced that, through APA projects such as Susitna, economic boomtimes would come back, electricity would be plentiful and too cheap to meter, and that everyone could have a high-paying job. APA did not particularly discourage this delusion, because it was readily translatable into support before the Legislature for capital and operating budgets, as well as any new legislation that it might want.

Added to this was the fact that the Power Authority was rapidly being involved in power projects of some form in almost every community in the State. Part of the political success of the Authority is that it has something going in everyone's district, thereby assuring continual success for its funding. As a result, much of the criticism which might be expected for development projects of the magnitude of those the Authority sponsors was simply not forthcoming. At the time initial construction began on the Tyee Hydropower project, virtually no objection to it surfaced, even though it was general knowledge that the project's cost was well over the original cost estimate, and that electric power from the project might not economically compete with alternative thermal power such as diesel or gas turbine.

The institutional problems are virtually guaranteed by the structures in the present Statues. Theoretically, the Authority is governed by a Board of Directors, who hires the Executive Director, who is in

turn, responsible for hiring and supervising additional staff, and for carrying out the duties of the Authority as directed by the Board. The Board of Directors is responsible to the Governor some as his lay appointees, and some as members of his Cabinet and staff. In either case, the individual Board members have neither the talent nor the time to understand comprehensively the complex technical and policy issues before them. Nor does the format for Board meetings, a public setting often surrounded by vociferous proponents and opponents of individual projects, lend itself to the reasoned debate which is required if the hundreds of millions of State dollars intrusted to APA are to be cared for properly. The Board must rely almost exclusively on its staff for the information it receives, and for recommending actions to be taken. It simply cannot generally lend its own creativity and initiative to the APA decision process. If individual Board members want to make changes in the Authority operations, or to have a major influence on the decisions made, they must develop the information themselves, with their own resources. This is simply not possible in a meaningful sense; it would not be practical for the Board to attempt an independent feasibility study for the Susitna project, or for the whole board to even read the entire report prepared by Acres. This is not to say that the staff doesn't do a good job of preparing material for the Board, it is simply to say that the task put before the Board is such that it serves as more of a public forum than it does as a decision-making entity.

Of course, the structure of the Alaska Power Authority is just one of the institutional difficulties that must be surmounted if the

Authority is to fulfill its mission. The Authority is only a part of Alaska's program for formulating and implementing energy policy. Also involved are the Division of Energy and Power Development, various entities in the Governor's Office, particularly what is now the Office of Management and Budget, the Department of Community and Regional Affairs, the Department of Natural Resources and the Department of Transportation and Public Facilities, among others. There is no mechanism for coordinating decisions made by these agencies so that conflicts are prevented. For example, APA is now engaged in condemnation proceedings, at substantial expense to the state, for the Fairbanks-Anchorage Intertie right of way. Some of these lands were only recently conveyed by the Department of Natural Resources to private landowners. It would certainly have been preferable to plan the Intertie and the land disposal together, to minimize ultimate project costs and local land use conflicts.

The unnecessary duplication of efforts over electric power demand projections is a further example. Virtually every major APA funded project must develop some projection of the demand for its power. The Division of Energy and Power Development has the responsibility for developing a state energy plan, which also entails long range power demand projections. Last year, Battelle Pacific Northwest Laboratories was contracted by the Office of the Governor to develop an analysis of long range power generation alternatives for the railbelt, and, as a result, a set of electric power demand futures. All of these efforts were very costly and, though there was a mandate for a great degree of coordination between them, the result was still

largely a set of projections which are generally recognized as unacceptable to the State. One of the last actions the Power Authority Board took while I was a member was to have its look into a process by which an annual, independent, forecast of demand could be made. Although theoretically this is the job of the Division of Energy and Power Development, we did not, as a Board, have confidence the Division could perform such an analysis with the degree of precision necessary for us to make our decisions. Of course, conflicts and overlap occur with other agencies as well, thus confusing the issue still more.

As I mentioned, the third problem area facing the Power Authority is procedural. Key in this is the fact that most of the actual work accomplished by the Authority is performed by contractors and subcontractors. For most projects, the Authority may have only a single staff person assigned full time, with limited support by its support staff. As a result, the degree of review by the Authority over the contract work has not been sufficiently detailed to uncover errors and omissions. While it is certainly not efficient to try to duplicate the expertise of a contractor, the Authority does need to have the high level of talent and number of staff necessary to insure that contractor work is performed well. My understanding is that the situation is improving at the Authority's staff as it matures and is able to attract talented staff, however, it would be well if the Legislature and perhaps the Governor's office took a hard look at the staffing plan of the Authority to determine if it is adequate to perform the mission assigned to it. This is particularly crucial in the area of feasibility

study and engineering review of projects. It is my opinion that some of the problems which have shown up in the Tyee project could have been avoided if the staff had been able to more closely supervise the design consultant for that project.

A more serious problem is the lack of a program to continually update the Power Authority's estimates of costs and benefits of a project. Few areas critical to the future development of Alaska are so sensitive as is the provision of electrical energy. Regardless of whether the State wants to subsidize projects which would not be able to pay for themselves otherwise, the State of Alaska must be aware, on a continuing basis, of the long range financial implications of the projects undertaken by the Energy Program for Alaska. This means that, if the cost of a project increases, the price of oil drops, demand projections change, the states equity portion of a project falls, or a myriad of other factors change, that a complete reformulation of the costs and benefits of a project must be undertaken. Failing to perform this crucial step will result in projects which are overbuilt, whose electricity cannot be sold to local utilities, or the provision of misleading information to the Legislature and the Governor. At present, there is no standard practice for routinely recalculating this information, and where attempts are made, obsolete data are often used. For example, although the estimated costs of the Fairbanks--Anchorage Intertie increased by over thirty million dollars from mid 1981 to mid 1982, the new cost/benefit figures published by Gilbert-/Commonwealth in its March 1982 Environmental Impact Assessment failed to include the fact that the demand projections, upon which the

benefits of this project are based, had been lowered dramatically as a result of the Battelle study and other estimates. In fact, the demand figures used by Commonwealth in calculating the benefit/cost ratio, the early Acres/ISER estimates, are in excess of the early Battelle high economic growth scenario. It is now generally accepted wisdom that even Battelle's low economic growth scenario may be too optimistic. This is not to say that the intertie is not a cost-effective project, for I am convinced that some configurations of the intertie have excellent net benefits whether it is subsidize completely by State General Funds or not. It may be, however, that the current design is simply not that of choice for maximum benefits.

Clearly, the Authority needs the in-house ability to reformulate the economics of these projects on a continuing basis, both as real data change and by using theoretical "what if" approaches. It is my understanding that neither the APA nor the Governor's Office of Management and Budget have this capability, even though it is a relatively straightforward technique.

Mr. Chairman, I have attempted to point out some of the problems that surround the Alaska Power Authority and make it difficult to accomplish its mission. I have purposely avoided discussing in depth the question of the Susitna Hydroelectric Project because you will hear extensively from those who are much more expert on that particular project than I. Further, the Legislature has the opportunity to take the corrective action needed to insure that APA can avoid the problems encountered in the Tyee project when and if Susitna is

built. Last year the administration discussed in depth changing APA to a line agency, whose chain of command comes clearly from the Governor. In this way, accountability for decisions would not be diffused through a Board of Directors that has neither the time nor the resources to understand the issues in depth. Such a reorganization would also strengthen the ties between State energy planning, and the construction of facilities to accomplish those plans. By putting a single commissioner and division director in responsible charge of the agency, you and the Governor can more effectively accomplish your respective oversight and supervision responsibilities of APA and its projects. The other problems I have mentioned are management in nature, problems that can be readily solved following some reorganization of the APA itself. The crucial issue is simply that there be a constant flow of timely and accurate information between the APA, State officials and the public. Only in this way can informed decisions be made.

Again, I want to thank the committee for this opportunity to share my views. I apologize for taking so much of your time, but as we all understand, the issues are complex and cannot be covered adequately in brief.

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE - ANCHORAGE, ALASKA 99501

Phone: (907) 277-7641
(907) 276-0001

January 17, 1983

Honorable William J. Sheffield
Governor of Alaska
Pouch A
Juneau, AK 99811

Dear Governor Sheffield:

It was a great pleasure to join you for dinner and discuss the future of the Susitna Project with you last week. I was honored by your invitation.

During the evening you indicated that several issues were of particular concern to you, and you also requested a "checklist" to guide your tracking of the development process.

The attached material is my response to your request. In preparing any brief list on such a major undertaking, there is always the chance of oversimplification. Therefore, I recommend it be used with some caution.

I continue to believe that the decision on Susitna will have to be made primarily on instinct, guided by the thoughtful advice of trusted associates. I cannot help but think that your dinner discussion last week was worth a multitude of consultants' reports.

Sincerely,

Eric P. Yould
Executive Director

copy with attachment: Charles Conway

Attachment: as stated.

HAVE ALL ALTERNATIVES BEEN EXAMINED?

The Office of the Governor, during the last two years of the Hammond Administration, contracted for a comprehensive assessment of alternatives to Susitna. This work is known as the Battelle Study. The Alaska Power Authority also evaluated alternatives, but concentrated on those that appeared to offer the most promise.

The major effort in the Battelle Project was the development of models and forecasting methodologies and associated data bases that would permit the State of Alaska to make its own forecasts to account for changing economic conditions or to evaluate different scenarios. The Battelle report illustrates the use of the models and methodologies based on economic forecasts prevalent in January, 1982.

The Battelle analysis included generating resources which could potentially contribute to meeting the electrical load over the time horizon of the study as well as conservation and consumer-installed small-scale generating resources. The generating resources included hydroelectric and those associated with the use of oil, gas, coal, wind, wood waste, municipal solid waste fuels, and tidal power. Nuclear plants were not considered because their size ranges do not match the load growths expected. In addition, State statutes specifically exclude nuclear energy production from the definition of power projects that can be funded through the Power Development Fund. Utility-scale solar thermal plants were not considered because of high construction costs and low capacity factor during winter peak load periods. Peat, while a potentially promising resource, was not included because of uncertainties relative to availability and cost of fuel-grade supplies in the Railbelt region.

Late in the study, Battelle reconsidered their estimates for the price of North Slope gas, but did not have the opportunity to fully evaluate the change. This, along with the postponement or demise of ANGTS, led the Legislature to appropriate $250,000 for further analysis of the North Slope gas generation option. This work is in progress and due for completion in early March, 1983. While definitive conclusions should await the completion of the study, it is expected that for this alternative to be cost competitive, the wellhead gas value will have to be so low that producers will have little incentive to sell the gas for this use.

In light of the recent downturn in the near-term outlook for oil prices, there is reason to update the comparison of alternatives to insure that decision-makers are kept fully informed of the latest trends. This type of update should be routinely accomplished on a periodic basis. The Power Authority is now conducting such an update, the results of which will be available in May, 1983. It will be performed using already existing analytic tools and in cooperation with the Division of Management and Budget.

The Chakachamna Hydroelectric Project has a power potential approximately 20 percent that of Susitna at a higher cost per kilowatt-hour than Susitna's Watana-Devil Canyon combination. If, for some reason, the Susitna Project is not developed in this century, Chakachamna is a logical project to turn to. For this reason, and to be able to answer the questions that will be raised during Susitna licensing, the Power Authority has continued evaluation of Chakachamna. The results of that work will be available in February, 1983. This supplemental information is not expected to be a factor in the Administration's decision on Susitna. → He doesn't say whether Chakachamna is cheaper than just the Watana phase & demand doesn't justify Devil Canyon

WHAT IS THE MARKET FOR SUSITNA POWER?

The Susitna Project will provide power to;

1) displace fossil fuel-fired generation and,
2) accommodate any growth in demand over the next several decades.

It consists of two equal-sized projects, thereby allowing phased development to match the growth in demand.

The financing approach to Susitna is designed to insure that the cost of Susitna power, even in the early years of operation, is equal to, or less than, the variable generation costs facing Railbelt utilities.

Assuming that such a finance plan is implemented, Railbelt utilities should be willing to shut down their fossil fuel-fired plants and purchase Susitna power. In the Railbelt today, total annual generation, excluding self-supplied industrial demand, exceeds 3,500 GWh. Netting out the generation potential from existing hydro-electric facilities (which would not be displaced), leaves a presentday market of 3,300 GWh. The most pessimistic Battelle forecast calls for another 450 GWh [1/] before 1990, giving a total potential market of at least 3,750 GWh when the Watana Project is completed. Watana will be able to provide 3,450 GWh, and therefore be fully utilized immediately upon its completion. Again, this presupposes that the finance plan will support a price for power that is competitive with the cost of alternative generation.

The Devil Canyon phase of the Project would then be added sometime later as Railbelt demand increased and the need dictated. Devil Canyon's additional 3,330 GWh would be available to accommodate demand growth, whether that resulted from population increases, increased per capital use, conversion from fossil fuels to electricity, or industrial demands.

1/ NOTE: This incremental demand (450 GWh over 10 years) is predicated on a Railbelt population of only 316,000 in the year 2000.

Since the addition of Devil Canyon reduces the average cost of Susitna power (Devil Canyon, when constructed after Watana, is an extremely good buy), the overall project's economic viability improves the earlier that Devil Canyon is required. If a substantial part of Devil Canyon's output is not needed until after 2010, Susitna's economic advantage over alternative generation options diminishes.

CAN THE PROJECT BE SUCCESSFULLY FINANCED?

The Alaska Power Authority has developed a number of viable financing options for the Watana phase (1985-1993) of the Susitna Project. These financing options were developed in consultation with the Power Authority's investment advisors (The First Boston Corporation, John Nuveen & Company, and First Southwest Company).

The actual financial outcome of the Project will depend not only on the real i.e., constant dollar characteristics of the Project, such as constant dollar cost, but also on a range of financial characteristics including the rate of inflation, the rate of interest, and the magnitude and timing of funding through State appropriations.

In order to move forward with the financing of the Watana phase, several essential pre-conditions must be met i.e., executed power sales contracts need to be in place, the question of tax exemption of Project revenue bonds must be resolved, the Project must have an acceptable level of cost of power in the early years while maintaining a coverage requirement of 1.1, and State equity capital of approximately $1.8 billion (1982 $) will be required.

The Power Authority and its financial advisors believe that the pre-conditions for successful Project financing can be met if the State resolves to commit the required equity capital to the Project.

The preferred financing option involves the concept of dedicated funds in the magnitude of $1.8 billion (1982 $). This option is designed to provide a secure and certain source of State funding over the long- term development period and would give potential investors greater assurance of on-going systematic development and hence, greater security for the borrowing of $2 billion (1982 $) in Project revenue bonds.

DO ALASKANS UNDERSTAND THE PROJECT AND THE ISSUES SURROUNDING IT?

A great deal has been done in an attempt to achieve a high level of understanding, especially among Railbelt residents. The Power Authority has engaged in an extensive public information and public participation program over the last three years. Newspaper coverage, until last week's Daily News series on the outlook for Cook Inlet gas supplies and prices, has tended to ignore the long-term Project benefits. Recent Chamber of Commerce and Susitna Power Now efforts have attempted to fill this void.

Among the general public, there is a basic appreciation for the merits of renewable, inflation-resistant hydroelectric development, there is an unnecessarily pessimistic sense of the Project's environmental implications, there is a lack of understanding regarding the finance plan and the State's investment role therein, and there is only a vague appreciation of the Project's positive employment impacts during the 15-year construction period of the two Project phases.

CHECKLIST

Two factors, future world oil prices and market rate of interest, strongly impact (if not dominate) the economic and financial viability of the Susitna Project. A number of other factors also influence the Project, but are of lesser relative importance.

Following is a checklist of preconditions or questions that may influence the ultimate decision to construct the Susitna Project. The items are grouped into two general categories: economic viability and project financing.

Economic viability encompasses those issues that relate to the determination of whether or not the Susitna Project will prove, in the long term, to be the lowest cost power option for the Railbelt. Included in this category are issues of power demand, the availability and cost of alternatives, and the cost of the Susitna Project itself.

Financial viability relates to the capability to actually assemble funds at a sufficiently low cost to insure that the resulting cost of Susitna power is competitive with the cost of alternative generation available to the Railbelt utilities. Rephrased, this issue focuses on the means of implementing a finance plan that allows the State the opportunity of capturing Susitna's long term benefits. Susitna's long term cost advantages cannot be captured unless the early year power costs can be brought in line with alternative generation costs.

Accompanying each item is a brief explanation of its importance, along with a status report. For some items, the status is subject to change and should be periodically reviewed, even after the Governor's endorsement of the Project. A status of "GREEN" indicates that the precondition is currently met or that conditions are favorable to the Susitna Project. "YELLOW" indicates that the situation is marginal and deserves close watching. If the precondition is not currently met, "RED" is used.

The final column on the table indicates when additional information, if any, may be forthcoming.

