SB

68-71

(FILE 6)

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

FINANCE DIVISION
POUCH WF–STATE CAPITOL
JUNEAU, ALASKA 99811
PHONE: (907) 465-3795

February 23, 1983

M E M O R A N D U M

TO: Honorable Vic Fischer, Chairman
Senate State Affairs Committee

FROM: Milt Barker MB
Fiscal Analyst

SUBJECT: SB 70

As requested by you, I have prepared the attached tables which show:

1. the annual contributions to the Alaska Energy Dividend Fund, in both actual and FY 1984 dollars (Table I);

2. the number of per capita grants those amounts would fund, taking account of annual escalation of grant amounts for inflation though not taking account of variation in grant amounts for regional cost differences (Table I);

3. state funding for Susitna under "Option D" of the January 1983 Acres financing plan, in both actual and FY 1984 dollars (Table I);

4. the amount that would be available for capital projects that have been proposed excluding power projects (Table II and graph).

The attached Legislative Finance computer runs labelled SB 70 show the entire fiscal picture for the State under SB 70 in both actual and FY 1984 dollars. It should be noted that under the assumptions used, general fund deficits would be incurred in FY 1990 and all subsequent years even without any capital budget. Should these conditions prevail, it might be difficult to maintain funding for the Alaska Energy Dividend Program.

If the Alaska Energy Dividend Program were discontinued after FY 1989, the amount of funding that would have accrued for the program would be $1,965.0 million (or $1,635 in FY 1984 dollars). These amounts are less than the State funding called for under "Option D" of Acres for Susitna.

All of the above analysis is based on the January 1983 revenue estimates of the Department of Revenue and could be subject to major revision depending on oil price developments.

SB 70 - Section 2

You have also requested an estimate of the impact of Section 2 of SB 70.

It is impossible to project the impact, not knowing what "energy project service districts" will be formed, what projects undertaken, their scale, their financing, the residential share of power consumption, the retail price of electricity and its effect on monthly residential consumption, etc. However, as an example of how Sec. 2 might work, the Sitka utility district and their Green Lake project are analyzed.

If one assumes that in the absence of SB 70, Green Lake would have been financed 90% with 35 year debt at 10% interest and 10% with equity which earned 12%, then the capital charges for Green Lake would have been $6.2 million per year. [1] With sales from Green Lake estimated at 59 million kwh annually,[2] the capital charges would have been 10.5¢ per kwh for Green Lake at the busbar.

It is implicitly the intent of SB 70 that no charges for recovery of Energy Dividend Fund grants be included in electricity rates. This should probably be stated in the bill.

It is also the intent of SB 70 that no charges for recovery of any other invested funds or return thereon be allowed in the residential rate for the first 1,000 kilowatt hours. The legislation needs to clarify that neither return of nor return on invested funds will be allowed.

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1. $59 million cost for Green Lake excluding any transmission costs multipled by (.9 X .10369, the debt service per dollar borrowed at 10% for 35 years + .1 X .12).

2. 37.8 million kwh generated from Green Lake for first seven months at FY 83 extrapolated to 12 months and multiplied by 91% for line losses, utility's consumption, etc.

The effect of these two elements of intent would be that the residential customer pays no charges for the capital cost of a project if there is any grant money at all in the project. Other customers would pay the entire charges for invested funds (though nothing for grant funds).

Assuming residential customers would have borne their pro-rata share of capital charges in the absence of SB 70,[3] SB 70 in this case would result in a 10.5¢ per kwh savings to residential customers on their first 1,000 kwh's. With current average monthly consumption in Sitka of 783 kwh per residential customer, the average customer's benefit would be $82 per month or $986 per year. Sitka has 2,480 residential customers and a population of 8,221. Thus, the average benefit per person would be $297 per year.

For commercial and industrial customers, there could be either an increase or a decrease in rates depending on the amount of grant funds in a project. Commercial and industrial consumption in Sitka is currently 71.8% of total consumption. If these customers picked up all Green Lake capital charges (in the absence of any SB 70 grants), their cost per kwh would increase from 10.5¢ to 14.6¢. A grant of $16.6 million would keep commercial and industrial charges at 10.5¢. If Sitka got $5,000 for each of its 8,221 persons it would have received a grant of $41 million which would have lowered commercial and industrial charges for Green Lake to 4.5¢ per kwh. Of course, a grant covering 100% of project costs results in a 10.5¢ per kwh saving for all customers, commercial and industrial as well as residential.

If Sec. 2 should result in an increase in commercial rates, businesses may well pass on the cost increase through price hikes. Should this occur, it would mean some dilution of the direct benefits to residential customers.

You have asked for an assessment of the efficiency of SB 70 as a mechanism for distribution of state wealth to residents. With a grant of $16.6 million which would keep commercial and industrial users at their existing rate, SB 70 provides a benefit estimated above at $297 per person. This benefit can be compared to the possible earnings on $16.6 million divided among the 8,221 people. This would be $202 per person if the funds earned 10% interest. SB 70 provides a greater benefit to residential customers for the money because of the subsidy from commercial and industrial customers paying the project costs not funded by grants.

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3. Some utilities, of which Sitka is one, provide a rate break to residential customers vis-a-vis commercial and industrial customers. Others may give a better rate to commercial and industrial users often through declining block rates.

If keeping commercial and residential rates constant while letting residential customers off the hook is the test, then this example would argue for $2,000 per capita grants. Of course, one can be even more efficient by giving even smaller grants, still letting residential customers off under Sec. 2 and hitting commercial and industrial users for the capital costs. Or one could just pass a bill forbidding residential charges for capital costs under any circumstances for the first 1,000 kwh per month.

At the $5,000 per capital level, the Green Lake example would suggest that individuals could receive more if the grants were invested. They would then receive $500 at 10%. At the $5,000 grant level in the Green Lake example much of the benefit goes to reduce commercial and industrial rates as shown above.

If the benefit under SB 70 is compared to the amount that individuals would receive under the Permanent Fund dividend program, the SB 70 benefits would look more favorable because individuals only receive 50% of the five year average income. But that is a matter of policy; individuals could be given the entire earnings off amounts deposited in the Permanent Fund. The full amount of earnings represents the opportunity cost of using funds for other purposes, such as SB 70 grants. Note too, that because of inflation-proofing, Permanent Fund dividends increase over time in nominal terms while the capital charges the electricity customer forgoes under SB 70 are a fixed amount for the life of the project.

attachments

cc: Senator Halford

MB:ro

TABLE I
ALASKA ENERGY DIVIDEND FUND (SB 70)

Fiscal Year	(1) Annual Contribution to Energy Dividend Fund (50% of Permanent Fund Income) ($ Millions)	(2) Thousands of Per Capita $5000 Grants	(3) State Funding for Susitna "Option D" ($ Millions)	(4) Annual Contribution to Energy Dividend Fund (Millions FY 84 $)	(5) State Funding for Susitna "Option D" (Millions FY 84 $)
1984	236	47.2	--	236	--
1985	268	50.1	806.8	251	658.0
1986	304	53.1	413.3	265	318.0
1987	342	55.8	475.3	279	345.0
1988	385	58.7	552.1	294	378.0
1989	430	61.3	156.4	310	101.0
1990	480	64.0	--	320	--
1991	540	67.3	--	330	--
1992	590	68.7	--	340	--
1993	650	70.7	--	350	--
1994	700	71.2	--	360	--
1995	760	72.2	--	360	--
1996	830	73.7	--	370	--
1997	890	73.9	--	370	--
1998	970	75.2	--	370	--
1999	1040	75.3	--	380	--
2000	1120	75.9	--	380	--
	10535	1114.3	2403.9	5565.0	1800.0

Notes: 1 & 4. From attached Legislative Finance computer runs labelled "SB 70";
2. Col. 1 + (5 x 1.07N) where N = Fiscal Year - 1984; grants increased 7% per annum for inflation;
3 & 5. "Option D" from Susitna Hydroelectric Financing, Task11: Financing Options, Acres, January 1983; from Table 4 and Table 3 respectively; FY 83-85 summed and shown as FY 85

PREPARED BY:
LEGISLATIVE FINANCE
2-22-83

TABLE II
FUNDS AVAILABLE FOR CAPITAL PROJECTS
UNDER SB 70
($ Millions)

	(1)	(2)	(3)	(4)	(5)	(6)
	Funds Available for Capital Projects					
	General Funds	GO Bonds	Total	Loan Program Appropriations	Governor's Six Year Capital Budget	Total Capital Projects
FISCAL YEAR						
Actual Dollars						
1985	546.0	--	546.0	300.0	2035.0	2335.0
1986	580.0	300.0	880.0	300.0	742.9	1042.9
1987	415.0	90.0	505.0	300.0	961.2	1261.2
1988	481.0	125.0	606.0	300.0	1066.2	1366.2
1989	250.0	--	250.0	300.0	?	300.0+
1990	--	50.0	50.0	300.0	?	300.0+
1991	--	140.0	140.0	300.0	?	300.0+
1992	--	--	--	300.0	?	300.0+
1993	--	--	--	300.0	?	300.0+
Total	2272.0	705.0	2977.0	2700.0	4805.3	7505.3+
FY 1984 Dollars						
1985	511.0	--	511.0	280.0	1901.9	2181.9
1986	507.0	262.0	769.0	262.0	648.9	910.9
1987	339.0	73.0	412.0	245.0	784.7	1029.7
1988	367.0	95.0	462.0	229.0	813.4	1042.4
1989	180.0	--	180.0	214.0	?	214.0+
1990	--	33.0	33.0	200.0	?	200.0+
1991	--	87.0	87.0	187.0	?	187.0+
1992	--	--	--	175.0	?	175.0+
1993	--	--	--	163.0	?	163.0+
Total	1904.0	550.0	2454.0	1955.0	4148.9	6103.9+

PREPARED BY:
LEGISLATIVE FINANCE
2-22-83

TABLE II

Notes: 1. From attached Legislative Finance computer run labelled "SB 70";

2. From Table 1, Susitna Hydroelectric Project, Task 11; Financing Options, Acres, January 1983;

4. Assumes loan appropriations at roughly the Governor's FY 84 budget level. $294.5 million;

5. Total of general fund capital projects (including voter approval) contained in Executive Budget, Book 2, Capital Budget and Six Year Capital Program, FY 83, Jay Hammond, Governor; FY 85 amount is sum of FY 83-85 amounts less amounts appropriated for capital and loans for FY 83 and less the amount of capital projects proposed by Governor Sheffield for FY 84.

