HB

120

To: Tony

From: Jim

Subject: Susitna Bills in Resources 4/6/83, HB 99 & 121

HB 99 appropriates 47 million for Susitna - it's Lacher's bill. The Gov has include $17.5 mil in his capital budget. This is the amount considered necessary for continuation of seeking FERC licensing. There is no real need for the full 47 million at this time.

HB 121 is for an advisory vote on whether to spend 2.3 billion for Susitna. We may question whether this would result in any meaningful response with out the full information of full costs of the project and extent of the benefits to be realized.

Attached are: 1) AEL position papers on Susitna and 2) Fisher's committee report on State Affairs hearings on Susitna.

Alaska Environmental Lobby, Inc.
419 6th Street, Suite 328 Juneau, Alaska 99801 907-586-2345

3 March 1983

TO: Resources Committee members
FROM: Jay Nelson, Executive Director, AEL JN
SUBJECT: Susitna

Enclosed is a critical analysis of three Susitna bills presently before the House Resources Committee. This paper was prepared by Mr. Eric Myers, Energy Specialist for the Northern Alaska Environmental Center, at my request.

I believe that the time for boosterism and wishful thinking are past. The legislature needs to critically examine the issue of how to best provide for the long term energy needs of the Railbelt. Steeply declining state revenues make it essential that we not risk our capital on projects with, at best, questionable economics.

I hope you and your staff will take the time to review this paper. Please contact our office if you have any further questions.

Thank you.

PROPOSED LEGISLATION: SUSITNA

HB 120, 121, 122

A REVIEW OF KEY ISSUES

ALASKA ENVIRONMENTAL LOBBY
419 6th Street, Suite 328
Juneau, Alaska 99801
586-2345

HB 120/ AUTHORIZATION AND APPROVAL OF THE SUSITNA FEASIBILITY STUDY AND APPROVAL OF THE PROPOSED "PLAN" OF FINANCE

Issue — Acceptability of the APA/Acres Feasibility Study

The Susitna Feasibility Study prepared for the APA by Acres American (March 1982), concluded that Susitna could offer the most attractive long term electrical energy source for the Railbelt but only on the basis of several very critical assumptions. Most importantly, these assumptions included: 1) high electrical demand growth (forecasts), 2) rapidly increasing oil prices, 3) outdated revenue projections/multi-billion dollar cash construction subsidies, and 4) tax exempt bond financing.

The Acres report included a "sensitivity analysis" which tested how critical certain assumptions were to the conclusion that Susitna was economically viable (Attachment A).

Since the time that the Acres study was prepared, fundamental changes in world economic circumstances has invalidated the conclusion that Susitna is the most attractive Railbelt alternative, at least until well into the next century.

Electrical Demand: The "need" for Susitna was predicated on a host of assumptions about future economic activity-population growth-employment-household formation, etc. which results in electrical demand. Assumptions included the ANGTS line, an ALPETCO-like refinery in Valdez, PacAlaska, and State spending trends as before the world oil market collapsed. In light of the changed circumstances, the most recent revised projections of Railbelt electrical demand for the year 2010 (Battelle, 1982) are close to half those used by Acres a couple of years back in its design development selection work which led to the choice of the Watana/Devil Canyon proposal currently under consideration (Attachments B and C).

The ISER (1980) projections used by Acres called for a Moderate (or "most likely") demand case of 8,940 Gwh per year in 2010 which compares to the more recent Battelle (1982) Moderate demand estimate of 4,986 Gwh/year in 2010. That is, the most recent demand projections for 2010 are only about 56% of those used by Acres to arrive at the conclusion that we "need" Susitna.

Another way of considering this question is in terms of capacity requirements: how many megawatts of additional capacity are needed to replace retired capacity over time and meet expected peak (highest) demand? Acres, in its design development and selection analysis, used the ISER (1980) projections calling for a Moderate case peak demand of 1,635 megawatts (MW); this contrasts with the more recent Battelle (1982) projection of peak demand projection of 1,003 MW. Approximately 577 MW of capacity would still be in place in the year 2010. The essential issue is how large a "capacity deficit" can be expected and how much additional capacity is needed to meet the shortfall. Using the capacity retirement schedule developed by Acres and the most recent capacity requirement projections by Battelle (including a 30% reserve capacity margin) it is evident that the Railbelt will experience a capacity shortfall of about 200 MW in the year 2000 and about 727 MW by the year 2010. This contrasts with the Susitna project at a total of 1,620 MW (Watana at 1,020 and Devil Canyon at 600). A premature commitment to Susitna would result in massive amounts of excess, idle capacity as is the case with the Lake Tyee project (Attachment D).

Note that the Acres' "sensitivity analysis" (Attachment A) tested a "Low" demand case for 2010 as 6,300 Gwh. This supposed "Low" scenario — which renders the project marginal at best — is 26% higher than the more recent "Moderate" case and 64% higher than the revised Battelle "Low" for 2010 (3,844 Gwh).

Using Acres own analysis, the new demand projections would indicate that the project had negative net benefits (ie, was more costly than the alternatives).

Fuel Price Escalation Rate: Acres assumed that there would be constantly rising fuel prices through 2010 reflecting the constantly increasing cost of the world price of oil. The Acres projection called for real (adjusted for inflation) price increases of 2.6%/year to 2000 and 1.2%/year to 2010 (Attachment A). The "sensitivity analysis" shows that a 0% real rate of fuel price increase yields a negative net benefit in excess of $1 billion. The Alaska Department of Revenue projects a negative (declining) real price of oil throughout most of this decade and does not anticipate positive real price increases anywhere near as great as the Acres base case assumed.

Again, using Acres own analysis, it is apparent that the project would cost more than the alternatives.

Outdated Revenue Projections/ Multi-Billion Dollar Subsidies: The Energy Program for Alaska was conceived of in a time of upwardly spiraling revenues; before the collapse of the world oil market. Superabundent revenues are clearly no longer available (Attachment E) yet the financing scheme proposed by HB 121 presumes the availability of $2.3 billion in grants for the project in order to make the project's cost of power artificially competitive with the less expensive alternatives. Acres/APA acknowledges that Susitna power (at 30¢/kwh) will cost more than twice the alternatives (at 14.5¢/kwh) when/if it is brought on line as scheduled in 1993 (Attachment F). The alternatives will continue to be lower in cost until well into the next century.

Tax Exempt Financing: Acres assumed that the project could be built with tax exempt bonds. This assumption has been questioned by, among others, the APA's own bond counsel (Acres: Task 11/January 1983, pp. 11-13).

General Comment: It is especially noteworthy that the Alaska Power Authority Board of Directors never endorsed the conclusion that the Susitna project was the most attractive electrical alternative for the Railbelt. At least until the APA Board formally adopts that position, it would be premature for the Legislature (with vastly less information and understanding) to do so.

The Feasibility Study should not be endorsed in the absence of such action on the part of the APA Board or without a formal reconsideration and economic reevaluation of the project in light of present economic realities.

Issue — Approval of the "Plan" of Finance

There is, in fact, no "plan" per se, but rather a vague set of options that have been proposed (Acres: Task 11/January 1983). These proposals call for multi-billion dollar grant subsidies with some sort of complimentary bonding — revenue bonds? G.O. bonds? "double barrel" bonds? There is no plan, just several nebulous scenarios.

What is being sought (in the form of approval of the so-called plan) is an open-ended commitment to multi-billion dollar subsidies. That's the plan.

The most basic issue raised by this aspect of the proposed legislation is: how does this finance "plan" approval relate to the other companion proposals: $2.3 billion subsidy grants (HB 121) and $5.4 billion "double barrel" bonding (HB 122)? What specifically is being contemplated?

General Comment: A proposed plan of finance should be very specific as to the marketing of power and power sales agreements. The object is, of course, to avoid a situation like Lake Tyee where we have a $120 million project and no takers ($82 million in State appropriations, $50 million in short term debt). The APA charged ahead with the 20 MW Tyee project without power sales agreements with Wrangell and Petersburg. Now nearly completed (with $10 million cost overrun), the two communities don't want the power because it would cost significantly more than oil-fired electricity (even with about 70% grant financing).

...hat is the
...lationship
... cash flow
...and power
...ales agreement

The "Plan" of Finance (Task 11) is very vague on the relationship of power sales agreements and State expenditures and bond financing. It is absolutely critical that this relationship be clear and explicit. Power sales contracts (take-or-pay) should be an absolute prerequisite to any State expenditures on the project.

HB 121/ CONSTITUTIONAL AMENDMENT AND $2.3 BILLION SUBSIDY FUND: ADVISORY VOTE

Issue — Constitutional Amendment

One can wonder whether the framers of the Constitution would approve of an amendment to the Constitution to secure a single capital project.

Issue — Advisory Vote/Costs and Public Education

It is estimated that a special statewide election would cost about $1 million.

It has been well documented that people generally don't have even a remote idea of what the project would actually cost. The recently released Dittman poll showed that while people were mostly supportive of the project, 53% didn't have any idea as to what the project would cost while 71% either didn't know or thought that it would cost less than $500 million. The acknowledged nominal (as spent) cost of the project is $10-15 billion excluding finance charges or the possibility of cost overruns. (A cost overrun the same size as experienced on the Tyee project — 9% — would amount to about $460 million).

Certainly any popular vote or advisory vote should be preceded by an objective and impartial educational effort designed to inform people about the true costs of the project (Attachment E). If billions are to be allocated to Susitna, as proposed by HB 121, the decision should be carefully considered in light of the opportunity costs. Susitna subsidies threaten the loan programs, municipal revenue sharing, Permanent Fund dividends, education funding, property tax relief, and would likely force the return of the personal income tax. These are the true costs of Susitna that nobody is talking about.

HB 122/DOUBLE BARREL BONDING

Issue — Change in APA Statutes/Public Vote on Susitna Bonds

Current APA statutes (AS 44.83.130(b)) expressly disallows the APA from engaging the State's credit in its bonding efforts. HB 122 would empower the APA to put the "full faith, credit and resources" of the State behind $5.4 billion of revenue bonds making them virtually indistinguishable from general obligation (G.O.) bonds. (Revenue bonds backed up by the State's general obligation are "double barrel" bonds). The basic issue to be addressed is whether the Susitna project justifies exemption from the explicit blanket prohibition to engage the State's credit.

The fiscal implications of this matter are profound. If the APA were to be empowered, by a public vote, to issue "double barrel" bonds in the amount of $5.4 billion the entire credit of the State would be at risk. It is a near certainty that that the public has little understanding of the issue and could well, in complete innocence, give over this power to the APA on the basis of a shallow understanding based on the pro-Suitna propaganda campaign.

Giving the APA autonomy to put the State into significantly greater debt is inadvisable in light of the State's presently precarious debt situation with what is perhaps the highest per capita debt for any state in the nation (Attachment G).

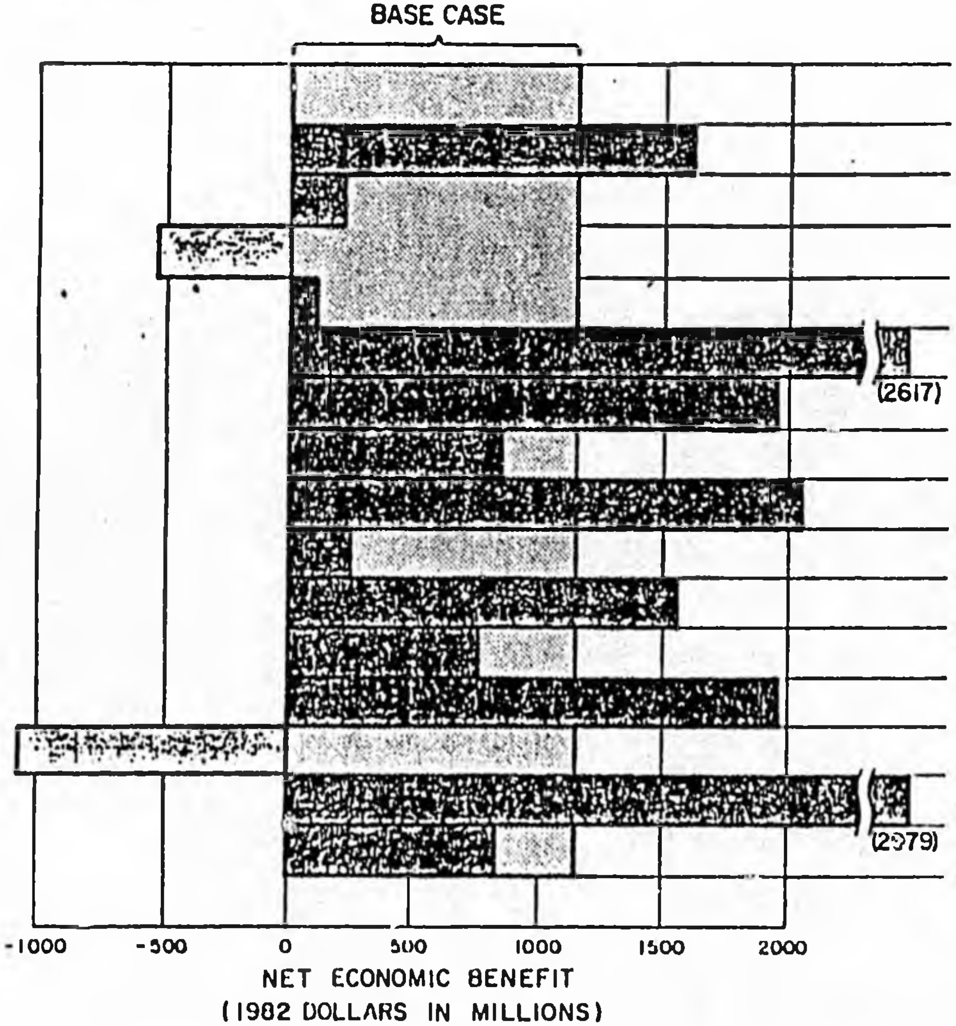
Again, if this measure is adopted there had better be some provision for a dispassioned educational effort in order to inform the public what the credit risks and opportunity costs are all about.

