

ALASKA LEGISLATURE COMMITTEE FILES
2673 SLC HB 4 (FILE 3) - HB 7 (FILE 1)

2673

FINANCIAL FACTORS

General Comment:

The Wrap-up Insurance costs were estimated to be 4.25% of construction costs. This resulted in estimated premiums of \$3,784,602 for the total Project costs of approximately \$89,000,000.

It appears that construction costs will be \$94,339,000 which would indicate a wrap-up insurance cost of \$4,009,408 using the 4.25% base.

Historically and on a continuing basis wrap-up insurance costs for wrap-ups have ranged from just over 1% to slightly higher than 2% of construction costs. These percentages do not include offsets of insurance costs generated from investment income.

Specific Tyee Lake Insurance costs.

One way of looking at wrap-up insurance cost is to compare total expenses to paid and incurred losses.

To date APA has paid premiums as of January 31, 1983 (Per P.M.M. Audit)	\$3,186,602
Deduct: expenses other than paid losses	<u>1,141,111</u>
Funds available for losses	\$2,045,491
add investment income	<u>53,091</u>
Total funds available to pay losses	\$2,098,592
Paid losses as of December 31, 1982	\$ 194,628

Per Peat, Marwick and Mitchell audit, expenses totalling \$1,335,749 have been incurred to pay \$194,628 in "paid" losses and available to pay incurred losses of approximately \$653,117.

As of January 31, 1983 APA had paid \$1,903,944 in funds excess of all required payments for losses, premiums and contract related expenses.

Ratio of expenses to paid losses $\frac{\$1,141,111}{\$194,491} = 5.86 : 1$

Ratio of expenses to incurred losses $\frac{\$1,141,111}{\$653,117} = 1.75 : 1$

The Project loss ratio, i.e. losses + premiums appears to be excellent because the premiums were higher than needed as demonstrated by the percentage of construction cost they represent.

Incurred losses $\frac{\$653,117}{\$3,186,602} = .205$ loss ratio



Historically and continuing, costs under a wrap-up costs \$.20 to \$.25* for each dollar of loss payment. Under the Tyee Program these costs are \$1.75 to \$1.00 of incurred loss.

These comparisons would indicate that paid loss retro would have been more favorable to APA than the present program.

* These are conservative expense factors.

Peat, Marwick, Mitchell & Co. Audit.

As referenced, this audit is essentially an account balance audit per instructions it received. As the audit reports, verification was made of supporting documents such as general ledger, cash receipts and disbursements. The audit did not include an examination of activities included in the performance of service nor did it attempt to determine if the various payments to various loss, investment or expense accounts were made on a particular basis, i.e. incurred loss levels requiring deposit to the trust accounts.

Based on this audit, there is no doubt that APA funds expended are properly accounted for and verified for the various purposes scheduled in the APCOP budget.

Agreement with Pac Mar.

Page 4 of the Peat, Marwick, Mitchell audit contains a statement of assets and fund balances showing the fund balance at \$1,903,944. Two funds are maintained by Pac Mar, one the investment account and the other self insured retention or claims account.

These fund balances should be audited at the time Pac Mar assumes claims liabilities for its account. The audit should include a thorough review of losses incurred and paid at that time. APA should participate in the review of the reserves for outstanding claims and agree to the amount of funds required by Pac Mar to pay the run-off of outstanding claims. APA should attend the meetings involving the amounts of the letters of credit at the 6, 18 and 30 month periods following completion of the Project.



In David Carlson's letter of March 2, 1983 on page three, in answer to my questions 8 and 9, contained in my February 14, 1983 letter; he states that Pac Mar's basic premium factor had reduced to \$100,000 from \$150,000 and that I would receive an amendment to the policy affecting this change. The amendment has not as yet been received. He also states that the "premium taxes are included in the \$100,000 fronting fee". At the time of the audit of trust funds, care should be taken in determining the amount of these taxes and for the period of time the taxes will be charged.

Brokerage fees should be verified at this time to reach agreed levels of:

Marsh & McLennan fee	\$151,000
Interest income to Marsh & McLennan	40,000
Corroon & Black	<u>50,000</u>
Total of all fees and income	\$241,000

In that amendment 3 to the APCOP agreement has not been executed by APA, it should be determined if Corroon & Black have received the requested \$50,000 for services to August 1982.

APA outlook:

On April 14, 1983 while in APA offices, Dave Carlson provided copies of letters written by John Haywood on November 25, 1981 and February 22, 1983 addressed to Corroon & Black and to APCOP Services respectively. He also provided a copy of his letter to John Haywood of March 1, 1983. He repeatedly stated he had provided literally everything asked for concerning the Tyee Wrap-up -- and more. But as late as April 14, these letters were provided which affect the entire insurance program provided the Project.

According to Dave Carlson the broker warranty policies for builders risk and transit and the Pac Mar Policy were issued in reliance on these letters. He referred to John Haywood's letters as indemnities and informed me that more than a year ago, in a meeting in Eric Yould's office, that John Haywood characterized the Tyee Wrap-up Program as being one of guaranteed cost --- to APA.

If the administration of the Tyee Wrap-up Program were changed from the Division Risk Management to the Power Authority, John Haywood would withdraw his letters. If this happened, Dave Carlson felt that major change in the insurance structure would be required. This because the referenced letters were the financial basis for the warranty policies and he did not know what Pac Mar would do concerning their policies should the security for their issuance be withdrawn.

All of this is understandable for the following reasons:

- Construction contracts have been issued indicating a \$5000 deductible in the builders risk insurance. A withdrawal of John Haywood's letters would require that APA assume the difference in deductibles, i.e. between \$5000. and the policy deductibles of \$250,000 for Earthquake and Flood and \$100,000 for all other perils; or the contracts would require amendment, to transfer the deductibles to the accounts of the contractors. This latter option would be most difficult to effect.
- The Pac Mar program may be modified, presumably per terms of its policies, retro agreement and filings. Should this occur, APA would be subject to the terms of the retro agreement which provides a maximum premium of the basic premium plus incurred losses. Presumably Pac Mar could ask for cancellation of their agreement with APCOP which provides for it, Pac Mar, to assume claims liabilities at a date following completion of the Project.

These changes would have dramatic effect on the Power Authority. Also the APA would be responsible for the difference in liability insurance protection afforded under the subscription policy and the limits of liability promised in the construction contracts for Phases I and II.

It appears that John Haywood may be unable to withdraw his letters despite a change in the administration of the wrap-up program.

The following should be required of APCOP with evidence of the corrections given to APA.

- The subscription liability policy should be amended to reflect the limit of liability provided, i.e. to bring it into conformance with the schedule of insurance. This will show a limit of \$55,000,000 provided by the participating carriers.

Endorsement 110A should be either deleted or affirmed that a \$35,000,000 limit per occurrence is provided or that a \$55,000,000 limit per occurrence is provided. Currently the subscription policy, on its declaration page, indicates a limit of \$35,000,000 for Bodily Liability and a \$35,000,000 limit for Property Damage Liability.

The ocean marine policy should have all the blanks in the endorsements attached to be completed.

The builders risk policy should be endorsed to indicate the total limit of protection afforded for all insureds. This in order to bring it into conformance with the schedule of insurance.

The Pac Mar policy amendment providing a change in the basic premium from \$150,000 to \$100,000 should be provided.

APCOP should provide APA with copies of the quarterly reporting required in section 8 under its contract with the Power Authority.

A schedule of actual deductibles or self insured retentions for all policies should be provided to APA.

The excess liability should be amended to bring it into conformance with the primary Pac Mar policy, particularly as respects the maritime coverage and a clear identification of the application of any aggregate limits of liability provided.

The following recommendations are made as respects other insurance provided the Power Authority.