FY 84 $ amounts are based on a 7% inflation factor: the Acres Susitna numbers appear to be on a calendar year basis and are thus adjusted for an extra 1/2 year.

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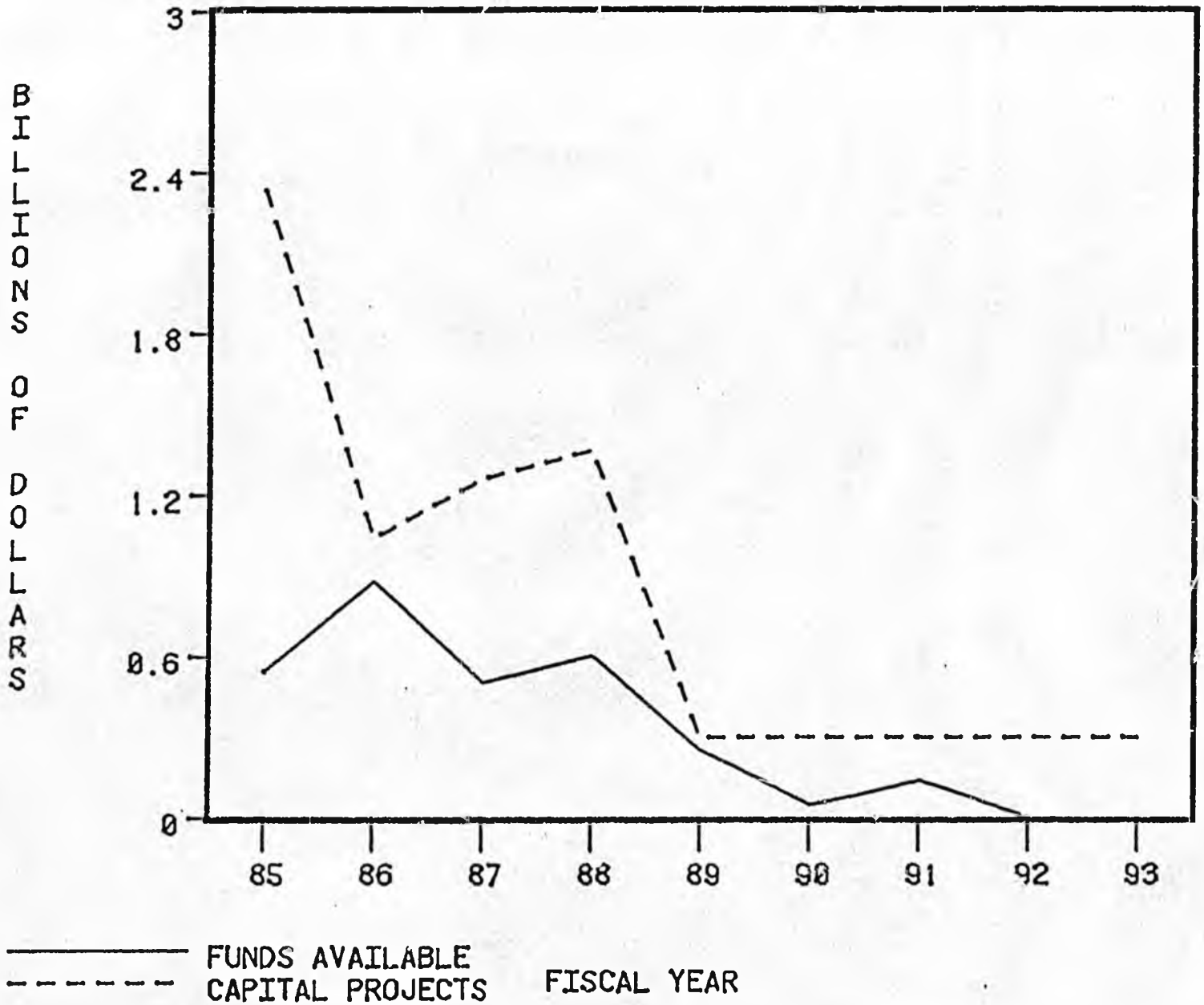
2-22-83

FUNDS AVAILABLE FOR CAPITAL PROJECTS
UNDER SB 70



STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

*** ACTUAL DOLLARS IN MILLIONS ***

JAN 83 DEPT OF REVENUE ESTIMATES
OPERATING BUDGET AT SPENDING LIMIT
SPENDING LIMIT INCREASES 10% PER ANNUM
SURPLUS SPENT ON CAPITAL
INFLATION 7% PER ANNUM
DIVIDENDS GO TO ALASKA ENERGY DIVIDEND FUND
PERMANENT FUND INFLATION-PROOFED
PERMANENT FUND EARNS 12% PER ANNUM
GO BONDS PER ACRES JAN 83 SUSITNA FINANCING PLAN

FISCAL YEAR	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-- ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF$ 0 MIL
1983										3790	88	
1984	2703	370	3072	1987	770	167	236	3161	-88	4321	0	0
1985	2775	389	3164	2185	546	164	268	3164	0	4892	0	0
1986	3029	422	3451	2404	580	163	304	3451	0	5532	0	0
1987	3112	456	3568	2644	415	166	342	3568	0	6222	0	0
1988	3456	499	3954	2909	481	179	385	3954	0	6998	0	C
1989	3540	540	4080	3200	250	190	430	4080	00	7860	00	00
1990	3300	580	3870	3520	00	190	480	4190	-320	8750	00	320
1991	3000	620	3620	3870	00	180	540	4580	-960	9650	00	960
1992	2890	670	3560	4260	00	160	590	5000	-1440	10600	00	1440
1993	2700	740	3430	4680	00	160	650	5490	-2050	11570	00	2050
1994	2610	810	3420	5150	00	130	700	5990	-2560	12590	00	2560
1995	2520	880	3390	5670	00	130	760	6560	-3170	13650	00	3170
1996	2380	950	3330	6240	00	120	830	7190	-3850	14760	00	3850
1997	2440	1030	3470	6860	00	80	890	7830	-4360	15950	00	4360
1998	2510	1120	3630	7540	00	60	970	8570	-4940	17210	00	4940
1999	2660	1210	3870	8300	00	40	1040	9380	-5510	18570	00	5510
2000	2800	1310	4110	9130	00	30	1120	10280	-6170	20040	00	6170
TOTAL	48410	12590	61000	80550	3050	2300	10550	96440	-35440			35350

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

*** FY 1984 DOLLARS IN MILLIONS***

JAN 83 DEPT OF REVENUE ESTIMATES
OPERATING BUDGET AT SPENDING LIMIT
SPENDING LIMIT INCREASES 10% PER ANNUM
SURPLUS SPENT ON CAPITAL
INFLATION 7% PER ANNUM
DIVIDENDS GO TO ALASKA ENERGY DIVIDEND FUND
PERMANENT FUND INFLATION-PROOFED
PERMANENT FUND EARNS 12% PER ANNUM
GO BONDS PER ACRES JAN 83 SUSITNA FINANCING PLAN

FISCAL YEAR	REVENUE	INTEREST	TOTAL REVENUE	OPERATING BUDGET	CAPITAL BUDGET	DEBT SERVICE	PERMANENT FUND DIVIDENDS	TOTAL BUDGET	SURPLUS OR DEFICIT	PERM-ANENT FUND	GENERAL FUND END OF YEAR	REVENUE REQ FOR GF BAL OF$ 0 MIL
1983										3790	88	
1984	2703	370	3072	1987	770	167	236	3161	-88	4321	0	0
1985	2594	364	2957	2042	511	154	251	2957	0	4572	0	0
1986	2645	369	3014	2100	507	143	265	3014	0	4832	0	0
1987	2540	372	2913	2159	339	136	279	2913	0	5079	0	0
1988	2636	380	3017	2219	367	137	294	3017	0	5338	0	0
1989	2520	390	2910	2280	180	140	310	2910	00	5610	00	00
1990	2200	380	2580	2350	00	130	320	2790	-210	5830	00	210
1991	1870	380	2260	2410	00	110	330	2850	-600	6010	00	600
1992	1680	390	2070	2480	00	90	340	2910	-840	6170	00	840
1993	1470	400	1870	2550	00	90	350	2990	-1120	6290	00	1120
1994	1330	410	1740	2620	00	70	360	3040	-1300	6400	00	1300
1995	1190	420	1610	2690	00	60	360	3120	-1500	6490	00	1500
1996	1060	420	1480	2770	00	60	370	3190	-1710	6560	00	1710
1997	1010	430	1440	2850	00	30	370	3250	-1810	6620	00	1810
1998	970	430	1410	2930	00	20	370	3320	-1920	6670	00	1920
1999	960	440	1400	3010	00	10	380	3400	-2000	6730	00	2000
2000	950	440	1390	3090	00	10	380	3480	-2090	6790	00	2090
TOTAL	30330	6800	37130	42520	2680	1550	5580	52320	-15190			15100

ERICKSON & ASSOCIATES

Consultants in Economics and Public Policy
526 Main Street, Juneau, Alaska 99801
Telephone 907/586-3118

MEMORANDUM

February 24, 1983

To: Senate State Affairs Committee
From: Thomas Singer and Gregg Erickson
Subject: Interim Financing of Power Proje

The Tyee Loan

The Tyee Lake Hydro Project illustrates the risks to the state inherent in the Alaska Power Authority's (APA's) present financial independence. While the state has appropriated $82 million for Tyee project, the APA has borrowed $50 million more -- on its own. This loan comes due in 19 months. At present there is no clear indication of where the money will be found.

In its agreement with lenders, the APA agreed to refinance, by October 1, 1984, any portion of the loan then unpaid. The APA's stated intention is to sell revenue bonds secured through power sales contracts with the electric utilities in Petersburg and Wrangell.