It should be emphasized that this checklist is simply a guide based on the Power Authority's best estimates. As such, it treats each item in isolation and does not address interactive effects. Reference should be made to pages 46-49 of the Susitna Hydroelectric Project Summary Report (attached) for further discussion. The findings of the feasibility report will be periodically updated to reflect current best estimates.

TABLE I

ECONOMIC VIABILITY ITEM	STATUS	UPDATES
1. Long-term oil price outlook calling for increases at a rate approximately one percent greater than inflation. If the long-term outlook is less than this threshold, the Project becomes a breakeven investment. This judgement, however, presupposes appreciable new economically recoverable supplies of Cook Inlet gas and/or an export market for Beluga coal. There is risk associated with both of these assumptions.	YELLOW	Periodic forecasts available from Department of Revenue and other forecasters.
2. Long-term average annual growth rate in Railbelt electricity demand equals or exceeds 2.8 percent. If the growth in energy demand in less than this, the significant benefits of the Devil Canyon phase are postponed to the point that alternatives become equally attractive as the Susitna Project. The average annual rate of demand growth in the Railbelt since 1970 has been about 9 percent. With the exception of an explosion in demand in 1982, the trend has been toward decreasing growth rates.	GREEN	Demand forecasts reflecting current outlook for State revenues and Sheffield Administration economic development policies to be updated periodically.
3. Capital cost escalation rates less than an average 4 percent above inflation over the next decade. Capital cost escalation has more impact on Susitna than other alternatives because of Susitna's relatively high capital cost.	GREEN	
4. The Susitna capital cost estimate does not increase by more than 20 percent in constant dollars. With a 20 percent increase in the capital cost, Susitna and the thermal alternative would be effectively equal in cost.	GREEN	

TABLE 1 (cont.)

ECONOMIC VIABILITY ITEM	STATUS	UPDATES
5. North Slope gas is not shown to be a preferred alternative. For this option to be preferred, Prudhoe gas must be made available to the State at a very low price (not yet determined) and Fuel Use Act exemptions must be secured.	YELLOW	Analysis to be complete in March.
6. Commitment to enhance Cook Inlet fisheries in conjunction with the Susitna Project. Planning to date has focused on achieving the pre-project status quo by means of flow regulation and maintenance of natural fishery habitat. Improved mainstem conditions may be able to offset losses in side channels and sloughs. A decision to develop a hatchery to achieve enhancement has not been made.	RED	The commitment to fishery enhancement is beyond the purview of the Power Authority. It requires direction from the Governor.
7. The Project has significant job creation potential Project construction will create a peak of 3,500 direct construction-related jobs and an average of 1,500 such jobs over the period 1985-2000. Additional indirect jobs will also be created.	GREEN	

TABLE I (cont.)

PROJECT FINANCING	STATUS	UPDATES
1. In place definitive contractual commitments by participating Railbelt utilities to purchase all of the Watana Project's power. In order to successfully conclude firm power sales contracts, the State must clearly demonstrate its intention to proceed with the Project.	RED	Contract negotiations to be initiated following the State's decision to proceed with Susitna.
2. Obtain a letter ruling by the Internal Revenue Service (IRS) to allow for tax-exempt revenue bond borrowing. It is not clear whether bonds issued to finance the Susitna Project are eligible for tax-exempt status. A recent private letter ruling by the IRS suggests that the "two-county rule" (no tax-exemption when non-tax-exempt power utility purchasers are in more than two Alaskan boroughs or cities) would not apply if power sale contracts are something other than "take-or-pay" contracts. However, applicability of that ruling is uncertain. Alternative methods of preserving tax-exempt status on APA Susitna bonds may include a limitation on the wholesale marketing of the power by, for example, granting to APA the authority to simply retail the produced energy and bypass those utilities which would otherwise throw the financing plan into a two-county sale situation or to convert the non-tax-exempt power utility purchasers into tax-exempt entities. In order to facilitate this ruling, it may be desirable to restructure existing utilities. An alternative is to seek specific exemption from Congress to allow for tax-exempt borrowing.	RED	Discussions with IRS are currently underway along with legal review of South Carolina Ruling.

TABLE I (cont.)

PROJECT FINANCING	STATUS	UPDATES
3. Sufficient uncommitted State funds for capital appropriations of approximately $1.8 billion for State equity in the Project available in the 1985-90 time frame. Forecasts of available State revenues have assumed the 30 percentile level for projected State revenue.	GREEN	
4. Real interest rates less than 4.2 percent. Expectations are to secure borrowed funds at about 3 percent.	GREEN	
5. Investment advisors continuing belief is that proposed financing options are viable and that required revenue bond financing can be obtained with no adverse impact upon the State's credit rating.	GREEN	
6. Cost of power in the early years must be close to or below the cost of energy that would result from pursuing the best thermal option.	GREEN	Will be periodically reviewed.

THE INFLATION OUTLOOK

DRI has lowered its forecast of inflation by another few tenths of a percent, with the CPI forecast to rise at a 5.3% average rate for the next three years, the finished goods producer price index by 5.1%, and the GNP deflator by 5.4%. Wages will retain most of the reductions achieved in the recession, but are not forecast to slow significantly further. Total compensation will accelerate because of the jump in Social Security taxes.

Table 6 shows the pattern of disinflation, from an 11.5% rate in 1979 to 1981 to 3.9% in the most recent 12 months. Of the 7.7% slowdown, home ownership, mainly mortgage rates and taxes, accounted for 3.6 percentage points. Lower energy prices, principally gasoline, contributed another 2.2 percentage points to the slowdown, and food accounted for 0.9 percentage points. Thus, interest rates, energy prices and farm prices account for 6.7 out of the 7.7 points of improvement. While the recession contributed to all of these improvements to a degree, there was considerable luck in these items, and not all of these gains are permanent. Farm prices will inevitably rise sooner or later, interest rates will cease to decline, and the energy price outlook will not always remain as favorable as it is today.

Table 6
Disinflation: How the CPI Slowed from 11.5% to 3.9%

	Annual Percent Change		Contribution to Slowdown (Percentage points)
	Dec 1978-Dec 1981	Dec 1981-Dec 1982	
CPI - All Items	11.5	3.9	7.7
Home Ownership	15.4	1.4	3.6
Home Prices	9.3	7.5	0.2
Finance, Taxes, Insurance	22.8	-4.0	3.2
Maintenance and Repairs	10.1	4.2	0.2
Energy	22.6	1.3	2.2
Gasoline	26.0	-6.6	1.9
Heating Fuels	29.8	0.9	0.4
Electricity	14.1	6.4	0.2
Natural Gas	16.5	25.4	-0.1
Food and Beverages	8.1	3.1	0.9
Clothing	6.1	3.3	0.1
Home Furnishings	4.4	0.9	0.1
New Cars	7.3	1.4	0.2
Medical Care	10.8	11.0	0.0
All Other			0.6

The question arises, therefore, whether the inflation improvement is to be short lived, and whether the danger of much larger inflation figures is very real. As we have pointed out before, the core inflation rate is in the 5% to 6% area, but the danger of much higher figures is quite remote. The farm price outlook is very moderate for the next year or two, interest rates are likely to show only small changes and in any event are removed from the index, and world energy prices are still headed lower. The rate of wage increase is currently near 5%, and it will not accelerate substantially for the next several years, given unemployment rates near 10%. Industrial prices, which will surely show some revival with recovery, cannot rise much as long as utilization rates are very, very low. Even in 1985, utilization rates do not quite reach 80%.

Data Resources Summary Table for the U.S. Economy - CONTROL012483

	1982		1983				1984		Years				
	III	IV	I	II	III	IV	I	II	1981	1982	1983	1984	1985
GNP and Its Components Billions of Dollars - SAAR													
Total Consumption	1986.3	2034.6	2064.2	2104.3	2150.0	2199.6	2244.2	2294.0	1843.2	1972.0	2129.5	2318.4	2528.2
Nonres. Fixed Investment	344.2	336.6	323.9	322.6	328.4	336.7	348.8	360.5	346.1	347.5	327.9	366.7	417.8
Res. Fixed Investment	94.3	99.8	112.1	120.0	128.1	134.6	139.5	145.8	105.0	95.8	123.7	149.8	180.3
Inventory Investment	4.7	-38.5	-12.2	0.6	5.3	8.3	18.7	17.3	20.4	-21.4	0.5	20.5	30.6
Net Exports	6.9	-6.9	-10.8	-13.8	-18.2	-19.3	-16.8	-14.2	26.1	16.6	-15.5	-13.2	-6.8
Federal Purchases	259.0	276.1	279.6	280.8	285.9	298.4	304.4	312.8	228.9	257.3	286.2	317.0	347.8
State and Local Govt. Purchases	392.7	399.6	404.2	409.8	415.2	421.0	427.3	435.0	368.0	389.8	412.5	439.3	474.2
Gross National Product	3088.2	3101.3	3160.8	3224.3	3294.8	3379.3	3466.0	3551.2	2937.7	3057.5	3264.8	3598.5	3972.1
Real GNP (1972 Dollars)	1481.1	1471.7	1481.8	1491.8	1505.9	1523.8	1540.7	1558.8	1502.6	1475.5	1500.8	1568.1	1635.6
Prices and Wages - Annual Rates of Change													
Implicit Price Deflator	5.0	4.3	5.0	5.4	5.0	5.6	5.9	5.2	9.4	6.0	5.0	5.5	5.8
CPI - All Urban Consumers	7.6	2.6	4.5	5.7	5.4	5.4	5.8	4.9	10.3	6.1	4.9	5.4	5.6
Producer Price Index - Finished Goods	6.4	4.2	2.7	4.0	5.2	5.4	5.2	5.0	9.3	4.0	4.0	5.1	6.0
Compensation per Hour	6.4	4.7	6.2	5.4	6.2	6.2	8.4	6.1	9.6	7.1	5.8	6.7	6.7
Core Inflation	7.6	7.3	6.8	6.4	6.0	5.7	5.5	5.5	9.0	7.8	6.2	5.4	5.4
Production and Other Key Measures													
Industrial Production (1967=1.000)	1.382	1.351	1.364	1.386	1.414	1.448	1.478	1.509	1.509	1.386	1.403	1.522	1.619
Annual Rate of Change	-3.4	-8.6	4.0	6.4	8.3	10.2	7.7	9.3	2.6	-8.1	1.2	8.5	6.3
Housing Starts (Mil. Units)	1.118	1.251	1.350	1.435	1.490	1.514	1.558	1.610	1.100	1.060	1.447	1.646	1.842
Retail Unit Car Sales (Mil. Units)	7.7	8.7	8.4	8.4	8.8	9.3	9.4	9.7	8.5	8.0	8.8	9.8	10.5
Unemployment Rate (%)	10.0	10.7	11.0	10.7	10.5	10.3	10.1	9.7	7.6	9.7	10.7	9.6	8.5
Federal Budget Surplus (NIA)	-156.0	-199.5	-191.6	-185.2	-201.5	-206.8	-204.1	-204.0	-60.0	-148.4	-196.3	-200.3	-188.4
Money and Interest Rates													
Money Supply (M-2)	1941.9	1985.7	2023.0	2062.4	2108.3	2161.0	2202.2	2252.7	1807.4	1985.7	2161.0	2367.1	2617.1
% Change, 4th-Qtr. to 4th Qtr.	10.1	9.3	7.7	8.0	9.2	10.4	7.8	9.5	9.5	9.9	8.8	9.5	10.6
New AA Corp. Utility Rate (%)	15.02	12.54	12.11	11.36	10.80	10.57	10.56	10.55	16.25	15.13	11.21	10.61	10.98
New High-Grade Corp. Bond Rate (%)	14.09	11.07	10.95	10.57	10.19	10.05	10.09	10.10	15.01	13.89	10.44	10.16	10.53
Federal Funds Rate (%)	11.01	9.29	7.96	8.27	8.64	8.94	9.59	9.32	16.38	12.26	8.45	9.09	9.61
Prime Rate (%)	14.72	11.96	10.34	10.51	10.81	11.27	11.90	11.63	18.87	14.86	10.73	11.42	11.50
Incomes - Billions of Dollars													
Personal Income	2592.4	2623.0	2659.8	2709.5	2772.2	2840.1	2905.5	2979.0	2415.8	2569.6	2745.4	3014.1	3299.2
Real Disposable Income (%Ch)	1.3	-0.2	0.3	2.2	7.1	4.6	3.9	5.0	2.5	1.1	2.0	4.5	3.7
Saving Rate (%)	6.9	5.8	5.6	5.6	6.4	6.5	6.8	7.0	6.4	6.5	6.0	7.0	7.2
Profits Before Tax	180.3	180.6	185.6	189.1	194.3	203.5	209.6	222.8	232.1	176.1	193.1	229.8	277.4
Profits After Tax	119.4	120.4	123.0	125.2	128.7	134.7	138.9	147.3	150.9	117.8	127.9	151.6	182.2
Company Profits	94.0	88.2	91.5	99.3	108.5	111.7	114.7	116.9	107.2	90.7	102.7	119.7	136.8
Four-Qtr. Percent Change	-11.1	-16.3	3.4	7.7	15.4	26.6	25.3	17.9	2.6	-15.4	13.2	16.5	14.3
Composition of Real GNP - Annual Rates of Change													
Gross National Product	0.7	-2.5	2.8	2.7	3.8	4.8	4.5	4.8	1.9	-1.8	1.7	4.5	4.3
Final Sales	-1.3	3.1	-0.5	1.2	3.3	4.6	3.3	5.0	1.0	-0.6	1.1	4.0	4.1
Total Consumption	0.6	5.0	1.1	2.3	3.5	4.2	2.5	4.2	1.8	1.0	2.5	3.5	3.4
Nonres. Fixed Investment	-7.7	-9.0	-15.9	-4.3	4.0	6.5	9.4	9.3	3.5	-3.8	-7.6	7.1	8.1
Equipment	-8.8	-12.1	-11.4	-0.2	9.8	11.0	12.4	12.4	2.4	-6.8	-5.9	10.6	9.0
Nonres. Construction	-5.2	-2.3	-24.6	-12.5	-7.9	-3.3	2.7	2.0	6.3	3.1	-11.1	-0.6	5.7
Res. Fixed Investment	-5.9	24.2	50.7	24.1	21.9	15.2	7.6	12.5	-4.9	-10.9	24.4	13.9	12.6
Exports	-16.7	-26.9	-2.8	3.0	6.0	6.0	7.7	5.9	-0.5	-6.9	-6.6	6.1	5.6
Imports	4.5	-14.8	0.2	3.7	7.3	5.8	5.3	3.7	7.2	0.6	0.3	4.9	4.1
Federal Government	23.2	28.4	-3.0	-6.9	0.3	6.9	2.0	5.9	3.7	5.2	4.8	3.1	2.2
State and Local Governments	-0.2	1.1	-1.1	0.1	-0.4	0.0	0.0	1.6	-0.8	-0.9	-0.1	0.6	1.8

Alaska State Legislature

Advisory Council Members
Senator Kerttula, Chairman
Senator Bennett
Senator Vic Fischer
Senator Fahrenkamp

Pouch V
State Capital
Juneau, Alaska 99811
Phone: (907)465-3114

SENATE ADVISORY COUNCIL

MEMORANDUM

TO: All Senators

FROM: Kurt S. Dzinich KSD

DATE: March 7, 1983

RE: APA Energy Rates

Over the past year, it has become increasingly obvious that the Energy Program for Alaska would require some fine tuning if it is to achieve the legislatively mandated goal of lowest reasonably costed energy. During the past few months, I have consulted with various interested parties and explored reasons for the problem as well as alternative solutions.

The attached HB9 Power Cost Study was prepared by APA for their February 28, 1983 Board meeting and will be addressed again at the next meeting now planned for March 14, 1983, in Juneau. The study is an excellent summary of how we got into the current predicament and some potential solutions.

The direct cause of the predicament appears to be our earlier expectations that the State grants derived from large oil revenues would be used to construct the projects thereby resulting in low rates which would only have to cover the cost of operations and maintenance. Contributing factors were overly optimistic cost estimates on early projects, the capital intensive nature of hydropower projects, and the growing pains associated with initiating such a large program.

While many lessons have been learned and the system substantially improved, there are still problems which must be solved in order to allow the program to succeed. Most importantly, the ongoing projects must be finished using debt financing in order to insure that the benefits are realized - and there is not doubt that in the long run the benefits will be substantial and that the projects will prove their economic feasibility.

I would be happy to discuss details of the report or the proposed solutions.

MEMORANDUM State of Alaska

TO: Eric P. Yould
Executive Director

DATE: December 28, 1982

FILE NO:

TELEPHONE NO:

FROM: Myles C. Yerkes
Director of Systems &
Planning Operations

SUBJECT: Marketing of Project Power Under the Energy Program for Alaska.

In discussing revisions to Power Sales Agreements required by House Bill #9 with concerned utilities, major problems with the Energy Program for Alaska surfaced. The Alaska Power Authority must consider modifications to this program or other actions necessary to secure power sales agreements with related utilities. Problems primarily relate to the inability of the current program to establish a reasonable and predictable energy rate for power customers under the program. Utilities voiced concern with current program language which allows the debt service for a particular project to be increased by the Legislature or the Power Authority without control by the utility. Utilities are understandably resistive to signing such "Take or Pay" agreements since the economic impact to related communities could be devastating.