Since the Division of Risk Management provides various insurances for APA, the Power Authority should be included among the insureds in all policies as is the University of Alaska shown as an insured.

The State's property insurance policies should be endorsed to automatically pick up all APA completed projects. The methodology used for establishing APA's responsibility for deductibles or self insured retentions should be clearly explained to APA for each area of insurance protection afforded through the services of the Division of Risk Management.

Alaska State Legislature

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



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Juneau, Alaska 99811
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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. Yerker
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 Tye 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 Tye 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.

*and 15¢
10¢ or higher!*

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 amortize 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 amortize 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

Mailed	<u>12/28/52</u>

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ALASKA POWER AUTHORITY	

HB 9 POWER COST STUDY

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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 Lake 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 inadvertently 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) its own operation and maintenance costs, (2) its 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.

2. 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 Tye 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		Tye ¢/KWH		Solomon ¢/KWH		Terror ¢/KWH		
	Hydro	Thermal	Hydro	Thermal	Hydro	Thermal	Hydro	Thermal	
1985	15.0	14.4	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	25.2

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 term, 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, Tye 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, Tye 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.

EARLY YEAR COST OF POWER & SYSTEM INCREMENT PROBLEM
WHOLESALE RATE (¢/kwh)

	<u>Swan</u>			<u>Tye</u>			<u>Solomon</u>			<u>Terror</u>	
% 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	17.4	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 Tye for example, would have the effect of reducing not only the Lake Tye 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

	<u>Swan</u>	<u>Tye</u>	<u>Solomon Gulch</u>	<u>Terror</u>
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 Tye 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 Tye 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 Tye 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)

	<u>Swan</u>	<u>Tyee</u>	<u>Solomon</u>	<u>Terror</u>	<u>Total</u>
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	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
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 time, the hydro power should be strongly competitive with the thermal alternative. 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 standpoint 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, Tye Lake and Solomon Gulch project.
 - ° Prior to the introduction into the system of Terror Lake, Swan Lake, Tye 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 Tye 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 Tye 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 16.5 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.

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.

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 18, 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 Glatoff Glacier. The diversions will be accomplished by small diversion dams, open

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.

ASSUMPTIONS FOR FINANCIAL FORECASTS

°Project Costs and Financing

<u>Projects Included</u>	<u>Total Cost (Millions \$)</u>	<u>State Appropriations (Millions \$)</u>	<u>Debt Financed (Millions \$)</u>	<u>On-Line Date FY</u>
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	<u>189.40</u>	<u>79.26</u>	<u>110.14</u>	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.

<u>Calendar Year</u>	<u>General Inflation (Percent) 1.</u>	<u>Interest Rate for Bonds (Percent)</u>
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 b

B-2 °OPERATION AND MAINTENANCE COSTS

<u>Project</u>	<u>Annual O/M Costs (Millions \$)</u>	<u>Year</u>
Swan Lake	1.028	1985
Lake Tye	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:

<u>FISCAL YEAR</u>	<u>SWAN LAKE</u>	(KWH in thousands) <u>TYEE LAKE</u>	<u>SOLOMON GULCH</u>	<u>TERROR LAKE</u>
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. Inflation 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 out).
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: $(12 + 11) \cdot (11 + 20)$.
35. Annual Borrowing \$ 1983: $15 \cdot 4$.
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	--	--	--	--	--

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 = $(A + B + C) / \text{Project Sales}$.

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)

$R1 = (\text{Total System Debt Service} + \text{Coverage}) / \text{Total Sales for all Projects.}$

$$R1 = (A + B) / \text{SUM}(E).$$

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

$R2 = \text{System Debt Service Average} \times (1 + .04 (\text{year}-1983)).$

$$R2 = R1 \times (1 + .04 \times C).$$

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

$R3 = (\text{Total System Debt System Service} + \text{Coverage} \times (\text{State's Investment in the Project} / \text{State's Investment in all Power Projects})) / \text{Project Sales.}$

$$R3 = ((A + B) \times (D / \text{SUM}(D))) / E$$

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.

$R5 = (\text{State's Investment in the Project} / \text{Total State Investment in all projects whose rates are less than the System Cap Rate}) \times \text{Shortfall.}$

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.

$$R4 = (R2 \text{ or } (R3 \times R5)) / E$$

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

	<u>Standard HB9 Rate</u>	<u>"Blackmail" Clause Rate</u>	<u>Percent Difference</u>	<u>Additional Revenues Generated (\$Millions)</u>
	(¢/KWH)	(¢/KWH)		
<u>Swan Lake</u>				
1987	15.5	27.8	79	4.4
1991	14.1	22.9	62	3.8
<u>Tyee Lake</u>				
1987	16.4	34.8	112	6.6
1991	15.8	25.6	62	4.8
<u>Solomon Gulch</u>				
1987	10.0	12.9	29	1.2
1991	10.6	12.9	22	1.0
<u>Terror Lake</u>				
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 HRP BASIS (EXCLUDING BLACKMAIL CLAUSE)

YEAR	PROJECTS																						
	SWAN LAKE				LAKE TYEE				SOLOMON GULCH				TERRAR LAKE										
	COST		C.O.P		C.O.P		C.O.P		C.O.P		C.O.P		C.O.P		C.O.P								
	ICL	INC	SALES	CAPPED	W/O	CAP	ICL	INC	SALES	CAPPED	W/O	CAP	ICL	INC	SALES	CAPPED	W/O	CAP					
\$/MILL		GWH	C/KWH	C/KWH		\$/MILL		GWH	C/KWH	C/KWH		\$/MILL		GWH	C/KWH	C/KWH		\$/MILL		GWH	C/KWH	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	7.9	6.9		202.5		0.0	0.0	0.0
1986	98.2		33.6	15.5	16.3		125.3		31.1	16.5	21.1		53.0		41.0	10.0	9.1		202.5		98.2	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		92.0	12.2	11.1
1988	98.2		37.0	15.5	15.3		125.3		39.2	16.2	19.4		53.0		41.0	10.0	9.4		202.5		95.9	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	93.2		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 TERRAR 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				TERRAR LAKE										
	COST		C.O.P		C.O.P		C.O.P		C.O.P		C.O.P		C.O.P		C.O.P								
	ICL	INC	SALES	ADD	REV	ICL	INC	SALES	ADD	REV	ICL	INC	SALES	ADD	REV	ICL	INC	SALES	ADD	REV			
\$/MILL		GWH	C/KWH	GEN	\$/MILL		GWH	C/KWH	GEN	\$/MILL		GWH	C/KWH	GEN	\$/MILL		GWH	C/KWH	GEN				
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	7.9	0.0		202.5		0.0	0.0	0.0
1986	98.2		33.6	15.5	0.0		125.3		31.1	16.5	0.0		53.0		41.0	10.0	2.0		202.5		98.2	13.0	0.0
1987	98.2		35.3	15.5	4.4		125.3		36.0	16.4	6.2		53.0		41.0	10.0	1.2		202.5		92.0	12.0	9.0
1988	98.2		37.0	15.5	4.1		125.3		39.2	16.2	6.2		53.0		41.0	10.0	1.2		202.5		95.9	11.4	9.3
1989	98.2		38.9	15.3	3.9		125.3		42.7	16.1	5.7		53.0		41.0	10.1	1.2		202.5		99.9	10.3	9.5
1990	98.2		40.8	14.5	3.9		125.3		46.5	16.0	5.1		53.0		41.0	10.3	1.1		202.5		104.2	10.2	9.6
1991	98.2		42.9	14.1	3.8		125.3		48.9	15.8	4.8		53.0		41.0	10.6	1.0		202.5		106.3	10.1	9.5