So far, Petersburg and Wrangell have been reluctant to sign such power sales contracts. The price at which power from the project has been offered to them is much higher than the price they now pay -- or expect in the future to pay -- for power from fossil fuels, and their own small hydo facilities. Negotiations between the APA and local utilities continue. Without ironclad contracts committing the utilities to buy enough power at a price sufficient to meet annual debt payments, the bonds will be virtually imposible to sell.[1]

If revenue bonds cannot be sold to refinance outstanding debt by October 1, 1984, the lenders, by terms of the loan agreement, have recourse to the "general assets" of the APA. Unfortunately, no one seems to know precisely what the term "general assets" encompasses. It may be that "general assets" include unexpended appropriations received by APA or being held in the state treasury for other projects. Or it may be that funds appropriated but not yet disbursed from the treasury are beyond the lenders reach, in which case the APA may have virtually no "general assets" apart from the uncompleted projects around the state. This is an important legal point, which the

ENDNOTES

1. Revenue bonds to repay the loan could be sold, notwithstanding the lack of power sales contracts, if the state stepped forward to backstop them. Double-barreled bonds (revenue bonds backed by the full faith and credit of the state) or even cash payments to consumers dedicated to their electric bills are examples of many possible ways the state could secure the bonds. (For a fuller discussion of the options see "Lake Tyee Power Costs and Project History: Research Request 83-39," House Research Agency, February 11, 1983.)

A third party guarantee was used to secure the outstanding $50 million loan. A major New York bank, the Bankers Trust Company, agreed to stand behind the APA (for a fee) with a $50 million "Letter of Credit" to repay the loan if necessary.

2. The security, pledged equally to repay the loan, is (1) the project and its revenues, (2) any unspent portion of the short-term loan, (3) bond proceeds, (4) the full faith and credit of the APA, and (5) **"...the proceeds of any appropriation by the State for the purpose of paying any Cost of the Project or repaying the loan or Letter of Credit."**

The loan agreement releases the APA from its obligation to issue revenue bonds if it **"...has deposited in the loan repayment Fund an amount at least equal to the principal of the Notes Outstanding...plus...interest."**

3. The APA has borrowed additional funds - $35 million for Swan Lake and $115 million for Terror Lake. Our understanding is that power supply contracts which are not "take or pay" have been signed for these projects, allowing local consumers to choose not to buy power if the price is unattractive.

Attorney General will undoubtably investigate in due course.

Lenders, of course, are not likely to be very interested in taking over partialy completed hydro projects, particularly in cases like these where the value of the power to be produced falls so far short of the revenue needed to service the debt. Their desire will doubtless be for the state to appropriate to the APA additional funds to repay the loan. The state is in no way legally obligated to do this, but it is clearly a possibility that the APA and the lenders had in mind from the outset: Despite the lack of legal claim on the state, the state is nevertheless prominently mentioned in the loan agreement as a possible source of repayment.[2]

If the legislature allows the APA to default on its Tyee loan, the ability of the state and all of its political subdivisions to borrow money would suffer. Alaska public sector credit ratings would undoubtedly fall, making loans both harder and more costly to obtain. Nevertheless, the option of allowing the APA to sink or swim on its own should not be dismissed without careful study.

A bailout of the APA by the legislature might be less painful than default, but it certainly wouldn't be painless. Increasingly scarce funds would be diverted from other uses. Worse, the legislature would be giving notice to bankers, contractors, and the APA that it is willing and able to come to the rescue, even when not legally bound to do so.

Implications for the Susitna Project

These facts raise questions about legislative intent and accountability. Did the legislature intend that the APA obligate its "general assets" (i.e. funds earmarked to other projects) to proceed with Tyee? Did the legislature intend that unforseen problems with the project be solved by simply dipping deeper into the state treasury? We don't know, but one thing does seem beyond dispute: The legislature needs to understand and control large financial transactions of the sort illustrated by the Tyee example because it and the state as a whole ultimately may have to be responsible for them.

As legislators begin to consider the Susitna Project involving billions of dollars, it is even more essential that they understand and assume responsibility for the APA. While this independent public corporation does not yet have authority to indebt the state, as a practical matter its financial actions have tremendous impact on the state's financial condition.

Answers to the following questions should help the legislature in its effort to gain understanding and control:

1. When the $50 million Tyee loan agreement was negotiated, what did the financial advisors and Bankers Trust Company understand the APA's "general assets" to be? How much of the APA's roughly $200 million total outstanding debt[3] is secured by their "general assets" and what is covered by that term?

2. Did the financial advisors, Bankers Trust Company, and the APA consider the state treasury to be the real security for the Tyee loan? If so, why?

3. What are the current prospects that long-term revenue bonds for the project can be sold before the October 1, 1984 deadline? What is the APA planning to do if bonds cannot be sold?

We may all hope that successful negotiation of contracts for Tyee power will resolve the APA's looming financial crisis. Unfortunately, that will not resolve the underlying problem. The APA continues to operate independently. If it is able to obtain substantial "general assets", we can expect such independence to increase.

The state can undoubtedly cover a $50 million loan. It could probably even handle problems with the entire $200 million debt without catastrophic consequences. But the Susitna project involves billions of dollars, and is financially much more risky. While the APA and its advisors may feel that the public interest and the APA's interests are the same, we do not belive that this is always the case. If the legislature is going to be aboard for the crash landing, perhaps it ought to have some say in the takeoff.

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

TO: Senate State Affairs Committee Members

FROM: Committee Staff

The attached packet includes additional Susitna back-up and testimony that was not received until after the hearings.

P.O.Box 100171
Anchorage, AK 99510
February 26, 1983

Senator Vic Fischer
Members Senate State Affairs Committee
Pouch V
Juneau, AK 99811

Dear Senator Fischer and members of the Committee:

I would like to express my concerns regarding the Susitna hydroelectric project. There are several bills currently before the Senate State Affairs Committee (i.e., SB68, SB69, SB70 and SB71) which are entirely premature and inappropriate and which cannot reflect an objective, knowledgeable perspective on Alaska's energy future. I would like to point out that 1) the project will be incredibly costly, 2) the State cannot afford it, 3) demand forecasts used by Acres in their cost analyses are no longer valid, and 4) alternative means of meeting Alaska's future energy needs are not being adequately addressed. The remainder of this letter focuses on costs.

The current $5.2 billion estimate can only be considered an arbitrary figure, one which does not include finance charges, inflation adjustment or a realistic provision for cost overruns. An inflation adjustment alone will bring the cost to $10 to $15 billion dollars. The overrun factor will certainly bring the cost to far more than that. Keep in mind that the Watana dam would be the largest earth filled dam built in the U.S., it would be the first one built in a sub-arctic environment, it would be in an area of earthquake risk, and there is a potential problem with flooding during construction. All of these factors imply the need for new and sophisticated engineering methods and techniques.

There are parallel situations. The Tyee Lake project experience a cost overrun of 200 percent, from $39 million to $120 million. If that percentage were applied to Susitna (using an inflation adjusted figure of $12.5 billion), the final cost would be 37.5 billion dollars.

The Trans-Alaska Pipeline (TAPS) had several construction budgets, which were developed at various stages of construction. The May 1974 budget, which predicted a cost to completion of $4.088 billion, was developed at a point where the project was significantly further along than Susitna is now: after 5 years of design studies, execution contractors had submitted their cost estimates, haul road construction had begun, the federal "Agreement and Grant of Right-of way for TAPS' including environmental "Stipulations" had been granted, mainline pipe and pumps had been purchased, labor agreements had been signed, and the organization structure had been established. When completed, the pipeline cost in excess of $7.9 billion, a 93% increase over the May 1974 budget.

Compare this to Susitna: feasibility studies are not complete, initial applications are just now being submitted to FERC, design has barely begun, labor agreements have not been considered, no materials have been purchased, there has been no regulatory agency input (which could result in design changes), no construction contractors have been put on contract, and environmental stipulations

have not been developed. Even if these, and other factors which are currently unknown, were incorporated in the $5.2 billion figure, the final inflation adjusted cost could conservatively reach the $20 to $30 billion range.

These figures, even the $5.2 billion, worry me, and they should worry you. I don't want to sacrifice other capital projects and other needs of Alaskans for Susitna, and I don't want to have to start paying state income taxes again.

Susitna is a potential financial disaster and it is high time the legislature got off the Susitna booster bandwaggon and began looking at this project objectively and responsibly.

Sincerely,

John Strasenburgh

MSG 83-00012817 PRTY 1 03/04/83 10:37:27 ORIG: LM00 IN= 0003 OUT= 0024
FROM: MARTIE/MATSU TO: JUNEAU INFORMATION
TARGET: LJHL SUBJ: POM'S

(THE FOLLOWING WAS PREPARED AS TESTIMONY FOR THE SENATE STATE AFFAIRS TELECONFERENCE ON SUSITNA HYDROPOWER. THE PARTICIPANT WAS NOT ABLE TO GIVE IT AT THAT TIME)

TO: SENATORS KERTTULA, V. FISCHER, RAY, STURGULEWSKI, RODEY AND KELLY)

FROM: CHUCK SMITH
BOX 1385
WASILLA 99687
PHONE: 376 2941

THE CONTINUOUS TESTIMONY ON SUSITNA OVER THE PAST FEW YEARS OBVIOUSLY BRINGS SOME REPITION, HOWEVER CERTAIN BASICS MERIT COVERAGE.

FOR EXAMPLE LOGIC TELLS US:
1. WE ARE RUNNING OUT OF POWER - SUSITNA PROVIDES IT
2. ENERGY COSTS MUST BE HELD DOWN -- SUSITNA WILL DO THAT
3. EMPLOYMENT IS NEEDED - SUSITNA WILL PROVIDE

OPPONENTS REPEATEDLY CALL FOR:
1. MORE STUDIES
2. ALTERNATE SITES

THE SUSITNA DAM PROJECT HAS BEEN STUDIED BY THE NATIONS TOP SPECIALISTS, GOING BACK TO THE THIRTIES.