The first major concern is the estimated initial cost of project power. Projected wholesale power rates by the financial group indicate Tyee at 18¢ per kilowatt hour in the initial years of operation with a very slow tapering following that period. Since existing utilities in the area (Wrangell and Petersburg) are currently generating power from diesel plants at a cost of approximately 10¢ per kilowatt hour, it is difficult, if not impossible, to market the project energy at this rate. This problem is not exclusive to the Tyee project, but will in all probability arise for most projects in the program. Program debt service must be reduced to in turn reduce the initial wholesale power rate. Since the Power Authority has no means to generate such revenue, it appears that our only option is to request the State of Alaska to appropriate additional funds to program construction to reduce future debt service. Unless debt service is reduced to allow marketing of project power at or slightly above the present cost of utility diesel generation, I sincerely doubt utilities will complete or abide by the terms of existing or proposed power sales agreements.

The second major concern is the inability of utilities to predict future wholesale power rates due to current program language which allows debt service to be increased by the Legislature through approval of additional projects to the program or implementation of the "Susitna Blackmail Clause". "Take or pay" wholesale power agreements with utilities are required to secure revenue bond financing of project costs above that appropriated by the State. For utilities to assume such a financial responsibility, they must see a predicable and reasonable wholesale power rate throughout the life of the contract.

Current legislation does not meet this criteria since costs can be unilaterally increased to the utilities by the Power Authority Board or the Legislature without consideration of alternatives to the utility. In summary, if we are to be successful in marketing Power Sales Agreements required for project revenue bonding, current program legislation must be amended to restrict the State from unreasonably increasing debt service to a project or causing rates to rise above reasonable alternatives.

The third concern is the ability of the Power Authority to provide stable wholesale power rates to the purchasing consumer. This problem arises primarily from two areas. First is the ability of the Legislature or the Power Authority Board to allow new projects under the program and assess increased debt service to existing utilities without specific regard to price stabilization to the ultimate consuming public. Second is program language which implies that wholesale power rates must be based upon estimated operation and maintenance expense for the upcoming year. If we are to provide reasonably stable wholesale power rates and proper price signaling to the general public, then current program legislation must be modified or interpreted to allow the Power Authority to ammortize annual operation and maintenance cost over a reasonable period to allow for reasonable price adjustment on a year by year basis and avoid the appearance of budget or fiscal irresponsibility. Such a policy would accommodate program language requiring purchasers pay the ongoing cost of project operations, maintenance, and debt service but would allow the Power Authority to ammortize operation and maintenance cost over a period of several years if required to provide reasonable and uniform wholesale power rates.

The final problem is the ability of Utilities to set power rates for different classes of customers in accordance with cost of service principles generally recognized by the State and Federal Regulatory Commissions. Current program language requires that a purchaser of project energy maintain power rates for industrial class customers equal to or above that provided to a residential class customer. Utilities have indicated concern that this may restrict their ability to market power on a reasonable cost basis to industrial customers and would hinder economic growth and expanded utilization of the hydroelectric projects. Utilities have suggested that current program language be changed to delete this requirement and allow a utility to set rates for all classes of customers in accordance with cost of service principals generally acceptable or approved by the FERC and the Alaska Public Utilities Commission.

The problem areas discussed must be dealt with during this legislative period if we are to successfully market the power from projects under the Energy Program for Alaska and reduce the incentive for a utility to default on an existing agreement. Your support and participation will be critical.

Sincerely,

Myles C. Yerkes
Director of Systems
Planning & Operations

MCY:cb

cc: Raymond J. Benish, APA, Anchorage

HB 9 POWER COST STUDY

1 - INTRODUCTION

At its inception in 1979/80 Alaska's hydroelectric program was provisionally based on the estimates that hydro units would come on at a period when thermal energy costs had continued to rise and the units would be substantially financed by the State of Alaska. This program, like many other energy programs elsewhere, now needs to be reviewed in the light of the currently prevailing circumstances under which some of the projects are expected to be substantially debt financed and may come on stream at a period when there has been a significant weakening in thermal energy prices.

This poses a number of problems which need to be addressed in the context of the HB 9 legislation which effectively interlocks the power rates of all projects in the system. The paper first describes the essentials of the HB 9 legislation and then considers the present status of the first four authorized projects (Swan Lake, Tyee Lake, Solomon Gulch and Terror Lake) in the light of this legislation. It then puts forward a number of possible solutions to the problems posed by this legislation for consideration by the Board before further development proposals are presented to the legislature.

This presentation focuses on the rate setting formula and presents four alternatives to attain a wholesale power rate comparable to the projected thermal rates. This approach may inadvertantly create the impression that HB 9 is itself a problem. However, the Power Authority does not in any way take issue with the legislation and believes that HB 9 is an equitable and workable rate setting mechanism.

2 - DESCRIPTION OF HOUSE BILL 9

2.1 - History

During the last session of the Legislature, HB 9 (subsequently enacted as Chapter 233, SLA 1982) was adopted to amend the Energy Program for Alaska.

The major and most detailed change introduced by HB 9 was to establish a system related but project-specific wholesale power rate rather than a single system-wide wholesale power rate. Under the previous legislation, the single wholesale power rate was calculated by totaling the operation and maintenance costs, inspection fees, and debt service costs for all projects in the system, then dividing by total sales to arrive at a cents-per-kilowatt hour rate, which would be applied to all project sales. The new and somewhat complex power rate system is outlined below.

2.2 - Wholesale Power Rates Under HB 9

Under the new HB 9 legislation a project's power rate will be based on the following three components: (1) it's own operation and maintenance costs, (2) it's own inspection fees, and (3) a portion of the total system debt service.

The O/M and inspection fee portion of the power rate is simply the actually incurred costs divided by project sales.

The debt service portion of any individual project's power rate is the most significant aspect of the legislation and is most easily described by the following formula. The debt service component is

$$\left(\frac{x - \frac{xp}{y}}{y - p} \right) z$$

where

x = the state's total investment in the particular project
y = the state's total investment in all projects within the energy program for Alaska
z = total debt service including coverage for all projects for the year in question
p = the amount of principal repaid as at the date of the calculation

This formula, however for our present purposes, simplifies to:

$$\frac{x}{y} \text{ times } z$$

Thus total system debt service z is allocated to individual projects on the basis of the project's share (x/y) in the total investment by the state. This formula holds, regardless of whether a project itself has incurred any debt service.

In essence, this formula therefore allocates debt service so that each project pays the same amount of debt service relative to project cost as all other projects. Thus the benefits of state grants, directed towards specific projects, will be shared by all.

This methodology is complicated by subsection (c) (h) of the legislation which places a "cap" on the level to which the debt service component of the wholesale rate can increase in any one year. The "cap" rate each year is equal to the average system debt service rate (total system debt service divided by total sales) times a factor which increases by four percent per annum from one in 1983. If any projects have the debt service portion of their rates capped then the other projects, whose rates are still less than the cap rate, will have their rates adjusted upwards (to a maximum of the cap rate) so that sufficient revenues are collected to meet debt service obligations of the entire system. This allocation of the remaining debt service is again based on project cost.

This "cap" provision applies only to Swan, Tyee, Terror and Solomon Gulch. In consequence, any new projects will have to carry a correspondingly higher burden of debt service.

The final wholesale power rate then is the sum of the operating cost rate and the debt service rate. Further details of the methodology for power rate calculations is contained in Appendix C.

3 - WHOLESALE POWER RATE FORECASTS FOR; SWAN LAKE, TYEE LAKE, SOLOMON GULCH AND TERROR LAKE

In this section the effect of the HB 9 legislation on wholesale power rates for the Swan Lake, Tyee Lake, Solomon Gulch, and Terror Lake projects are examined to the year 2001. Power rate calculations under HB 9 depend not only on the usual parameters such as project cost, sales and financing, and economic variables such as inflation and interest rates, but also on which projects are included in the calculations. For example, Solomon Gulch, with a current wholesale rate of 3¢/kwh, would see its rate increase substantially when the Swan Lake and Tyee Lake projects are brought on-line and into the calculations in FY 1985.

3.1 - Forecast Assumptions

The forecasts presented are based on the assumptions detailed in Appendix B. A detailed description of the forecast methodology and model are provided in Appendix C.

3.2 - Wholesale Power Rates

Table 1 gives the wholesale power rates for each of the four authorized projects under the existing HB 9 legislation. The table is essentially for record and does not compare the results with the cost of thermal power. This is considered in the fuller context of the analysis of Section 4.

TABLE 1

WHOLESALE POWER RATES UNDER HB 9 (¢/kwh) IN THEN CURRENT DOLLARS

% Debt/% Equity	Swan 26/74	Tyee 36/64	Solomon 0/100	Terror 58/42
1985	11.4	12.1	9.7	N/A
1986	15.0	15.8	10.1	12.3
1987	15.1	16.1	10.1	11.7
1988	15.2	16.3	10.2	11.1
1989	15.2	16.6	10.4	10.6
1990	14.7	16.9	10.7	10.2
1991	14.3	17.4	11.0	10.1

Project Summary *

Project	Total Project Cost ($ millions)	Installed Capacity	On-line Date FY	Utilities Served
Swan Lake	93.50	22.5 MW	1985	Ketchikan
Tyee Lake	124.60	20 MW	1985	Petersburg/ Wrangell
Solomon Gulch	53.00	12 MW	1983	Copper Valley
Terror Lake	189.40	20 MW	1986	Kodiak
Total	460.50			

* See Appendixes A and B for further details

3.3 - Retail Power Rates Under the Power Assistance Program

The impact of the hydro projects on retail rates for the regions served are materially reduced at the retail level by the Power Cost Assistance Program. This in outline provides (with some limitations) for 95 percent of the cost of power in excess of 15 cents per kwh in 1985 to be covered by State grants to the utility. This reference level of 15 cents in 1985, however, increases by one (1) cent each year. The effect of this in mitigating the early year cost of the hydro projects is shown in Table 2 in the context of the retail power rates to which the Power Cost Assistance Program provisions apply.

It is seen from this that after the power assistance grants, the average net retail cost (after the Power Cost Assistance is applied) of the hydro power to consumers is competitive with that of thermal for all projects in 1985.

The effect of Terror Lake coming on in 1986 is to introduce a jump in the cost of power for the whole system. This occurs as a result of the debt/equity ratio for Terror Lake which is substantially below the system average. This, as also shown in Table 2, results in Tyee Lake having a cost of power nine percent higher than thermal.

TABLE 2

AVERAGE NET RETAIL POWER RATE
UNDER POWER ASSISTANCE PROGRAM

	Power Assistance Level	Swan ¢/KWH		Tyee ¢/KWH		Solomon ¢/KWH		Terror ¢/KWH	
		Hydro	Thermal	Hydro	Thermal	Hydro	Thermal	Hydro	Thermal
1985	15.0	14.4	16.1	16.1	16.4	14.3	20.2	N/A	N/A
1986	16.0	17.1	17.2	19.1	17.5	15.1	21.6	17.8	18.3
1987	17.0	17.8	18.4	19.8	18.8	15.5	23.2	17.9	19.6
1988	18.0	18.5	19.6	20.6	20.0	16.0	24.7	18.1	20.9
1989	19.0	19.1	20.8	21.4	21.3	16.6	26.3	18.1	22.3
1990	20.0	19.0	22.1	22.2	22.7	17.3	28.1	18.3	23.8
1991	21.0	18.8	23.5	23.1	24.1	18.1	30.0	18.7	25.4

1. See Appendix A for project descriptions

It is possible that these temporary differentials, in net cost, will be lower and that they will be acceptable to the local utilities as a small price for the major long term benefits conferred by having large resources of low cost hydro power indefinitely. The Power Authority planning must, however prepare for the contingency that this is not the case since, short te , it depends both on the unpredictable short term cost of fuel oil and on the continuance of the Power Cost Assistance Program. It is also possible that the utilities will wish to negotiate the power rate, while ignoring the Power Cost Assistance Program.

The following section, therefore, reviews the HB 9 legislation and the competitive position of the hydro development at the wholesale power rate level excluding the mitigation effect of the Assistance Program.

4 - THE EARLY YEAR POWER COST, SYSTEM INCREMENT AND UNIFORM RATE PROBLEMS UNDER HB 9

4.1 - The Problems

The wholesale power rates as they stem from existing legislation (and as shown in Table 1) need to be considered in the context of the estimated cost of thermal power generation from existing capacity in the areas served. Here the economics of the Swan, Tyee and Terror Lake projects are each seen to be materially affected by three interrelated problems arising from their basic economics and the impact of the HB 9 legislation. The problems are:

The Early Year Power Cost Problem

This is the problem of the recent weakening of oil prices which may result in making the early year cost of power from the hydro projects being higher than the early year cost of the diesel operation which they displace.

The System Increment Problem

This is the problem of all power rates on the system being increased through the HB 9 mechanism when a new project is introduced to the system and the project has a higher proportion of debt finance than the average of the existing system as a whole. The Terror Lake project is more heavily debt financed than the existing projects (58 percent compared with 26 percent). When this project comes on stream in FY 1986 the effect of HB 9 is to share this increased cost of debt service among all four projects and so further increase the cost of power for Swan Lake, Tyee Lake and Solomon Gulch.

The Uniform Rate Problem

The HB 9 legislation requires that a single-power rate be established for each project. As noted in Section 5, this creates underutilization and consequently higher unit costs by precluding the Power Authority from offering lower priced power to secure industrial and home heating loads.

The effect of the early year power cost problem alone is shown in Table 3 on the assumption that diesel oil costs increase by only the rate of inflation between the end of 1983 and the first year of service (FY 1985). On this assumption, in 1985 all projects show power rates less than local thermal generation cost.

However, a problem occurs when Terror Lake is brought into the calculations in 1986. This is the System Increment problem - the effect of HB 9 when a higher than system average debt financed project is added to the system. When this occurs it is seen from Table 3 to have the effect of:

(i) increasing the cost of power of Swan and Tyee over their 1985 level by 32 percent and 31 percent, respectively (even with the "cap" in place);
(ii) making the cost of power of Tyee Lake 15.8 ¢/kwh compared with 13.4 ¢/kwh for diesel generation.

Terror Lake itself, with its higher debt service, would come in at approximately the same cost as thermal. On the inflationary assumptions given, it would take four years to close the net cost gap between thermal and hydro for Tyee Lake.

TABLE 3

EARLY YEAR COST OF POWER & SYSTEM INCREMENT PR[illegible]EM
WHOLESALE RATE (¢/kwh)

	Swan			Tyee			Solomon			Terror	
% Debt/Equity	26/74			36/64			0/100			58/42	
	Thermal[1]	Hydro Without Terror	Hydro With Terror	Thermal[1]	Hydro Without Terror	Hydro With Terror	Thermal[1]	Hydro Without Terror	Hydro With Terror	Thermal[1]	Hydro
1985	14.1	11.4	11.4	12.5	12.1	12.1	18.1	9.7	9.7	N/A	N/A
1986	15.2	11.8	15.0	13.4	12.7	15.8	19.5	9.3	10.1	13.0	12.3
1987	16.3	12.0	15.1	14.4	13.0	16.1	20.9	8.9	10.1	14.0	11.7
1988	17.4	12.2	15.2	15.4	13.4	16.3	22.4	8.5	10.2	15.0	11.1
1989	18.6	11.9	15.2	16.5	13.8	16.6	24.0	8.6	10.4	16.0	10.6
1990	20.0	11.5	14.7	17.6	14.1	16.9	25.6	8.8	10.7	17.1	10.2
1991	21.4	11.1	14.3	18.9	14.5	17.[illegible]	27.5	9.1	11.0	18.4	10.1

[1] Source: Based on 1981/1982 utility accounts for; Ketchikan, Wrangell, Petersburg, Copper Valley and Kodiak.

Diesel oil price assume constant until 1984 and increasing thereafter in line with inflation (as given in Appendix B).
Units o/a costs assumed to increase with inflation from 1981.

4.2 - Solution to the Early Year Power Cost and System Increment Problem

Possible Solutions

It is seen from the preceding analysis that the Early Year Power Cost problem alone is not unduly severe. The System Increment problem, however, is of considerably great seriousness first, because it compounds the Early Year Power Cost problem by increasing the cost of power whenever heavily-debt financed projects are added to the system. Second, and of more importance, it places the utilities in a position of appreciable uncertainty as to the future burden of power costs which they might be obliged to assume through the HB 9 mechanism.