* COST OF POWER CALCULATION BASED ON THE INCLUSION OF THE FOLLOWING PROJECTS:
 SWAN LAKE LAKE TYEE SOLOMON GULCH TERRAR LAKE
 COST OF POWER CALCULATED USING BLACKMAIL CLAUSE I.E. THE GREATER OF
 THE STANDARD UNCAPPED HRP RATE OR 10% OF THE AUTHORITY'S INVESTMENT IN EACH PROJECT

A SPECIAL REVIEW OF THE
ALASKA POWER AUTHORITY
INSURANCE PROGRAMS
ADMINISTERED THROUGH THE
ALASKA POWER AUTHORITY AND THE
DEPARTMENT OF ADMINISTRATION
DIVISION OF RISK MANAGEMENT

June 29, 1982

Chairman, Alaska Power Authority

Chuck Conway

Commissioner, Department of
Administration

Carole J. Burger

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

AUDIT DIVISION
POUCH W—ALASKA OFFICE BUILDING

JUNEAU, ALASKA 99811

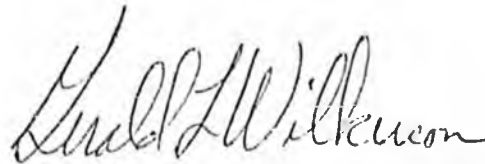
June 29, 1982

Members of the
Legislative Budget and Audit Committee:

In accordance with the provisions of Title 24 of the Alaska Statutes, the attached report is submitted for your review:

A SPECIAL REVIEW OF THE
ALASKA POWER AUTHORITY
INSURANCE PROGRAMS
ADMINISTERED THROUGH THE
ALASKA POWER AUTHORITY AND THE
DEPARTMENT OF ADMINISTRATION
DIVISION OF RISK MANAGEMENT

June 29, 1982



Gerald L. Wilkerson, CPA
Legislative Auditor
Division of Legislative Audit

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In accordance with the provisions of Title 24 of the Alaska Statutes and a special request of the Legislative Budget and Audit Committee, we have reviewed certain issues relating to an insurance "wrap-up" program for Alaska Power Authority construction projects. Our review encompassed activities of the Alaska Power Authority (APA) and the Department of Administration, Division of Risk Management, as well as those of insurance brokers and agents handling APA accounts.

In the Spring of 1981, legislation was enacted that broadened the scope of APA's authority and responsibility for administering Alaska's energy program. APA became directly involved in the construction and acquisition of power projects throughout the State.

The first construction project to come on line was the Tye Lake hydroelectric project. This project, located approximately 40 miles southeast of Wrangell, was to be constructed in three phases. Bids for Phase I were solicited in early June 1981, with construction scheduled to begin the following October.

The Request for Proposal (RFP) for Tye Lake contained generally standard wording in which the burden for purchasing and maintaining adequate insurance was placed on the contractor. Simultaneous to the Tye Lake bid process, APA also sought advice from the Division of Risk Management about the insurance requirements and liability ramifications of APA contracts in general. The Division of Risk Management in turn consulted with the State's major insurance broker, Marsh & McLennan Inc. During July 1981, a series of discussions and correspondence ensued among APA, Risk Management, Marsh & McLennan Inc. and various consultants, which ultimately resulted in a decision to substitute an owner provided insurance program for contractor provided insurance on the Tye Lake project. That is, rather than requiring the contractor to purchase insurance and to see that his sub-contractors do likewise, the owner (APA) would "wrap-up" all parties and exposures into a comprehensive safety and insurance program.

Correspondence between Marsh & McLennan Inc. and APA indicates that the decision to employ a wrap-up program for Tye Lake was reached during the latter part of July. Bid openings were scheduled for August 11, 1981. Given the time constraints, APA elected to have contractors submit bids with insurance costs included, as specified by the RFP. Upon the award, APA would then determine whether the contractor would agree to an owner provided insurance program and, if so, would negotiate an amount to back out of his bid.

Bids were opened as scheduled on August 11, 1981. Proposals were evaluated and the contract eventually awarded on September 25 to the joint venture of Southeast Drilling Co., Inc. - Harrison Western Corp. (SE-HW) for a bid of \$44,952,000. SE-HW subsequently agreed to owner provided insurance, and a change order was signed October 20 reducing the contract amount by \$1,798,867.

On October 28, 1981, subscription policies effective October 1 for Phase I of the Tyee Lake project were issued by the two firms that handle the State's master insurance policies: Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc. During November and December, the brokers and the Division of Risk Management worked out details on how to structure and administer the wrap-up program. This involved arranging for claims adjusting, safety consulting, actuarial and related services, as well as negotiating with underwriters for insurance placements. In addition, the two brokerage firms worked out internal agreements on how to jointly handle the APA account.

The contract between APA and the brokers to provide the above services was not finalized until December 22, 1981. This contract, backdated to October 1, 1981, provides for APA to use Risk Management as a consultant for risk management services, and for Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc., to provide for specified services necessary to administer the Alaska Power Construction Program (APCOF). Contract terms are stated in general language, but the appendix on consideration clearly limits the contractual agreement to the SE-HW portion of the Tyee Lake project. Consideration for this contract was to be \$1,790,000, but a premium discount of \$100,000 was subsequently applied. First payment on the contract in the amount of \$540,000 was made December 23, 1981.

ISSUES AND ALLEGATIONS

During the Spring of 1982, several issues and allegations were raised about the series of events outlined in the preceding paragraphs. Various members of the Legislature, representatives from interested professional groups, and State administrators questioned whether owner "wrap-up" was an appropriate or allowable insurance method for State agencies. Specific allegations surfaced regarding the procedures for bidding and awarding the Tye Lake construction and insurance contracts, and the brokers' and Division of Risk Management's administration of the APA insurance programs.

We have not included in this report a general discussion of the pros and cons of wrap-up insurance. This issue was the subject of considerable debate during the last session of the Legislature and resulted in the passage of SB 831, which prohibited State agencies from providing insurance to contractors awarded State construction projects. SB 831 was vetoed by the Governor because he did "not find this prohibition in the best interests of the State". Whether or not this legislation is pursued is a matter of legislative and executive decision during the next session.

We have, however, examined the various allegations and legal issues that have been raised. A discussion of each issue and our findings thereon follow:

A. Contractual Procedures - Tye Lake Construction Contract

No allegations have been raised and we found no improprieties on the bidding and preliminary award of the Tye Lake - Phase I contract to SE-HW. Allegations have been raised, however, that SE-HW failed to provide proof of adequate insurance as required by RFP, and that as a result a change order was issued wherein APA would provide insurance instead.

We found that the insurance provided by SE-HW was inadequate, but that this was due to misunderstanding rather than the fact that SE-HW was uninsurable. The chronology of events is outlined below:

09/10/81 APA Board approves contract award to SE-HW.

09/11/-- Negotiations begin between SE-HW and Division of Risk Management on amount of bid attributable to insurance. Dates uncertain, but no indication that negotiations pre-date Board approval. APA copied on at least one related letter dated 09/21/81.

- 09/15/81 Contract award challenged by Pacific Ventures, a lower bidder rejected because proposal did not conform to RFP. Temporary restraining order placed.
- 09/25/81 Temporary restraining order lifted. Notice of Award sent to SE-HW, subject to certain requirements including proof of adequate insurance. This letter signed by same APA individual involved in earlier insurance discussions with Marsh & McLennan Inc. and Risk Management, and copied on 09/21/81 letter regarding cost of contractor insurance.
- 10/08/81 SE-HW responds to Notice of Award, signs contract, and supplies performance bonds and certificates of insurance.
- 10/16/81 APA acknowledges receipt of signed contract but notifies SE-HW that performance bonds deficient and insurance inadequate. Letter to SE-HW states: "Pursuant to advice of the State Division of Risk Management, the Alaska Power Authority proposes to provide a wrap-up insurance program A change order has been prepared to effect these modifications" SE-HW given option of agreeing to change order or supplying evidence of adequate insurance.
- 10/20/81 Change Order No. 1 substituting owner provided insurance for contractor provided insurance and decreasing contract by \$1,798,867 signed.
- 10/20/81 Notice to Proceed issued.