HOPEFULLY THIS DAM PROJECT WILL NOT SUFFER THE SAME FATE AS THE PIPELINE WHERE THE SAME DELAYING TACTICS WERE DEMANDED WITH THE END RESULT THAT THE PIPELINE COSTS MORE THAN DOUBLED AND THE CONSTRUCTION WAS DELAYEDD SOME THREE YEARS.

POLLS INDICATE THE HIGH MAJORITY OF OUR POPULATION REALIZE THE NEED FOR AND SUPPORT THE CONSTRUCTION OF THE SUSITNA DAM.

A FEW YEARS BACK WHEN U.S. SENATOR GRUENING WAS PUSHING THE RAMPART DAM, THE CONSERVATIONISTS WERE AGRESSIVELY IN OPPOSITION TO RAMPART AND PUSHED SUSITNA AS THE ALTERNATIVE. NOW I SUGGEST WE DO EXACTLY AS THE CONSERVATIONISTS SUGGESTED -- LETS'S GET SUSITNA BUILT PROMPTLY!

COMMENT BY CHUCK SMITH, 38 YEAR ALASKA RESIDENT.

COMMENT ON RELATED MATTER FROM MR. SMITH

I WOULD LIKE TO COMMEND THE GOVERNOR'S APPOINTMENT OF BOB HUFFMAN OF FAIRBANKS TO THE ALASKA POWER AUTHORITY BOARD.

1. BOB IS AN EXPERT ON POWER TECHNOLOGY.
2. HIS EXPERTISE IS NEEDED ON THE BOARD.
3. HE IS A LIFELONG ALASKAN, A PIONEER WHO KNOWS THE DESIRES AND NEEDS OF ALASKANS.
4. HE IS A FINE FAMILY MAN OF IMPECCABLE INTEGRITY.
5. IT WOULD BE DIFFICULT TO FIND A PERSON BETTER PREPARED FOR THIS BOARD.

I URGE YOUR ENDORSEMENT OF BOB HUFFMAN FOR THE APA BOARD.

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

Pouch Y, State Capitol
Juneau, Alaska 99811
(907) 465-3991

March 3, 1982

MEMORANDUM

TO: Representative Hugh Malone

FROM: Jack Kreinheder
Research Staff

RE: Comparison of Susitna and Natural Gas Power Costs
Research Request 83-32

You requested that we compare, from now through the year 2000, the wholesale or busbar cost of power in Anchorage from:

-- Cook Inlet natural gas, as indicated by the recent Entar gas contracts;
-- the Acres fossil fuel (thermal) base case in the Susitna feasibility studies; and
-- the Acres Susitna hydroelectric power cost projections (1994-2000).

Your request also specified that the escalation rate for gas prices was to be based on the most recent Department of Revenue petroleum price forecast.

SUMMARY OF FINDINGS

A summary comparison of the three power cost scenarios is presented in Table 1 on the next page. This information is also illustrated graphically in Figure 1. Given the assumptions and methodology outlined in this memo, the following conclusions can be drawn from this comparison of power costs:

(1) If future oil prices correspond closely to the Department of Revenue's January forecast over the next 10-15 years, the actual cost of power generation for the Anchorage utilities may be about 38 percent less in 1994 than projected by Acres (9 cents per KWH vs. 14.5 cents), and about 50 percent less than the Acres projection in 1996 (11 cents vs. 22 cents).

(2) This potential difference in thermal power costs would both reduce the net economic benefits of the Susitna project and increase the amount of State funding necessary to reduce the price of Susitna power to marketable levels. About $600-700 million (1982 dollars) more in State funding, in addition to the $1.8 billion projected by Acres, would be necessary to lower the price of Susitna power to the level indicated by this analysis.

TABLE 1

SUMMARY POWER COST COMPARISON OF GAS-FIRED GENERATION,
ACRES THERMAL BASE CASE, AND SUSITNA HYDRO PROJECT

(Cents Per KWH - nominal dollars)

Year	Enstar-Based Gas-Fired Generation	Acres Thermal Base Case		Susitna (Watana) Project	
		Coal-Gas	Gas Only	Full Price	Price with $1.8 Billion State Funding
1982	4.3	--	4.9	--	--
1983	4.3	--	5.2	--	--
1984	4.2	--	5.5	--	--
1985	4.0	--	5.9	--	--
1986	4.2	--	6.3	--	--
1987	4.7	--	6.6	--	--
1988	4.9	--	7.1	--	--
1989	5.4	--	7.5	--	--
1990	5.7	--	8.0	--	--
1991	6.2	--	8.5	--	--
1992	6.6	--	9.1	--	--
1993	7.8	14.0	10.4	--	--
Susitna On-Line Date 1994	9.0	14.5	12.0	30.0	14.5
1995	9.6	15.0	13.1	30.0	14.5
1996	11.0	22.0	15.4	30.0	14.5
1997	11.8	23.0	17.4	30.0	14.5
1998	12.7	24.0	19.6	30.2	14.5
1999	13.7	25.5	22.1	30.5	14.5
2000	14.7	26.0	25.0	30.8	14.5

See detailed tables and text for explanation of assumptions and methodology.

(Nominal Cents Per KWH)

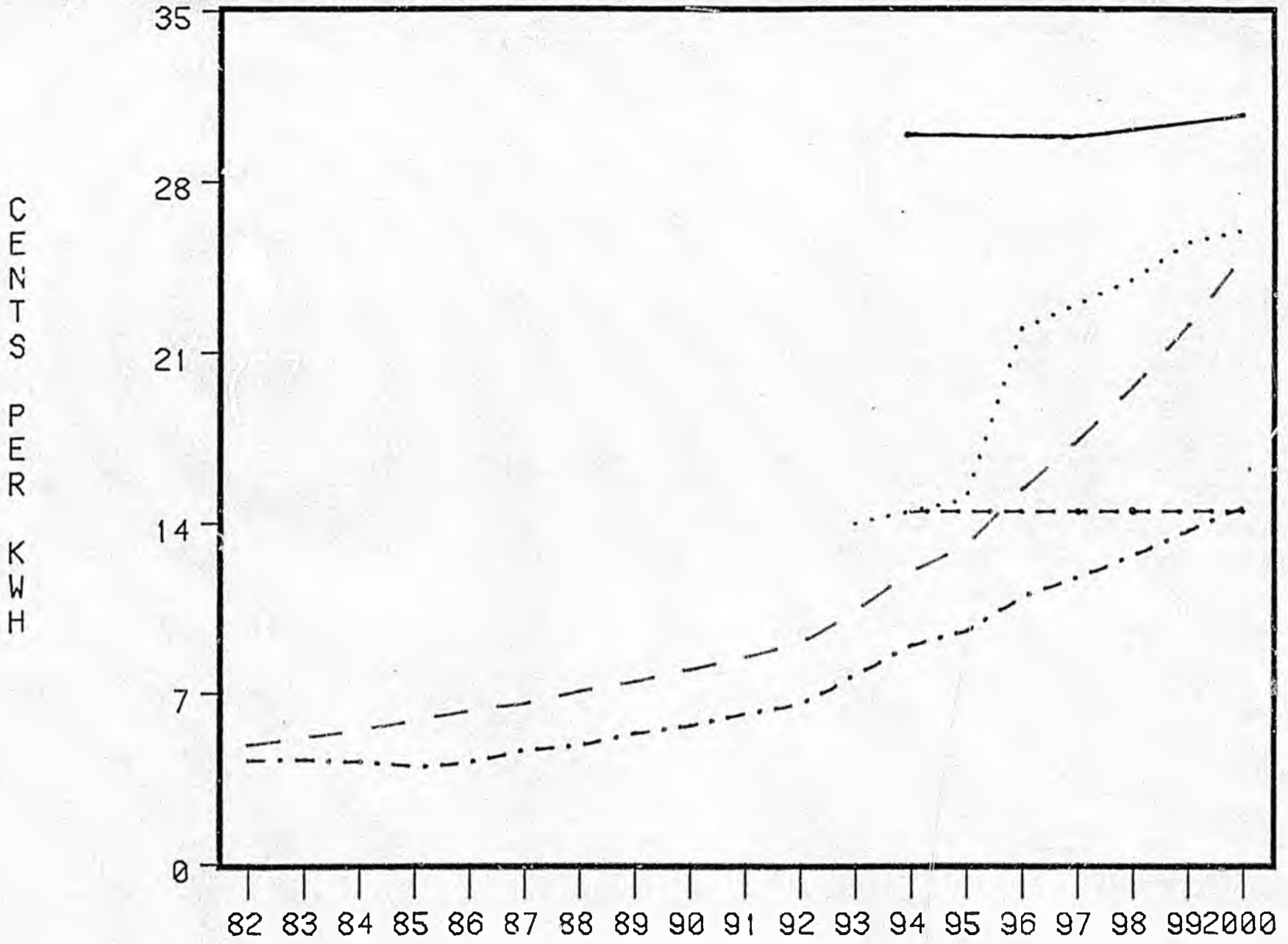


FIGURE 1

(3) The gas prices in the new Enstar contracts are not significantly different from those estimated by Acres; it is the use of the lower oil escalation forecasts of the Department of Revenue which result in the lower power costs shown in Table 1 and Figure 1. However, even using Acres' own prices and escalation rates, it appears that the short-term cost of gas-fired generation could be substantially lower than the cost of the coal-fired plants incorporated by Acres into the thermal generation alternative, as shown in Table 1.

(4) The Enstar power costs in Table 1 do not take into account the much lower cost of gas from older Beluga field contracts held by the Chugach Electric Association. There appears to be some controversy over whether these gas supplies will extend beyond 1993, when Susitna is scheduled to come on-line if constructed. Battelle's gas analysis indicates that these low-cost gas supplies could supply over 50 percent of Chugach's fuel requirements through 1995. If so, the cost of power under both Acres price assumptions and this analysis could be 2-3 cents per KWH lower than shown in Table 1.

(5) Finally, a thorough review and expansion of the Acres thermal cost analysis would appear to be warranted to address the factors mentioned above, and to ensure that the thermal costs are based on the most likely generation scenario. Such a review is necessary both to be more certain of the amount of State funding necessary for the project, and to have realistic power cost information for power sales negotiations with Railbelt utilities.