It is true that the HB 9 mechanism does provide a "cap" for the existing four projects on the rate of increase of individual project power rates resulting from new increments to the system. But this does not rectify the basic fact that over the long term, utilities coming into the system are exposed to what might appear an open-ended liability to meet their share of whatever the debt service cost is of additional increments to the system. This was not a material issue while expectations were that the hydro power, even in the early years, would be less expensive than the highly escalating cost of the thermal option and there was the general expectation that the hydro additions would, in very large measure, be financed by equity contributions from the State. With the weakening of both these expectations, a concern on the part of utilities joining the system as to the extent of escalation in future hydro power costs is understandable. It is also possible that this combined with the Early Year Cost of Power problem (which it exacerbates) will result in difficulties in negotiating contracts with the local utilities.

This problem has no easy solution. A range of possible solutions have been considered and are as outlined below.

4.2.1 - Stand Alone Legislation

The first option to be considered is that of amending HB 9 such that future projects had a calculated cost of power which was on a stand-alone basis, that is, the "new" projects were exempt from the HB 9 debt service sharing provision. This would indeed shelter the existing projects from any high debt service component of new projects, but would have the obvious serious disadvantage of leaving these new projects disadvantaged relative to the projects which preceded them under the HB 9 legislation.

At a practical level it would also appear to be unacceptable since, for example, in the case of Terror Lake it would imply a wholesale cost of power in the first year (1986) of 15.4 cents and 25 percent higher than under HB 9. Rather than meet this cost of power (estimated to be some 25 percent higher than that of the thermal option) the local utilities might feel obliged to forego the very substantial long-term advantage which would be conferred by the fact that the cost of the hydro power would be virtually fixed in money terms.

In summary, the "stand-alone" solution would involve the probability of foregoing the long-term falling real cost of power which the present hydroelectric program is designed to achieve.

4.2.2 - Higher State Equity Contributions

Higher State Equity Contributions than those which form the basis of the forecast power rate of Table 1 would have the overall effect of reducing power rates and so helping to resolve the Early Power Cost and System Increment problems. The major difficulty with this solution, however, is that the HB 9 legislation effectively shares the benefits of any larger state equity in any particular project between all the projects in the system thus reducing all power rates. In consequence, higher State Equity contributions to reduce the cost of power, in the case of Lake Tyee for example, would have the effect of reducing not only the Lake Tyee power rate, but also the power rates of Swan Lake, Terror Lake, and Solomon Gulch, although the last would already have a power rate 50 percent less than the cost of thermal under the existing proposed financing. Moreover, this sharing of the benefits of greater state equity of necessity, means that much larger state equity is required to reduce the power rate of any given project. The numerical effect of this is shown in Table 4.

TABLE 4

WHOLESALE POWER RATES RESULTING FROM ADDITIONAL STATE EQUITY CONTRIBUTIONS

	Swan	Tyee	Solomon Gulch	Terror
Thermal Rate				
1985	14.1	12.5	18.1	N/A
1986	15.2	13.4	19.5	13.0
1987	16.3	14.4	20.9	14.0
HB 9 Rate Under Base Financing Assumption [1]				
1985	11.4	12.1	9.7	N/A
1986	15.0	15.8	10.1	12.3
1987	15.1	16.1	10.1	11.7
HB 9 Rate After Additional State Grants of $40 million				
1985	11.4	12.1	9.7	N/A
1986	12.5	13.4	8.6	9.9
1987	12.7	13.7	8.8	9.6

[1] See Appendix B Total state contributions assumed to be $281 million (approximately 60% of total financing)

This estimates the total additional equity contribution which will be required to ensure that all the power rates from the authorized projects are below the cost of the best thermal option. As seen from Table 4, Lake Tyee presents the most serious problem with a cost of power 2.4 cents higher than the thermal cost in 1986. Consequently, the equity contribution would be determined by whatever was required to achieve this objective. It would, however, require $40 million of equity. As can be seen from the table, this makes Lake Tyee equal in power rate to the cost of thermal by reducing the cost by 2.4 cents. But it also reduces the cost of power for Swan, Solomon Gulch, and Terror Lake by 2.5, 1.5, and 2.4 cents respectively in 1986, thus bringing their cost well below the cost of thermal power in their areas. This is again because the high equity contribution to Lake Tyee has the effect, through the operation of HB 9, of reducing all other power rates. It is because HB 9, effectively makes it necessary to reduce all power rates in order to reduce any one of them by greater equity, that the magnitude of the equity contribution at $40 million is so large.

4.2.3 - Low Interest Rate Loans

The Early Year Power Cost and System Increment problems could also be reduced by the state providing financing in the form of low interest rate loans. The larger the amount of such loans and the lower the interest rate, the lower the burden of debt service which HB 9 would require to be shared among all the projects on the system.

This solution, however, has much the same disadvantages as the higher state equity proposal considered above. Again the whole of the benefit of this low cost form of financing would be shared among all projects on the system irrespective of their power rate so that the problem of sharing applies here as in the equity financing case.

Moreover, in terms of the total level of appropriations required, this proposal would require very much higher appropriations than in the greater state equity case. This is because it would require $2.4 million of (say) five percent interest rate money to reduce power cost by as much as $1 million of state equity since the latter involves no burden of interest or repayment. Hence the low interest loans will have all the adverse affects of greater state equity and the addition would require appropriations 140 percent higher to achieve the same impact on the power rates.

4.2.4 - Equalization Grants as an HB 9 Over-ride

It is clear from the options considered above that any state assistance in meeting the Early Power Cost and System Increment problems through state financing assistance is made very costly by the effect of HB 9 sharing the benefits among all the projects on the system, irrespective of their existing power rates. Economical and effective state assistance, therefore, needs to be in a form which was not treated in this way by the HB 9 division and so could be directed at the particular projects which have the Early Year Cost of Power and System Increment problems.

This could be achieved by a system of annual "Equalization Grants" directed towards making the cost of power from the hydro station equal to that of thermal alternative, until such time as the increase in fuel costs on the thermal alternative brought its costs up to that of hydro and thus made further Equalization Grants unnecessary. To ensure that such grants were not swept up by the HB 9 legislation and the benefits shared among all projects irrespective of need, it will be necessary to legislate that the Equalization Grants were not to be taken into account in the application of HB 9.

Specifically, the legislation might take the following form. It would apply to areas where the cost of power from the hydro source was higher than the existing thermal power option. The program would then undertake for, say, a five to six year period, a special "Equalization Grant". This grant would meet the whole of the estimated difference between the cost of the hydro power and the cost of the thermal power as estimated each year based upon the price of diesel oil.

In the case of Tyee Lake, where the early year cost problem has been seen to be most material under HB 9, the cost of this (on the assumption of diesel oil prices increasing at the rate of inflation from 1984) would be approximately $1.8 million in then current dollars (approximately $1.4 million in 1983 dollars). The year-by-year costs of the Equalization Grant are shown in Table 5 in then current dollars. On the inflation assumptions assumed, the Tyee Lake power rate would be competitive with that of thermal at the end of four years so that the Equalization Grant could be terminated. Thereafter, as already noted, the cost of the hydro power would be falling progressively in terms of constant dollars as inflation progresses.

TABLE 5

COST OF EQUALIZATION GRANTS ($ millions)

	Swan	Tyee	Solomon	Terror	Total
1985	0	0	0	N/A	0
1986	0	0.8	0	0	0.8
1987	0	0.6	0	0	0.6
1988	0	0.3	0	0	0.3
1989	0	0.1	0	0	0.1
1990	0	0	0	0	0
1991	0	0	0	0	0
TOTAL	0.0	1.8	0	0	1.8

Similar Equalization Grants might need to be extended to other projects. The total cost in the latter case, however, is likely to be relatively small given that with this solution to the system increment cost problem, their cost of power would become competitive with thermal within a very short period.

The Equalization Grant provisions could be written into the power contracts of the utilities with the Power Authority, thus giving the assurance of their continuation over the appropriate period.

4.2.5 - Equalization Loans

An alternative to the Equalization Grants would be Equalization Loans. These would be simply the grants made repayable at a date when the hydro power was competitive with the thermal alternative. Under this proposal the grants would be carried as an unsecured loan for a given period - for example, eight years from the commencement of the grant. By this date, the hydro power should be strongly competitive with the thermal option. In consequence, by this time it should be possible for the utility to accept an increase in the power rate, which would be sufficient to support long-term commercial borrowing with the proceeds of the borrowing going to repay the outstanding loan accounted for by the Equalization Grant.

This proposal would involve some technical problems in the debt financing. It would, for example, be necessary to secure the prior consent of the existing bond holders for this additional subsequent borrowing, and the terms on which the borrowing would take place would need to be precisely and legally specified if the existing bond holder interests were to be protected. These problems, however, would have to be overcome without undue difficulty if this particular proposal won the consent and cooperation of the utilities concerned.

There might remain the problem for the utilities that they would be subject to uncertainty as to whether or not the Equalization Grant would apply to later increments to the system or whether, after their own Equalization Grants had run out, they were to be subject to the effect of the System Increment problem as other projects with relatively high debt service were added to the system and were not in receipt of Equalization Grants. This potential exposure, however, might be acceptable to the utilities given they had the shelter provided by the Equalization Grants over the first five years and the then highly competitive economics of their own sources of hydro.

Turning to the economics of the Equalization Grant system from the stand point of the State of Alaska, it is seen from Table 5 to involve only $1.8 million in total ($1.4 million in 1983 dollars). Against this must be set the major long term economic advantages of reduced future costs from the hydro program.

4.2.6 - Standardized State Financing Until System Maturity

It has been seen that the System Increment addition problem essentially arises where the increment to the system has higher debt service costs than the then existing units in the system. This particularly arises with Terror Lake where it is 58 percent financed by debt compared with 26 percent for the system as a whole. A means of substantially eliminating the System Increment problem would therefore be to ensure that for an interim period at least (for, say seven years) additions to the system were financed with the same proportion of debt as the existing system - that is only 26 percent with the balance being funded from state equity.

This would be needed for only an interim period until the system was established and like other "mature" power systems, begin to reap the benefits of decreasing cost of power in constant dollars from the substantial amount of capacity acquired in the past. This measure would realistically address the fundamental problem which all newly established power systems pose, namely that they have no backlog of cheap capacity acquired at the lower prices prevailing in earlier years. In consequence they have an inherent problem introducing into the system new units of capacity, the current costs which, in an inflationary world, inevitably involve higher costs than units purchased at the substantially lower prices prevailing in earlier years. If this problem is not addressed and resolved it would result in the system being permanently locked into whatever types of capacity have the lowest early year costs irrespective of the long term economics.

The Standardized Financing Option would be a solution which, within existing legislation, would create a "mature" system such that the power rates resulting from this option would all rapidly become competitive with the existing thermal option so that within a few years other units could be introduced into the system without causing excessively large increases in power rates.

The evident major problem with this option is that it would involve additional equity of approximately $60 million to be appropriated in FY 1984 and 1985 and as such may be deemed unacceptable.

5 - MARKETING AND DEVELOPMENT SOLUTIONS

The preceding sections have addressed the immediate problems in a legislative context since these need detailed and lengthy consideration prior to legislation. The Power Authority is, however, actively pursuing the marketing and development activities which will help improve the economic competitiveness of the projects under construction or authorization. This includes:

(1) Transmission interconnections to serve adjacent communities or interties;
(2) Securing home heating markets and
(3) New industrial and commercial loads.

Very substantial potential increases in sales of power (and consequent reduction in unit costs) are possible given that the three projects have substantial underutilized in the early years and, in the case of Swan Lake, only about 40 percent.

The uniform rate imposed by HB 9 for all power from a given project is a serious obstacle to the greater utilization of capacity by securing home heating and industrial and commercial loads. These loads can only be secured on the basis of a price of power significantly lower than the single wholesale rates of Table 1.

On these grounds, it is recommended that HB 9 be modified to permit multiple tariffs whenever this is shown as likely to improve utilization and reduce unit costs overall.

6 - SUMMARY AND CONCLUSIONS

1. The report reviews the key elements in the Power Authority's hydroelectric program in the light of the issues posed by the recent weakening of alternative energy prices, the present stage of development of the projects, and the impact of the HB 9 legislation.

2. The HB 9 legislation is designed to share the debt service cost of all projects on the system between all projects, irrespective of the actual level of debt service which they have incurred individually. The allocation of the system debt service between individual projects is in proportion to the percentage which the state investment for each project represent of the total state investment for all projects. If, for example, the investment in a particular project represented 20 percent of all such investment it would have to carry 20 percent of all the debt service on the system. This means that the power rates of individual projects are not fixed but will increase if new projects with heavy debt financing are added to the system. This is referred to below as the System Increment problem.

3. This legislation and the weakening in diesel oil prices has created three separate but inter-related problems. These are:

   The Early Year Power Cost Problem - the problem that a weakening in the cost of diesel oil can make a new and substantially debt financed hydro project uncompetitive with the thermal alternative it displaces in the early years.

   The System Increment Problem - the phenomenon of additional, largely debt financed project increasing the power rates on all the existing projects.

   The Uniform Rate Problem - the problem that HB 9 calls for each project to have single uniform wholesale power rate.

4. These three problems represent significant difficulties in the marketing of hydro-electric power and the realization of the long term economic benefits of this renewable power source. Utilities may be reluctant to take the hydro-electric power where it involves higher early year power costs and may also be reluctant to enter into long term contracts given that the System Increment problem presents them with an indeterminate future cost of power. The Uniform Rate problem also makes it difficult to resolve the problems by securing greater sale since it precludes offering lower tariffs to secure "low cost" loads such as those offered by industrial demand and the home heating market.

5. These problems are illustrated by an analysis of the Terror Lake, Swan Lake, Tyee Lake and Solomon Gulch project.

   - Prior to the introduction into the system of Terror Lake, Swan Lake, Tyee Lake and Solomon Gulch are all competitive with the cost of the thermal power which they displaced.

   - Adding Terror Lake (with its 58 percent debt financing) to the system in 1985 highlights the increments to system problem. Through the HB 9 mechanism this increment to a system has the effect of increasing the power rates of all the projects on the system and in particular making Tyee Lake 2.4 cents more costly than the cost of thermal power.

6. While these problems are inherent in the HB 9 legislation their numerical magnitude results from the small size and recent establishment of the system. This means that any new project can be relatively large compared with the rest of the system, and because the system is relatively new it does not have a large base of old assets acquired at the much lower prices obtained years earlier into which to easily assimilate any new high cost source of power.

7. A wide range of possible solutions to these problems were considered in Section 4 including greater state equity contributions, lower interest rate loans, etc. The problem, however, is to find a solution to these problems that is economical in terms of the magnitude of the state contribution required. The HB 9 legislation makes the additional state equity solution very costly since this legislation would share the benefits of such contributions between all projects in the system thus reducing all power rates irrespective of the extent of which they were already competitive with thermal.

8. In the light of this analysis it is concluded that the most economical and effective means of resolving the problems indicated in paragraph 4.2.4 would be that of "Equalization Grants". These would be special state grants designed to reduce the cost of the hydro power in the early years into equality with the cost of the thermal power which it displaces. On present forecasts, grants would only be required for Tyee Lake for a period of four years. The total cost (in 1983 dollars) would be $1.4 million compared with approximately $37 million in the case of the additional state equity.

9. It is expected that the Equalization Grants might be necessary for a number of projects until the system achieves the "maturity" and competitiveness inherent in the low escalation rate of hydro and thus becomes able to absorb new high cost additions to the system without unacceptably high increases in power rates.

10. Turning to the Uniform Rate problem, it is concluded that this is a material obstacle to greater utilization of the hydro projects and prevents the system obtaining lower unit costs by supplying the industrial and heating markets. It is recommended, therefore, that consideration be given to changing the legislation to permit the Power Authority to establish multi-rate tariffs wherever this appears likely to secure larger markets and hence lower unit costs. Given such legislation the Power Authority would expect to be able to significantly improve the competitiveness of the hydro power projects.

11. In summary, the HB 9 legislation as it now stands poses significant problems for the hydro-electric development program at its current relatively immature stage of development and in the context of the weakening in thermal fuel prices. Legislation along the lines indicated in paragraph eight and paragraph ten of this section would, however, resolve these problems and enable the program to realize its ultimate objective of long term low cost power for most Alaskans.

APPENDIX A

A.1 I. SWAN LAKE HYDROELECTRIC PROJECT HISTORY AND DESCRIPTION

The City of Ketchikan, having made the decision to discontinue its reliance on the use of diesel electric generation to meet rising energy demands, authorized the engineering firm of R. W. Beck in September of 1977 to investigate the feasibility of developing, as a major hydroelectric generating resource, the Swan Lake Project which is located approximately 22 miles northeast of Ketchikan near the northern end of Carroll Inlet in the central portion of Revillagigedo Island.

In June of 1978, R. W. Beck issued a feasibility report indicating that a hydroelectric project which would demonstrate a benefit/cost ratio of 1.25 could be constructed at Swan Lake at a total investment cost of $80,924,000. Subsequently, the City of Ketchikan, Ketchikan Public Utilities (KPU) authorized R. W. Beck to proceed with preparation of final design of the project.

The 1980 Legislature through joint resolution authorized the Alaska Power Authority to issue bonds up to the maximum amount of $120,000,000 for financing the construction of the Swan Lake Project.