From discussions we have held with involved parties, it appears that by the time SE-HW responded to the 09/25/81 tentative Notice of Award, an understanding had been reached that APA would be providing insurance coverage and thus little attention was given to evidences of insurance. There is no indication that SE-HW was uninsurable.

There is some question as to whether Risk Management exceeded its authority by dealing directly with the contractor without APA's knowledge and before APA had officially proposed the idea of owner provided insurance. We have received conflicting information about this. Most likely, this was a case of bad communication both within APA and between APA and Risk Management.

B. Contractual Procedures - APA Brokerage Contracts

To date, all APA insurance reviews or brokerage services have been performed by Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc. (A schedule of APA contracts with and payments to the brokers is presented in Appendix A). This has generated considerable controversy, with specific questions raised about:

- ④ Meetings of Risk Management, APA, and Marsh & McLennan Inc. prior to Tyee Lake brokerage contract.
- ④ Awarding of Tyee Lake contract to Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc. without competitive bid.
- ④ Expectations by brokers that Tyee Lake contract would be expanded to future APA construction projects.
- ④ Expansion of broker's involvement to cover completed or acquired projects.
- ④ Awarding of APA insurance review contract to brokers without competitive bid.

Each of these areas is discussed below.

Pre-contract meetings: It is unclear when wrap-up discussions first took place and who it was that first proposed the concept. Our review indicates, however, that wrap-up on Tyee Lake was not explicitly agreed to until late July, when representatives from APA, Risk Management, and Marsh & McLennan Inc. met in Marsh & McLennan's Seattle offices. There is no evidence to suggest that there was anything conspiratorial about this meeting, or that the decision by APA and Risk Management to utilize owner provided insurance was anything more than an attempt to explore economical insurance alternatives. Undoubtedly, Marsh & McLennan Inc. wished to secure the State's business, but as a profit making firm this is only normal.

Awarding of Tyee Lake contract without competition: In our July 1980, performance review of the Division of Risk Management, we criticized the Division for not utilizing competitive procedures in its selection of brokers. During FY'81, the Division went through an extensive broker selection process, and in May 1981, Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc., were contracted with to provide risk management and insurance programs for the State. When APA sought advice from Risk Management about the insurance ramifications of its newly expanded role, then, it was reasonable that Risk Management in turn sought advice from its primary consultant, Marsh & McLennan Inc.

The question is whether it was also reasonable to contract with Marsh & McLennan Inc. for the Tyee Lake wrap-up. In the first place, if a consultant believes he will be awarded the contract for any services he recommends, then he is more likely to recommend that those services are necessary. Secondly, it is State policy to utilize competitive selection procedures, and no attempt was made to do so in this case.

It is our belief that APA and Risk Management tried to objectively evaluate the wrap-up option, and decided that it was in the best economic interests of the State. The fact that the time frame for Tyee Lake was too short to go through a broker selection process was not considered a major problem. This had just been done for the State's other coverages, and it was reasoned that that selection process would satisfy similar requirements for Tyee Lake. Therefore, it was decided to utilize the State's current brokers.

While we do not question APA or Risk Management's motives behind this decision, we do think they acted in haste. If there was insufficient time to go through a broker selection for Tyee Lake or to look into the legal questions raised later in this report, then it would perhaps have been better to utilize contractor provided insurance on Tyee Lake and reconsider wrap-up for future projects instead.

Expectations of future APA wrap-up contracts: Marsh & McLennan Inc. correspondence indicates that the firm was vying for and in fact expected to provide brokerage services on future APA wrap-up programs. In addition, the contract between APA and the brokers was worded in such a way that future projects could simply be appended to it. However, the contract as signed December 22, 1981, is clearly limited to Tyee Lake - Phase I (with the implicit understanding that Phases II and III would be added), and APA and Risk Management memos demonstrate that the insurance alternatives for other APA construction projects would be decided on a case-by-case basis. This intention is also evidenced by testimony of APA staff at the October 2, 1981, APA Board meeting.

We cannot verify whether APA and Risk Management would in fact have gone through a broker selection process on future projects, since the APA Board opted that contractor provided insurance be used on the only other construction project to date, Terror Lake. Certainly no procedures for broker selection were begun prior to the Board's April 15, 1982, Terror Lake decision, though this may be attributable to the controversy and questionable future of State agency wrap-ups at that point in time.

Expansion to cover completed or acquired projects: The issue of whether or not to use owner provided insurance applies only to construction projects. Another issue is how best to insure completed or acquired projects, the immediate cases in point being Solomon Gulch and Swan Lake.

The Division of Risk Management has taken the stand that, as State owned property, completed projects such as Solomon Gulch automatically become a Risk Management responsibility. As is done for other State owned property, Risk Management would negotiate the cost and conditions of coverage and bill APA accordingly. Furthermore, it is Risk Management's responsibility to determine whether coverage in place on acquisitions such as Swan Lake adequately protects the State, and, if not, to cover exposures. In both of the above instances, the method for providing insurance has been to fold the projects into the State's master insurance programs which are brokered through Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc. The brokers have adopted the acronym "APOP" for these projects, which stands for Alaska Power Operations Program.

Vague allegations have been raised about the nature and extent of APOP, and that it is being thrust upon the entities from which projects are being acquired. We found no substance to these allegations, and to our knowledge APOP is no more than as described above. In addition, until or unless a separate risk management program is developed for APA, we concur with the Division of Risk Management's judgment on how to handle completed or acquired projects.

Awarding of insurance review contract: APA also contracted with Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc., to perform an insurance review of all APA contracts. This agreement, signed the same day as the APCOP - Tyee Lake contract, involved an evaluation of contract insurance language and evidences of insurance, establishment of on-going contract review procedures, and other related services. Contract consideration was to be for services rendered, not to exceed \$40,000.

Results of this contract demonstrate that APA contracts generally did not have adequate insurance language and that APA's exposures were greater than intended. However, the fact that there was evidently a legitimate need for this contract does not justify its being awarded without competitive bids. Nor was there any particular time pressure, as there was with the APCOP - Tyee Lake contract, that would preclude normal competitive bid procedures.

C. Administration of APCOP - Tyee Lake Contract

Several questions have also been raised about the administration of the APCOP - Tyee Lake contract; that is, how the brokers and the Division of Risk Management are performing those services they were contracted with to provide. These questions are discussed below.

One question is whether the Workers' Compensation (WC) reserve established for State employees is commingled with or has in fact been used for Tyee Lake employees. The APCOP - Tyee Lake and State WC reserves are not commingled, and as of July 1, 1982, they will also be handled by different adjusters. Prior to the establishment of an APCOP reserve account, however, a Tyee Lake employee was injured and \$9,417 was paid out of the State WC reserve to cover related claims. The State's reserve was subsequently reimbursed upon establishment of the APCOP WC reserve account in January 1982.

Another question has to do with whether the brokers and/or Risk Management have conducted business using "secret" bank accounts. We have found references to three bank accounts. The first was established with First Interstate Bank in Seattle, and was used by the brokers for paying all bills related to their APCOP account. This account was subsequently closed and replaced with an account with the National Bank of Alaska. A third account, also with the National Bank of Alaska, is a depository account used by Northern Adjusters for paying APCOP Workers' Compensation claims. All three of these accounts are utilized internally by the brokers or their sub-contractors to perform services necessary to fulfilling the APCOP contract. Risk Management neither deposits nor withdraws funds from these accounts. Therefore, these accounts are not subject to the requirement that as State accounts they be reported to the Department of Revenue.