ENSTAR CONTRACT TERMS

The gas purchase contracts which Enstar recently signed with Shell and Marathon provide a base price of $2.32 per thousand cubic feet (MCF). In order to determine the net price to electric utilities, three other charges must be added. These charges are the State severance tax of $0.23 per MCF (10 percent), a premium deliverability charge of $0.35 per MCF, and a pipeline transportation charge, estimated by Dale Teel of Enstar at about $0.30 per MCF. The premium deliverability charge is assumed in this memo to take effect in 1986. The pipeline transportation charge is assumed to apply to Anchorage Municipal Light and Power, but only partially to the Chugach Electric Association, as Chugach is likely to continue to generate most of its electricity at its Beluga power plant.

Future gas prices under the Enstar contracts are linked to changes in the price of Tesoro fuel oil. Thus, Enstar gas prices will rise or fall proportionately to changes in Tesoro oil prices. You have specified that we base our calculations of future gas prices on world oil price forecasts of the Division of Petroleum Revenue. Although Tesoro fuel oil prices should track world oil prices fairly closely, there may be some variance due to market conditions and other factors.

Table 2 shows the year-to-year percentage changes in oil prices forecast by the Division of Petroleum Revenue and the corresponding Enstar gas prices through the year 2000. As you know, there are a wide range of oil price forecasts and considerable uncertainty exists over future prices.

It is important to emphasize that although the new Enstar contracts have provided a good reference point for Cook Inlet gas prices, there are still several major uncertainties affecting future gas prices and the cost of thermal power generation, including: (1) future trends in oil price escalation or deescalation; (2) the potential for melding or combining lower cost gas supplies under "old" contracts with higher cost gas under new contracts; (3) the amount of unproven reserves which may be brought into production; and (4) the gas prices which may be obtained by the Chugach Electric Association under new supply contracts.

THE ACRES THERMAL COST ANALYSIS

The published Acres reports do not contain sufficient documentation to determine the individual power costs of the different thermal generation sources which are included in Acres' base plan, primarily natural gas and coal, with some hydroelectric and oil-fired generation. In addition, Acres' explanation of escalation in gas prices is very confusing. In the text of several reports, Acres states that gas prices were escalated at a real rate of 2.5 percent annually from 1982 to 2000, from a 1982 base value of $3.00 per thousand cubic feet (MCF). However, in the detailed tables, Acres shows a 1993 price (in 82 dollars) of $3.03 per MCF, with real escalation of 4 percent annually from 1993 to 1995, and 8 percent annually from 1995 to 2000. The gas prices shown in Table 3.8 of the Task 6 report are used in this analysis.

Acres did not estimate thermal fuel costs before 1994, which would be the first full year of operation for the Watana dam under current schedules. Therefore, the Acres power costs shown in tables 1 and 3 from 1982 to 1993 are estimates based on the Acres gas costs and on generation cost data provided by the Chugach Electric Association.

TABLE 2

PROJECTED COOK INLET GAS PRICES UNDER ENSTAR CONTRACT TERMS
Weighted Average price for Chugach Electric
and Municipal Light and Power
(Nominal dollars per MCF)

Year	Base Price	Severance Tax	Premium Deliverability Charge	Sub-Total Gas Price	Pipeline Transmission Charge (Prorated)	Total Price With Trans. Charge
1982-3	$2.32	$0.06	---	$2.38	$0.14	$2.52
1984	2.05	.05	---	2.10	.15	2.35
1985	1.93	.05	---	1.98	.16	2.14
1986	2.00	.05	---	2.05	.18	2.23
1987	2.05	.05	$0.31	2.41	.19	2.60
1988	2.15	.05	.32	2.52	.20	2.72
1989	2.39	.06	.36	2.81	.22	3.03
1990	2.59	.07	.39	3.05	.23	3.28
1991	2.82	.08	.43	3.33	.25	3.58
1992	3.06	.09	.46	3.61	.26	3.87
1993	3.34	.10	.50	3.94	.28	4.22
1994	3.64	.11	.55	4.30	.30	4.60
1995	3.96	.12	.60	4.68	.32	5.00
1996	4.33	.13	.65	5.11	.35	5.46
1997	4.74	.14	.71	5.59	.37	5.96
1998	5.18	.16	.78	6.12	.40	6.52
1999	5.70	.17	.86	6.73	.42	7.15
2000	6.21	.19	.94	7.34	.45	7.79

ASSUMPTIONS:

1. Gas price (de)escalation rate based on Division of Petroleum Revenue oil price forecast, January 1983. This rate also applies to the adjustment of the premium deliverability charge.
2. Inflation rate is 7 percent per year (consistent with Acres Susitna study).
3. Severance tax is 6 cents per MCF (Source: Dale Teel of Enstar, through Alaska Power Authority), adjusted for changes in base gas price.
4. Pipeline transmission charge is estimated at $.30 cents by Mr. Teel. This figure is adjusted downward to reflect the assumption that only Municipal Light and Power will pay the full 30 cent charge, while Chugach will obtain additional gas supplies from the Beluga gas field for its power plant at that location, with no pipeline charge on that gas. Chugach is assumed to pay the pipeline charge on the 20 percent of its gas which is purchased from Enstar for its non-Beluga generators. The Chugach/AML&P ratio of power production is about 65/35. Thus, [.65 x (.2 x 30 cents)] + (.35 x 30 cents) = 14.4 cents weighted average pipeline charge.

TABLE 2 ASSUMPTIONS (Continued)

5. The base gas prices in column 1 of Table 2 are adjusted for year to year percentage changes in the Division of Petroleum Revenue oil price forecast. These percentage changes are shown below.

DIVISION OF PETROLEUM REVENUE OIL PRICE FORECAST
(Nominal Dollars)

Fiscal Year	Percentage Increase or Decrease in End-Year Prices
1983	- 11.4 %
1984	- 6.1
1985	+ 3.4
1986	3.0
1987	4.5
1988	11.3
1989	8.5
1990	8.7
1991	8.7
1992	8.9
1993	8.9
1994	9.1
1995	9.1
1996	9.4
1997	9.5
1998	9.3
1999	9.6
2000	9.6

Source: Charles Logsdon, Division of Petroleum Revenue, based on January 83 mean forecast. Figures converted from real to nominal dollars based on PetRev inflation projections.

In their thermal cost analysis, Acres assumed that 600 megawatts (MW) of coal-fired generation would be added in 1993, 1994, and 1996 to meet baseload power demand in the Railbelt. Acres did not assume gas supplies to be limited; rather, the choice of coal generation over gas was made on the basis of power cost alone. As shown in Table 1, the combined coal and gas generation case used by Acres appears to be significantly more expensive from 1993 to 2000 than the cost of generation entirely from natural gas.

The reason for this apparent discrepancy is that the choice of coal generation was made on a life cycle cost basis. Thus, although coal generation would be more expensive than gas before 2000, the higher cost of gas generation in later years would make gas the more costly alternative over the 30-year life of the generating plants. This approach is generally a sound one, but raises the possibility that thermal power costs would be lower than projected by Acres if Anchorage utilities rely on gas generation rather than coal. This continued reliance on gas could occur if the Beluga field is not developed for the export market or if the utilities simply prefer the lower initial cost of gas generation over the high capital costs and long-run savings of coal plants.

GAS-FIRED GENERATION COSTS

In addition to gas price forecasts, the calculation of projected power costs required estimates of operation and maintenance costs and debt service costs for existing and new gas generation plants. Mr. Tom Kolasinski, production manager for Chugach, provided these costs for 1982 for the Chugach system (the costs are footnoted in Table 3). Acres did not explain to what extent, if at all, actual generation costs for Railbelt utilities were used in their analysis. Therefore, these figures may be somewhat lower than those used by Acres. However, these actual costs, adjusted for inflation and capacity additions, are the best measure of the future cost of thermal power against which Susitna must compete.

Table 3 shows the projected power costs under the Acres thermal generation analysis and under the Enstar contract terms, with the Enstar gas prices determined under the oil price forecast in Table 2. Two costs are shown under the Acres thermal case. The "coal-gas" figures represent the thermal costs presented by Acres, while the "gas" case shows the estimated cost of power under continued gas generation, using Acres' gas prices.

Gas generation costs under the Enstar case and the Acres gas case are based on the addition of new gas generation capacity in 1993, 1994, and 1996. The capital and operating costs of this new capacity are based on Acres data, adjusted for inflation and real escalation, as explained in the footnotes to the table.

TABLE 3

PROJECTED BUSBAR POWER COSTS UNDER ACRES THERMAL GENERATION ANALYSIS AND UNDER ENSTAR GAS CONTRACT TERMS
(Cents per KWH -- Nominal dollars)

		Gas Turbine Operation, Maintenance, and Debt Service Costs[1]	ACRES Gas Cost Per KWH Generated[2]	ACRES Total Thermal Power Cost Gas-Coal	(Gas)[3]	ENSTAR Gas Cost Per KWH Generated[4]	ENSTAR Total Power Cost[5]
	1982	1.21	3.66	--	4.87	3.07	4.28
	1983	1.27	3.92	--	5.19	3.07	4.34
	1984	1.32	4.19	--	5.51	2.87	4.19
	1985	1.38	4.48	--	5.86	2.61	3.99
	1986	1.45	4.80	--	6.25	2.72	4.17
	1987	1.51	5.13	--	6.64	3.17	4.68
	1988	1.58	5.49	--	7.07	3.32	4.90
	1989	1.65	5.88	--	7.53	3.70	5.35
	1990	1.73	6.29	--	8.02	4.00	5.73
	1991	1.81	6.73	--	8.54	4.37	6.18
	1992	1.89	7.20	--	9.09	4.72	6.61
Susitna	1993	(2.69)	(7.66)	14.0	(10.35)	5.15	7.84
On-Line	1994	(3.37)	(8.63)	14.5	(12.00)	5.61	8.98
Date	1995	(3.52)	(9.59)	15.0	(13.11)	6.10	9.62
	1996	(4.36)	(11.08)	22.0	(15.44)	6.66	11.02
	1997	(4.56)	(12.81)	23.0	(17.37)	7.27	11.83
	1998	(4.77)	(14.80)	24.0	(19.57)	7.95	12.72
	1999	(4.99)	(17.10)	25.5	(22.09)	8.72	13.71
	2000	(5.21)	(19.76)	26.0	(24.97)	9.50	14.71

[1] Based on 1982 Chugach data provided by Mr. Tom Kolasinski, Production Manager for Chugach (personal communication - 3/1/83). Total busbar cost = 1.76 cents/KWH; O&M = 0.56 cents/KWH; debt service, depreciation, etc. = .65 cents/KWH; fuel = .55 cents/KWH. O&M cost escalated at real rate of 2 percent/year plus 7 percent inflation; debt service costs assumed fixed through 1992.