Moreover, the APA's own bond counsel has advised that if "a major portion of (Susitna's costs) were met from State G.O. Bonds, Alaska's present double A ratings would be endangered" (Acres: Task 11/January 1983, p.12). The bond counsel has also stated that the State can "only 'safely' issue about $565 million (nominal dollars, using 8% inflation) G.O. Bonds during the period fiscal 1983-1990."* Finally, the bond counsel recommends that "to the fullest extent possible" The APA should use revenue bonds secured by income derived from participating Railbelt Utilities pursuant to long term power sales contracts" (emphasis added).

---

* Using the December 1982/30th Percentile Department of Revenue forecasts.

ATTACHMENT A



ELEMENT TESTED	BASE CASE VALUE
HIGH LOAD FORECAST (11,400 GWH IN 2010)	7,800 GWH IN 2010
LOW LOAD FORECAST (6,300 GWH IN 2010)	7,800 GWH IN 2010
5 % REAL DISCOUNT RATE	3 %
4 % REAL DISCOUNT RATE	3 %
2 % REAL DISCOUNT RATE	3 %
HIGH CAPITAL COST FOR ALTERNATIVE (20 % ABOVE ESTIMATE)	BATTELLE ESTIMATE
LOW CAPITAL COST FOR ALTERNATIVE (10 % BELOW ESTIMATE)	BATTELLE ESTIMATE
LOW SUSITNA CAPITAL COSTS (83 % OF ESTIMATE)	PROJECT ESTIMATE
HIGH SUSITNA CAPITAL COSTS (117 % OF ESTIMATE)	PROJECT ESTIMATE
ZERO CAPITAL COST ESCALATION	1.8 % / ANNUM
HIGH CAPITAL COST ESCALATION (3.6 % / ANNUM)	1.8 % / ANNUM
HIGH BASE COAL PRICE ($ 2.08 / MM BTU)	$ 1.43 / MM BTU
ZERO FUEL PRICE ESCALATION	2.6 % TO 2000 1.2 % TO 2010
HIGH FUEL PRICE ESCALATION (5 % TO 2000, 2.2 % TO 2010	2.6 % TO 2000 1.2 % TO 2010
CHAKACHAMNA ALTERNATIVE	ALL THERMAL PLAN

PLATE 24 SENSITIVITY ANALYSIS

ATTACHMENT B

TABLE 5.6: ISER 1980 RAILBELT REGION LOAD AND ENERGY FORECASTS USED FOR GENERATION PLANNING STUDIES FOR DEVELOPMENT SELECTION[5]

	LOAD CASE											
	Low Plus Load Management and Conservation (LES-GL Adjusted)[1]			Low (LES-GL)[2]			Medium (MES-GM)[3]			High (HES-GH)[4]		
Year	MW	GWh	Load Factor	MW	GWh	Load Factor	MW	GWh	Load Factor	MW	GWh	Load Factor
1980	510	2790	62.5	510	2790	62.4	510	2790	62.4	510	2790	62.4
1985	560	3090	62.8	580	3160	62.4	650	3570	62.6	695	3860	63.4
1990	620	3430	63.2	640	3505	62.4	735	4030	62.6	920	5090	63.1
1995	685	3810	63.5	795	4350	62.3	945	5170	62.5	1295	7120	62.8
2000	755	4240	63.8	950	5210	62.3	1175	6430	62.4	1670	9170	62.6
2005	835	4690	64.1	1045	5700	62.2	1380	7530	62.3	2285	12540	62.6
2010	920	5200	64.4	1140	6220	62.2	1635	8940	62.4	2900	15930	62.7

Notes:

(1) LES-GL: Low economic growth/low government expenditure with load management and conservation.
(2) LES-GL: Low economic growth/low government expenditure.
(3) MES-GM: Medium economic growth/moderate government expenditure.
(4) HES-GH: High economic growth/high government expenditure.
(5) Excludes reserve requirements. Energy figures are for net generation.

Source: Acres (1982) Vol. 1 Section 5.

ATTACHMENT C

Revised Moderate and Low Case Electricity Forecasts, Railbelt

	Revised Annual Energy[a] (GWh)		Old Annual Energy (GWh)	
	Moderate	Low	Moderate	Low
1980	2551	2551	2551	2551
1985	3000	2560	3136	3028
1990	3391	3001	4256	3853
1995	3884	3164	4875	4063
2000	4010	3106	5033	3988
2005	4319	3332	5421	4278
2010	4986	3844	6258	4936

	Revised Peak Demand[b] (MW)		Old Peak Demand (MW)	
	Moderate	Low	Moderate	Low
1980	531	521	521	521
1985	615	525	643	621
1990	701	621	880	797
1995	791	652	993	837
2000	810	673	1017	815
2005	870	678	1092	870
2010	1003	780	1259	1001

(a) Revised downward based on low case annual consumption of 9.84 MWh per capita and moderate case annual consumption of 10.40 HWh per capita in the year 2000. See Appendix B, Tables B.3, B.4, B.12, and B.18. Other years consumption reduced proportionately. 1985 figures was adjusted upward judgmentally for moderate case; 1985-1995 adjusted upward for low case.

(b) Based on the ratio of peak demand to annual energy from Appendix B, Tables B.12 and B.18.

Source: Battelle NW (1982)

ATTACHMENT D

MODERATE DEMAND

PROJECTED ADDITIONAL CAPACITY NEEDS

FOR THE RAILBELT

(megawatts)

Year	Existing Installed Capacity [1]	Projected Peak Demand (w/ 30% RSRV) [2]	Required Additional Capacity
1985	1154 MW	690 MW	0 MW
1990	1242	911	0
1995	1095	1028	0
2000	853	1053	200
2005	610	1131	521
2010	577	1304	727

[1] Ebasco (1982): Assumes already planned additions of 158.4 MW of gas turbines in 1982 and Bradley Lake at 97 MW in 1988 with a capacity retirement schedule for existing plants from Acres (1981).

[2] Battelle (1982/revised): Moderate Growth Case with 30% reserve margin.

ATTACHMENT E

TABLE I
FUNDS AVAILABLE FOR CAPITAL PROJECTS UNDER CURRENT LAW
($ Millions)

FISCAL YEAR	(1) FUNDS AVAILABLE FOR CAPITAL PROJECTS: GENERAL FUND	(2) GO BONDS	(3) TOTAL	(4) SB 68* STATE FUNDING FOR SUSITNA	(5) OTHER APA CAPITAL PROJECTS	(6) TOTAL HYDRO PROJECTS	(7) LOAN PROGRAM APPROPRIATIONS	(8) GOVERNOR'S SIX YEAR CAPITAL BUDGET	(9) TOTAL CAPITAL PROJECTS
ACTUAL DOLLARS									
85	593.0	--	593.0	403.7	244.5	648.2	300.0	2035.0	2983.2
86	611.0	300.0	911.0	472.7	282.3	755.0	300.0	742.9	1797.9
87	447.0	90.0	537.0	479.7	125.8	605.5	300.0	961.2	1866.7
88	503.0	125.0	628.0	499.5	--	499.5	300.0	1066.2	1865.7
89	280.0	--	280.0	938.3	--	938.3	300.0	?	1238.3+
90	--	50.0	50.0	738.4	--	738.4	300.0	?	1038.[illegible]+
91	--	140.0	140.0	--	--	--	300.0	?	300.0+
92	--	--	--	--	--	--	300.0	?	300.0+
93	--	--	--	--	--	--	300.0	?	300.0+
Total	2434.0	705.0	3139.0	3532.3	652.6	4184.9	2700.0	4805.3	11690.2+
FY 84 DOLLARS									
85	554.0	--	554.0	364.5	228.5	593.0	280.0	1901.9	2774.9
86	534.0	262.0	796.0	398.9	246.6	645.5	262.0	648.9	1556.4
87	365.0	73.0	438.0	378.3	102.7	481.0	245.0	784.7	1510.7
88	384.0	95.0	479.0	368.2	--	368.2	229.0	813.4	1410.6
89	200.0	--	200.0	646.4	--	646.4	214.0	?	860.4+
90	--	33.0	33.0	475.4	--	475.4	200.0	?	675.4+
91	--	87.0	87.0	--	--	--	187.0	?	187.0+
92	--	--	--	--	--	--	175.0	?	175.0+
93	--	--	--	--	--	--	163.0	?	163.0+
Total	2037.0	550.0	2587.0	2631.7	577.8	3209.5	1955.0	4148.9	9313.4+

(Notes to Table I on next page.)

* SB 68 is identicle to HB 121

Source: Legislative Finance, "Funds Available for Capital Projects", prepared by Milt Barker for the Senate State Affairs Committee (21 February 1983).

ATTACHMENT F

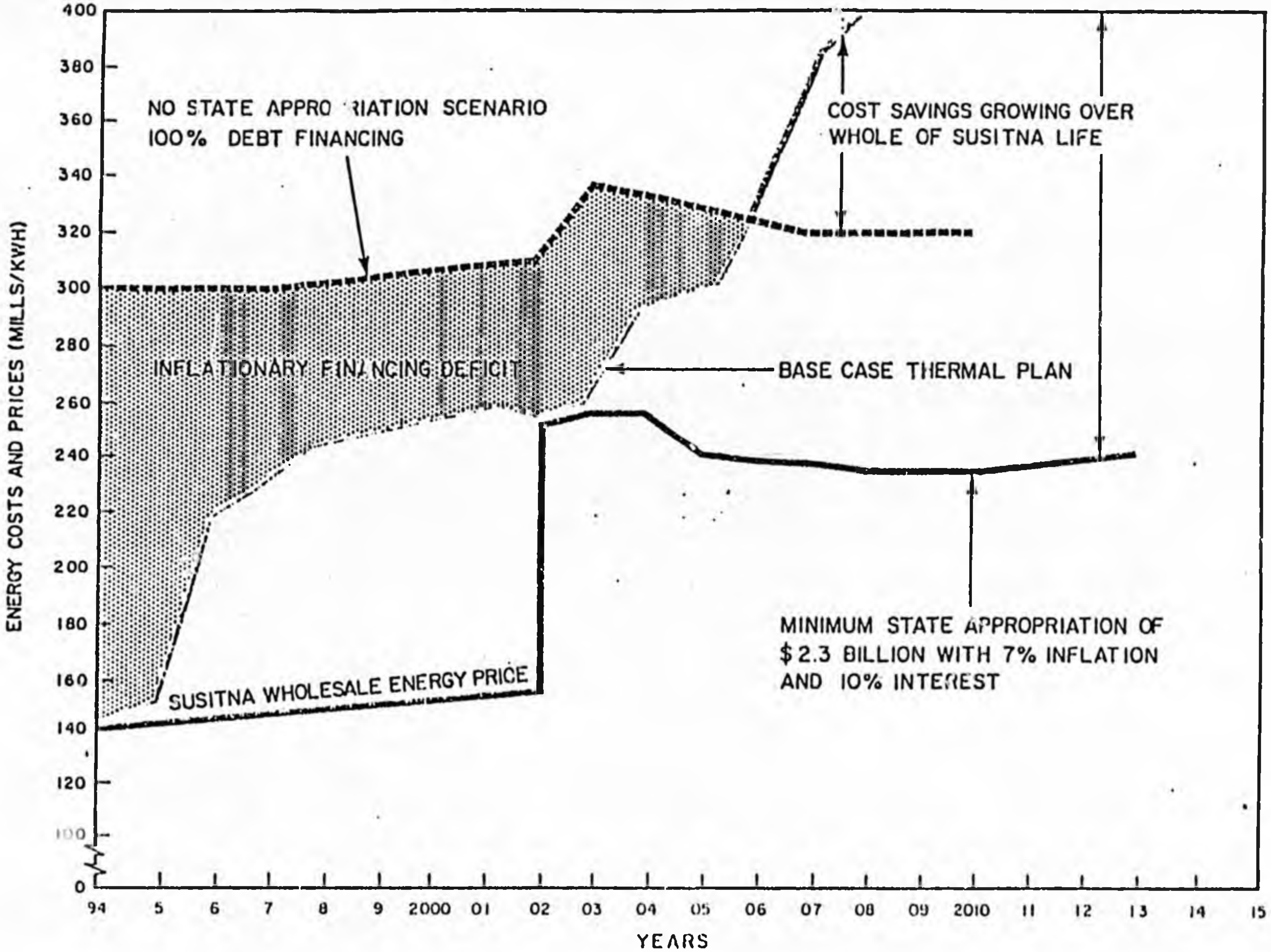


PLATE 26 | ANNUAL COST COMPARISION

ATTACHMENT G

SEATTLE BUSINESS JOURNAL February 7, 198[illegible]

STATE DEBT

State	Net Tax-Supported Debt (millions)	Per Capita	Western States	Per-Capita Debt
1. Alaska	$1,045	$2,610	Alaska	$2,610.43
2. Hawaii	1,424	1,476	Hawaii	1,476.49
3. Delaware	581	977	Washington	398.36
4. Connecticut	2,132	686	New Mexico	202.67
5. Maryland	2,851	676	Oregon	131.18
6. Massachusetts	3,355	567	California	108.79
7. New York	9,300	557	Utah	106.85
8. West Virginia	991	508	Montana	99.04
9. Louisiana	2,116	503	Idaho	21.90
10. Vermont	241	472	Arizona	19.60
11. Washington	1,645	398	Wyoming	7.07
(National median)		203	Colorado	0.28

(Information provided by Moody's Investors Service municipal department, as of Feb. 28, 1982)

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

March 25, 1983

TO: Senate State Affairs Committee Members
Senate President Jay Kerttula
Senator Bettye Fahrenkamp, Resources Chair
Senator Don Bennett, Finance Co-chair
Senator John Sackett, Finance Co-chair

FROM: Senator Vic Fischer, State Affairs Chair

RE: Committee Report on the Susitna Project

Attached is the committee report on the proposed Susitna project, based on the hearings held by the committee in late February and early March. A great deal of information was presented, and we have attempted to summarize and synthesize it into a readable document. The report also includes a list of the witnesses who testified, a copy of the letter I sent to the Governor on March 10 requesting the Administration's position on Susitna and answers to related questions, and the Governor's response of March 16.