Questions have also been raised about the propriety of payments from the APCOP bank accounts, particularly for such things as lunches, dinners, or drinks. We think these questions are moot. Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc., are being paid a fixed sum, a portion of which is attributable to brokerage fees. In general, it is not within our control to dictate to the brokers and their respective managements how those fees may be used.

Another issue is whether State competitive bid procedures have been bypassed by contracting with brokers who then in turn sub-contract with other firms to perform certain services. Particular questions have been raised about the sub-contracts for claims adjusting. We think

that while State procedures may be bypassed, there is very little incentive on the brokers' part for not employing competitive procedures of their own. As noted before, the brokers are being paid a fixed sum to perform certain services. It is certainly not in their best interests to over-pay sub-contractors. As far as the claims adjusting sub-contract is concerned, State competitive procedures were not bypassed. The contract RFP and award process was administered through the Division of Risk Management along with the claims adjustment contracts for other State accounts, and met standards for objective and competitive review.

Two final questions, which underlie all the above, are what APA is buying in its APCOP - Tyee Lake contract, and whether it is less expensive than contractor provided insurance would have been. A budget for all phases of the Tyee Lake wrap-up program is being prepared but has not been finalized. Once the budget is established, the Division of Risk Management has informed us that in its capacity as risk management consultant for APA, it will arrange for audits of APCOP expenses and actuarial reviews of loss reserves.

It is also too early to determine if wrap-up for Tyee Lake will be cost effective. Tyee Lake - Phase I was bid with insurance, with \$1,798,867 subsequently backed out. The APCOP Phase I insurance contract cost, after premium discount, \$1,690,000. Therefore, there is an immediate apparent cost savings of \$198,867. Since the other Tyee Lake contracts were bid net of insurance, no easy "upfront" numbers are available, and it is beyond the scope of this report to project them. A schedule of claims as of May 31, 1982, is presented in Appendix B, but the total insurance costs of Tyee Lake will not be known for several years.

D. Legal Issues

In addition to the legal issues implied in the matters already discussed, several specific legal questions have been raised. These include:

- ① Is the State insured on Tyee Lake and has it been from the start?
- ② Do wrap-ups by State agencies violate existing law?
- ③ Is the State self-insuring Workers' Compensation for Tyee Lake, and if so, is this in compliance with law?

Each question is discussed below.

Is the State insured on Tyee Lake and has it been from the start? The basis for this question is two-fold. First, while work on the Tyee Lake project began in November 1981, the insurance contract between APA and the broker was not signed until December 22, 1981. Second, while APA was provided with "subscription policies" by the brokers in October 1981, these policies were not agreed to by underwriters until, in some cases, months later.

From our review of legal opinions and documents, it appears that the State is and has been covered on Tyee Lake, if for no other reason than that it has clear recourse against the brokers themselves. This is established through letters of intent and brokerage warranties in which the brokers certify that they have placed insurance as specified in the "subscription policies." Marsh & McLennan Inc. and Corroon & Black/Dawson & Co., Inc., it should be noted, have assets valued far in excess of dollars being insured under the APCOP - Tyee Lake contract. In addition, the State's master insurance contract is broadly worded and would include Tyee Lake exposures.

Do wrap-ups by State agencies violate existing law? We have reviewed several legal opinions and discussed this question with representatives of the Attorney General's Office. To our knowledge there is no Alaska law or body of laws that generally prohibit wrap-up insurance programs by private or public entities.

Is the State self-insuring Workers' Compensation for Tyee Lake, and if so, is this in compliance with law? This is the primary legal question on the owner provided insurance program that is in place for Tyee Lake, and to date it is unresolved. Through our discussions with the two agencies who have jurisdiction over Workers' Compensation - the Division of Workers' Compensation and the Division of Insurance - we have identified the key issues to be:

1. All employers must provide Workers' Compensation coverage for their employees. This may be done one of two ways: The employer may purchase a WC policy through an insurer approved by the Division of Insurance, or may be granted a self-insurance certificate by the Workers' Compensation Board.

2. The WC coverage for Tyee Lake contractors and their employees is provided under a policy by an approved insurer, but is, in the end, self-insured by the State. This is illustrated as follows:
 - ① APA contracts with broker for APCOP services.
 - ② Brokers contract with Pacific Marine Insurance Co., an approved Alaska insurer.
 - ③ Pacific Marine issues policy, makes necessary filings with Division of Insurance, WC Board.
 - ④ Pacific Marine, in effect, reinsures total liability back through APCOP brokers.
 - ⑤ Brokers establish loss reserve fund from which Tyee Lake WC claims, up to \$300,000 per occurrence, are paid (insurance purchased for excess coverage); amount of fund comes out of lump sums paid by APA to brokers. The final amount to be set aside for WC reserves is still being negotiated.
 - ⑥ Brokers receive assurance from Division of Risk Management that if actual losses exceed loss reserves, "the State loss reserve fund would be made available to pay losses after exhaustion of the APCOP loss reserves."
3. The question now becomes, by what authority can the State self-insure Tyee Lake employees? The State of Alaska has been granted a self-insurance certificate and self-insures Workers' Compensation for State employees. According to the Workers' Compensation Board, however, this certificate does not allow the State to insure non-State employees, such as the contractors and their employees on Tyee Lake.
4. A related question is whether the State is, in effect, acting as an insurance company.
5. Finally, a significant question exists as to where the funds would come from if the WC loss reserves established for Tyee Lake claims prove to be inadequate. This question has not been adequately considered, let alone answered.

One scenario is that these excess losses would be covered under the State's aggregate of excess coverage. Under this insurance, virtually all State losses above a given aggregate are covered. For the year ended May 15, 1981, the aggregate base was \$7,500,000; for the current period, the base is reduced to \$7,000,000. Actuarial estimates indicate that State losses will exceed the aggregate for the year just ended, and the trend of losses has been to increase each year.

A second scenario is that State losses will not exceed the aggregate, and therefore the excess losses on Tyee Lake will have to be absorbed elsewhere. It is unclear how this would be done.

A third scenario is that losses on Tyee Lake will be less than the reserves. In this event, funds would be returned to APA.

CONCLUSIONS AND RECOMMENDATIONS

In general, we found the allegations that APA, Risk Management, or brokers/agents acted improperly to be unsubstantiated. We do believe, however, that APA, relying heavily on the advice of Risk Management, acted hastily in its decision to employ owner provided insurance for Tye Lake, even though delay would have precluded this option. By so doing, they did not adequately consider the legal ramifications or impact of wrap-up as viewed by other State insurance agencies, and entered into a major contract without utilizing competitive procedures. In any event, while time constraints may arguably support the Tye Lake sole source contract, they do not justify the awarding of a separate \$40,000 contract by APA to the brokers without competitive bid.

In conjunction with the Tye Lake wrap-up program and in anticipation of this concept being applied to future APA projects, we make the following recommendations:

1. The Divisions of Risk Management, Insurance, and Workers' Compensation should discuss, in a formal setting if necessary, the Workers' Compensation and other insurance questions that have been raised. Using a State-funded loss reserve for non-State employees is clearly a divisive and unresolved issue. It is incumbent on these agencies to clarify what is a very gray area.
2. APA and Risk Management should monitor and evaluate the Tye Lake wrap-up program in order that some comparative data be available for future projects. This would entail audits and actuarial reviews of payments and loss reserves, as well as an independent evaluation of owner vs. contractor provided insurance.
3. APA should decide whether or not to utilize owner provided insurance far enough in advance to incorporate this into the contractor RFP. For example, contractors could submit bids with insurance, without insurance, or both with and without insurance and then be measured against some pre-determined criteria.