Construction was initiated by KPU in November of 1980. Funding for project design and initial construction was secured primarily through the proceeds of loans from the Power Authority's Power Project Revolving Loan Fund.

On May 28, 1981, the Power Authority loaned KPU $35,000,000 for construction from funds which had been raised through the sale of General Obligation Bonds.

On May 21, 1982, the Power Authority and KPU executed an acquisition agreement under which, in return for providing funds to complete project construction, the Power Authority will receive title to the project and as operation of the project will provide sufficient power for the City of Ketchikan's needs via a Power Sales Agreement.

The Swan Lake Project consists of a dam, a power tunnel and a powerhouse situated at tidewater on Carroll Inlet, plus approximately 30 miles of transmission line from the site to Ketchikan.

The dam, which is essentially completed, is a double curvature concrete arch structure located about 0.75 mile downstream from the outlet of the existing Swan Lake. The dam has a maximum height of 174 feet above the base of the foundation excavation. The dam crest of elevation 344 above mean lower low water (MLLW) is 428.5 feet long. The dam has a crest thickness of 6 feet and has a base thickness of 15.5 feet.

A 100-foot wide ungated ogee service spillway section with the crest at elevation 330 is located in the central portion of the dam. Spillway

discharges will be flipped downstream from the toe of the dam to a plunge pool excavated in rock in the existing stream channel. The spillway is designed to pass a Probable Maximum Flood which is estimated to have a peak inflow of 37,150 cfs and a volume of 38,700 acre-feet.

A.2 I. TYEE LAKE HYDROELECTRIC PROJECT HISTORY AND DESCRIPTION

On December 19, 1979, the Alaska Power Authority submitted an application to the Federal Energy REgulatory Commission (FERC) for the construction of the Tyee Hydroelectric Project in the vicinity of Wrangell and Petersburg, Alaska. Our engineers, R. W. Retherford Associates/International Engineering Company (IECO), estimated the cost of the project at that time at $53,333,000.00, including an allowance for inflation at the rate of seven percent per year during the construction period.

Procurement of long-lead-time turbines began in July 1981, in anticipation of a FERC license. FERC issued a license August 5, 1981, and the award of several additional procurement and one construction contract followed almost immediately thereafter.

The power-on-line date is scheduled for January 1984. The current estimate of the total project cost is $124,000,000.00. Available funds include $82,000,000.00 in State grants and $50,000,000.00 in interim financing.

The powerhouse is located in the Tongass National Forest, approximately 40 miles eastsoutheast of Wrangell, Alaska. The project is designed to develop the energy potential of Tyee Lake--a natural lake at Elevation 1396---convert it to electricity, and transmit the energy to the communities of Wrangell and Petersburg for distribution. The project includes the following principal features:

1. A tunnel system between Tyee Lake and a powerhouse, which is located at sea level on the south side of the Bradfield River valley. The tunnels consist of approximately 4,770 feet of 10-foot diameter tunnel, 1,880 feet of 13-foot diameter tunnel, and 1,380 feet of 10-foot diameter vertical shaft, all nominally unlined. The tunnel will contain a rock-trap, tunnel plug, access gate, steel penstock, and manifold. The tunnels will be connected to Tyee Lake by the "Lake-Tap" method at a water depth of approximately 140 feet. A dam is not required.

2. A gate-shaft near the upstream end of the tunnel, consisting of approximately 420 feet of vertical, 12-foot diameter shaft, containing an intake gate, stoplog, and fine trashrack.

3. A powerhouse containing two, 10-MW hydro-generating units with provision for a future third unit. There will be an adjacent outdoor switchyard.

4. A 1200-foot long tailrace for discharging water from the powerhouse to an existing slough.

5. A 138-kv transmission system, 81-miles long. Approximately 60 miles will be overhead line and 12 miles will be underwater in four separate crossing.

A.3 I. SOLOMON GULCH HYDROELECTRIC PROJECT HISTORY AND DESCRIPTION

The Solomon Gulch Project, located outside of Valdez, is a 12 MW hydroelectric project owned by the State of Alaska. Associated with the Project and also owned by the State are approximately 100 miles of 138 KV transmission line connecting the Project with Valdez and Glennallen, and three substations. The Project has been operational for a year and during that time has been operated for the State by the Copper Valley Electric Association (CVEA). Under agreements between the Authority and CVEA, it is expected that CVEA will continue to operate the Project for the State and, as has been the case for the past year, CVEA will continue to be the sole purchaser of the output of the Project. The average annual generation from the Project is expected to be 55,000 MWH, although at the present time, CVEA can use only approximately 40,000 MWH per year. CVEA is presently paying three cents per KWH for the project output.

On June 21, 1978, the Federal Energy Regulatory Commission (FERC) granted CVEA a license to construct, own, and operate the Solomon Gulch Hydroelectric Project. The project site faces the City of Valdez from the opposite shore of Port Valdez and is located approximately 3 miles east of the Trans-Alaska Pipeline Terminal.

The site was originally licensed in 1932 for a 480 HP project construction in 1907. This project was operational until 1945 when the license was surrendered to the Federal Power Commission (FPC), forerunner to the FERC). In 1952, the FPC issued a license for a 225 HP project which was to be a partial restoration of the original project. This project was never constructed, and at the time of the application in 1975 by CVEA for a license to construct the project as it presently exists, all that remained of the original project was the 100-surface-acre reservoir (Solomon Lake), scattered remnants of the penstock and powerhouse machinery, and a deteriorating operator's cabin.

CVEA proposed to replace the existing dam at Solomon Lake, raising the normal elevation of the lake from 610 feet to 685 feet. Surface area of the reservoir would be increased from 100 to 660 acres, and storage capacity would be increased from 1,700 acre-feet to 31,500 acre-feet. The power plant was proposed to produce 12,000 kilowatts of capacity with an annual average energy output of approximately 55,596,000 kilowatthours.

CVEA, an REA borrower serving Glennallen, Valdez, and an irregularly shaped service area in between the communities, has realized substantial growth in recent years, mostly due to the increased population and industrial activity generated by construction of the pipeline. The Solomon Gulch Project was determined to be the most economical means of supplying the additional generating capacity needed by CVEA and of providing an interconnection between the Glennallen and Valdez distribution systems. Using REA and CFC loans for funding, CVEA began construction of the project.

In 1981, prior to completion of the project the State of Alaska, directed the Alaska Power Authority, to approach CVEA about the idea of purchase of the project from CVEA. It was felt that by using funds appropriated by the State for the capital costs of the project, the

costs of the utility, and hence its customers, would be less. The State and CVEA signed an Acquisition Agreement in 1981 whereby the State assumed the project and all costs and debt associated with the project. Agreements were also signed specifying the conditions under which the project would be operated by CVEA for the State and under which the entire output of the project would be sold to CVEA.

Construction of the project and the transmission line was completed in January, 1982, and commercial operation of the project began on March 31, 1982. The FERC license for the project was transferred to the Power Authority on May 28, 1982, and the Power Authority assumed full ownership of the project in July, 1982. Since that time, the project has been operated by CVEA for the Power Authority with sale being made to CVEA of the usable output of the project.

A.4 I. TERROR LAKE HYDROELECTRIC PROJECT HISTORY AND DESCRIPTION

The Terror Lake Hydroelectric Project was initiated by the Kodiak Electric Association (KEA) in the mid-1960's to provide lower cost electrical power to its customers. Tippetts, Abbett, McCarthy and Stratton and Robert W. Retherford and Associates were retained to prepare a feasibility study which indicated the the project was not economically feasible at that time. The rapid rise in the cost of diesel fuel in the mid-seventies resulted in KEA retaining Robert W. Retherford and Associates and International Engineering Company to upgrade the previous feasibility study, apply for a Federal Energy Regulatory License and to accomplish the project design. The application for a license was submitted to the Federal Energy Regulatory Commission (FERC) in December 1978, and their initial review indicated that more environmental data was required. The additional data was acquired during 1979 and was submitted to FERC in February, 1980. The Department of the Interior, the Alaska Department of Fish and Game, the Legal Defense Fund of the Sierra Club, the Audubon Society and the Northwest Wildlife Federation were granted interventions by FERC. By letter of July 28, 1981, KEA transmitted an Agreement between KEA and the interveners in which the interveners agreed to withdraw their objections in return for certain additional stipulations. The FERC License was issued to KEA on October 5, 1981, and transferred to the Alaska Power Authority on May 12, 1982.

The Terror Lake Hydroelectric Project is located on Kodiak Island as shown in and is about twenty-five miles southwest of the City of Kodiak.

The principal components of the project consist of the following:

- The natural storage of Terror Lake will be increased by 108,000 acre-feet by building a dam across the lake's natural outlet. This dam will raise the water surface level from the present elevation of 1,250 feet to a maximum elevation of 1,420 feet.

- The dam will be a compacted rockfill structure with an upstream concrete face. It will have a maximum structural height of 193 feet and an effective crest elevation of 1,420 feet. A sidechannel spillway will be excavated in the rock of the right abutment. It will be ungated and unlined, and it will have an inlet crest 625 feet long. A reinforced-concrete outlet conduit will pass through the base of the dam, and will be used to make controlled releases down the Terror River for maintenance of the fish spawning beds.

- A power tunnel will leave Terror Lake from an intake structure on the eastern shore and head northeast for 26,300 feet to an outlet portal on the slopes of the Kizhuyak Valley. It will have an 11-foot-diameter section, and will be unlined, with only nominal lengths of concrete lining and other supports as required.

  Runoff from the 15.1 square miles of the natural catchment area of Terror Lake will be supplemented by diversion from 8.6 square miles of adjacent catchment areas. These areas are Shotgun Creek, Falls Creek, Rolling Rock Creek, and Mount Glotoff Glacier. The diversions will be accomplished by small diversion dams, open

channels, and intake tunnels and shafts connecting into the main power tunnel. One of these shafts (of Rolling Rock Creek) will also function as a surge shaft. Provisions have been made in the design for the future diversion of the runoff from 4.0 square miles of the Upper Hidden Basin Creek catchment area and the 5.1 square miles of the Upper Uganik catchment area.

- A single, inclined, steel, penstock, 3,100 feet long, will extend from the tunnel outlet portal, down the side of the Kizhuyak Valley, to an above ground powerhouse located on the valley floor. The powerhouse will contain two vertical-axis, 18,336hp Pelton-type, 6 nozzle impulse turbines, each connected to a 10-MW electrical generator. Thus, the total initial installed capacity will be 20 MW. The turbines, which will be set at Elevation 103.5, will operate at an average net head of 1,207 feet. Provisions will be made for a future third generating unit in the powerhouse, and the power tunnel and penstock have been designed to accommodate the additional flow, without modification.

- Transmission of the electric power to Kodiak will be via a single circuit, 138-KV, 19 mile long transmission line, using a combination of steel and wooden pole structures and AACSR conductor.

APPENDIX "B"

ASSUMPTIONS FOR FINANCIAL FORECASTS

°Project Costs and Financing

Projects Included	Total Cost (Millions $)	State Appropriations (Millions $)	Debt Financed (Millions $)	On-Line Date FY
Swan Lake	93.50	69.09	24.41	1985
Tyee Lake	124.60	79.48	45.12	1985
Solomon Gulch	53.00	53.00	0.00	1983
Terror Lake	189.40	79.26	110.14	1986
	410.50	280.83	179.67	

Notes

1. Costs are the total projected costs including escalations.
2. Debt is assumed to be 35-year bonds with a 10 percent interest rate.
3. Bond coverage was assumed to be 1.10 (i.e. 10 percent in excess of debt service costs).
4. Debt amounts exclude any Reserve Funds.

B-1 INFLATION AND INTEREST RATES

Calender Year	General Inflation (Percent) 1.	Interest Rate for Bonds (Percent
1983	6.8	10.0
1984	6.5	10.0
1985	7.4	10.0
1986	7.4	10.0
1987	6.9	10.0
1988	7.0	10.0
1989	7.1	10.0
1990	7.1	10.0
1991	6.8	10.0
1992	6.6	10.0
1993	6.5	10.0
1994	6.4	10.0
1995	6.4	10.0
1996	6.4	10.0
1997	6.4	10.0
1998	6.4	10.0
1999	6.4	10.0
2000	6.4	10.0
2001	6.4	10.0

NOTES

1 Source: Data Resources Incorporated, July 1982.

2. All costs shown in forecasts represent a January 1 or mid-fiscal year base.

B-2 °OPERATION AND MAINTENANCE COSTS

Project	Annual O/M Costs (Millions $)	Year
Swan Lake	1.028	1985
Lake Tyee	1.32	1985
Solomon Gulch	1.27	1985
Terror Lake	1.08	1986

NOTES

1. Source: Alaska Power Authority

2. No real escalation in O/M costs was assumed, inflationary increases only DRI Indices.

B-3 °AGGREGATE PROJECT FIRM SALES:

FISCAL YEAR	(KWH in thousands) SWAN LAKE	TYEE LAKE	SOLOMON GULCH	TERROR LAKE
1985	32,000	33,620	41,000	-0-
1986	33,600	34,460	41,000	88,200
1987	35,280	35,320	41,000	91,954
1988	37,044	36,210	41,000	95,867
1989	38,896	37,110	41,000	99,947
1990	40,841	38,040	41,000	104,200
1991	42,883	38,990	41,000	106,294
1992	45,027	39,960	41,000	108,430
1993	47,279	40,960	41,000	110,609
1994	49,643	41,990	41,000	112,832
1995	52,125	43,040	41,000	115,100
2000	66,526	48,690	41,000	125,800
2001	69,850	49,910	41,000	128,060

Source: Alaska Power Authority

APPENDIX "C"

C.1 DESCRIPTION OF FINANCIAL MODEL
(refer to Table C.1)

1.	Year:	Fiscal years ending June 30.
2.	Energy GWH:	Total firm sales for all projects included in forecast.
3.	Real Price &/KWH:	Price ¢/KWH : inflation index.
4.	Inflati n Index:	Mid-year FY 1983 (January 1, 1983) = 100.
5.	Price ¢/KWH:	Wholesale Power Rate calculated under HB9. When more than one project is included in the forecast the rate shown is the average cost of power (Revenue ÷ Energy) for all projects
6.	Revenue:	Sum of the revenues for all projects included in the forecast. Revenues are based on project sales and the power rate calculated under HB 9 Legislation.
7.	Less Oper. Costs:	Sum of operating costs for all projects included. The calculation for each project is: Operating Costs = (Generation KWH) X variable O/M costs ($/KWH)). plus (fixed O/M costs ($/KW) X KW). plus administration costs. plus insurance costs.
8.	Operating Income:	6 - 7
9.	Add Interest Earned on Funds:	Interest Rate X Reserve and Contingency Fund (previous year balance) (see 25 below)
10.	Less Interest on Long-Term Debt:	Interest Rate X Outstanding Short-Term Debt (previous year balance) (see 16 below)
11.	Less Interest on Long-Term Debt:	Annual interest costs for long-term debt (bonds and state loans)
12.	Net Earnings from Operations:	(8 + 9) - (10 + 11)

13.	Cash Income from Operations:	12
14.	State Grants:	Annual state grants
15.	Long-Term Debt Drawdowns:	Long-term debt drawn (including state loans and capitalized interest)
16.	Workcap Debt Drawdowns:	Short-term debt drawn for working capital (see 25 and 26 below)
17.	Total Sources of Fund:	13 + 14 + 15 + 16
18.	Less Capital Expenditures:	Annual capital expenditures, including capitalization interest and annual provision for renewals and replacements (0.3 percent of project construction cost per annum, no real escalation)
19.	Less Workcap and Funds:	Increase in, working capital and reserve and contingency fund (See 25 and 26 below)
20.	Less Debt Repayment:	Allowance for special payments to the state (not currently used)
21.	Less Payment to State:	Allowance for special payments to the state (not currently used)
22.	Cash Surplus (Deficit):	Surplus or shortfall of funds. For projects which receive more revenue under HB9 than is required to meet obligations (including debt service) the surplus is paid to the general state fund. For projects which do not receive sufficient revenues under HB9 to meet obligations, the deficit is met by a transfer from the general fund. This deficit will only occur for single projects. On a combined basis, a deficit can never occur under HB9 Legislation.
23.	Recovery from HB9:	Transfer of funds under HB9 to projects which show a deficit (see 22)
24.	Cash Recovered:	Cash retained by the project. This will always be zero as all excess funds are sent to the general state fund.