It is assumed that 140 MW of gas-fired turbines are added by Chugach each year in 1993, 1994, and 1996, with 70 MW assumed to be added by ML&P in accordance with current power production ratios. This 210 MW added in each of the three years approximates the 200 MW of coal-fired generation assumed by Acres to be added in 1993, 1994, and 1996. The calculation of O&M and debt service costs from 1993 to 2000 is based on a weighted average of these costs for "old" existing generation units and the costs for the new generating units.

Acres tables 3.4 and 3.6 in the Task 6 report indicate that total Chugach capacity in 1992 will be about 435 MW. The additional 140 MW added by Chugach in 1993, 1994, and 1996 is weighted against this existing capacity.

FOOTNOTES TO TABLE 3 (Continued)

[1] (continued). The cost of new generation capacity is based on Acres Table 6.6 in Volume 1 of the feasibility report, with a capital cost per KW (82 dollars) of $636, O&M costs as stated in the table, and 10 percent interest, with 1.1 debt service coverage. The 1982 costs are increased by 2 percent real escalation and 7 percent inflation. Under these assumptions, the O&M and debt service costs of new generation would be 4.69 cents/KWH in 1993, 5.12 cents/KWH in 1994, and 6.1 cents/ KWH in 1996.

[2] Assumes a simple cycle gas turbine heat rate of 12,200 BTU/KWH, as per ACRES Table 6.6, Volume 1 of the Susitna Feasibility Report. (Thus, $3.00 per MCF gas = 3.66 cents/KWH busbar gas cost).
Acres gas prices based on $3.00 per MCF in 1982, inflated at 7 percent annually through 1992 (0 percent real inflation), 3.9 percent real escalation 1993-1995, 8.0 percent real escalation 1996-2000 (Source: Acres Task 6 Close-Out Report, Table 3.8, April, 1982). Figures in parentheses indicate that these numbers were used to estimate Acres gas generation costs after 1992.

[3] Acres did not estimate thermal prices before 1994, because Susitna would not be in full operation until this time. The Acres thermal cost estimates begin in 1994 at 14.5 cents/KWH under the "Gas-Coal" column in Table Y (I extrapolated to 1993 at 14.0 cents/KWH). As noted above, Acres assumed coal plants would meet the need for additional base-load generation capacity. The "Gas" column in parentheses shows the estimated power costs if all new generation were gas-fired, based on the Acres gas price assumptions. Acres did not separate the cost of coal and gas generation in published reports; it is also not clear to what extent existing generation costs were considered. Therefore, the Acres gas generation cost figures could differ considerably from these estimates.

[4] Enstar gas cost from Table 2, adjusted for 12,200 BTU/KWH heat rate.

[5] Column 1 plus column 4.

EFFECT OF OTHER GAS CONTRACTS

Both the Chugach Electric Association and Enstar have existing gas purchase contracts at much lower prices than the new contracts obtained by Enstar from Shell and Marathon Oil Co. Although gas supplies under the older Enstar contracts are expected to be depleted by 1990, the Chugach contracts may last through 1995. It is difficult to project the life of gas supplies under these older contracts, because it depends largely on the provisions of any new contracts which may be obtained by Chugach. Because of this uncertainty, I did not include this low-cost gas in any of the tables in this memo, but it is important for the Power Authority and its consultants to address the possible effect of this low-cost gas on the marketability of Susitna power.

Battelle's gas analysis indicated that the existing Chugach contracts could supply over 50 percent of Chugach's gas requirements through 1995 (see Battelle's Table 2.8, attached). If this occurs, Chugach's average gas cost could be about half of the cost under the Enstar contracts. This lower cost gas could reduce power costs by 2-3 cents per KWH in the 1993-1995 period.

* * * *

I hope this information is useful. If you have any questions or would like additional research, please let us know.

TABLE 2.8. Estimated Natural Gas Acquisition Cost for Chugach Electric Association Without Pacific Alaska LNG Plant, 1982 $'s, 0% Inflation

Year	Beluga Bcf/Yr	Beluga $/Mcf	Alaska Gas and Service Bcf/Yr	Alaska Gas and Service $/Mcf	Supplemental Gas Bcf/Yr	Supplemental Gas $/Mcf[a]	Weighted Average Gas Bcf	Weighted Average Gas $/Mcf
1980	17.76	0.27	3.95 (3.98)[b]	1.34 (1.04)	--	--	21.71	0.46
1981	18.66	0.26	4.15 (4.65)	1.32 (1.20)	--	--	22.81	0.45
1982	19.60	0.27	4.35	1.33	--	--	23.95	0.46
1983	20.57	0.27	4.57	1.31	--	--	25.14	0.46
1984	21.63	0.27	4.80	1.32	--	--	26.43	0.46
1985	21.90	0.27	5.04	1.33	--	--	26.94	0.51
1986	21.90	0.28	5.17	1.62	0.41	1.62[a]	27.48	0.54
1987	21.90	0.28	5.31	1.84	1.01	1.84[a]	28.22	0.66
1988	21.90	0.30	5.45	1.95	1.62	1.95[a]	28.97	0.70
1989	21.90	0.30	5.60	2.16	2.25	2.16[a]	29.75	0.78
1990	21.90	0.32	5.75	2.41	2.89	2.41[a]	30.54	0.90
1991	21.90	0.32	6.04	4.01	4.84	4.01	32.78	1.53
1992	21.90	0.34	6.35	4.10 Enstar	5.20	4.10 Enstar	33.45	1.66
1993	21.90	0.34 .71 6.67 nominal dollars		4.18 4.22	7.63	4.18 4.22	36.20	1.87 2.15 =
1994	21.90	0.36	7.01	4.27	9.13	4.27	38.04	2.00 melded
1995	21.90	0.36	7.36	4.37	10.71	4.37	39.97	2.17 Enstar
1996	0	--	7.48	4.46	34.09	4.46	41.57	4.46 price
1997	0	--	7.58	4.56	35.65	4.56	43.23	4.56
1998	0	--	7.69	4.68	37.27	4.68	44.96	4.68
1999	0	--	7.79	4.79	38.97	4.78	46.76	4.78
2000	0	--	7.88	4.91	40.75	4.91	48.63	4.91

(a) The minimum price available from AGAS or Beluga Field producers, assumed to be about equal.
(b) Items in parentheses are actual percent and quantities for 1980 and 1981.

SOURCE: BATTELLE VOLUME VII

Department Of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

March 2, 1983

FOR SENATE STATE AFFAIRS COMMITTEE
HOUSE STATE AFFAIRS COMMITTEE
THIRTEENTH ALASKA LEGISLATURE

I had opportunity to listen to presentations at the Committee hearings on March 1, and wanted to offer some personal observations on the WPPSS experiences and natural gas pricing issues.

1. WPPSS

Ms. Titmuss' presentation was excellent, and the following notes are intended only as additional information.

WPPSS initiated its nuclear program at a time in history when the nuclear outlook was exceptionally rosy. Cost experience in the industry up to that time was exceptionally good and most were forecasting incredibly low cost power from nuclear over the long term. Some have said that the low cost was partly due to government and industry subsidies of the first generation of nuclear plants.

WPPSS attempted to implement its program during a time of: rapid evolution of the nuclear regulatory function; rapid escalation of costs for nuclear facilities; unprecedented inflation; and unprecedented costs for borrowing money.

The situation was complicated by poor performance in the PNW economy, which is quite well documented in various sources. A large part of the reduction in estimates of power requirements is directly related to recession or near depression-level economy.

These factors would have meant long delays of completion for projects and high increases in costs even if management was the very best.

It could well be that the largest problem for WPPSS was its failure to scale back its program, early on, when it encountered the above problems.

My point is, the initial assumptions of the 1960's under which the hydro-thermal program was initiated were probably pretty good. However, hindsight shows WPPSS wasn't able to make the necessary adjustments over the years as the conditions changed.

Many other power entities went into the 1970's with similarly ambitious construction programs. Most underwent some rather painful adjustments to the new realities, but most were able to make the necessary adjustments.

In relating the WPPSS experience to Alaska, it may be useful to also explore how some of the other power companies handled the adjustment period. It would also seem important to maintain some sort of distinction between the nuclear and water power technologies.

The WPPSS experience occurred during a period of rapid evolution of nuclear generation techology--particularly on the design criteria necessary to minimize risk to failure. That situation carries with it a high risk of cost increases and delay. There just should not be comparable risks to the hydroelectric projects which involve very mature technologies.

2. GAS PRICING

These are just a few thoughts based on the history of natural gas pricing assumptions in Alaska.

Generally, the period 1960-1973 was one in which most people assumed that Cook Inlet gas would be available at very low cost to meet conceivable instate needs, including electric power. Many studies assumed a future price to the year 2000 of 15 cents per million Btu.

Direct results of this gas assumption that I can recall include:

Conversion of coal-fired plants (utility and military) in the Anchorage area to gas and closure of the Matanuska coal mining operations.

Cancellation of the Central Alaska Power Pool (CAPP) plans to interconnect Anchorage and Fairbanks with power to come from coal-fired plants at Sutton and Healy (GVEA did complete the northern part of this system).

Deferral of construction start on Bradley Lake in 1964 at a time when power cost was estimated at 11 mills per kWh.

Lack of interest in pursuing Susitna. (Susitna originally proposed for authorization in 1960.)