Also provided here are minutes of the February 24, February 26, March 1, and March 3 committee meetings and transcripts of the testimony by witnesses Eileen Titmuss, Gregg Erickson, and Lee Gorsuch.

cc: All Senators
All Representatives

Note to recipients of the report only: Copies of the minutes and transcripts, as well as all documents referenced in the committee report and minutes, are available in my office.

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

SENATE STATE AFFAIRS COMMITTEE

COMMITTEE REPORT

ON

THE SUSITNA PROJECT

SENATE BILLS 68, 69, 70, AND 71

MARCH 24, 1983

Senate State Affairs Committee
Committee Report -- the Susitna Project
Senate Bills 68, 69, 70, and 71

The Senate State Affairs Committee held four days of hearings on hydroelectric development and the proposed Susitna project. Testimony on three days was primarily from witnesses invited to address specific issues. In an all-day public hearing in Anchorage, the views of more than thirty members of the public were heard. The focus of the hearings was on economic and fiscal concerns within the province of the committee.

Summary of Principal Findings

1. Alaska's oil revenues have fallen below anticipated levels, making uncertain the state's ability to fund the Susitna project.

2. Falling oil prices have also affected the net benefits of the Susitna project, and the Acres determination that the project is economically feasible may no longer be supportable.

3. Other questions, including whether Susitna would be eligible for tax-exempt bonds, remain to be answered.

4. As the federal construction license is not expected before 1986, three years remain in which to reevaluate the project's economics and financing and to gather additional data before making a decision to construct.

5. Other APA hydro projects have experienced significant cost increases. Power projects in Washington State are facing default because of poor planning and management; this is expected to result in a tighter bond market for new projects like Susitna.

6. Power sales contracts are a prerequisite for the construction of Susitna. Utilities are reluctant to sign take-or-pay contracts until they have assurance that the price of this power will be competitive with alternatives.

7. The APA is continuing to assess Susitna and the alternatives, with a report expected in May.

8. The public, while supporting hydropower generally, is concerned about the the costs of Susitna power, both in power rates and in opportunity costs.

Bills Before the Committee

Of the bills currently before the committee, SB 68, SB 69, and SB 71 would authorize construction of Susitna and would approve a finance plan for the project consisting of a state appropriation of $2.3 billion in 1983 dollars to be dedicated through a constitutional amendment and revenue bonds of the APA backed by the general obligation of the state. SB 70, an alternative financing bill, would provide for power project funding through per capita "energy dividends."

Background of The Proposed Susitna Project

The Susitna project is a two-dam (Watana and Devil Canyon) hydroelectric project proposed by the Alaska Power Authority (APA) to provide power to the railbelt area. As planned, the Watana phase (1020 MW) would come on-line in 1993 and the Devil Canyon phase (600 MW) in 2002.

A 2½-year feasibility study was conducted by Acres American at a cost to the state of $41 million. A $1 million study of railbelt power alternatives was conducted concurrently for the Governor's office by Battelle.

The Acres study concluded that the project was technically viable, environmentally acceptable, and economically feasible. The determination of economic viability was based on a number of assumptions, many of which have changed since the completion of the study last year.

The APA Board of Directors, in making its recommendations to the State of Alaska last April, noted that while the project offers a potential for long-term benefits, realizing those benefits will depend on skillful management, proper timing, and assumptions about an uncertain future holding true. They concluded, "The Authority believes it is premature to make any commitment, at this time, to actual project construction."[1]

The capital costs of the project are estimated at $5.1 billion 1982 dollars or $12.5 billion nominal dollars at 7% inflation. Acres concluded that in order for power in the early years of the project to be priced competitively against thermal alternatives, a state appropriation of $2.3 billion (later revised to $1.8 billion) in 1982 dollars would be required.[2]

This appropriation, variously referred to as an equity investment, state financing, grant, or subsidy would not be repaid to the state's treasury; instead, benefits in terms of jobs, economic development, and state electric rates would be expected to accrue to Alaskans.

Last year, the legislature authorized work to be done on project design and a license application to be submitted to the Federal Energy Regulatory Commission (FERC), and appropriated $25.6 million. The engineering firm of Harza-Ebasco has been selected for the design work; the FERC application was filed on February 28.

Financing of Hydro Projects in Alaska

The Energy Program for Alaska (AS 44.83.400), adopted in 1981, provides that power projects developed by the Alaska Power Authority are to be funded largely through cash grants from the general fund, with supplemental funds coming from the sale of revenue bonds by APA. The stated purpose of this state participation in the funding of power projects was to convert a portion of Alaska's one-time oil wealth into a renewable resource with long-term benefits to Alaskans. In addition, state funding of such capital-intensive projects would help ensure that consumer costs in the projects' early years would be competitive with the costs from alternative (oil or gas) power sources.

The Energy Program for Alaska currently includes four major hydro projects that are either in operation or under construction. These are Solomon Gulch, Swan Lake, Tyee Lake, and Terror Lake. So far, $270 million has been appropriated by the Legislature for direct funding of these projects. In addition, the APA has borrowed in the form of short-term notes $200 million in interim financing to supplement the financing of these projects.[3] The next major projects anticipated to be added to the Energy Program for Alaska are Bradley Lake and Susitna.

A characteristic of the Energy Program for Alaska is that each project must pay a proportionate share of the combined outstanding debt. This means additional debt cannot be added to the system in a proportion higher than the existing ratio of debt to state funding without raising all rates throughout the system.

Under this system there must be sufficient state revenues available if hydroelectric projects are to be successfully financed in Alaska. As 88% of the state's income comes from oil revenues, the future of the state, and its hydro development plans, is inextricably tied to the price of oil on the world market.

Future State Oil Income

There is now great uncertainty concerning the direction in which oil prices, which have fallen significantly in the last year, are heading. While some analysts believe that prices will stabilize in the long-run and continue to escalate in real terms, others anticipate a serious drop in the short-term that will only very gradually return to price levels experienced during the last decade.[4]

To demonstrate the expected severe decline in state revenues, the Institute of Social and Economic Research compared their 1983 preliminary projections of petroleum revenues with projections they made just two years ago.[5]

For FY 84, their former projection of $5.6 billion (nominal dollars) compares to the new projection of $3.2 billion. For FY 93 (the year in which the Watana phase of Susitna could be expected to come on-line) the 1981 projection of $13.8 billion compares with a new projection of just $4.0 billion.

The Department of Revenue and the Legislative Finance Division have projected similar revenue declines.[6] <u>Alaska's peak oil revenue year appears to have already passed</u>.

Effect of Oil Prices on Susitna

Lower oil prices will affect the Susitna project in at least four major ways:

1) Lower state revenues may be insufficient to pay for Susitna.

Reduced state income may mean that there are insufficient state funds to pay for the state's portion of Susitna.

The Legislative Finance Division has compared projected revenues to funds available for capital projects and to funds needed for Susitna.[7] They identify just $2.4 billion in nominal dollars available for all capital projects between 1985 and 1993, under current law, after subtracting funds needed for the operating budget. This compares to the $3.5 billion alone that would be required for Susitna under SB 68 and to the $11.7 billion that has been identified for other planned capital projects. Even if the law were changed so that both permanent fund inflation-proofing and dividends were repealed, the analysis shows that there would still be a total of only $6.6 billion available for capital projects in the same time period.

2) Less state spending and reduced economic activity decreases the demand for power.

Battelle, in revising its electricity forecasts for the railbelt last year, adjusted its forecasts downward to reflect this effect.[8] The previous peak demand projected for 1995, for example, was 993 MW in the moderate case; the revised peak demand is 791 MW for the same year.

3) Lower inflation rates may result in higher financing costs.

If interest rates remain high, the discount rate--the difference between inflation and interest rates-- will increase. Higher discount rates will result in higher real costs for bonds.

4) Thermal alternatives to Susitna will be cheaper than anticipated.

Less expensive thermal alternatives (oil, gas or coal) reduce the net economic benefits of Susitna. The financial feasibility of Susitna would also be affected, as more state funding would be required to assure the marketability of Susitna power. The House Research Agency has studied the effect of lower natural gas prices on Susitna feasibility.[9] The recent gas contracts signed by Enstar Natural Gas Company and the Department of Revenue's most-recent oil price escalation forecast were used as the basis for comparison with the Acres feasibility analysis. The conclusion was that if oil prices correspond closely to the Department of Revenue's forecast, the price of power from gas generation would be 38% less in 1994 than projected by Acres, and 50% less in 1996. This means that, in order for the price of power from Susitna to be at a marketable rate, an additional $600-700 million in state grant funds, above the $1.8 billion projected by Acres, would have to be appropriated to the project.

Key Feasibility Factors

The real discount rate and fuel price escalation are the key feasibility factors that must fall within defined limits for Susitna to be an economically feasible long-term source of railbelt power. Acres, in performing the feasibility analysis, made assumptions on future values of these factors based on the information available at the time of the study. Acres performed a sensitivity analysis,[10] that showed the net economic effect of changes in these assumptions.

Acres assumed a base case discount rate of 3%, and the APA continues to assume that Susitna financing can be obtained at that rate. Acres concluded that Susitna was viable only with a discount rate of less than 4.2%. A discount rate of 5%, the sensitivity analysis showed, would result in a negative net benefit of over $500 million. The current discount rate, according to Data Resources Inc., is more than 6%.[11] Even that favorable rate assumes tax-exempt financing.

It is not clear whether Susitna bonds will be eligible for tax-exempt status. According to the APA, the IRS has indicated that the "two-county rule" would prohibit tax-exemption, unless power sale contracts were something other than take-or-pay. The APA has identified alternative methods of obtaining tax-exempt status, including granting the APA authority to retail power (by-passing the utilities) or restructuring the existing utilities.[12]

The fuel escalation rate assumed by Acres in its base case was 2.6% above inflation to 2000 and 1.2% to 2010. An escalation rate less than 1%, according to the APA, would result in negative net benefits. A zero percent escalation rate would result in a negative net benefit of over $1 billion.

Other critical factors in the feasibility analysis include load forecasts, capital costs and capital cost escalation, and base fuel costs.

There is now considerable uncertainty regarding oil and gas price trends. Other elements of the feasibility analysis are also in flux. The APA is currently reevaluating the assumptions for its Susitna update, which will be reviewed by the Office of Management and Budget. Much of this information can be fed into computer models, so that project feasibility may be continually monitored.

Susitna Financing Plan

The APA is required by statute to submit a finance plan for each proposed project. Acres has prepared a report for the APA, "Task 11: Financing Options," which is the first step towards a finance plan for Susitna.

The financing options suggested by Acres, and reviewed by the APA's financial advisors, involve state appropriations of between $1.4 and $1.8 billion (1982 dollars) between 1984 and 1989, with the balance of funding coming from revenue bonds. Two of the four options involve state appropriations guaranteed through a constitutional amendment.

Among the recommendations of APA's financial advisors are that prior to major state expenditures or the sale of any bonds, participating utilities sign definitive contractual commitments, an updated economic and financial analysis of the project be completed, and the question of whether or not tax-exempt bonds can be sold be answered.

The advisors stressed that bonding, to the greatest degree possible, should be with revenue bonds, backed by the moral obligation of the state, rather than relying upon general obligation (G.O.) bonds . They said that G.O. bonds would, in any case, be of limited usefulness, as they will be marketable only if their maturity dates fall within the state's short oil revenue curve, and the state can only incur an additional \$565-\$900 million in G.O. debt without negatively affecting its bond rating. The advisors also recommended that the state appropriation be made first, before any bonds are sold.