25.	Reserve and Contingency Fund:	Reserve fund is equal each year to 100 percent of provisions for renewals and replacements plus 100 percent of operating costs.
26.	Other Working Capital:	Annual working capital is equal each year to 15 percent of operating costs plus 10 percent of revenues.
27.	Cumulative Capital Expenditure:	Cumulative 18.
28.	Capital Employed:	25 + 26 + 27.
29.	State Contribution:	Cumulative 14.
30.	Recovery from HB9:	Cumulative 23.
31.	Retained Earnings from Operations:	Cumulative (net earnings from operations - cash surplus paid our).
32.	Debt Outstanding Short-term:	Cumulative 16.
33.	Debt Outstanding Long-term:	Outstanding long-term debt (bonds and State loans) after principal repayments.
34.	Debt Service Cover:	(12 + 11) · (11 + 20).
35.	Annual Borrowing $ 1983:	15 · 4.
36.	Cumulative Borrowing $ 1983:	Cumulative 35.
37.	Annual State Grants $ 1983:	14 : 4
38.	Cumulative State Grants $ 1983:	Cumulative 37.
39.	Total Annual Financing $1983:	35 + 37.
40.	Total Cumulative Financing $ 1983:	Cumulative 39.

Table C.1

Alaska Power Authority Financial Forecast for Fiscal Years ending June 30.

		($ MILLIONS)				
1.	YEAR	1982	1983	1984	1985	1986
2.	ENERGY GWH	--	--	--	--	--
3.	REAL PRICE	--	--	--	--	--
4.	INFLATION INDEX	--	--	--	--	--
5.	PRICE - ¢/KWH	--	--	--	--	--
	----------INCOME----------					
6.	REVENUE	--	--	--	--	--
7.	LESS OPERATING COSTS	--	--	--	--	--
8.	OPERATING INCOME	--	--	--	--	--
9.	ADD INTEREST EARNED ON FUNDS	--	--	--	--	--
10.	LESS INT. ON SHORT-TERM DEBT	--	--	--	--	--
11.	LESS INT. ON LONG-TERM DEBT	--	--	--	--	--
12.	NET EARNINGS FROM OPERATIONS	--	--	--	--	--
	----------CASH SOURCE AND USE----------					
13.	CASH INCOME FROM OPERATIONS	--	--	--	--	--
14.	STATE GRANTS	--	--	--	--	--
15.	LONG-TERM DEBT DRAWDOWNS	--	--	--	--	--
16.	WORKCAP DEBT DRAWDOWNS	--	--	--	--	--
17.	TOTAL SOURCES OF FUNDS	--	--	--	--	--
18.	LESS CAPITAL EXPENDITURES	--	--	--	--	--
19.	LESS WORKCAP AND FUND	--	--	--	--	--
20.	LESS DEBT REPAYMENTS	--	--	--	--	--
21.	LESS PAYMENT TO STATE	--	--	--	--	--
22.	CASH SURPLUS (DEFICIT)	--	--	--	--	--
23.	RECOVERY FROM HB 9	--	--	--	--	--
24.	CASH RECOVERED	--	--	--	--	--
	----------BALANCE SHEET----------					
25.	RESERVE AND CONT. FUND	--	--	--	--	--
26.	OTHER WORKING CAPITAL	--	--	--	--	--
27.	CUM. CAPITAL EXPENDITURE	--	--	--	--	--
28.	CAPITAL EMPLOYED	--	--	--	--	--
29.	STATE CONTRIBUTION	--	--	--	--	--
30.	RECOVERY FROM HB 9	--	--	--	--	--
31.	RETAINED EARNINGS FROM OPS.	--	--	--	--	--
32.	DEBT OUTSTANDING SHORT-TERM	--	--	--	--	--
33.	DEBT OUTSTANDING LONG-TERM	--	--	--	--	--
34.	DEBT SERVICE COVERAGE	--	--	--	--	--
35.	ANNUAL BORROWING $ 1983	--	--	--	--	--

36.	CUM. BORROWING $ 1983	--	--	--	--	--
37.	ANNUAL STATE GRANTS $ 1983	--	--	--	--	--
38.	CUM. STATE GRANTS $ 1983	--	--	--	--	--
39.	TOTAL ANNUAL FINANCING $ 1983	--	--	--	--	--
40.	TOTAL CUM. FINANCING $ 1983	--	--	--	--	--

C.2 METHODOLOGY USED FOR CALCULATION OF POWER RATES IN FINANCIAL MODEL

I. Operation and Maintenance Portion of Power Rates

This rate is calculated independent of other projects.

Components of Rate

A. Operation and Maintenance Costs. (see C.1 - 7).

B. Net short-term interest costs (interest on short-term debt - interest earned on reserve funds). [1] (See C.1 - 9 and 10).

C. Annual provision for renewals and replacements. [2] (see C.1 - 18).

O/M portion of the Power Rate = (A + B + C)/Project Sales.

II. Debt Service Portion of Power Rate

Components Used in Rate Calculation

A. Total System Debt Service (see C.1 - 11 and 20).

B. Bond Coverage (ten percent).

C. Period (year-1983).

D. State's Investment in each Project (equal to project cost for this analysis).

E. Project Sales (see C.1 - 2).

NOTES

1. A provision for working capital has been included in this analysis as well as a general reserve and contingency fund. Working capital is assumed to be met by short-term debt, with an annual interest rate of ten percent. The reserve and contingency fund earns interest at ten percent per annum, (on the previous year's ending balance).

2. The annual provision for renewals and replacements (0.3 percent of project construction costs (excluding IDC) per annum) is assumed to be funded with bond coverage where possible. If this coverage proves to be insufficient, then revenues (and rates) are increased so that this shortfall is just met.

Methodology Used to Calculate Debt Service Portion of Wholesale Power Rates

1. Calculate Average System Debt Service Rate (R1)

   R1 = (Total System Debt Service + Coverage)/Total Sales for all Projects.

   R1 = (A + B)/SUM(E).

2. Determine System Cap Rate (R2) (see Subsection 44.83.398(2)(h)).

   R2 = System Debt Service Average x (1 + .04 (year-1983)).

   R2 = R1 x (1 + .04 x C).

3. Calculate each project's initial, proportionate share of total debt services and Without Cap Rate (R3).

   R3 = (Total System Debt System Service + Coverage x (State's Investment in the Project/State's Investment in all Power Projects))/Project Sales.

   R3 = ((A + B) x (D/SUM(D))/E

4. Determine whether the Without Cap Rate for each Project exceeds the System Cap Rate and if it does, set that Project's Debt Service Rate (R4) equal to the System Cap Rate.

   If R3 greater than R2 then R4 = R2

5. If any projects are capped then using these rates would result in a shortfall of funds to meet debt service obligation. In order to correct this, the debt service share (and thus power rates) for projects whose debt service rates are still below the cap rate, are adjusted upwards (to a maximum of the System Cap Rate). This adjustment (R5) is again based on the State's Investment in the project.

   R5 = (State's Investment in the Project/Total State Investment in all projects whose rates are less than the System Cap Rate) x Shortfall.

   If a project's rate should exceed the System Cap Rate under this reallocation of the shortfall, its rate is also capped and the above procedure is repeated for the remaining projects whose rates are still less than the System Cap Rate.

6. The final debt service portion of the power rate for each project is equal to Project's share of Total System Debt Service Costs after application of limits/Project Sales.

   R4 = (R2 or (R3 x R5))/E

APPENDIX "D"

EFFECT OF "BLACKMAIL" CLAUSE ON POWER RATES

Section 44.83 383 (b) (2) states that if the general state fund does not stand at $5 billion by July 1, 1986, the power rate for each project will be set at the greater of

(a) the standard HB9 rate,

(b) a rate which will return 10 percent annually on the amount invested in the project, including loans and grants made by the state.

A comparison of power rates under standard HB9 calculations and those under the "Blackmail" clause starting in FY 1987 is presented in Table F.1. These results are also summarized for 1987 and 1991 in Table F.2. These calculations assume bond coverage of 1.10.

Results

The "Blackmail" clause, if invoked in 1987, would result in power rates increasing by more than 75 percent for Swan Lake, Tyee Lake, and Terror Lake. The rate for Solomon Gulch would increase by approximately 30 percent. These levels of rate increases would generate additional revenues in 1987 ranging from $1.2 million for Solomon Gulch to $9.0 million for Terror Lake. Total additional revenues for 1987 would be $21.2 million. These results are itemized in Table F2.

The difference between the standard HB9 rate and the "Blackmail" clause rate is seen to decline over time. Since the revenue generated under the "Blackmail" clause is fixed (at 10 percent of project cost) the "Blackmail" clause rates will decline as sales continue to increase. For the standard HB9 rates there is a decline in rates over time for most projects but this is much less since operating costs are increasing with inflation.

Table F.2

SUMMARY COMPARISON OF STANDARD HB9 AND "BLACKMAIL" CLAUSE RATES

	Standard HB9 Rate (¢/KWH)	"Blackmail" Clause Rate (¢/KWH)	Percent Difference	Additional Revenues Generated ($Millions)
Swan Lake				
1987	15.5	27.8	79	4.4
1991	14.1	22.9	62	3.8
Tyee Lake				
1987	16.4	34.8	112	6.6
1991	15.8	25.6	62	4.8
Solomon Gulch				
1987	10.0	12.9	29	1.2
1991	10.6	12.9	22	1.0
Terror Lake				
1987	12.2	22.0	80	9.0
1991	10.1	19.1	89	9.5

Table F.1

COST OF POWER SUMMARY FOR AUTHORISED PROJECTS USING STANDARD HR9 BASIS (EXCLUDING BLACKMAIL CLAUSE)*

YEAR	PROJECTS															
	SWAN LAKE				LAKE TYEE				SOLOMON GULCH				TERROR LAKE			
	COST ICL IDC $MILL	SALES GWH	C.O.P CAPPED C/KWH	C.O.P W/O CAP C/KWH	COST ICL IDC $MILL	SALES GWH	C.O.P CAPPED C/KWH	C.O.P W/O CAP C/KWH	COST ICL IDC $MILL	SALES GWH	C.O.P CAPPED C/KWH	C.O.P W/O CAP C/KWH	COST ICL IDC $MILL	SALES GWH	C.O.P CAPPED C/KWH	C.O.P W/O CAP C/KWH
1983	83.0	0.0	0.0	0.0	87.9	0.0	0.0	0.0	53.0	41.0	3.0	3.0	108.1	0.0	0.0	0.0
1984	98.2	0.0	0.0	0.0	125.3	0.0	0.0	0.0	53.0	41.0	3.3	3.3	193.4	0.0	0.0	0.0
1985	98.2	32.0	11.6	12.1	125.3	30.4	12.8	16.3	53.0	41.0	9.9	6.9	202.5	0.0	0.0	0.0
1986	98.2	33.6	15.5	16.3	125.3	33.1	16.5	21.1	53.0	41.0	10.0	9.1	202.5	53.2	13.0	11.3
1987	98.2	35.3	15.5	15.8	125.3	36.0	16.4	19.7	53.0	41.0	10.0	9.3	202.5	93.0	12.2	11.1
1988	98.2	37.0	15.5	15.3	125.3	39.2	16.2	18.4	53.0	41.0	10.0	9.6	202.5	98.5	11.4	10.7
1989	98.2	38.9	15.2	14.9	125.3	42.7	16.1	17.3	53.0	41.0	10.1	9.9	202.5	99.9	10.7	10.4
1990	98.2	40.8	14.5	14.5	125.3	46.5	16.0	16.2	53.0	41.0	10.3	10.2	202.5	104.2	10.2	10.2
1991	98.2	42.9	14.1	14.1	125.3	48.9	15.8	15.8	53.0	41.0	10.6	10.6	202.5	106.3	10.1	10.1

* COST OF POWER CALCULATION BASED ON THE INCLUSION OF THE FOLLOWING PROJECTS:
SWAN LAKE LAKE TYEE SOLOMON GULCH TERROR LAKE

COST OF POWER INCLUDES O/M PORTION

COST OF POWER SUMMARY FOR AUTHORISED PROJECTS UNDER BLACKMAIL CLAUSE*

YEAR	PROJECTS															
	SWAN LAKE				LAKE TYEE				SOLOMON GULCH				TERROR LAKE			
	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV GEN C/KWH	C.O.P ADD REV GEN $MILL	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV GEN C/KWH	C.O.P ADD REV GEN $MILL	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV GEN C/KWH	C.O.P ADD REV GEN $MILL	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV GEN C/KWH	C.O.P ADD REV GEN $MILL
1983	83.0	0.0	0.0	0.0	87.9	0.0	0.0	0.0	53.0	41.0	3.0	0.0	108.1	0.0	0.0	0.0
1984	98.2	0.0	0.0	0.0	125.3	0.0	0.0	0.0	53.0	41.0	3.3	0.0	193.4	0.0	0.0	0.0
1985	98.2	32.0	11.6	0.0	125.3	30.4	12.8	0.0	53.0	41.0	9.9	6.0	202.5	0.0	0.0	0.0
1986	98.2	33.6	15.5	0.0	125.3	33.1	16.5	0.0	53.0	41.0	10.0	0.0	202.5	53.2	13.0	0.0
1987	98.2	35.3	27.8	4.4	125.3	36.0	31.0	7.3	53.0	41.0	12.2	1.5	202.5	93.0	27.0	9.0
1988	98.2	37.0	26.5	4.1	125.3	39.2	32.0	8.2	53.0	41.0	12.3	1.2	202.5	98.5	21.1	9.3
1989	98.2	38.9	25.3	3.7	125.3	42.7	29.4	8.7	53.0	41.0	12.9	1.2	202.5	99.9	20.3	9.5
1990	98.2	40.8	24.1	3.9	125.3	46.5	27.9	9.1	53.0	41.0	12.7	1.1	202.5	104.2	19.4	9.6
1991	98.2	42.9	22.9	3.8	125.3	48.9	25.6	4.8	53.0	41.0	12.7	1.0	202.5	106.3	19.1	9.5

* COST OF POWER CALCULATION BASED ON THE INCLUSION OF THE FOLLOWING PROJECTS:
SWAN LAKE LAKE TYEE SOLOMON GULCH TERROR LAKE

COST OF POWER CALCULATED USING BLACKMAIL CLAUSE I.E. THE GREATER OF:
THE STANDARD UNCAPPED HR9 RATE OR 10% OF THE AUTHORITYS INVESTMENT IN EACH PROJECT

SB

68-71

(FILE 7)

ALASKA STATE LEGISLATURE
SENATE STATE AFFAIRS COMMITTEE
SENATOR VIC FISCHER, CHAIRMAN
POUCH V, JUNEAU 99811
(907) 465-4954

February 21, 1983

TO: Senate State Affairs Committee Members
FROM: Committee Staff
RE: Briefing materials for hydro/Susitna hearings

The enclosed packet includes:

A. SB 68-71 and a summary of them

B. statutory references

C. Task 11 financing options and a summary

D. article from the Legislative Digest

E. summary of Birch-Horton "Regulatory Impact Management Plan"

F. historical perspective and statutory framework from Battelle "Alternatives Study"

G. House Research memo -- Jan. 1983 -- Susitna Status Report

H. House Research memo -- Feb. 1983 -- Tyee

I. article from 'Business Week"

J. correspondence between Sen. Vic Fischer and the APA

K. SRI report -- "Potential for Industrial Development..."

L. Tussing/Erickson report -- "Alaska Energy Planning Studies"

M. memo from Milt Barker re: funds available for capital projects

Additional back-up material will be forth-coming as it is provided by sponsors and witnesses. Please contact Nancy Lord at x4955 if there is particular information that you would like.

<u>This is the only copy of this packet you will receive. If you wish to refer to it during the meetings, including the one in Anchorage Feb. 26, please bring it with you.</u>

SUMMARY OF SENATE BILLS 68, 69, 70, AND 71

Senate bills 68, 69, and 71 are a package. Together they approve the Susitna project and a method of financing for it. Senate bill 70 provides for an alternative method of financing electric projects, with per capita energy dividends derived from the permanent fund income.

***

SB 69, an Act approving and authorizing the Susitna River Hydroelectric Project.

Sec. 1. Approves the feasibility study and plan of finance.

Sec. 2. Approves the project with a construction cost of $5.4 billion in 1983 dollars.

Sec. 3. Approves the preliminary report and project.

Sec. 4. Provides for separate legislative approval for the second-phase Devil Canyon Dam prior to its construction

Sec. 5. Effective date -- immediately.

***

SB 68, an Act authorizing an advisory vote on a method of financing the Susitna River Hydroelectric Project.

Sec. 1. Provides for an October 1983 advisory vote on whether the legislature should put before the voters in 1984 a constitutional amendment that would dedicate over 10 years $2.3 billion in 1983 dollars to a fund for the construction of the Susitna project.

Sec. 2. Effective date -- immediately.

***

SB 71, an Act relating to bonds issued by the Alaska Power Authority.

Sec. 1. Provides for the Alaska Power Authority to sell revenue bonds for the Susitna project for up to $5.4 billion in 1982 dollars, and provides for those bonds to be unconditionally guaranteed by the State as a general obligation of the State.

Sec. 2. Provides for a public vote before the state-guaranteed revenue bonds can be sold.

Sec. 3. Specifies the language of the ballot proposition that would go before the voters at the next general election.

Sec. 4. Effective date -- immediately.

***

SB 70, an Act establishing the Alaska Energy Dividend Fund and providing for the use of Alaska Permanent Fund income to finance electrical generating facilities in the state.