I can recall specifically that the 15-cent gas assumption was used in the 1969 FPC Alaska Power Survey and 1971 Corps of Engineers final report on Rampart.

There was really not much significant work on alternative power plans (other than natural gas) for Cook Inlet power systems between 1962 and 1973.

Thus the key theme of the "history" is that everyone was way off base on the gas price issue up to about 10 years ago, with the apparent result of foreclosing a series of important alternatives that probably would have been constructed if there had been a better understanding of future gas prices.

Obviously, it doesn't do much good now to second-guess the decisions of the '60's. However, it is important to use the historical perspective as a guide to the decisions next to come.

In that light, while I give a great deal of credit to people like Ericksen and Gorsuch for advocating their beliefs that future oil and gas prices will be much lower than assumed in most of the recent studies, I suggest there is high likelihood that their most recent gas pricing estimates are way too low.

The potential for error based on pricing assumptions is immense. One example is Prudhoe Bay. Up thru the final debates on permitting construction of the Trans Alaska pipeline, many eminent economists were convinced the wellhead value at Prudhoe was either zero or negative. Those people were off by at least $200 billion.

The biggest potential for error would be to shelve all the alternatives based on the latest trend in world oil prices. In that regard, it makes a lot of sense to proceed with those actions on Susitna which would put the State in a position to build the project if and when the decision to build is made.

3. RECAP

The above notes are offered as personal views.

I'd like to add that the periodic, careful review of major programs, such as your Committees are now doing, must be one of the very good ways of assuring best possible results and avoiding unpleasant consequences.

I'd like to compliment the Committees and your staff for the thoroughness of their reviews.

Sincerely,

R. J. Cross

Robert J. Cross
Administrator

Testimony of

Ernst W. Mueller

on

Alaska Power Authority Operations

before

Senate State Affairs Committee
Alaska State Legislature
24 February 1983

Mr. Chairman, I want to thank you and the members of the Senate State Affairs Committee for holding this hearing on the operations of the Alaska Power Authority, and particularly for this opportunity to share with you some of my experiences and observations. As many of you know, I spent the years from December 1974 until December 1982 as Governor Jay Hammond's Commissioner of Environmental Conservation. During the final two years of my tenure, I was one of the three cabinet members appointed by the Governor to serve on the Board of Directors of the Alaska Power Authority. Upon my appointment I was selected by the Board to be its Vice-Chairman. Because of the structure of the Alaska Power Authority, I was also closely involved in development of policy at the Governor's level, and in negotiations over the final capital and operating budgets of the Authority.

The Alaska Power Authority is a unique institution in Alaskan politics and a phenomenon which has little parallel in other states.

When it was initially conceived in 1976 by act of the legislature (chapter 156 SLA 1976), its purpose was to conduct feasibility studies and develop large power projects, in the main using revenue bonds. As a result, it was envisioned as a more-or-less autonomous entity, not unlike the Alaska State Housing Authority. It could engage in tax-exempt bond sales, and, because it had a state-wide base of operations, could provide large blocks of electric power from a single project to many local utilities. In this way, economies of scale could provide energy to the ultimate consumer at the lowest possible cost. Because it was initially invisioned to use revenue bonds to build projects, market forces and the Authority's own operating procedures mandated that the projects would not be constructed unless power sales would be at prices competitive with alternatives, particularly thermal generation.

The other advantage which the Alaska Power Authority was thought to have as a result of its quasi-independent existence was a form of isolation from the political whims of the moment. Because its commitments and goals were long range in nature, and because it was potentially dealing in vary large sums of money, it seemed important that the Authority's decision-making process be as divorced as possible from the everyday scramble that politics requires of normal operations of the Executive branch of government.

However, when the famous Alaskan windfall of oil money arrived, many of the controls placed on the Power Authority disappeared. Now

that the state could put large sums of general fund money into power projects, they did not have to pass the scrutiny of the market place, and did not have to generate power at competitive prices, for it was thought that any difference between cost of power from APA projects, and that from alternatives, would be simply paid by the state. Enactment of the Power Cost Assistance Program reinforced this idea that we could have our cake, eat it too, and be paid for it in the bargain.

Its not particularly surprising, even in the real world of no free lunches, that if someone else, in this case the State, pays most of your electric bill, that your bill will be lower, and that you might be enthusiastic about a new power project. Despite what some might contend, there was absolutely no attempt by the APA or its subcontractors to hide the fact that a major portion of everyone's power bill would be paid by the state, although perhaps to language used to express this phenomenon was a bit cryptic. Last Spring, for example, the Alaska Power Authority staff and its Susitna feasibility study consultant, Acres American, held public meetings around the State, including one here in Juneau, describing the results of its study. In a nice color graphic, Acres described an "Inflationary Financing Deficit" that might be otherwise known as a State subsidy. This proposal simply stated that, in order to be competitive with alternative thermal sources of electricity, Susitna's power would have to be sold at somewhat less than one-half of its cost of production for at least the first eight years of its life. Further, although the project might eventually produce electricity at a cost considerably less than that of thermal options, there were simply no plans to ever charge a

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ALASKA POWER AUTHORITY

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

January 17, 1983

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

Dear Governor Sheffield:

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

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

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

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

Sincerely,

Eric P. Yould
Executive Director

copy with attachment: Charles Conway

Attachment: as stated.

HAVE ALL ALTERNATIVES BEEN EXAMINED?

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

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

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

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

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

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

WHAT IS THE MARKET FOR SUSITNA POWER?

The Susitna Project will provide power to;

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

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

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

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

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

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

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

CAN THE PROJECT BE SUCCESSFULLY FINANCED?

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

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

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

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

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

DO ALASKANS UNDERSTAND THE PROJECT AND THE ISSUES SURROUNDING IT?

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

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

CHECKLIST

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

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

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

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

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

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

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

TABLE I

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

TABLE 1 (cont.)

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

TABLE I (cont.)

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

TABLE I (cont.)

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

THE INFLATION OUTLOOK

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

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

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

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

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

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

	1982		1983				1984		Years				
	III	IV	I	II	III	IV	I	II	1981	1982	1983	1984	1985
GNP and Its Components Billions of Dollars - SAAR													
Total Consumption	1986.3	2034.6	2064.2	2104.3	2150.0	2199.6	2244.2	2294.0	1843.2	1972.0	2129.5	2318.4	2528.2
Nonres. Fixed Investment	344.2	336.6	323.9	322.6	328.4	336.7	348.8	360.5	346.1	347.5	327.9	366.7	417.8
Res. Fixed Investment	94.3	99.8	112.1	120.0	128.1	134.6	139.5	145.8	105.0	95.8	123.7	149.8	180.3
Inventory Investment	4.7	-38.5	-12.2	0.6	5.3	8.3	18.7	17.3	20.4	-21.4	0.5	20.5	30.6
Net Exports	6.9	-6.9	-10.8	-13.8	-18.2	-19.3	-16.8	-14.2	26.1	16.6	-15.5	-13.2	-6.8
Federal Purchases	259.0	276.1	279.6	280.8	285.9	298.4	304.4	312.8	228.9	257.3	286.2	317.0	347.8
State and Local Govt. Purchases	392.7	399.6	404.2	409.8	415.2	421.0	427.3	435.0	368.0	389.8	412.5	439.3	474.2
Gross National Product	3088.2	3101.3	3160.8	3224.3	3294.8	3379.3	3466.0	3551.2	2937.7	3057.5	3264.8	3598.5	3972.1
Real GNP (1972 Dollars)	1481.1	1471.7	1481.8	1491.8	1505.9	1523.8	1540.7	1558.8	1502.6	1475.5	1500.8	1568.1	1635.6
Prices and Wages - Annual Rates of Change													
Implicit Price Deflator	5.0	4.3	5.0	5.4	5.0	5.6	5.9	5.2	9.4	6.0	5.0	5.5	5.8
CPI - All Urban Consumers	7.6	2.6	4.5	5.7	5.4	5.4	5.8	4.9	10.3	6.1	4.9	5.4	5.6
Producer Price Index - Finished Goods	6.4	4.2	2.7	4.0	5.2	5.4	5.2	5.0	9.3	4.0	4.0	5.1	6.0
Compensation per Hour	6.4	4.7	6.2	5.4	6.2	6.2	8.4	6.1	9.6	7.1	5.8	6.7	6.7
Core Inflation	7.6	7.3	6.8	6.4	6.0	5.7	5.5	5.5	9.0	7.8	6.2	5.4	5.4
Production and Other Key Measures													
Industrial Production (1967=1.000)	1.382	1.351	1.364	1.386	1.414	1.448	1.478	1.509	1.509	1.386	1.403	1.522	1.619
Annual Rate of Change	-3.4	-8.6	4.0	6.4	8.3	10.2	7.7	9.3	2.6	-8.1	1.2	8.5	6.3
Housing Starts (Mil. Units)	1.118	1.251	1.350	1.435	1.490	1.514	1.558	1.610	1.100	1.060	1.447	1.646	1.842
Retail Unit Car Sales (Mil. Units)	7.7	8.7	8.4	8.4	8.8	9.3	9.4	9.7	8.5	8.0	8.8	9.8	10.5
Unemployment Rate (%)	10.0	10.7	11.0	10.7	10.5	10.3	10.1	9.7	7.6	9.7	10.7	9.6	8.5
Federal Budget Surplus (NIA)	-156.0	-199.5	-191.6	-185.2	-201.5	-206.8	-204.1	-204.0	-60.0	-148.4	-196.3	-200.3	-188.4
Money and Interest Rates													
Money Supply (M-2)	1941.9	1985.7	2023.0	2062.4	2108.3	2161.0	2202.2	2252.7	1807.4	1985.7	2161.0	2367.1	2617.1
% Change, 4th-Qtr. to 4th Qtr.	10.1	9.3	7.7	8.0	9.2	10.4	7.8	9.5	9.5	9.9	8.8	9.5	10.6
New AA Corp. Utility Rate (%)	15.02	12.54	12.11	11.36	10.80	10.57	10.56	10.55	16.25	15.13	11.21	10.61	10.98
New High-Grade Corp. Bond Rate (%)	14.09	11.07	10.95	10.57	10.19	10.05	10.09	10.10	15.01	13.89	10.44	10.16	10.53
Federal Funds Rate (%)	11.01	9.29	7.96	8.27	8.64	8.94	9.59	9.32	16.38	12.26	8.45	9.09	9.61
Prime Rate (%)	14.72	11.96	10.34	10.51	10.81	11.27	11.90	11.63	18.87	14.86	10.73	11.42	11.50
Incomes - Billions of Dollars													
Personal Income	2592.4	2623.0	2659.8	2709.5	2772.2	2840.1	2905.5	2979.0	2415.8	2569.6	2745.4	3014.1	3299.2
Real Disposable Income (%Ch)	1.3	-0.2	0.3	2.2	7.1	4.6	3.9	5.0	2.5	1.1	2.0	4.5	3.7
Saving Rate (%)	6.9	5.8	5.6	5.6	6.4	6.5	6.8	7.0	6.4	6.5	6.0	7.0	7.2
Profits Before Tax	180.3	180.6	185.6	189.1	194.3	203.5	209.6	222.8	232.1	176.1	193.1	229.8	277.4
Profits After Tax	119.4	120.4	123.0	125.2	128.7	134.7	138.9	147.3	150.9	117.8	127.9	151.6	182.2
Company Profits	94.0	88.2	91.5	99.1	108.5	111.7	114.7	116.9	107.2	90.7	102.7	119.7	136.8
Four-Qtr. Percent Change	-11.1	-16.3	3.4	7.7	15.4	26.6	25.3	17.9	2.6	-15.4	13.2	16.5	14.3
Composition of Real GNP - Annual Rates of Change													
Gross National Product	0.7	-2.5	2.8	2.7	3.8	4.8	4.5	4.8	1.9	-1.8	1.7	4.5	4.3
Final Sales	-1.3	3.1	-0.5	1.2	3.3	4.6	3.3	5.0	1.0	-0.6	1.1	4.0	4.1
Total Consumption	0.6	5.0	1.1	2.3	3.5	4.2	2.5	4.2	1.8	1.0	2.5	3.5	3.4
Nonres. Fixed Investment	-7.7	-9.0	-15.9	-4.3	4.0	6.5	9.4	9.3	3.5	-3.8	-7.6	7.1	8.1
Equipment	-8.8	-12.1	-11.4	-0.2	9.8	11.0	12.4	12.4	2.4	-6.8	-5.9	10.6	9.0
Nonres. Construction	-5.2	-2.3	-24.6	-12.5	-7.9	-3.3	2.7	2.0	6.3	3.1	-11.1	-0.6	5.7
Res. Fixed Investment	-5.9	24.2	50.7	24.1	21.9	15.2	7.6	12.5	-4.9	-10.9	24.4	13.9	12.6
Exports	-16.7	-26.9	-2.8	3.0	6.0	6.0	7.7	5.9	-0.5	-6.9	-6.6	6.1	5.6
Imports	4.5	-14.8	0.2	3.7	7.3	5.8	5.3	3.7	7.2	0.6	0.3	4.9	4.1
Federal Government	23.2	28.4	-3.0	-6.9	0.3	6.9	2.0	5.9	3.7	5.2	4.8	3.1	2.2
State and Local Governments	-0.2	1.1	-1.1	0.1	-0.4	0.0	0.0	1.6	-0.8	-0.9	-0.1	0.6	1.8