Cost History of Other Power Projects

The four hydro projects of the APA that are either in operation or under construction have experienced significant increases in construction cost estimates between the feasibility and actual construction stages. These have varied from 54% for Swan Lake to 218% for Tyee.[13]

The committee specifically reviewed the Tyee Project. Its wholesale power price, even with the state paying 70% of the capital costs, will be much higher than the cost of diesel power for Petersburg and Wrangell. Problems identified were major changes in project design, poor initial cost estimates, poor review of cost estimates, poor pricing analyses, hasty decisions made without the benefit of accurate data and analysis, overcapacity resulting in underutilization, and mid-project statutory changes.

In response to committee concerns, APA staff testified that they expect to gain better control of project costs in the future through more professional and complete engineering work, closer supervision by the APA, and a requirement for independent cost estimates.

Other lessons may be learned from the experiences of the Washington Public Power Supply System (WPPSS), as explained by Eileen Titmuss, a bond analyst for Drexel, Burnham, and Lambert in New York City.

In WPPSS, Washington created an agency to enter into long-term power sales contracts with utilities to build nuclear plants. The bond market believed that the projects were backed by the full faith and credit of the U.S.

Government, and the bonds found a generous market acceptance. In truth, the real security behind the bonds was the ability of the Bonneville Power Administration to raise rates. When costs of the nuclear plants rose and power demand proved to be less than had been projected, two of the five plants had to be mothballed and a substantial rate increase was proposed. Participating utilities balked at the increase, claiming they simply could not raise the required revenues, despite take-or-pay contracts.[14] This has resulted in a revenue shortfall that may soon force WPPSS into defaulting on these bonds.

The lessons of WPPSS that could be applied to Susitna include knowing true and full project costs, having realistic demand forecasts, requiring the utilities to participate in project investment, providing for rate-payer education and involvement, and close state monitoring of agency management and contracting.

The bond market, after WPPSS, is expected to be tighter because of competition for funds among other large-scale projects. In addition, bond purchasers can be expected to take a harder look at both the sanctity of power sales contracts and the economic assumptions underlying project feasibility analyses.

Power Sales Contracts

Power sales contracts help assure the marketability of a project's power. It is standard industry practice to obtain power sales contracts prior to beginning project construction.[15]

Until now, the APA has not followed this practice, and utilities have been under no obligation to purchase power from its completed projects. In the Ketchikan case, the power sale contract that was eventually signed allows the utility to cease purchasing Swan Lake power if it becomes higher priced than the diesel alternative.

The APA is currently in the process of developing a standard take-or-pay contract, requiring utilities to purchase the power regardless of its cost.

Utilities are understandably reluctant to sign such contracts if the price of project power may cost more than the alternatives. This problem has been most apparent in the case of Petersburg and Wrangell, where it appears that the power from Tyee Lake will cost significantly more than continuing to generate with diesel.

Utilities are also reluctant to sign take-or-pay contracts for power under the Energy Program for Alaska because of flaws in the legislation.[16] One concern is the provision that if $5 billion is not appropriated for energy projects by 1986, all projects must pay a 10% return on state investment each year. Further, because of the "pooling" nature of the Energy Program for Alaska, utilities are responsible for paying a proportionate share of any new debt that enters the system and have no control over rate increases to meet that debt. This makes it impossible to predict rates or ensure price stability.

The APA has recommended, the Federal Energy Regulatory Commission will require, and the Governor has insisted that construction not begin on Susitna without first having rigorous power sales contracts in place. The utilities are reluctant to make commitments and have indicated that they will not do so until they have a better assurance that Susitna costs will be competitive with alternatives.

All major railbelt utilities were represented at the Anchorage hearing, and all testified that they must have more information about the level of state funding and the possible price of power before they will be willing to negotiate take-or-pay contracts.

Although the Alaska Public Utilities Commission has no jurisdiction over the APA, it does have authority to review the power supply contracts of regulated utilities to ensure reasonable consumer rates. It would likely become involved if the reasonableness of Susitna prices came into question.

Information and Work Schedule

APA's Susitna feasibility update will not be completed until mid-May, and will include, besides economic feasibility factors, information on alternatives including Cook Inlet gas, North Slope gas, coal, and Chakachamna hydro.

The Administration indicated that it will be prepared, also in May, when oil market fluctuations may have steadied, to discuss the state's ability to finance Susitna.

A license application was filed with FERC on February 28, 1983. FERC approval for construction is not expected until December 1986, although FERC hopes to expedite the approval process.

The APA Board of Directors, meeting March 14, altered their request for funding for the Susitna project from the $37 million recommended in the Governor's preliminary FY 84 capital budget to $22 million. This smaller amount of money will enable them to continue with the work required for FERC licensing, but will not provide for detailed design engineering. The reason given for the decision was to request funds only as needed; as FERC licensing is expected to take three years, it is not necessary to proceed with detailed design work during FY 84.

The APA is also studying the possibility of lowering the height of the Watana Dam. Preliminary indications are that dropping the dam height by 85 feet could save 10% of the Watana construction costs for 12% less annual energy, while a drop of 185 feet could save 20% of the costs for 26% less energy. The intent of such a design change would be to enhance the financial viability of the project by requiring less appropriation of state funds. Although the project cost would decrease, the per unit cost of energy would increase.

Conclusions

The two major outstanding questions regarding the viability of the Susitna project concern its economic and financial feasibilities.

Economic feasibility relates to the project's net benefits, compared to the alternatives for providing electricity to the railbelt. The study completed by Acres in 1982 concluded that at that time the project appeared feasible. Since that time, a number of fundamental assumptions have changed and remain unsettled. An updated feasibility analysis is required to determine if Susitna remains the most economic choice.

This feasibility analysis must realistically consider the alternatives to Susitna. These include Cook Inlet gas, North Slope gas, coal, other hydro including Chakachamna, and conservation. Each of these alternatives has so far received far less consideration than the Susitna option.

Financial feasibility relates to whether, regardless of the project's economic feasibility, the project can be financed so that the price of power will be at a marketable rate. The Acres analysis showed that a state appropriation of at least $1.8 billion (in 1982 dollars) would be required to keep the price of power competitive. Unless Alaska is both willing and able to pay this price, the project will not be financially feasible, utilities will not contract to purchase Susitna power, and project bonds will not be marketable.

A workable finance plan for Susitna needs to answer at least three questions:

(1) How much does the state need to appropriate to Susitna to assure that its power will be initially priced no higher than the alternatives?

(2) Will state revenues be sufficient to make such an appropriation without negatively impacting other state needs?

(3) Can a mechanism be developed that

would either guarantee the availability of the necessary funds or provide for the accumulation of all necessary funds prior to bonding and construction?

The finance plan proposed in the legislation before the committee does not answer these questions. The state revenues available for Susitna have not been determined, the tax-exempt status of Susitna revenue bonds is uncertain, the degree to which the state can safely obligate to back the revenue bonds is unknown, and other elements of a successful finance plan are absent. Accordingly, the basis for acting on the bills is not currently available.

A public vote would be desirable to assure public acceptance of both project subsidies and future power rates. Such a vote requires a realistic and workable finance plan, and a question for the voters with specific information as to total project costs and levels of state funding.

The FERC license for Susitna is not expected before late 1986, so a construction decision is not required at this time.

NOTES

1. Letter from Charles Conway to Governor Hammond, April 26, 1982.

2. A distinction is made between economic feasibility and financial feasibility. Economic feasibility relates to whether a project is the lowest-cost option in the long-run. Financial feasibility relates to the ability to finance a project in such a manner that the price of power is competitive with alternatives. A project might thus be economically feasible without being financially feasible.

3. The interim financing is divided between Tyee Lake ($50 million), Swan Lake ($35 million), and Terror Lake ($115 million).

4. Recent forecasts are noted in "Alaska Energy Planning Studies," by Arlon Tussing and Gregg Erickson, Nov. 1982. The authors note that, while the government agency forecasters referenced by Acres project increases in real oil prices, recent internal forecasts by petroleum producers assume real declines through 1985 and a long-term trend between a level nominal-dollar and a level constant-dollar trajectory. The significance of varying forecasts is not whether one may be more reliable than another but that there is neither consensus nor certainty.

5. "Comparison of ISER MAP Model Projections Prepared in 1981 for Battelle Railbelt Study and Preliminary Projections Prepared in 1983," prepared for the Alaska Senate State Affairs Committee by Scott Goldsmith and Gunnar Knapp, Feb. 1983

6. All revenue projections are simply projections, and actual revenues could vary widely. The Department of Revenue currently bases its projections on the 30th percentile of probability, which means that there is a 70% chance that revenues might be higher than projected. With the recent drop in OPEC prices, however, the 30th percentile projections are considered most likely.

7. "Funds available for Capital Projects," memo to Senator Vic Fischer from Milt Barker, Fiscal Analyst, Feb. 21, 1983

8. "Railbelt Electric Power Alternatives Study," Battelle, Volume 1, Dec. 1982, p. xv

9. "Comparison of Susitna and Natural Gas Power Costs," memo to Rep. Hugh Malone from Jack Kreinheder, Research Staff, March 3, 1983

10. Plate 24, "Sensitivity Analysis," Acres summary report, 1982

11. Data Resources U.S. Review, Feb. 1983

12. APA Susitna "Checklist," Table 1, transmitted to Governor Sheffield Jan, 17, 1983

13. "Cost History of APA Hydro Projects", Chart 5 accompanying transcript of testimony by Gregg Erickson before the Senate State Affairs Committee, March 1, 1983

14. In Oregon, the courts have ruled that contracts binding municipal utilities to WPPSS debts are illegal. At question is whether the utilities had the right to make such commitments without a vote of the ratepayers.

15. Letter to Charles Conway from Eric Yould, October 11, 1982

16. "Marketing of Project Power Under the Energy Program for Alaska," memo from Myles Yerkes to Eric Yould, Dec. 28, 1982

WITNESSES WHO TESTIFIED BEFORE THE COMMITTEE

WITNESS	AFFILIATION
Governor Sheffield	Administration
Eric Yould	APA
Ray Benish	APA
William Wakefield	FERC
Tom Singer	Erickson & Associates
Ernie Haugen	Thomas Bay Power Commission
Richard Underkofler	City of Petersberg
Kenneth Mason	City of Wrangell
George Matz	OMB
Ernie Mueller	Environmental Services, Limited
Kent Wick	Homer Electric Association
Bob Mellin	Self
Mike Kelly	Golden Valley Electric Association
Jeff Bohman	Self
Harold Pomeroy	Self
Jeff Eustis	Self
Bob Penney	State Chamber of Commerce
Mano Frey	Laborers' Union Local 341
Joseph Henri	Resource Development Council
Jim Ayres	Self
Paul Lowe	Self
Larry Underwood	Self
Wayne Beckwith	Anchorage Chamber of Commerce
Budd Goodyear	Matanuska Electric Association
Tom Stahr	Municipal Light and Power
Lee Woreham	Susitna Power Now
Liz Gilbert	Chugach Electric Association
Sharon O'Dell	Self
Nancy Lee	Self
Mary Pat Haberle	Self
Keith Treseder	Self
Victor Mittasch	Self
Judy Zimicki	Northern Alaska Environmental Center
Jim Sykes	Self
George Skladal	Self
Doug Stark	Self
Ron Kuzek	Self
Mark Beltz	Self
Bill Holton	Self
Brian Boyd	Self
Earl Finkler	CSM

Chuck Konigsburg	Self
Lisa Moorehead	Self
George Rogers	Self
Don Grimes	First Southwest
Steve McAleer	First Boston
Sterling Gallagher	John Nuveen
Tony Merritt	Acres American
Gervin Wernock	Acres American
Eileen Titmuss	Drexel Burnham Lambert
Gregg Erickson	Erickson and Associates
Lee Gorsuch	ISER
Milt Barker	Legislative Finance Division
Robert Heath	Department of Revenue
Harrison Call	RMI Pacific Northwest
Carolyn Guess	APUC
Dick Emmerman	OMB
David Rogers	Senate Advisory Council
Al Carson	DNR
Dennis Kelso	ADFG

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

March 10, 1983

Honorable Bill Sheffield
Office of the Governor
Pouch A
Juneau, Alaska 99811

Dear Governor Sheffield:

The Senate State Affairs Committee has completed extensive hearings on the proposed Susitna hydroelectric project. We appreciated your taking the time to share your thoughts on this project with us.

The inescapable conclusion of the hearings is that the precipitous drop in oil prices has substantially altered the economic foundations of the Susitna project. Unless an immediate and thorough re-evaluation is made, and new answers provided, Susitna may well change from its desired goal of being the high benefit keystone to future state development into an uneconomic white elephant with an appetite for state funds capable of destroying Alaska's economy for years to come.

It has become clear that action by you and your administration is critical before the project can move ahead, and before we will be in position to act knowledgeably on legislation pending before the Senate State Affairs Committee (SB 68, 69, 70, and 71). We trust that you will cooperate in providing the necessary information and answers.

A summary of the extensive information and analytical work presented at the hearings will be completed next week and will be presented with the meeting minutes and edited transcripts. The purpose of this letter is to share with you, immediately, some of the questions that have been raised so that they may begin to get the attention that they require.

Though most people favor hydroelectric power and Susitna, the crucial question now facing Alaska is, simply, how and whether the state can pay for the project. The economic and financial picture was quite different a few years ago, when oil revenues were piling up and it appeared that we would have billions of dollars in "surplus" revenues to spend on Susitna. If we are to proceed, we must find new ways of financing the project that will not undermine the fiscal structure of the state.