Sec. 1. Establishes a dividend fund which receives one-half of the permanent fund earnings and allows them to be distributed as grants for electrical projects in an amount equal to $5000 per capita in a service district.

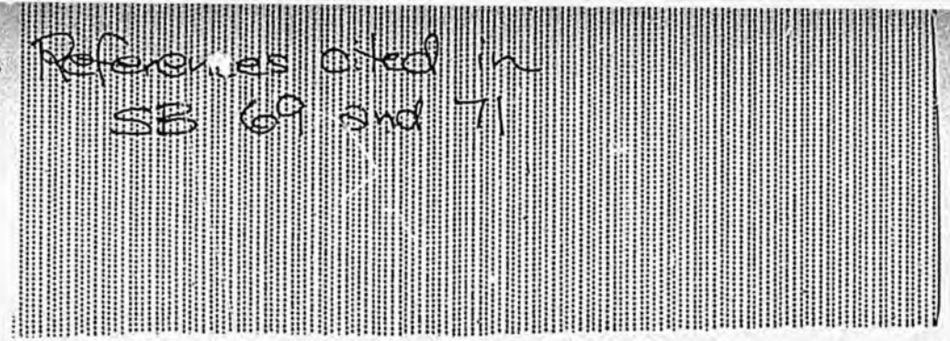
Sec. 2. Provides that residential customers of projects that have received the grants may not be charged for the cost of the capital for the first 1000 kwh/month used.

Sec. 3. Repeals the permanent fund dividend program.

Sec. 4. Transfers any left-over money in the dividend fund to the energy dividend fund.

Sec. 5. Clarifies that the PFD repeal is for dividend distributions after 1982.

Sec. 6. Effective date -- immediately.



Sec. 44.83.181. Feasibility study and finance plan. (a) Unless the reconnaissance study has been disapproved by the division of budget and management under AS 44.83.179, the authority shall complete a feasibility study and plan of finance for each proposed project.

(b) A feasibility study shall include

(1) information about the proposed project, including but not limited to estimates of total project construction costs, total project operating costs, the costs of transmission systems and reserve power requirements, the timing and amount of anticipated returns from the completed project, a benefit-to-cost ratio, the potential effect of the project on the environment of the area which will be served by the project when completed, and the availability of alternative government financing;

(2) a statement of all assumptions which affect the economic feasibility of the project, including but not limited to the discount rate and interest rate of amounts of money to be used for the project, anticipated fuel prices, an escalation rate, state and local electric load growth, and estimates of indirect costs and benefits;

(3) a comparative analysis of all reasonable alternatives to construction of the proposed project; and

(4) information based on engineering and design work which meets the requirements for submission of a license application for the project to the Federal Energy Regulatory Commission.

(c) The plan of finance shall include recommendations of the most appropriate means to finance a project, including, but not limited to,

(1) the issuance of revenue bonds of the authority;

(2) the issuance of

(A) general obligation bonds of the state; or

(B) revenue bonds of the authority which are guaranteed or partially guaranteed by the state;

(3) an appropriation from the general fund

(A) to pay debt service on bonds or for other project purposes; or

(B) to reduce the amount of debt financing for the project;

(5) financing arrangements with other entities using leveraged leases or other financing methods;

(6) assistance from any federal agency, including, but not limited to, the Rural Electrification Administration;

(7) a loan from the power project fund (AS 44.83.170(a)), or from the renewable resources investment fund (AS 37.11.050); or

(8) any combination of financing arrangements listed in this subsection.

(d) When financial assistance from the state is necessary for a project to meet financial feasibility criteria, the plan of finance shall include an estimate of the minimum amount of financial assistance required from the state. The plan of finance shall include an estimate of the present value of the financial assistance from the state, computed as the difference between

(1) a market rate of interest, which is

(A) the rate determined under AS 44.83.170(f)(2)(B)(i); or

(B) the estimated interest rate for revenue bonds to be issued by the authority for the project; and

(2) the effective rate of interest because of state financial assistance provided.

(e) The authority, in consultation with the division of budget and management, shall adopt regulations defining

(1) the techniques which it shall apply to determine that the information required by (b) — (d) of this section is obtained; and

(2) standard criteria and measures for comparative analysis of alternative financing arrangements. (§ 24 ch 83 SLA 1980; am § 6 ch 133 SLA 1982)

Effect of amendments. — The 1982 amendment, effective June 25, 1982, inserted "the costs of transmission systems and reserve power requirements" in paragraph (1) of subsection (b).

Sec. 44.83.183. Review of feasibility studies and plans of finance by division of budget and management. (a) The division of budget and management in the Office of the Governor shall review the feasibility study and plan of finance for a project of the authority for compliance with the provisions of AS 44.83.181(b) — (d).

(b) In its review under this section, the division of budget and management may obtain an independent evaluation of a feasibility study and plan of finance to determine compliance with the provisions of AS 44.83.181(b) — (d).

(c) When the division of budget and management has completed a review of the feasibility study and the plan of finance for a project under this section, it shall submit a report to the governor. The report shall examine the feasibility study and plan of finance for compliance with the requirements of AS 44.83.181(b) — (d). The report of the

division of budget and management shall include a recommendation to the governor and legislature for approval or disapproval of the project based on the division's review of the feasibility study and plan of finance for compliance with the requirements of AS 44.83.181(b) — (d).

(d) The report required by (c) of this section shall be prepared and submitted not later than 60 days after the feasibility study and plan of finance for a proposed project have been received by the division of budget and management.

(e) The report required by (c) of this section shall include a financial analysis of the proposed project of the authority that evaluates proposed bond resolutions or other financial arrangements or financial plans, security plans and arrangements, cost and demand uncertainties, and debt volume, as they relate to the total direct and indirect indebtedness of the state. In preparing the financial analysis required by this section the division of budget and management may use the services of outside agencies or institutions that are not otherwise involved in the project. (§ 24 ch 83 SLA 1980; am § 7 ch 133 SLA 1982)

Effect of amendments. — The 1982 amendment, effective June 25, 1982, added subsection (e).

Sec. 44.83.185. Submission to the legislature. (a) The authority shall submit a feasibility study and plan of finance for a proposed new project to the legislature. When the report of the division of budget and management examining the feasibility study and plan of finance is completed as required by AS 44.83.183, it shall be submitted to the legislature.

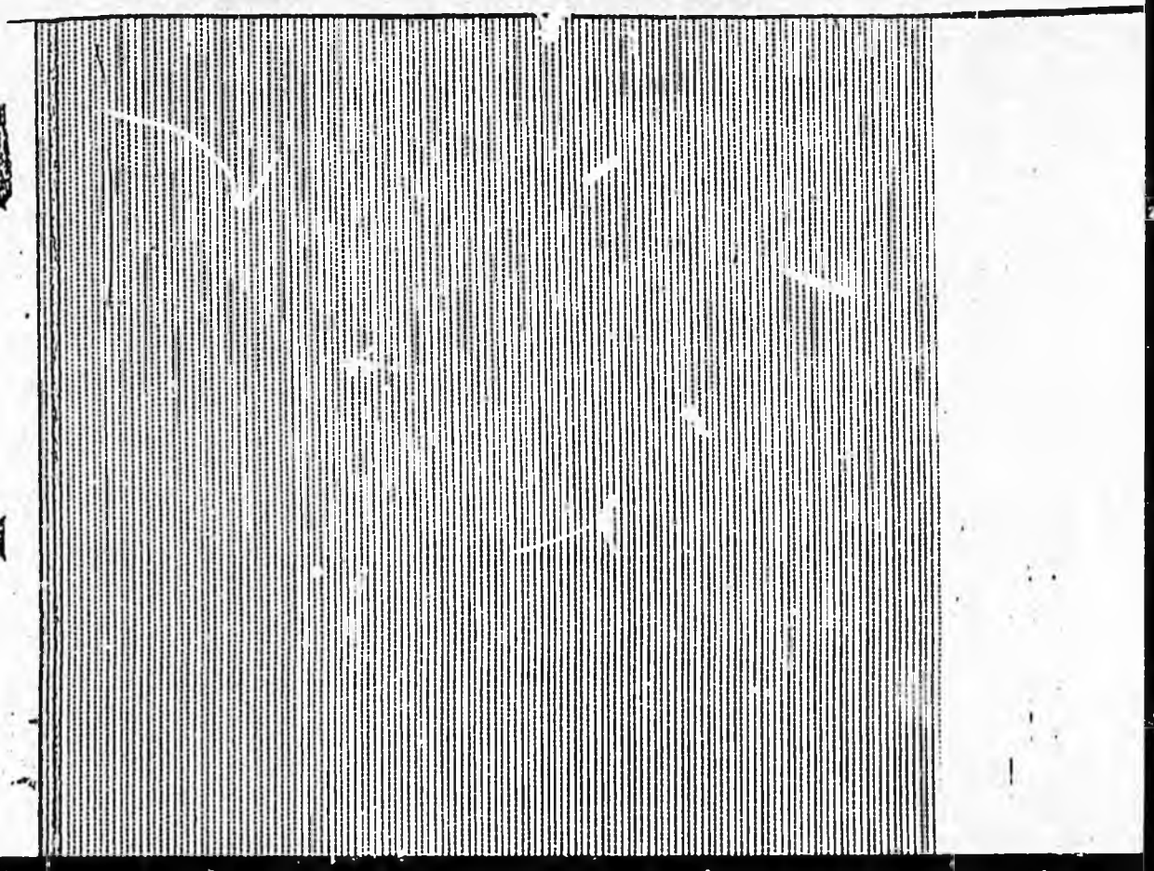
(b) The authority may not proceed with work on the engineering or design phase of a proposed new project for which legislative approval is required until the legislature approves the proposed new project. However, the authority may proceed with the engineering or design work necessary to meet the requirements for submission of a license application for the proposed new project to the Federal Energy Regulatory Commission without obtaining legislative approval of the proposed new project.

(c) The legislature shall consider and must approve all proposed new projects except proposed new projects that are exempt under AS 44.83.187. The legislature may approve a proposed new project only by enacting law that authorizes the project and approves a construction cost for that project. (§ 24 ch 83 SLA 1980; am § 8 ch 133 SLA 1982)

Effect of amendments. — The 1982 amendment, effective June 25, 1982, substituted "that authorizes the project and approves a construction cost for" for "authorizing" in the second sentence of subsection (c).

Sec. 44.83.186. Final cost estimate and reauthorization by the legislature. If a project is approved under AS 44.83.185(c), the authority shall obtain a final cost estimate for the project from an independent source qualified to make such an estimate. If the final cost estimate does not exceed the construction cost authorized by the legislature under AS 44.83.185, adjusted for inflation, by more than seven and one-half percent, the authority may proceed with the construction of the project. If the final cost estimate exceeds the construction cost authorized by the legislature under AS 44.83.185, adjusted for inflation, by more than seven and one-half percent, the authority shall revise its feasibility study and, if it determines that the project remains feasible, the authority shall submit the revised feasibility study and the independent cost estimate to the legislature. A proposed project that is returned for reconsideration by the legislature under this section may not be constructed unless the legislature reauthorizes it by enacting law for that purpose. (§ 9 ch 133 SLA 1982)

Effective dates. — Section 22, ch. 133, SLA 1982, makes this section effective June 25, 1982, in accordance with AS 01.10.070(c).



Sec. 44.83.130. Nonliability on bonds. (a) Neither the members of the authority nor a person executing the bonds is liable personally on the bonds or is subject to personal liability or accountability by reason of the issuance of the bonds.

(b) The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, except the authority, but shall be payable solely from the income and receipts or other funds or property of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state, except the authority, to the payment of a bond and the issuance of a bond by the authority does not directly or indirectly or contingently obligate the state or a political subdivision of the state to apply money from, or levy or pledge any form of taxation whatever to the payment of the bond. (§ 1 ch 278 SLA 1976)

Article 7. Susitna River Hydroelectric Project.

Sec. 44.83.300. Description of project. The Susitna River hydroelectric project consists of dams and related reservoirs, and power plants located in the Upper Susitna River Basin, and related transmission lines, facilities, and load centers, as described in the Alaska Power Authority's report required by AS 44.83.320(b). (§ 2 ch 169 SLA 1980)

Sec. 44.83.310. Purpose of project. The primary purpose of the Susitna River hydroelectric project is to generate, transmit and distribute electric power in a manner which will

(1) minimize market area electrical power costs;

(2) minimize adverse environmental and social impacts while enhancing environmental values to the extent possible; and

(3) safeguard both life and property. (§ 2 ch 169 SLA 1980)

Sec. 44.83.320. Preliminary reports. (a) By March 30, 1981, the authority shall prepare and submit to the governor and to the legislature a preliminary report recommending whether work should continue on the Susitna River hydroelectric project, and, if the recommendation is to continue on the project, the report shall explain in detail

(1) economic evaluations and preliminary environmental impact assessments for the Susitna River hydroelectric project and all viable alternatives;

(2) the federal and state permits required to be obtained before construction can begin and the expected construction start date; and

(3) any other information the authority considers appropriate or necessary to adequately inform the governor and the legislature of the status of the Susitna River hydroelectric project.

(b) By April 30, 1982, the authority shall prepare and submit to the governor and to the legislature a preliminary report recommending whether work should continue on the Susitna River hydroelectric project, and other viable alternatives. If the recommendation is to continue on the Susitna River hydroelectric project, the report shall explain in detail

(1) the proposed conceptual design and phases of construction of the Susitna River hydroelectric project;

(3) the expected cost of each phase of construction;

(4) the costs to the state and consumers of the project under alternative methods of project financing, including revenue bonds, general obligation bonds, and general fund appropriations; and

(5) any other information the authority considers appropriate or necessary to adequately inform the governor and the legislature of the status of the Susitna River hydroelectric project.

(c) The preliminary reports required under (a) and (b) of this section are in addition to any reports required under AS 44.83.180 — 44.83.224. (§ 2 ch 169 SLA 1980)

Sec. 44.83.325. Restrictions on contracting. The authority may not enter into contracts under AS 44.83.300 — 44.83.360 other than those contracts necessary to complete (1) feasibility studies, (2) the preliminary reports required by AS 44.83.320, or (3) construction of the Anchorage-Fairbanks intertie, until the legislature approves by law the preliminary report required under AS 44.83.320(b). (§ 2 ch 169 SLA 1980)

Sec. 44.83.330. Construction, maintenance and operation of project. Within one year after approval of its preliminary report submitted under AS 44.83.320(b), the authority may enter into a contract for the construction of the Susitna River hydroelectric project in a manner consistent with the purpose of the project as described in AS 44.83.310. (§ 2 ch 169 SLA 1980)

Sec. 44.83.340. Annual report. (a) If the Susitna River hydroelectric project is approved by the legislature under AS 44.83.320(d), beginning in 1983 the authority shall prepare an annual report which explains in detail

(1) the status of construction on the Susitna River hydroelectric project;

(2) the completion date of any phase of the Susitna River hydroelectric project which has been completed and the reasons for any deviation between the completion date and the expected completion date stated in the preliminary report required under AS 44.83.320(b);

(3) the actual cost of any phase of the Susitna River hydroelectric project which has been completed and the reasons for any deviation between the actual cost and the expected cost stated in the preliminary report required under AS 44.83.320(b);

(4) the federal and state permits necessary to begin or continue construction of the Susitna River hydroelectric project, the actual dates on which the federal and state permits necessary to begin or continue construction were obtained, and the reasons for any deviation between the actual dates and the expected dates stated in the preliminary report required under AS 44.83.320(a) or in the earlier annual reports required under this section;

(5) any other information the authority considers appropriate or necessary to adequately inform the governor and the legislature of the status of the Susitna River hydroelectric project.

(b) The annual report required under (a) of this section is in addition to any reports required under AS 44.83.180 — 44.83.224 and shall be submitted, by March 30 of each year, to the governor and to each member of the legislature. (§ 2 ch 169 SLA 1980)

Sec. 44.83.350. Legislative and executive oversight. The legislature or the governor may provide for ongoing oversight, review and selected in-depth analysis of the Susitna River hydroelectric project plan of study. The authority shall provide all data, analyses, reports, and other information to whomever conducts the oversight, review, or analysis activities. Selected in-depth analyses shall include assessments of the power alternatives, financing, and power marketing sections of the Susitna River hydroelectric project plan of study. (§ 2 ch 169 SLA 1980)

Sec. 44.83.360. Project financing. The Susitna River hydroelectric project shall be financed by general fund appropriations, general obligation bonds, revenue bonds, or other plans of finance as approved by the legislature. (§ 2 ch 169 SLA 1980)

Article 7. Susitna River Hydroelectric Project.

Sec. 44.83.325. Restrictions on contracting.