Alaska State Legislature

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

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

SENATE ADVISORY COUNCIL

MEMORANDUM

TO: All Senators

FROM: Kurt S. Dzinich KSD

DATE: March 7, 1983

RE: APA Energy Rates

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

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

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

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

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

MEMORANDUM State of Alaska

TO: Eric P. Yould
Executive Director

DATE: December 28, 1982

FILE NO:

TELEPHONE NO:

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

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

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

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

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

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

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

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

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

Sincerely,

Myles C. Yerkes
Director of Systems
Planning & Operations

MCY:cb

cc: Raymond J. Benish, APA, Anchorage

HB 9 POWER COST STUDY

1 - INTRODUCTION

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

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

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

2 - DESCRIPTION OF HOUSE BILL 9

2.1 - History

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

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

2.2 - Wholesale Power Rates Under HB 9

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

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

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

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

where

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

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

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

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

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

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

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

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

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

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

3.1 - Forecast Assumptions

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

3.2 - Wholesale Power Rates

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

TABLE 1

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

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

Project Summary *

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

* See Appendixes A and B for further details

3.3 - Retail Power Rates Under the Power Assistance Program

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

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

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

TABLE 2

AVERAGE NET RETAIL POWER RATE
UNDER POWER ASSISTANCE PROGRAM

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

1. See Appendix A for project descriptions

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

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

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

4.1 - The Problems

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

The Early Year Power Cost Problem

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

The System Increment Problem

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

The Uniform Rate Problem

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

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

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

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

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

TABLE 3

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

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

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

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

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

Possible Solutions

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

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

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

4.2.1 - Stand Alone Legislation

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

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

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

4.2.2 - Higher State Equity Contributions

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

TABLE 4

WHOLESALE POWER RATES RESULTING FROM ADDITIONAL STATE EQUITY CONTRIBUTIONS

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

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

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

4.2.3 - Low Interest Rate Loans

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

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

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

4.2.4 - Equalization Grants as an HB 9 Over-ride

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

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

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

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

TABLE 5

COST OF EQUALIZATION GRANTS ($ millions)

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

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

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

4.2.5 - Equalization Loans

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

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

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

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

4.2.6 - Standardized State Financing Until System Maturity

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

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

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

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

5 - MARKETING AND DEVELOPMENT SOLUTIONS

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

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

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

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

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

6 - SUMMARY AND CONCLUSIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

APPENDIX A

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The principal components of the project consist of the following:

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

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

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

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

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

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

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

APPENDIX "B"

ASSUMPTIONS FOR FINANCIAL FORECASTS

°Project Costs and Financing

Projects Included	Total Cost (Millions $)	State Appropriations (Millions $)	Debt Financed (Millions $)	On-Line Date FY
Swan Lake	93.50	69.09	24.41	1985
Tyee Lake	124.60	79.48	45.12	1985
Solomon Gulch	53.00	53.00	0.00	1983
Terror Lake	139.40	79.26	110.14	1986
	410.50	280.83	179.67	

Notes

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

B-1 INFLATION AND INTEREST RATES

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

NOTES

1 Source: Data Resources Incorporated, July 1982.

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

B-2 °OPERATION AND MAINTENANCE COSTS

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

NOTES

1. Source: Alaska Power Authority

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

B-3 °AGGREGATE PROJECT FIRM SALES:

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

Source: Alaska Power Authority

APPENDIX "C"

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

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

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

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

Table C.1

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

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

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

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

I. Operation and Maintenance Portion of Power Rates

This rate is calculated independent of other projects.

Components of Rate

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

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

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

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

II. Debt Service Portion of Power Rate

Components Used in Rate Calculation

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

B. Bond Coverage (ten percent).

C. Period (year-1983).

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

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

NOTES

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

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

Methodology Used to Calculate Debt Service Portion of Wholesale Power Rates

1. Calculate Average System Debt Service Rate (R1)

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

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

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

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

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

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

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

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

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

   If R3 greater than R2 then R4 = R2

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

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

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

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

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

APPENDIX "D"

EFFECT OF "BLACKMAIL" CLAUSE ON POWER RATES

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

(a) the standard HB9 rate,

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

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

Results

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

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

Table F.2

SUMMARY COMPARISON OF STANDARD HB9 AND "BLACKMAIL" CLAUSE RATES

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

Table F.1

COST OF POWER SUMMARY FOR AUTHORISED PROJECTS USING STANDARD HB9 BASIS (EXCLUDING BLACKMAIL CLAUSE)*

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

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

COST OF POWER INCLUDES O/M PORTION

COST OF POWER SUMMARY FOR AUTHORISED PROJECTS UNDER BLACKMAIL CLAUSE*

YEAR	PROJECTS															
	SWAN LAKE				LAKE TYEE				SOLOMON GULCH				TERROR LAKE			
	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV C/KWH	GEN $MILL	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV C/KWH	GEN $MILL	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV C/KWH	GEN $MILL	COST ICL IDC $MILL	SALES GWH	C.O.P ADD REV C/KWH	GEN $MILL
1983	83.0	0.0	0.0	0.0	87.9	0.0	0.0	0.0	53.0	41.0	3.0	0.0	108.1	0.0	0.0	0.0
1984	98.2	0.0	0.0	0.0	125.3	0.0	0.0	0.0	53.0	41.0	3.3	0.0	193.4	0.0	0.0	0.0
1985	98.2	32.0	11.6	0.0	125.3	30.4	12.8	0.0	53.0	41.0	9.9	6.0	202.5	0.0	0.0	0.0
1986	98.2	33.6	15.5	0.0	125.3	33.1	16.5	0.0	53.0	41.0	10.0	0.0	202.5	88.2	13.0	0.0
1987	98.2	35.3	27.8	4.4	125.3	36.0	31.0	7.3	53.0	41.0	12.2	1.5	202.5	93.0	33.0	9.0
1988	98.2	37.0	26.5	4.1	125.3	39.2	32.0	8.2	53.0	41.0	12.3	1.2	202.5	98.5	31.9	9.3
1989	98.2	38.9	25.3	3.7	125.3	42.7	29.4	8.7	53.0	41.0	12.9	1.2	202.5	99.9	30.3	9.5
1990	98.2	40.8	24.1	3.9	125.3	46.5	27.9	9.1	53.0	41.0	12.7	1.1	202.5	104.2	19.4	5.6
1991	98.2	42.9	22.9	3.8	125.3	48.9	25.6	4.8	53.0	41.0	12.7	1.0	202.5	106.3	19.1	5.5

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

COST OF POWER CALCULATED USING BLACKMAIL CLAUSE I.E. THE GREATER OF:
THE STANDARD UNCAPPED HB9 RATE OR 10% OF THE AUTHORITYS INVESTMENT IN EACH PROJECT