In addition, sufficient time should be allowed to go through a broker selection process on construction projects where APA opts for owner provided insurance.

4. APA and Risk Management should clarify their respective responsibilities over APA projects, whether under construction or completed. In December 1981, the two agencies signed a memorandum of understanding outlining the role each played in providing risk management

services for APA. However, this "understanding" has become somewhat strained. For example, brokers have been given conflicting signals over certain coverages, and APA is even considering employing its own risk manager.

We would hope that APA's decision will be based on economics and need, and will consider all those issues inherent in wrap-up regardless of who administers it. In any event, until and unless APA establishes its own risk management program, the existing memorandum of understanding should be followed to ensure comprehensive and continuous coverage on APA projects.

APPENDIX A

SCHEDULE OF APA CONTRACTS WITH
AND PAYMENTS TO BROKERS
As of June 15, 1982

<u>Contract Encumbrance Number</u>	<u>Description</u>	<u>Contract Amount</u>	<u>Payments at 06/15/82</u>
CC082307	Alaska Power Construction Program (APCOP) - Tyee Lake, Phase I ¹	\$1,790,000	\$540,000 ²
CC082304	APA Contract Insurance Review	\$ 40,000	\$ 20,000

1 To date, no provisions for Tyee Lake - Phases II-III have been appended to the APCOP contract. These phases were bid net of insurance, but how and through whom APA will provide insurance has not been finalized.

2 Scheduled payments are:

10/01/81	\$ 640,000	
Less Premium Discount	<u>(100,000)</u>	
		\$ 540,000
08/01/82		580,000
02/01/83		<u>570,000</u>
		<u>\$1,690,000</u>

APPENDIX B

TYEE LAKE LOSSES AND PAYMENTS
As of May 31, 1982

<u>Loss Type</u>	<u>Estimated Loss Incurred</u>	<u>Loss Payments</u>
Workers' Compensation ¹	\$111,846	\$33,108
Property	<u>20,000</u>	<u>-0-</u>
	<u>\$131,846</u>	<u>\$33,108</u>

1 As of May 31, 1982, 14 Workers' Compensation claims had been submitted for adjustment. Largest estimated loss for a single claim was \$25,000.

DEPARTMENT OF ADMINISTRATION

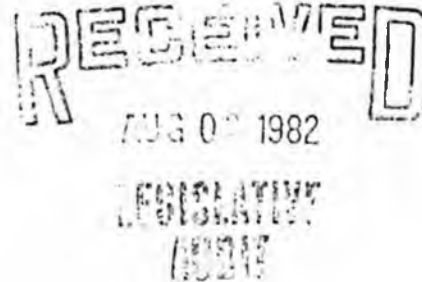
OFFICE OF THE COMMISSIONER

POUCH C

JUNEAU, ALASKA 99811

August 2, 1982

Mr. Gerald Wilkerson, CPA
 Legislative Auditor
 Division of Legislative Audit
 Legislative Budget and Audit Committee
 Pouch W
 Juneau, AK 99811



Re: Response to a Special Review of the Alaska Power Authority Insurance Programs Administered Through the Alaska Power Authority and the Department of Administration, Division of Risk Management, Dated June 29, 1982

The decision to recommend the Wrap-up program to the Alaska Power Authority (APA) was completely the responsibility of the Division of Risk Management. Wrap-up insurance has been the normal way to cover large construction projects for the last 30 years. This is not to imply that wrap-ups are not controversial because they are. This controversy, however, does not deter from the cost effective nature of wrap-ups. There are three valid reasons for not considering wrap-up insurance:

1. The construction project is not large enough (50 million or greater);
2. The Risk Management Program of the owner or contractor is not sophisticated enough to adequately coordinate the required services.
3. The political considerations which have resulted in several states passing restrictive legislation prohibiting wrap-ups.

Prior to recommending wrap-up to the APA, meetings were held between Risk Management and the Division of Insurance. Even though wrap-ups are acceptable in Alaska, the Division of Insurance is responsible for setting up guidelines and if required, adopting regulations. After reviewing the guidelines and discussing Risk Management's program, the Division of Insurance decided to not adopt regulations. Most of the questions regarding wrap-ups had been answered

several years ago when Alyeska Pipeline Co. was given approval to provide an owner wrap-up for the Taps Construction.

Before answering the individual recommendations, we would like to make two observations: First, the atmosphere surrounding the initiation of this audit was inflammatory in that there were a considerable number of rancorous accusations made against the Division of Risk Management, APA and the APCOP brokers. We believe that the auditors were able to cut through the periphery issues and produce a professional report which is notable for its objectivity.

Second, many of the legal issues on closer examination did not have substance. In order to completely counteract the questions, we had legal research done on several of these legal questions and they were not found to be meritorious.

The conclusion that there were no improprieties are concurred with. The decision to use the State's recently appointed brokers for the first wrap-up program is justified from a Risk Management standpoint and the brokers who participated in the RFP understood it to be for Risk Management services over a three to five year period.

The \$40,000 contract review program has received more publicity than it warrants. This contract review had two facets: 1. To determine what existing liabilities were outstanding, and to provide coverage if needed. Since the State's brokers were responsible for providing the coverage ex commission, there was no logical way to select another contractor. Also, there was a sense of urgency due to the pending acquisition of the Solomon Gulch and Swan Lake projects and the need to become immediately involved in the contract negotiations between the APA and the project attorneys.

Recommendations

1. The Divisions of Risk Management, Insurance, and Workers' Compensation should discuss, in a formal setting if necessary, the Workers' Compensation and other insurance questions that have been raised. Using a State-funded loss reserve for non-State employees is clearly a divisive and unresolved issue. It is incumbent on these agencies to clarify what is a very gray area.

Agreed. Attached is a memo (Appendix I) which has been sent to both the Division of Insurance and the Workers' Compensation Board which should resolve the problem. If not, we are prepared to meet with appropriate personnel to answer any questions.

2. APA and Risk Management should monitor and evaluate the Tye Lake wrap-up program in order that some comparative data be available for future

projects. This would entail audits and actuarial reviews of payments and loss reserves, as well as an independent evaluation of owner vs. contractor provided insurance.

Agreed. This recommendation is an excellent one and one in which Risk Management is quite interested in pursuing. We believe that the Tye Program will prove to be extremely cost effective and will also have a considerably better safety record than similar projects of this type. In addition, we believe that we are using a maximum of Alaska Risk Management contractors on the Program and that we are making it available for the smaller Alaska contractor to participate by furnishing raw coverage insurance that the smaller contractor might not be able to purchase on its own. See Appendix II and III for allocation of costs.

3. APA should decide whether or not to utilize owner provided insurance far enough in advance to incorporate this into the contractor RFP. For example, contractors could submit bids with insurance, without insurance, or both with and without insurance and then be measured against some pre-determined criteria.

In addition, sufficient time should be allowed to go through a broker selection process on construction projects where APA opts for owner provided insurance.

Agreed. Risk Management was limited by the decision process that the APA and its board of directors were operating under. There is no question but that the insurance language should be incorporated prior to the bids being put out. In addition, we would recommend that all insurance specifications include the owner wrap-up language and that after the bid is let that the contractor's firm be given the option of proposing its price to write the coverage. In this way a direct comparison of advantages of owner or contractor wrap-up could be made and a decision made at that time.

4. APA and Risk Management should clarify their respective responsibilities over APA projects, whether under construction or completed. In December, 1981, the two agencies signed a memorandum of understanding outlining the role each played in providing risk management services for APA. However, this "understanding" has become somewhat strained. For example, brokers have been given conflicting signals over certain coverages, and APA is even considering employing its own risk manager.