Editor's note. — Section 21, ch. 133, SLA 1982, provides: "Notwithstanding the provisions of AS 44.83.325, the Alaska Power Authority may enter into contracts under AS 44.83.300 — 44.83.360 for preliminary work without the approval required by AS 44.83.325. In this section, 'preliminary work' means the preparation of plans and studies and the preparation and submission of license applications, as well as other types of work, that must be completed before actual construction of the Susitna River hydroelectric project, described in AS 44.83.300, may begin. This section does not authorize the Alaska Power authority to enter into contracts for the actual construction of the Susitna River hydroelectric project or for the preparation of the site of the Susitna River hydroelectric project without the approval required by AS 44.83.325."

LOOKING AT SUSITNA ISSUES

A number of bills promoting the Susitna hydroelectric project face the legislature this session. Debate on the issue promises to be spicier than in previous sessions.

What was in most minds a few years ago, simply a matter of proving Susitna was feasible and then selecting a financing method, has suddenly become vastly more complicated. The complications are not the usual conservationists versus the Chamber of Commerce boosters syndrome either. There is, in fact, a good deal of agreement between the two, that the Railbelt needs a long term, environmentally acceptable source of power: Susitna. However, even among the voices who concede that Susitna is our best bet for the future, we are beginning to hear dissent about the feasibility (economic and social) of bringing Susitna power on line before the next century.

Some Arguments Against

The arguments being voiced against going ahead with Susitna, at least in the decade of the 1980s, are: 1) the decline of oil revenues to finance the $10-$15 billion project, 2) uncertainty in the level of long term need for a large quantity of power in the Railbelt area, 3) the cost and availability of alternative fuels (natural gas) with which to generate power, 4) the construction cost of the project and 5) the cost of financing the hydro project.

A few years ago, oil revenue analysts projected a continual rise in Alaska's oil revenue. The curve was to increase steadily until 1989 and then begin a gradual decline to the end of the century. The decline, because of the fluctuation in world oil prices, has already begun. With our income in decline, 89 percent of which comes from sales of oil, the anticipated population and industrial boom of the 1980s may not materialize as predicted. The upshot of decreased revenues is that as oil and gas prices fall, less money will be available with which to build the Susitna project. At the same time, again because of falling oil and gas prices, Susitna becomes a less feasible source of power because of the cheaper thermal alternative: natural gas. The price of natural gas will not rise as sharply in the 1980s and early 1990s as previously thought.

A slow down in the money supply will also directly affect one of the most significant factors analysts point to as a determinant in the feasibility of the Susitna project: future demand for electricity.

Electrical demand is based on the ability of the state to stimulate industrial growth and create jobs. The assumptions made by the two state funded feasibility studies (Battelle and Acres American) tied their positive recommendations to go ahead with Susitna on population and industrial growth stimulated by, at the very least, the construction of the Alaska Gas Pipeline and continued state spending at current levels even in a "low growth" scenario. With the gas pipeline project on hold and cut-backs in state spending, critics claim it is risky at best to predict, much less project a rate of growth sufficient to justify the project.

New Gas Price

A more recent fact has produced concern about the project's near-term feasibility: the Enstar gas contract. Last December Enstar Natural Gas Company negotiated a 15-year gas contract, which would supply hugh quantities of low cost natural gas to Railbelt electrical power generators. The price negotiated was not only much lower than anticipated, but cost escalation terms and the quantity of gas contracted for were both unanticipated in previous feasibility studies. In terms of price the $2.32 per mcf Enstar negotiated actually computes to about $2.00 per mcf when older, cheaper gas is factored into the rate. The escalation terms basically removed natural gas from the wildly fluctuating world oil and gas market by tying the fuel to the price movement of #2 Tesoro diesel oil

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SUSITNA QUESTIONS . . . . (from page 3)

which is used for home heating. The difference between the reality of the Enstar contract and the original projections of the Battalle and Acres American feasibility studies is that, while Acres predicted a 2 percent annual escalation in gas prices starting with an anticipated base of $3.00, the Battelle report predicted a 6 percent annual increase at $.64 per mcf which adds up to about the same dollar figure Acres came up with when figured over a period of years.

Both the Acres and Battelle studies based their assumptions on per KWH cost of Susitna power being comparable to gas or coal fired generation by the early 1990s. The Enstar contract, which will run nearly to the 21st century, has thrown new light on some not so old assumptions.

Actual Cost

A fourth critical concern being voiced about Susitna is a question about the actual cost of the dam. The well known cost overruns of the TransAlaska Pipeline and dozens of other smaller capital projects makes this an important point of analysis to many. Susitna would be one of the highest dams in the world and one of the single largest efforts of its type. Both of these factors, according to construction analysts, make cost estimation tricky and overruns a probability. In defense of estimators it is notable that the hugh Churchill Falls dam in Canada, which is by all accounts similar to Susitna, came in on time and near budget. It may be that estimators have found the handle on estimating big projects during these inflationary times.

Bonding Costs

The final of the five factors heard in criticism of the Susitna project is the currently unattractive bond market and a generally soft market for bonding hugh public utility projects. The financial problems encountered by the Washington Public Power System which analysts predict will run into the biggest financial default this country has seen because of cost overruns have bonding companies looking sharply at public utility investments. The Acres American study, which appears the more rigorous of the two reports, concludes that unless the bonding of Susitna were carried out in a tax-exempt market at a discount rate for 3 percent, the project would not be cost effective. Currently, the bond market is running at 4 percent and above. Whether the rate will decline to acceptable levels is a complete uncertainty.

Despite these criticisms it would be hard to find a knowledgable person, including those who would be in direct competition with Susitna, who would disagree with the belief that at some point we will need Susitna hydro power, whether it is the high Devils Canyon dam or a combination of the Watana and Devils Canyon dams. The question critics are asking is: When and how much?

Alaska has had a long and sometimes politically stormy love affair with hydro projects. Rampart Dam on the Yukon was the big "grand daddy" of them all, and native and environmental issue surrounding that project contributed to the defeat of U.S. Sen. Ernest Gruening in 1968. The project also pushed Alaska into the mainstream of the growing stream of U.S. environmentalism, and oddly, it was that issue that pushed Don Young, a Fort Yukon school teacher into the political arena (on the side of environmentalists against Rampart. Susitna in those days was the alternative to giant Rampart.

Susitna Hearings

The Senate State Affairs Committee will hold hearings on the Susitna Project on Feb. 26 in Anchorage at the Westward Hotel (9 a.m. to 4 p.m.)

The committee hearing will resume on March 1st and 3rd in Juneau and will be teleconferenced. Expert witnesses on the project are scheduled to appear before the panel.

Summary of 3 Volumn Report + 2 Volumns of appropriate regulat

REGULATORY IMPACT MANAGEMENT PLAN

FOR THE SUSITNA HYDROELECTRIC PROJECT

Presented to:

Honorable Ed Dankworth
Honorable Don Bennett
Co-Chairmen
Senate Finance Committee

January 15, 1982

Contractor:

Ronald G. Birch
BIRCH, HORTON, BITTNER AND MONROE

Subcontractors:

S. John Byington
ROGERS HOGE & HILLS

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REGULATORY IMPACT MANAGEMENT INC.

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EXECUTIVE SUMMARY

The Susitna hydroelectric project is facing obstacles which place its successful completion in doubt. Even if Acres American's (the license-preparation company under contract to the Alaska Power Authority) study concludes that the project is feasible (from an environmental, economic and engineering standpoint) and if the Alaska government and active interest groups agree, the massive inter-group coordination required of any major hydroelectric project could delay this project to the point of jeopardizing its completion. The most notable of the pitfalls include:

- 15 to 20 state and local government approvals
  - air and water quality permits, fish and game impact-mitigation measures, waste disposal, etc.;
- 10 to 15 federal permits
  - involving at a minimum these federal agencies:

    Federal Energy Regulatory Commission (FERC); Environmental Protection Agency (EPA); Corps of Engineers (COE); Coast Guard; U.S. Fish and Wildlife Service (USF&WS); Bureau of Land Management (BLM); Advisory Council on Historic Preservation (ACHP); National Marine Fishery Service (NMFS); and the Federal Aviation Administration (FAA);
- other factors
  - uncertain land ownership patterns, water rights disputes, and subsistence rights, plus probability of intra- and inter-agency communications breakdowns concerning the adequacy and implications of the data base.

Multi-agency involvement at the federal, state and local government levels, and the attendant demands for different information and possibly conflicting interpretations of data, make delay inevitable. Delays and resulting confusion can cost hundreds of millions of dollars. The threat of such significant cost increases alone jeopardizes the project. The project sponsors must, therefore, seek to minimize delay and maximize cooperation.

Management of the regulatory process can reduce delay and confusion substantially by coordinating and giving definition to the agency reviews and agency information needs. Avoiding agency jurisdiction disputes and planning to fill agency information requirements promptly will, in a very real sense, ensure timely and successful completion of the Susitna hydroelectric project.

A regulatory impact management system will give Alaska the appropriate tools to shepherd the project through the bureaucratic maze efficiently and at the least possible cost.

This report constitutes the first step of Phase I of such a system. It identifies and documents the problems, both regulatory and non-regulatory, facing the Susitna project. The report makes specific findings and recommendations that require state officials' immediate consideration. Futhermore, the identification of issues and deficiencies provides a foundation for implementing a regulatory management system in the future.

Examples of major problems which could affect the ultimate completion of the Susitna hydroelectric project significantly include:

- Unsettled Native land ownership disputes in the project area which could delay the project for years unless efforts are made to bring about a negotiated settlement;

- Inadequate data bases concerning fish and wildlife resources in and along the Susitna River, and the absence of any analysis of the project's impacts on subsistence uses of such resources by Natives;

- Unsettled jurisdictional disputes among federal agencies concerning certain aspects of the licensing and construction of hydroelectric dams and associated transmission facilities;

- Inadequate inventory of persons or entities who may have appropriated water rights or who may have valid water claims along the Susitna River which could be affected by construction of the dams; and

- The absence of a clearly defined policy governing land use in the project area, including an analysis of the socio-economic impacts of the project on the people and natural resources in the region.

The remaining steps of Phase I of the management system would initiate a review of all data, studies, and other materials which currently are available to interested groups and agencies. Initially the data would be checked to ensure that it is adequate to meet the agencies' informational and regulatory needs. Then the data and conclusions would be used to prepare the various permit and license applications. Agency memoranda of understanding (MOUs) would be negotiated, presetting agency review by defining its scope and timetable. This will reduce the uncertainty and confusion attendant to any project of this magnitude.

Upon filing the applications, the regulatory process formally begins. To ensure that the permitting process stays on track, the second phase will feature:

- frequent status reports to keep all parties informed and to show agency compliance with the pre-agreed schedule;
- management reports to the Alaska Legislature to facilitate effective oversight and to ensure the efficient use of public funds.

The following information on a historical perspective of power planning in Alaska and the statutory framework are from the Battelle "Railbelt Electric Power Alternatives Study" (February 1982). It does not include the events of the last session and the statutory amendment to establishing wholesale power rates.

9.2 A HISTORICAL PERSPECTIVE OF POWER PLANNING IN ALASKA

In Alaska, state involvement in planning and directly providing generating capacity and transmission facilities is a new undertaking. Prior to 1976, planning and construction of facilities were performed either by the individual municipal or cooperative utility, or by various federal government agencies. For example, the Alaska Power Administration (now within the U.S. Department of Energy) has owned and operated the Eklutna Hydroelectric project since 1995. Chugach Electric Association has planned and assumed responsibility for both constructing hydroelectric projects such as Cooper Lake (1961) and installing gas-fired generating capacity, as well as the transmission and distribution systems associated with these projects. Other local utilities also assumed responsibility for constructing facilities and conducting various feasibility studies. Federal agencies also undertook a variety of feasibility and planning studies.

Lack of direct state involvement in the first fifteen years after statehood can be explained by several factors. Perhaps most significantly is that little need for such involvement was perceived. Another major factor was that the local utilities were able to plan and manage the projects they required. Furthermore, federal funds were available and state funds were not.

In the mid-seventies, however, these factors began to give way to other forces. Estimated project costs escalated significantly because of inflation, government regulation, and the expected growth in demand, which implied bigger facilities. Additionally, state revenues were rising. In 1976 these forces resulted in passage of a bill creating the Alaska Power Authority. The legislative findings and declaration of purpose in the enabling legislation reveal the broad purposes and objectives that the legislation sought to address.

Legislative Finding and Policy

(a) The legislature finds, determines and declares that

(1) there exist numerous potential hydroelectric and fossil fuel generating sites in the state;

(2) the establishment of power projects at these sites is necessary to supply lower cost power to the state's municipal electric, rural electric, cooperative electric, and private electric utilities, and regional electric authorities, and thereby to the consumers of the state, as well as to supply existing or future industrial needs;

(3) the achievement of the goals of lower consumer power costs and long-term economic growth and of establishing, operating and development power projects in the state will be accelerated and facilitated by the creation of an instrumentality of the state with powers to incur for constructing, and with powers to operate, power projects.

(b) It is declared to be the policy of the state, in the interests of promoting the general welfare of all the people of the state, and public purposes, to reduce consumer power costs and otherwise to encourage the long-term economic growth of the state, including the development of its natural resources, through the establishment of power projects by creating the public corporation with powers, duties and functions as provided in this chapter.

To accomplish its objectives the Power Authority was given broad powers, including the power to issue bonds, to enter into contracts for the construction, acquisition, operation and maintenance of power projects, and to transmit and sell such power. It was also authorized to conduct feasibility studies for hydroelectric and fossil fuel power generating projects.

The same legislation that created the Power Authority also created the Power Project Revolving Loan fund. The Power Authority administered this fund, which was set up as a "trust fund" to make loans to municipal or public

utilities for feasibility studies, preconstruction engineering and design, and construction of hydroelectric and fossil fuel plants. For example, in 1977 $1.6 million was appropriated for the Green Lake Hydroelectric project at Sitka and $540,000 was appropriated to the Power Project Revolving Loan Fund. Through the fund, loans also could be made to cities, boroughs, village corporations, village councils and nonprofit marketing cooperatives for meeting their "energy requirements."

In 1978 the legislature significantly amended its 1976 legislation. The findings were changed to state that the legislature's policy was to foster power projects to supply power at "the lowest reasonable cost . . .," whereas the earlier findings had referred only to "lower cost" power. The provision relating to pricing of power was amended to make certain that the prices at which power was sold covered the "full cost of the electricity and services..."

In 1978 the legislature also adopted resolutions approving the sale of $300,000,000 in revenue bonds for constructing a coal-fired electric generating plant at Healy and authorizing the Power Authority to incur indebtedness ($25,000,000) for Phase I studies for the Susitna Hydroelectric Project. Additionally, the state Senate adopted a resolution directing its Special Committee on the Permanent Fund to investigate the use of money from the permanent fund as a source of revenues for financing hydroelectric projects.

In 1979 the legislature adopted two resolutions related to power. One asked the Army Corps of Engineers to use funds from the Small Hydroelectric Plants program to investigate the feasibility of small-scale hydroelectric projects in rural Alaska as an alternative to the high cost of diesel-generated electricity. The other resolution approved issuance of $120 million in revenue bonds for the Terror Lake Hydroelectric project and $20 million for the Solomon Gulch project.

The 1980 session of the legislature passed substantial legislation relating to the Power Authority. Approximately $50 million was appropriated for some 35 projects. The major appropriations were $15 million for the Tyee Lake project at Wrangell and an $18 million loan for the Swan Lake project. Most other projects received funds ranging from $40,000 to $2 million.

In addition to these direct appropriations, two resolutions authorized the issuance of a variety of revenue bonds. The revenues from those bonds would be

used for constructing or acquiring generating facilities or for financing expansion of distributions systems by local utilities. The revenues used included the following:

- $70 million toward construction of the Tyee Lake project
- $120 million for the Swan Lake project
- $110 million for waste heat power generation facilities to be constructed by Golden Valley Electric Association
- $15 million to finance the Lake Elva (Dillingham) project
- $30 million for the Bear Lake project (Prince of Wales Island)
- lesser amounts for Homer Electric Association, Naknek Electric Association, Matanuska Electric Association, Glacier Highway Electric Association and Cordova Electric Association.

In addition to this legislation relating to funding, two bills were passed that again amended substantially the legislation creating the Power Authority. The first bill was a major piece of legislation on the general subject of energy. One part of this bill contained the provisions relating to amendment of the Power Authority statute. These amendments gave the Power Authority the power to recommend power project financing through the use of general obligation bonds--a financing approach that earlier legislation had not contemplated. This bill also amended substantially the provisions creating the Power Project Revolving Loan Fund. One change converted the fund from a revolving loan fund to a direct loan program, with funds for loans appropriated by the legislature to the fund and revenues from repayment deposited in the state's General Fund rather than in the Power Project Fund. The purposes for which loans could be granted were expanded. A provision that permitted the Power Authority to make unsecured loans in some instances also was added. The right to forgive loans was transferred from the Power Authority to the legislature itself.

A new section was added requiring the Authority to undertake reconnaissance studies to identify power alternatives for communities. Under this addition reconnaissance studies must be reviewed by the Division of Budget and Management and submitted to the legislature. The Susitna Hydroelectric project was addressed directly in subsequent 1980 legislation.