The committee was told that falling oil prices will affect the Susitna project in four ways:

*First, state revenues will be lower, and the funds simply will not be available to appropriate the state's "equity" portion without sacrificing other needs. As Lee Gorsuch, of the Institute of Social and Economic Research, testified, it now looks as though our peak revenue year may well be past.

*Second, lower state revenues will result in less economic activity within the state, which will reduce the future demand for the project's power.

*Third, lower oil prices and reduced economic activity should result in a lower inflation rate, which may raise the real cost of project financing.

*Fourth, lower prices mean that the cost of the thermal alternatives to Susitna will be less.

To elaborate on the last point, a recent memo by the House Research Agency indicates that with lower than expected gas prices (as evidenced by the recent Enstar contracts) the Susitna project would need subsidies of an additional $600-700 million in state appropriations, above the minimum$1.8 billion projected by Acres, as necessary to simply make Susitna power marketable relative to the alternatives.

Given the projected revenue situation, an awareness seems to be emerging that the factors that made Susitna an economically positive project just a short time ago may no longer be present. These factors must be continually monitored from this time forward so that when the time is right, we will be in a position to go forward with Susitna. Some of these factors, as identified by OMB, are:

--load forecasts
--fuel prices
--capital costs
--the discount rate

All of these factors are now different from the assumptions made by Acres in evaluating Susitna eighteen months ago, and are still changing.

At this stage, we have identified some of the key issues and questions that now need to be addressed in order to proceed with decisions on Susitna. We need your help to deal with them.

1. FINANCING

The basic question is: is there, can there be, a workable finance plan for Susitna? So far, the Alaska Power Authority has not presented a finance plan, only a list of possible options. APA has suggested that only a dedicated revenue stream of $1.8 billion ($1982) would satisfy the need for a cash contribution by the state, with revenue bonds to supplement the financing. Analysis by the Legislative Finance Division, however, has found that such a dedicated stream would leave no money for any other capital projects in the whole state. Commissioner Heath has indicated that the administration is "very nervous" about Susitna financing, but is not prepared to comment more specifically on a finance plan until some of the uncertainties in the oil market are resolved. I believe we will have no progress on Susitna until a realistic financing plan is in place, one that can be approved by all parties.

What are Administration plans with respect to Susitna financing?

Is a financing plan being prepared?

When can the legislature expect a bona fide proposal from the administration for financing Susitna?

What is the Administration position on the financing bills pending before the Senate State Affairs Committee?

SB 68 -- advisory vote on financing Susitna
SB 70 -- Alaska Energy Dividend Fund
SB 71 -- bonding for Susitna

2. UPDATING ASSUMPTIONS

Which of the Susitna study and feasibility assumptions need to be updated, and how shall the updates be incorporated into the project's evaluation?

Who will be responsible for what data, and how will it all be tracked?

When will an authoritative re-assessment be available?

Many of the factors in question were identified during our hearings. They include the forecasted demand, fuel prices and price escalation, capital costs, and the bond discount rate. The APA is responsible for the update, but they have indicated that it will not be completed until May. Even then, these factors will still be subject to considerable uncertainty.

3. DECISION TIMING

You and others testified to the necessity to meet various criteria before a decision can be made to go ahead with Susitna.

The FERC representative, William Wakefield, testified that FERC approval is not likely before December, 1986, maybe not until 1987.

How far shall we go and what shall we do with Susitna before we are sure that it is both feasible and financable?

What is the Administration position on SB 69, which would authorize first phase construction of Susitna?

What schedules do you anticipate for provision of necessary answers?

APA staff testified that a smaller Watana Dam is under consideration. They also indicated the possibility of a different, single dam on the Susitna River in lieu of the two-dam configuration; it would be designed for smaller load demands and would cost less. At the same time, site specific design and engineering are being considered and appropriations have been requested to pursue plans previously prepared.

What timing and effort is considered appropriate for further preparatory work pending FERC approval? What further action will be required in pursuit of FERC application action? What costs are entailed in what activities in FY 84, 85, and 86? In other words, how much money is required, and when, to keep the Susitna project viable during the FERC application and re-evaluation periods?

4. RELATIONSHIP TO BRADLEY LAKE

APA staff testified that Bradley, in order to compete with gas, would require a cash contribution of 50-75% of the project cost which is estimated at a total of about $400 million.

How does Susitna fit with the need for and financing of other planned hydro projects, specifically Bradley Lake?

How and when shall we proceed with Bradley? Shall it be the 135 MW size or the 60-90 MW size? Such decisions are clearly intertwined with a decision on the timing of Susitna, and they need to be addressed in that context.

In addition, is it wise to begin funding this smaller but still expensive dam incrementally, without considering where the full funding will come from and whether we can afford it either with or without Susitna?

5. ALTERNATIVES

Serious questions have been raised about the extent to which alternatives to Susitna hydro have been adequately examined. This matter becomes particularly important if Susitna decisions are deferred due to financing, marketability, or other problems.

It has been very difficult in the past to evaluate alternatives--gas, coal, other hydro--because they have not enjoyed the same degree of financial support as Susitna. Although many studies have been completed, the focus has not always been clear. For example, of the two recent studies concerned with using North Slope gas for electrical generation, one (Ebasco) is principally a hardware study, and the other (Booz-Allen) basically avoided the option because Ebasco had already looked at it. The representative from Booz-Allen, when asked to compare the gas option to Susitna, commented that the way to decide on how to meet railbelt electrical needs was to identify the need and then look at all the options, not to identify a source and then show how it could serve the need.

It was also suggested that we let the marketplace do the choosing, and then decide whether to subsidize the capital costs of that choice.

In any case, in order to be prepared, additional consideration of the short-term and long range alternatives to Susitna appear to be called for.

How can we best continue to evaluate alternatives? Who should do that?

Are there technologically "clean" ways of using coal for power generation? Could such use facilitate development of coal resources for export and other economic development? Would state subsidies be required to make that feasible? How much money would be required to adequately study coal potentials?

How can we best determine what the realistic prospects are for use of gas to meet future power demand? What effect would state equity or subsidies akin to Susitna have on future gas and power cost?

Chakachamna and other hydro?

The Department of Commerce and Economic Development (DCED) has documented significant savings, even in Anchorage, through residential energy conservation. In other parts of the country, utilities have found that it's usually more cost effective to invest in conservation than in new generating facilities. Even though conservation will not by itself solve future power requirements problems, its potential for energy and cost savings is enormous.

What role can and should conservation play in decreasing the need for additional power for the railbelt?

How do the benefits of other alternatives, including subsidized power costs, compare with the benefits of energy conservation?

There are many other questions that need to be answered in the near future, including: tax-exempt bonding, land ownership, fisheries mitigation, and power sales contracts. The ones I noted above seem, based on the committee hearings, to be those that are the most basic and urgent at this time.

The above questions are, of course, difficult to answer. But they must be confronted in light of the fiscal realities now faced by the Susitna Project. As the issues before us are of such importance that they must be addressed at the highest level, I look forward to your Administration taking the lead in seeking answers to all the many questions and establishing a policy course for Alaska's energy future.

It is clear from the information we obtained in the hearings that legislative actions on Susitna will be stymied unless we receive critical financial and other information from your administration. Your cooperation in this will be greatly appreciated.

Sincerely,

Vic Fischer

Senator Vic Fischer

cc: Commissioner Dick Lyon
Commissioner Esther Wunnike
Commissioner Dan Casey
Peter McDowell, OMB
Charles Conway
John Schaeffer
Robert Huffman

BILL SHEFFIELD
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

March 16, 1983

The Honorable Vic Fischer
Senator
Alaska State Legislature
Pouch V
Juneau, AK 99811

Dear Senator Fischer:

This will acknowledge receipt of your letter of March 10, sharing with me the questions raised during the extensive hearing held by the Senate State Affairs Committee on the proposed Susitna hydroelectric project.

A copy of your list of questions has been sent to the Commissioner of the Department of Commerce and Economic Development, Dick Lyon. I have asked him to personally coordinate the Administration's response to these questions and to assist you further, if necessary.

I look forward to receiving a summary of the hearings when it is completed.

Sincerely,

Bill Sheffield

Bill Sheffield
Governor

JAY S. HAMMOND, GOVERNOR

STATE OF ALASKA

Pouch 7-028
Anchorage, Alaska 99510
274-9681

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF GEOLOGICAL & GEOPHYSICAL SURVEYS

February 1, 1983

Mr. Eric P. Yould
Executive Director
Alaska Power Authority
334 West 5th Avenue
Anchorage, Alaska 99501

Dear ~~Mr. Yould~~ Eric:

The Division of Geological and Geophysical Surveys, Department of Natural Resources has just completed a preliminary appraisal of the undiscovered oil and gas resource potential of the Cook Inlet Basin. The area assessed is outlined in Attachment "A". Attachment "B" presents the resource distributions for oil, gas and their sum, barrels of oil equivalent (BOE), in place. That is, these "in place" distributions reflect total quantities of fluids trapped in reservoir rock; no adjustment is made to account for any economic considerations such as what proportion of in place resources in a reservoir are actually recoverable.

However, in response to your request, in the November 5, 1982 letter to Commissioner Katz, for estimates of "economically recoverable" resources we have developed a method for adjusting the in place resource distributions to approximate what proportion might be economically recoverable. This approximation method applys two assumptions regarding what proportion of the resources in a reservoir would actually be recovered and what size a reservoir would have to be to be commercial. By assumption we have used recovery factors of 0.5 for oil and 0.9 for gas and minimum commercial deposit sizes of 50 million bbl. for oil and 200 billion cubic feet for gas. Based on these assumptions Attachment "C" presents our preliminary estimate of the undiscovered but economically recoverable oil and gas resources in the Cook Inlet Basin. Summarizing Attachment "C", the expected (average) amount of undiscovered but economically recoverable natural gas remaining in the Cook Inlet Basin is two trillion cubic feet, with a 5 percent chance that it could be as much as five trillion cubic feet.

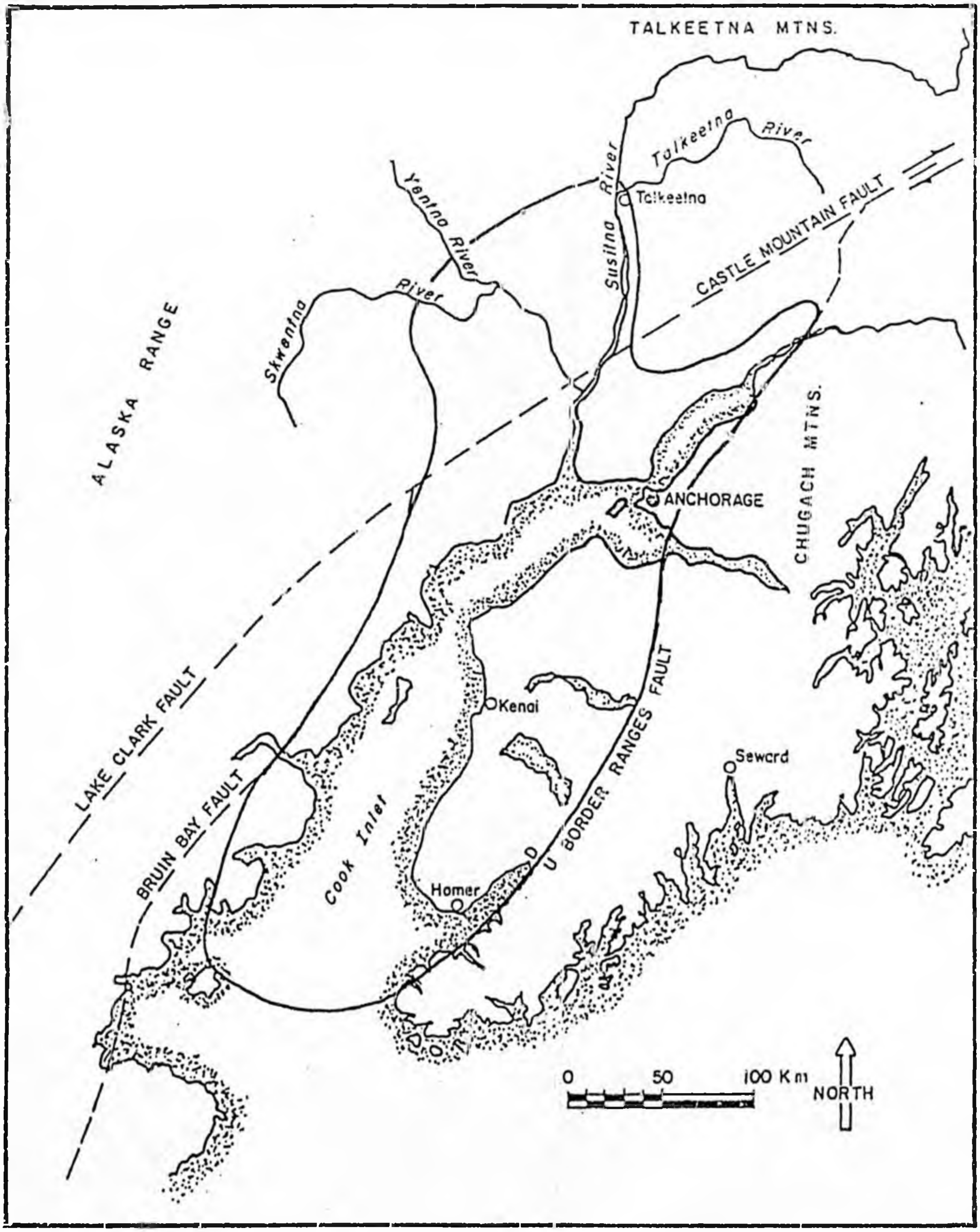
A full report on these assessments is in preparation and will be published as a DGGS Open File Report in the near future. Should you have any questions regarding these preliminary assessments please contact Red White of my staff.