We would hope that APA's decision will be based on economics and need, and will consider all those issues inherent to wrap-up regardless of who

August 2, 1982

administers it. In any event, until and unless APA establishes its own risk management program, the existing memorandum of understanding should be followed to ensure comprehensive and continuous coverage on APA projects.

Agreed. There have been meetings with the APA and Risk Management since the pressure of the legislative activity has been reduced. The result of the last meeting was that Risk Management would take over the administration of the contract between the AFA and the APCOP brokers. In this way the APA would not be responsible for understanding and administering a Risk Management Program but instead, will pass this responsibility to Risk Management pending any decision to set up their own program. In this regard there is presently a Request for Proposal (RFP) for a Risk Management consultant to study the whole wrap-up insurance question for the APA.

Although it is difficult to quantify the exact savings to the State, a Federal government study has verified savings of 30-40 percent of conventional insurance costs. This relates to two percent of construction costs. In addition, since the State holds on to the loss reserves, an additional one per cent of costs is realized through investment earnings. If the present construction schedule of the APA is realized, the savings would amount to \$192,600,000.

It is important that the controversy surrounding this program not obscure the potential savings to the State, which would be lost if the program were terminated.

Sincerely,


Carole J. Burger
Commissioner

CB/JH/jbh
3/0802-02/RM2

MEMORANDUM

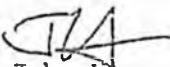
State of Alaska

TO: Ms. Jackie McClintock
Director
Division of Workers' Compensation
Department of Labor

DATE: August 2, 1982

FILE NO:

TELEPHONE NO: 465-2180

FROM:  John Haywood
Director
Division of Risk Management
Department of Administration

SUBJECT: Tyee Lake Wrap-up
Program Insurance

There have been several questions raised as to the details of the Workers' Compensation Insurance for the Tyee Lake Wrap-up Program. There are many ways in which large accounts structure their workers' compensation programs and some are more controversial than others.

Due to the unusual level of interest in this program, it was Risk Management's decision with the concurrence of Marsh and McLennan and Pacific Marine Insurance Company to provide one of the conventional forms of coverage.

Consequently, we have negotiated a Retrospective Rating Plan "D" combined Workers' Compensation and General Liability. This is an incurred loss retro program which puts it in the mainstream of insurance programs.

JH/je
5/0802-06/RM1

APPENDIX II
TYEE PREMIUM ALLOCATION

TOTALS	I - Tunnel & Powerhouse	=	\$1,690,000
	II - Submarine Cable	=	598,000
	III - Transmission Line	=	1,496,602
	TOTAL		\$3,784,602

PHASE I - Powerhouse & Tunnel Contract - \$1,690,000 - Total Premium

1. General Liability & Workers' Compensation - 2 yrs	=	974,000
2. Inland & Marine Cargo	=	303,000
3. Non-owned Aviation	=	61,000
4. C.O.C. - Builders Risk	=	181,000
5. Excess Insurance	=	171,000
		\$1,690,000

PHASE II - Submarine Cable Contract - \$598,000 - Total Premium

1. General Liability & Workers' Compensation	=	179,400
2. Non-owned Aviations	=	32,500
3. C.O.C. - Builders Risk	=	29,900
4. Excess Insurance	=	63,980
5. Marine Insurance	=	292,220
		\$ 598,000

PHASE III - Transmission Line Contract - \$1,496,602 - Total Premium

1. General Liability & Workers' Compensation	=	1,174,327
2. C.O.C. - Builders Risk	=	162,100
3. Excess Insurance	=	160,130
		\$1,496,602

APPENDIX III
TYEE WRAP-UP BUDGET
August 22, 1982

PHASE	I	-	1,690,000
	II	-	598,000
	III	-	1,496,602
TOTAL		-	3,784,602

PREMIUM			1,242,000
RETENTION			1,894,000
ADMIN. EXP.			82,000
BROKER FEE			119,000
EXTRAORDINARY TRAVEL/LEGAL			40,000
SAFETY			78,000
CLAIMS ADJ			60,000
ATTORNEYS			15,000
CONTINGENCY			207,602
PRESS RELEASE			5,000
INSURANCE LIASON			20,000
CPA/ACTUARIAL			10,000
CLAIMS MANAGEMENT			<u>12,000</u>
TOTAL			3,784,602

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE - ANCHORAGE, ALASKA 99501

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

August 1982
RECEIVED
AUG 09 1982
LEGISLATIVE
AUDIT

Mr. Gerald Wilkerson, CPA
Budget and Audit Committee
Legislative Auditor
Division of Legislative Audit
Pouch W
State Office Building
Juneau, Alaska 99811

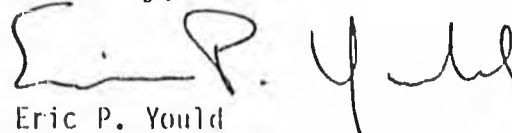
Subject: Response to Preliminary Audit Report
Alaska Power Authority Insurance Programs

Dear Mr. Wilkerson:

Attached is our response to the Preliminary Audit of June 29, 1982. Mr. Conway requested that I respond to you directly. The Alaska Power Authority has expressed its agreement with each of the Audit Report Recommendations and has initiated action to implement the recommendations.

The Power Authority is currently selecting an Insurance Consultant to provide professional services on insurance matters. This action will increase our expertise and management of insurance related issues and thereby mitigate the administrative concerns addressed in the Legislative audit.

Sincerely,



Eric P. Yould
Executive Director

Attachment: as stated

ALASKA POWER AUTHORITY

RECOMMENDATION ONE:

1. The Divisions of Risk Management, Insurance, and Workers' Compensation should discuss, in a formal setting if necessary, the Workers' Compensation and other insurance questions that have been raised. Using a State-funded loss reserve for non-State employees is clearly a divisive and unresolved issue. It is incumbent on these agencies what is a very gray area.

POWER AUTHORITY RESPONSE:

This recommendation is not addressed to the Alaska Power Authority.

RECOMMENDATION TWO:

2. Power Authority and Risk Management should monitor and evaluate the Tyee Lake wrap-up program in order that some comparative data be available for future projects. This would entail audits and actuarial reviews of payments and loss reserves, as well as an independent evaluation of owner vs. contractor provided insurance.

POWER AUTHORITY RESPONSE:

The first part of this recommendation addresses the monitoring and evaluation of the Tyee Lake wrap-up program and refers to an audit program. The Power Authority agrees that this is a necessary and beneficial action since the Tyee wrap-up program is the Power Authority's first owner's provided insurance program.

In order to implement this recommendation, the Power Authority has issued an RFP for an Insurance Consultant. An evaluation of the Tyee wrap-up will be a primary task of the Consultant.

The Insurance Consultant will, if appropriate, define an audit scope and follow through with an audit program.

Secondly, the Power Authority Insurance Consultant will conduct an independent evaluation of owner vs. contractor provided insurance.

RECOMMENDATION THREE:

3. Power Authority should decide whether or not to utilize owner provided insurance far enough in advance to incorporate this into the contractor RFP. For example,

contractors could submit bids with insurance, without insurance, or both with and without insurance and then be measured against some pre-determined criteria.

In addition, sufficient time should be allowed to go through a broker selection process on construction projects where Power Authority opts for owner provided insurance.

POWER AUTHORITY RESPONSE:

Power Authority agrees that should the review of the Insurance Consultant indicate that owner-provided insurance is cost effective and in the best interest of the Power Authority and provided that the Power Authority staff concur with the Consultant's opinion, any owner-provided insurance programs will be incorporated in the contract issuance process.

Power Authority will take steps to insure that sufficient time is allowed to properly select a qualified broker.

RECOMMENDATION FOUR:

4. Power Authority and Risk Management should clarify their respective responsibilities over Power Authority projects, whether under construction or completed. In December, 1981, the two agencies signed a memorandum of understanding outlining the role each played in providing risk management services for Power Authority. However, this "understanding" has become somewhat strained. For example, brokers have been given conflicting signals over certain coverages, and Power Authority is even considering employing its own risk manager.

We would hope that Power Authority's decision will be based on economics and need, and will consider all those issues inherent to wrap-up regardless of who administers it. In any event, until and unless Power Authority establishes its own risk management program, the existing memorandum of understanding should be followed to ensure comprehensive and continuous coverage on Power Authority projects.

POWER AUTHORITY RESPONSE:

The Power Authority agrees with this recommendation and as such the Power Authority and the Division of Risk Management have mutually agreed that the day-to-day administration and monitoring of Tye "wrap-up" insurance program should be the responsibility of Risk Management. The Power Authority Tye insurance contracts are in the process of being assumed by Risk Management. The Power Authority believes that the existing memorandum of understanding has been clarified for both parties.

The Power Authority will approve insurance premium payments prior to Risk Management making payment. Payment will be made on the basis of insurance premium invoiced cost and in accordance with the terms specified by the Power Authority's transmitted RSA.

The existing memorandum of understanding applies only to the Tye "wrap-up" insurance program. The Power Authority will rely on the advise of its Insurance Consultant in evaluating future project insurance requirements.

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THE CASE AGAINST COMPULSORY AUTOMOBILE
LIABILITY INSURANCE

An Insurance Industry White Paper

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insurers would only be too willing to support legislation which could generate more sales and result in higher premiums for each policy sold.

Why, then, does a united insurance industry refuse to support state compulsory automobile insurance laws? Why do insurers oppose legislation requiring each person who owns and operates a motor vehicle to purchase liability insurance?

In truth, the economic self-interests of the insurance industry are not well-served by compulsory auto liability insurance. Nor are the economic self-interests of motor vehicle owners, taxpayers, or state legislators served by compulsory insurance laws.

Every interest group but one, the plaintiff's bar, faces economic risks with compulsory auto liability insurance. It costs everyone else money.

This joint industry statement explains why most insurers oppose enactment of compulsory insurance laws, and relates how these emotionally-appealing laws fail to meet the well-meaning intentions of legislators and constituents.

Cost-efficient, proven alternatives that overcome the deficiencies of compulsory automobile liability insurance do exist. A discussion of these alternatives--stricter Financial Responsibility Laws, Uninsured Motorist Protection and No-Fault Insurance--is included at the end of this statement.

THE ISSUE

The issue is: Should a person who owns and operates a motor vehicle be required by state law to purchase liability insurance?

Voluntary auto liability insurance is already available to interested drivers. It enables those who purchase it to protect their personal assets

driving.

The purpose of voluntary auto liability insurance is to provide financial security by protecting the assets of the purchaser. By contrast, compulsory auto liability insurance is intended, but fails to pay the damages sustained by those who might otherwise be involved in accidents with uninsured drivers. Compulsory insurance laws aim toward reducing the numbers of uninsured motorists. They require the purchase of automobile liability insurance coverage and make it a criminal offense to drive a motor vehicle without such coverage.

HISTORICAL BACKGROUND

Compulsory automobile liability insurance is not a new issue. It's been a topic of discussion for over 50 years. In 1927, Massachusetts became the first state to adopt compulsory auto liability insurance, but the approach proved unpopular with both legislators and insurers. It wasn't until 1956 and 1957 that two other states, New York and North Carolina, established compulsory liability insurance systems.

Other states refused to enact compulsory insurance measures primarily because of cost comparisons with Massachusetts, New York and North Carolina. The compulsory states were experiencing significant increases in the number and frequency of insurance claims, primarily resulting from the higher accident rates among the small percentage of formerly uninsured drivers who were abiding by the law and buying insurance. In the ten years following Massachusetts' enactment of compulsory insurance, its claim frequency per thousand insured vehicles had increased 33 percent, while the countrywide frequency declined 21

above the estimated rise in the number of insured drivers. And, the increases were forcing safe and responsible drivers to pay higher insurance premiums.

The financial responsibility law was another principal reason for the failure of the early compulsory movement. During the nearly 30 years that elapsed between the first two state compulsory insurance laws, other states had turned to this more limited form of compulsion. Financial responsibility laws require certain individuals to prove--by posting a bond for a certain amount, by depositing cash or securities in that amount, or by another method stated in the law--that they will be able to pay damages that might be awarded to other accident victims. If they fail to do so, they face the possible suspension or revocation of their driving license for a certain length of time. Insurers nurtured and supported the financial responsibility law concept because they considered it to be a favorable alternative to compulsory liability insurance, and because it focused on those drivers actually involved in accidents, not on all drivers.

No new compulsory liability insurance laws were enacted until the 1970's. Twenty-seven states have turned to compulsory systems in the past decade. These states were not attempting to imitate existing successful compulsory insurance systems. There were none. In fact, Massachusetts, New York, and North Carolina each were facing massive paper blizzards in trying to keep track of uninsured motorists. Yet, they had little, if any, progress toward reducing the number of uninsured drivers.

For example, when New York enacted its mandatory rule in 1957, an estimated six percent of car owners didn't carry insurance. By 1979, the number of uninsured motorists had risen to 12 percent of all drivers in the

The movement toward compulsory insurance in the 1970's instead can be attributed to the growth in popularity of "no-fault" laws. Most of the states implementing a compulsory liability insurance system in the past decade made this system part of an automobile no-fault insurance package. A majority of the automobile insurance industry supported automobile no-fault laws and it was generally accepted that eliminating certain tort rights required the substitution of a guaranteed benefit package. Little thought was given to the residual liability component of that package, but, as we now know it is possible to have guaranteed first party benefits without compulsory liability insurance.

Florida was among the states which made liability insurance compulsory when enacting a no-fault insurance plan in the early 1970's. In 1979 Florida repealed its compulsory automobile liability insurance requirement and now requires only the purchase of PIP (personal injury protection) coverage. Liability insurance is now purely voluntary coverage. Florida state legislators took this action to eliminate a growing number of unnecessary lawsuits and to lessen the financial burden for low-income citizens, who were being forced to purchase both liability insurance and no-fault insurance. Fully supported by the insurance industry, the Florida no-fault law is the only one of its kind in the United States.

Whether or not the compulsory systems were part of a no-fault system, they simply did not work. In 1980 and 1981, fourteen states introduced legislation to repair the enforcement procedures of their compulsory automobile insurance laws.

Today, the insurance industry is largely opposed to compulsory automobile liability insurance. Its opposition is based on five major adverse effects of compulsory insurance.

Compulsory automobile liability insurance laws:

Do not protect consumers against uninsured motorists because the laws are not enforceable.

Are very costly to state government, motor vehicle owners and insurers.

Force individuals to buy a product for which they have no need.

Lead to unnecessary harassment of responsible drivers, who comprise a vast majority of the total driver population.

Are more expensive and have more deficiencies than the cost effective, viable alternatives which are available.

Compulsory automobile liability insurance laws do not protect consumers against uninsured motorists because the laws are not enforceable.

Requiring every motorist to carry auto liability insurance sounds like a good idea. But in practice, it doesn't work. In state after state, compulsory automobile liability insurance systems have failed to meet their goals. Compulsory laws do not guarantee that innocent victims of accidents caused by uninsured motorists will be compensated for their injuries and financial losses; and they do not reduce the number of uninsured motorists on the road.

As a general rule, compulsory automobile liability insurance laws require that evidence of insurance be submitted to public authorities at least once a