Cordially yours,

Ross G. Schaff
State Geologist

cc: Commissioner Wunnicke, DNR

RGS/plc


TALKEETNA MTNS.
Talkeetna River
Talkeetna
Susitna River
Yentna River
Skwentna River
CASTLE MOUNTAIN FAULT
ALASKA RANGE
CHUGACH MTNS.
ANCHORAGE
LAKE CLARK FAULT
BRUIN BAY FAULT
Kenai
Seward
Cook Inlet
BORDER RANGES FAULT
U
D
Homer
0
50
100 Km
NORTH

PRELIMINARY ESTIMATES OF UNDISCOVERED OIL AND GAS RESOURCES IN PLACE FOR THE COOK INLET BASIN

Division of Geological and Geophysical Surveys
Department of Natural Resources
State of Alaska
January 28, 1982

RESOURCES IN PLACE[a] (barrels of oil equivalent)		DEPOSIT SIZE[b]		OIL IN PLACE		GAS IN PLACE[a]	
Probability that quantity is at least the given value (%)	Billions of barrels of oil equivalent	Conditional probability that size is at least the given value (%)	Billions of Cubic Feet	Probability that quanity is at least the given value (%)	Billions of barrels	Probability that quanity is at least the given value (%)	Trillions of cubic feet
99	.13	99	1.5	99	.00	99	.47
95	.28	95	5.2	95	.00	95	.93
90	.38	90	9.6	90	.03	90	1.24
75	.61	75	26.8	75	.13	75	1.98
50	.96	50	76.0	50	.36	50	3.07
25	1.43	25	203.3	25	.73	25	4.38
10	2.02	10	475.2	10	1.20	10	5.84
5	2.49	5	761.7	5	1.62	5	6.93
1	3.76	1	1688.2	1	2.72	1	9.06
Average BOE	1.12	Average Deposit Size	191.6	Average Oil	0.53	Average Gas	3.36

[a]Because the distribution of each resource is estimated indepenaently, "Gas in Place" after conversion to barrels of oil equivalent, cannot be added to "Oil in Place" to get "Resources in Place (barrels of oil equivalent)" at any probability level except at the expected value (average).

[b]Conditional upon the existence of oil and gas deposits in the Cook Inlet Basin, this column presents the estimated distribution of deposit size measured in cubic feet of gas.

PRELIMINARY ESTIMATES OF UNDISCOVERED OIL AND GAS ECONOMICALLY RECOVERABLE RESOURCES

FOR THE COOK INLET BASIN

Division of Geological and Geophysical Surveys
Department of Natural Resources
State of Alaska
January 28, 1983

ECONOMICALLY RECOVERABLE RESOURCES[a] (barrels of oil equivalent)		DEPOSIT SIZE[b]		ECONOMICALY RECOVERABLE OIL		ECONOMICALLY RECOVERABLE GAS[a]	
Probability that quantity is at least the given value (%)	Billions of barrels of oil equivalent	Conditional probability that size is at least the given value (%)	Billions of Cubic Feet	Probability that quanity is at least the given value (%)	Billions of barrels	Probability that quanity is at least the given value (%)	Trillions of cubic feet
99	.00	99	202	99	.00	99	.00
95	.09	95	211	95	.00	95	.22
90	.15	90	223	90	.00	90	.43
75	.28	75	266	75	.00	75	.93
50	.50	50	373	50	.14	50	1.76
25	.78	25	597	25	.32	25	2.78
10	1.12	10	993	10	.55	10	4.04
5	1.39	5	1358	5	.78	5	4.90
1	2.01	1	2353	1	1.31	1	6.83
Average BOE	0.58	Average Deposit Size	525	Average Oil	0.22	Average Gas	2.04

[a]Because the distribution of each resource is estimated independently, "Economically Recoverable Gas" after conversion to barrel of oil equivalent, cannot be added to "Economically Recoverable Oil" to get "Economically Recoverable Resources" (barrels of oil equivalent)" at any probability level except at the expected value (average).

[b]Conditional upon the existence of oil and gas deposits in the Cook Inlet Basin region, this column presents the estimated distribution of deposit size measured in cubic feet of economically recoverable gas.

S U S I T N A   P R O J E C T   S T A T U S   R E P O R T

F E B R U A R Y 1 9 8 3

FIVE STAGES OF PROJECT DEVELOPMENT

RECONNAISSANCE STUDY	PRELIMINARY ANALYSIS. NARROW RANGE OF OPTIONS
↓	
FEASIBILITY STUDY	DETAILED ALTERNATIVES COMPARISON. FEASIBILITY LEVEL COST ESTIMATE. INDEPENDENT COST ESTIMATE. FINANCE OPTIONS.
↓	
DESIGN AND PERMITTING	FINAL COST ESTIMATE. CONSTRUCTION DECISION. FINAL FINANCE PLAN. POWER SALES AGREEMENTS.
↓	
PROJECT CONSTRUCTION	OPERATION AND MAINTENANCE AGREEMENTS.
↓	
OPERATION AND POWER PRODUCTION	

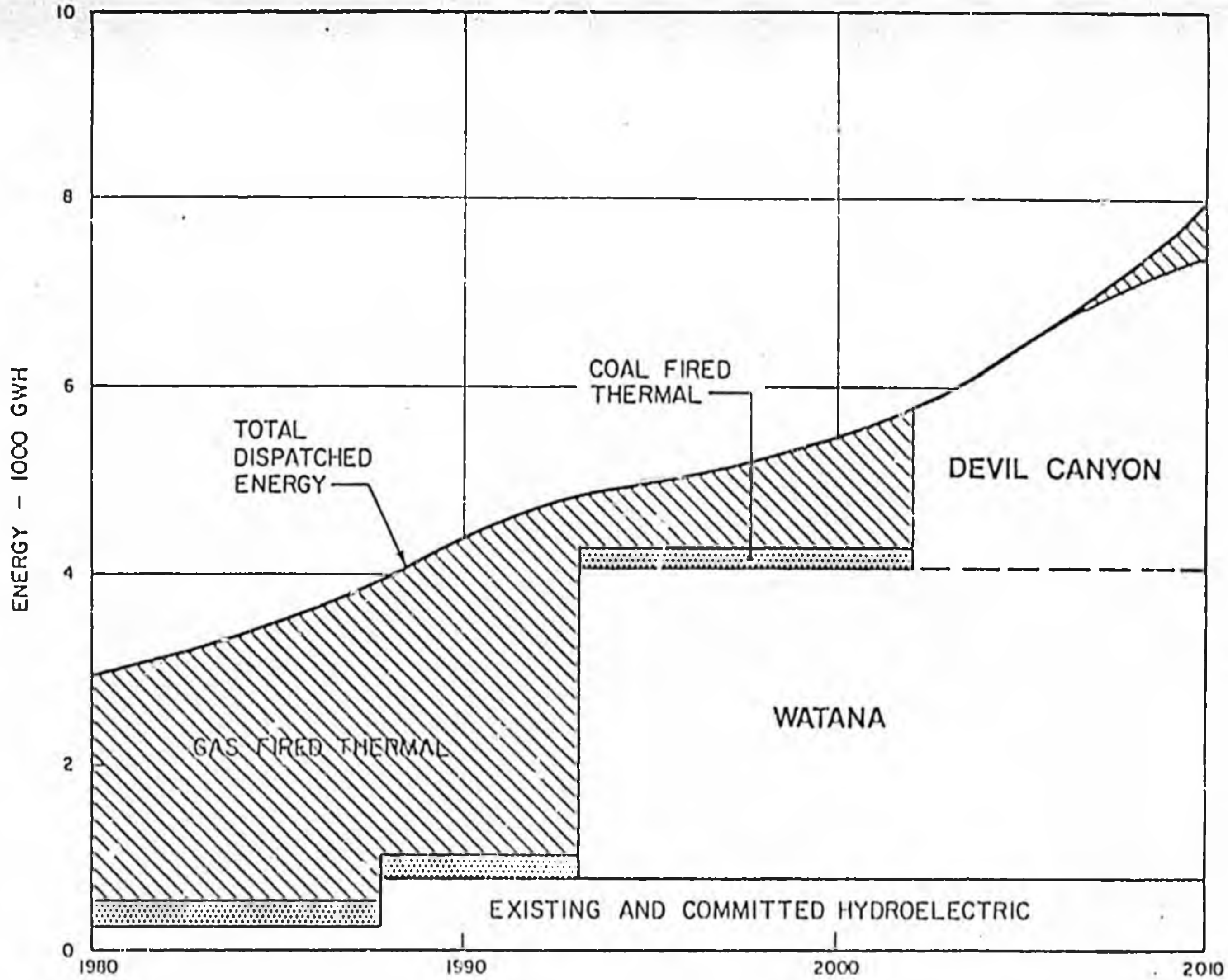
THE SUSITNA PROJECT

	WATANA	DEVIL CANYON
DAM TYPE	ZONED EARTHFILL	CONCRETE ARCH
DAM HEIGHT	885 FEET	645 FEET
RESERVOIR LENGTH	48 MILES	26 MILES
INSTALLED CAPACITY	1,020 MW	600 MW
AVERAGE ANNUAL ENERGY	3,460 GWH	3,340 GWH
TRANSMISSION SYSTEM	345 KV	345 KV
COST ($ 1982)	3.58 BILLION	1.57 BILLION
COST (@ 6% INFLATION)	5.94 BILLION	---
COMMISSIONING DATE	1993	2002

PROJECT PURPOSE

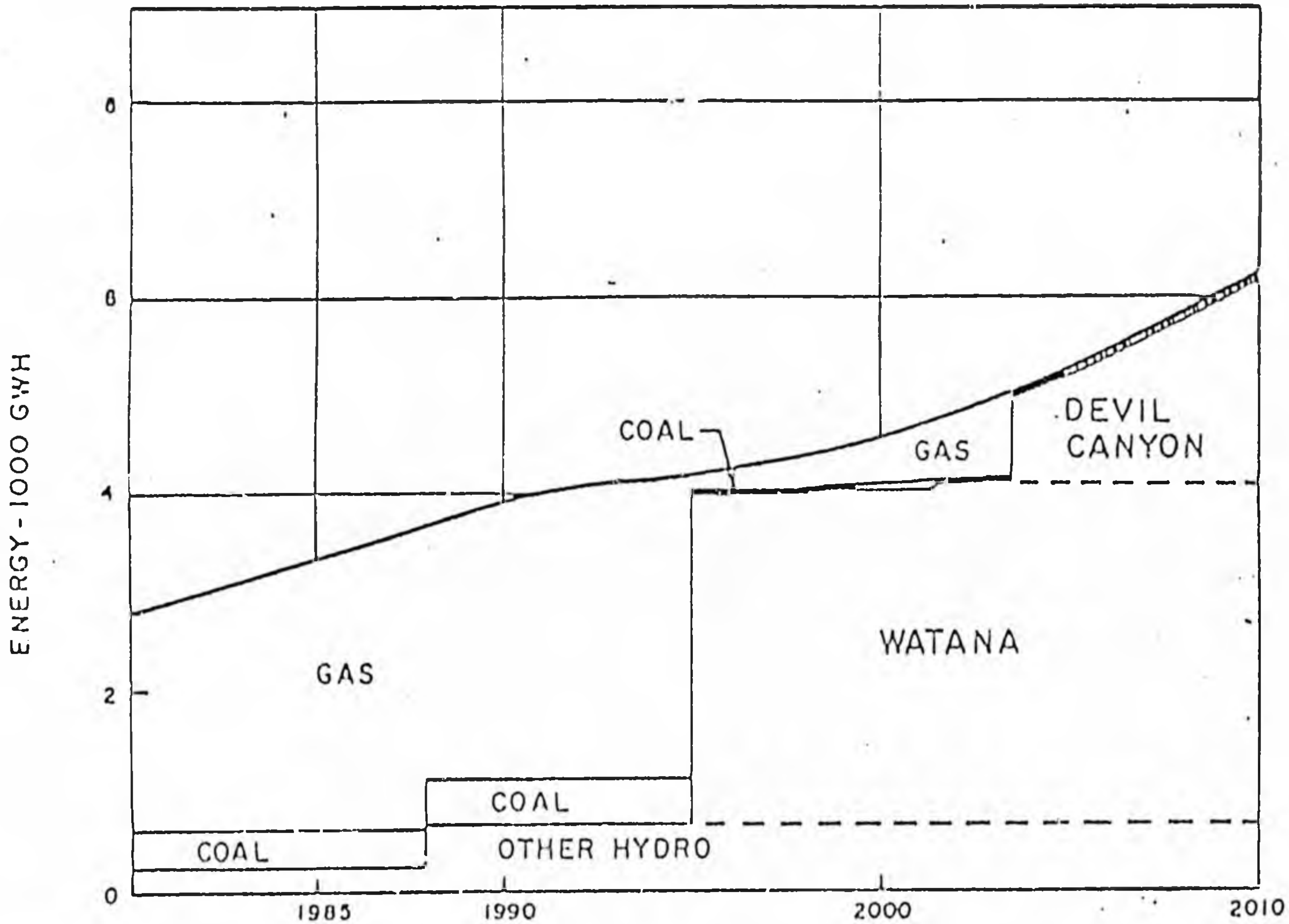
- MEET RESERVE MARGINAL AND ENERGY REQUIREMENTS
- REDUCE OVERALL COST OF THE GENERATING SYSTEM

USE OF SUSITNA GENERATION



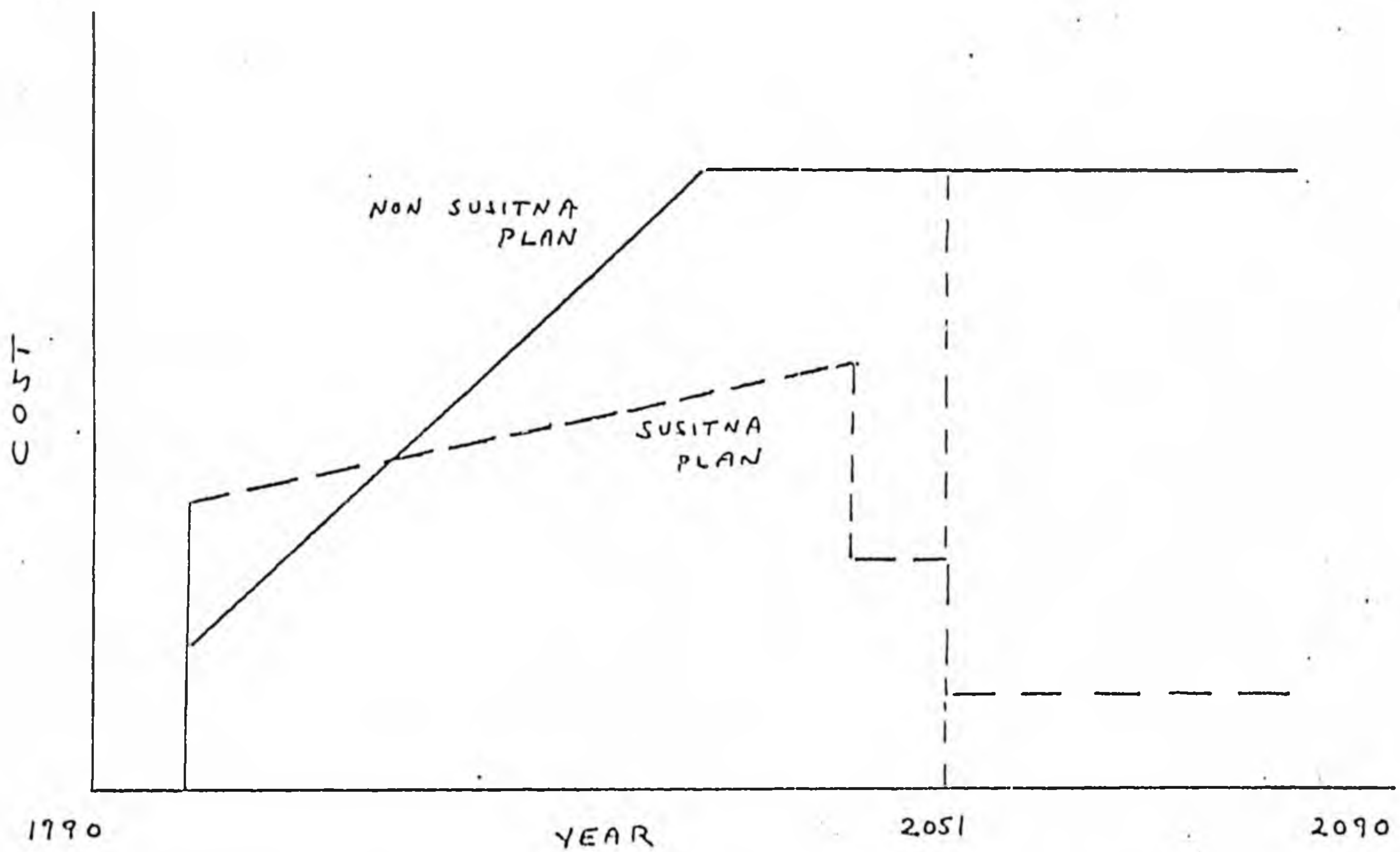
Medium Load Forecast

USE OF SUSITNA GENERATION



LOW LOAD FORECAST

ECONOMIC FEASIBILITY TEST



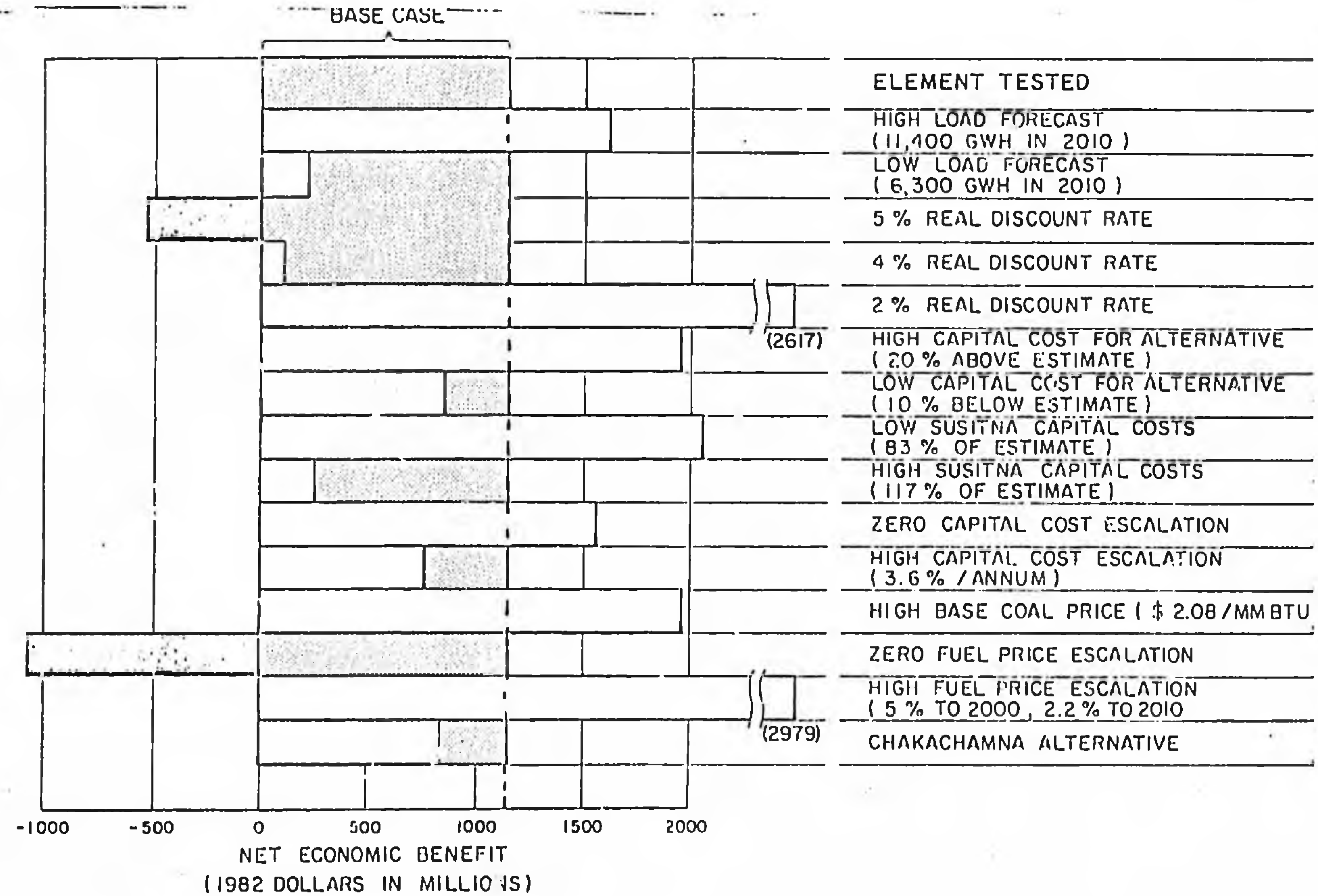
SYSTEM COSTS WITHOUT SUSITNA (A)

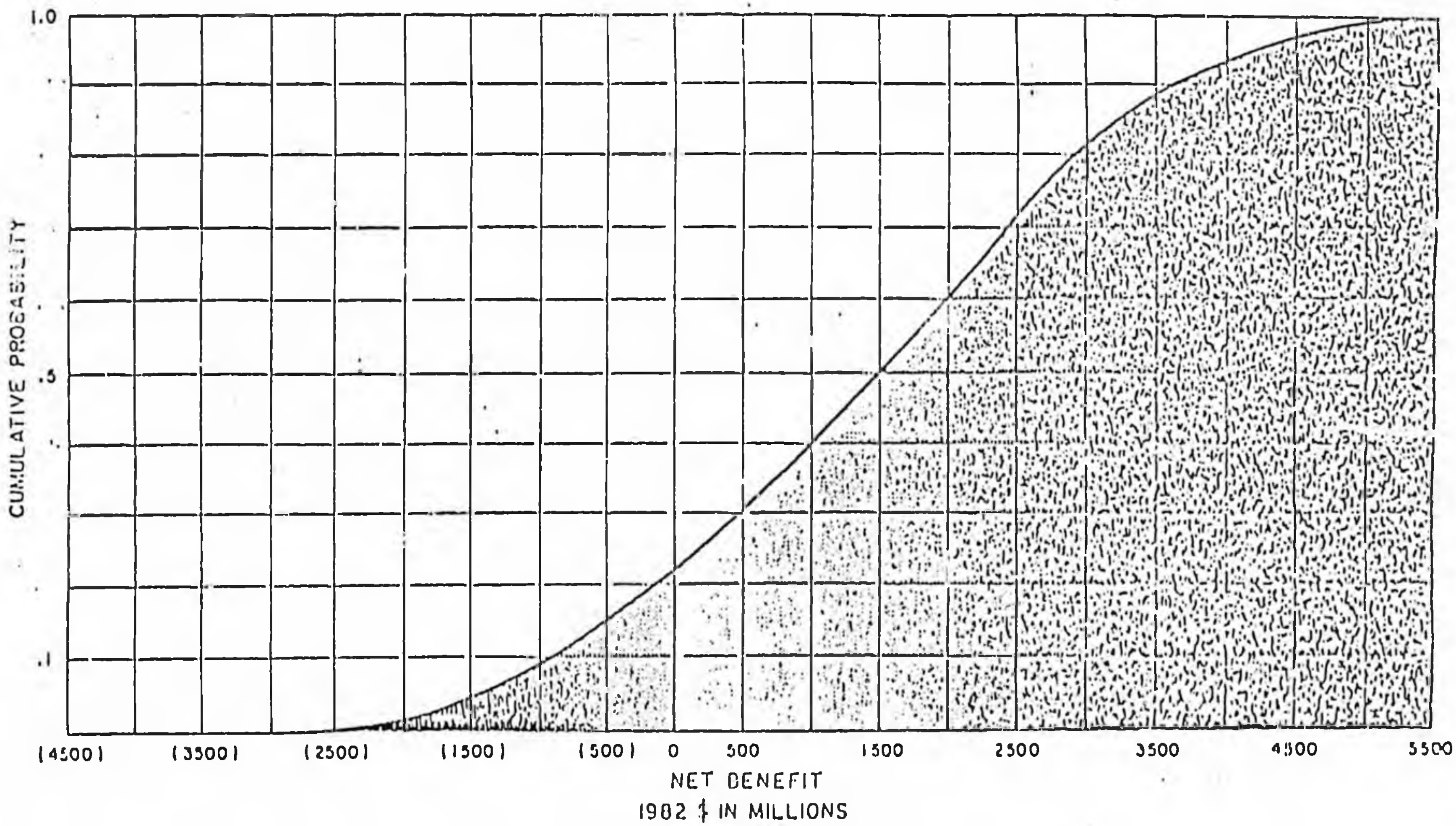
COMPARED TO

SYSTEM COSTS WITH SUSITNA (B)

(A - B) = NET BENEFITS OF SUSITNA PLAN

SENSITIVITY ANALYSIS





MULTIVARIATE ANALYSIS

	Low	Medium	High
Load Forecast	0.2	0.6	0.2
Susitna Capital Cost	0.60	0.25	0.15
Fuel Cost Escalation	0.25	0.50	0.25

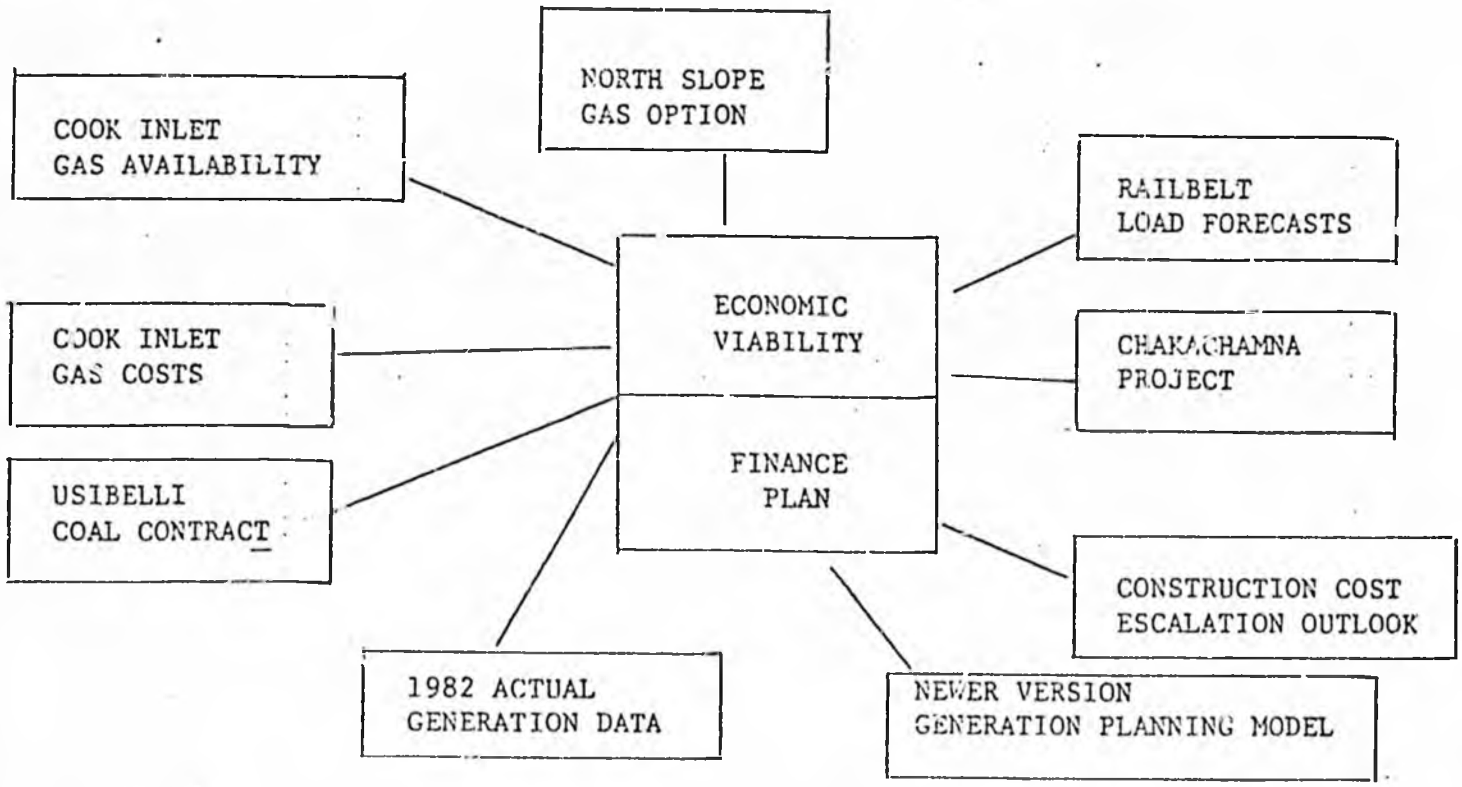
PREREQUISITES TO CONSTRUCTION

- 100 PERCENT DESIGN COMPLETION FOR INITIAL CONTRACTS.
- ACCEPTABLE MASTER LABOR AGREEMENT.
- FINAL PRE-CONSTRUCTION COST ESTIMATE.
- POWER SALES AGREEMENTS.
- FERC LICENSE AND OTHER MAJOR PERMITS.
- EXTERNAL REVIEW PANEL CONCURRENCE WITH DESIGN, SAFETY, AND MITIGATION MEASURES.
- FINANCE PLAN WITH FUNDING SOURCE ESTABLISHED.
- TAX EXEMPT STATUS RULING FOR REVENUE BONDS.
- LEGISLATIVE AUTHORIZATION.
- POWER AUTHORITY DECISION TO CONSTRUCT.
- PROJECT LANDS ACQUIRED.

LAND ACQUISITION SCHEDULE

JANUARY 1980 - DECEMBER 1982	o IDENTIFY PROJECT LANDS
	o IDENTIFY LAND STATUS
MARCH - JULY 1983	o PRIORITIZE ACQUISITION
	o EFFECT CONVEYANCE OF STATE AND NATIVE SELECTED LANDS
JULY 1983 - JANUARY 1985	o NEGOTIATE WITH PRIVATE LANDOWNERS
	o ACQUIRE ROW, LEASES

SPRING 1983 UPDATE



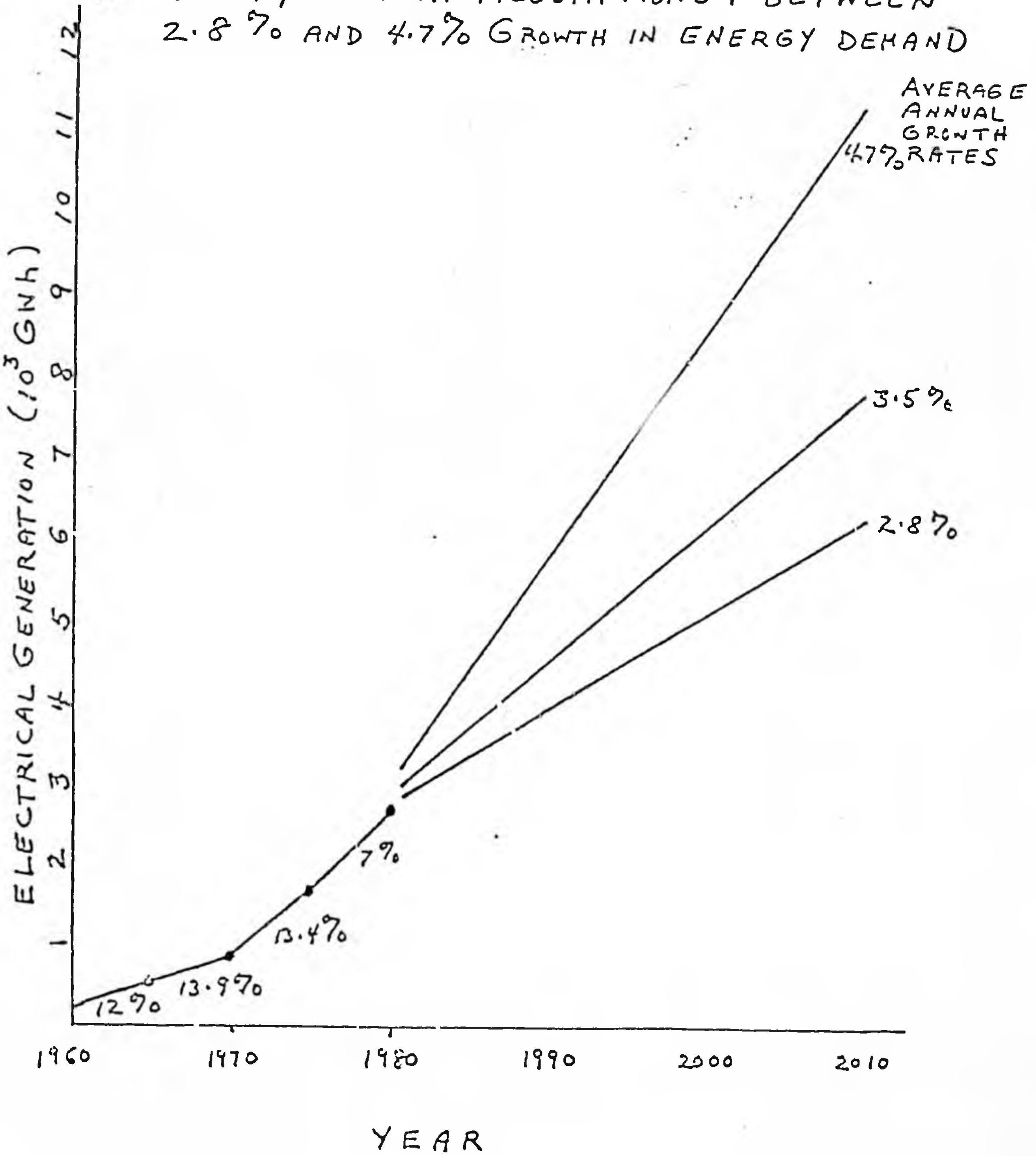
IMPORTANT PARAMETERS

	LOW	BASE	HIGH
LOAD FORECAST (in 2010) ANNUAL GROWTH RATE	6,300 GWh (2.8%)	7,800 GWh (3.5%)	11,400 GWh (4.7%)
DISCOUNT RATE (CONSTANT $)	2%	3%	5%
SUSITNA CAPITAL COSTS (CONTINGENCY)	0%	20%	40%
CAPITAL COST ESCALATION	0%	2%	4%
FUEL PRICE ESCALATION*			
BELUGA COAL ($1.51/MMBTU)**	0%	2.1%/1.2%	4.2%/2.2%
NATURAL GAS ($3.00/MMBTU)	0%	2.5%/2.0%	5.0%/2.0%
OIL ($6.50/MMBTU)	0%	2.5%/2.0%	5.0%/2.0%

* (1982-2000)/2001-2010)
** 1982 Price Estimate

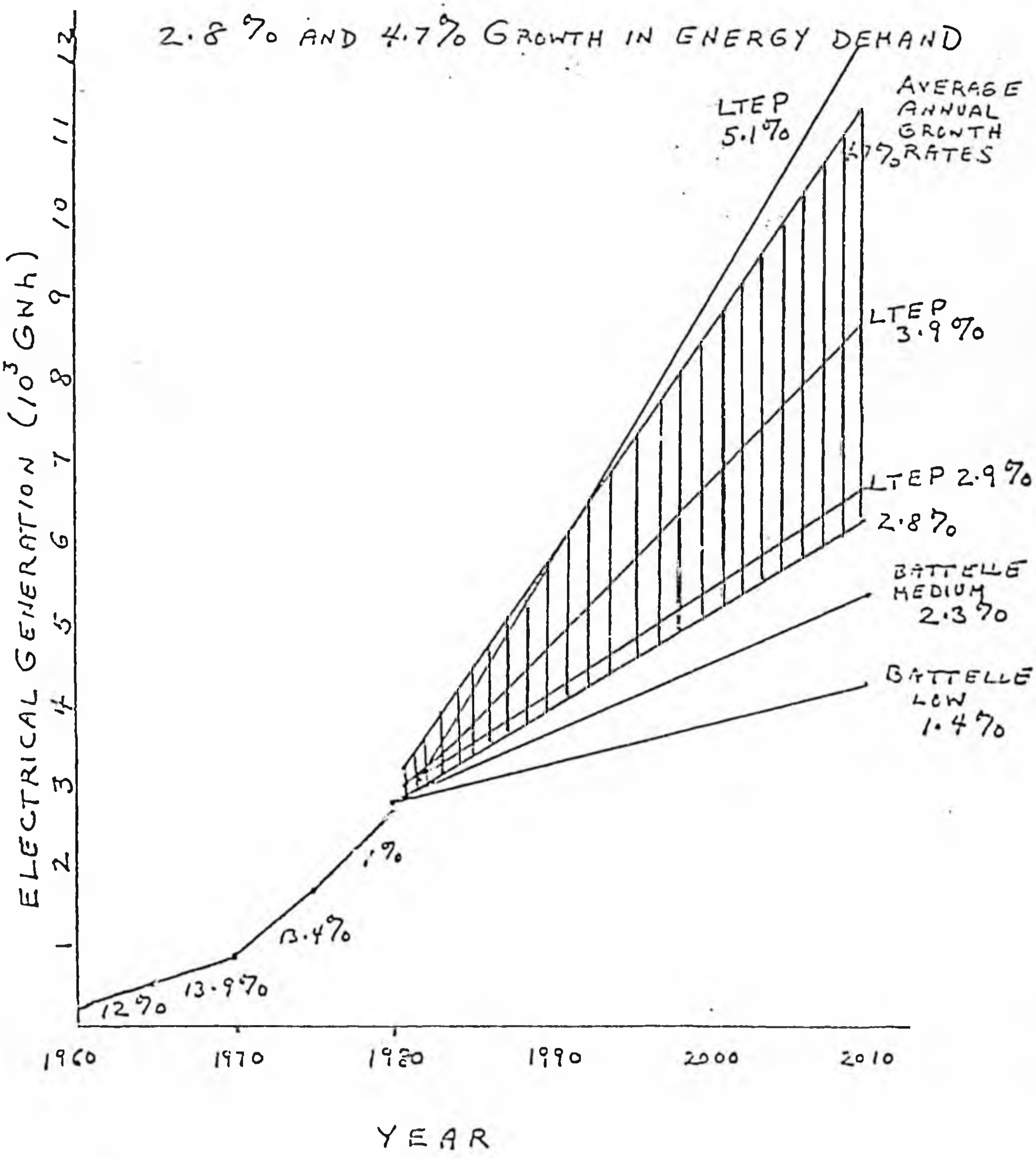
LOAD FORECAST

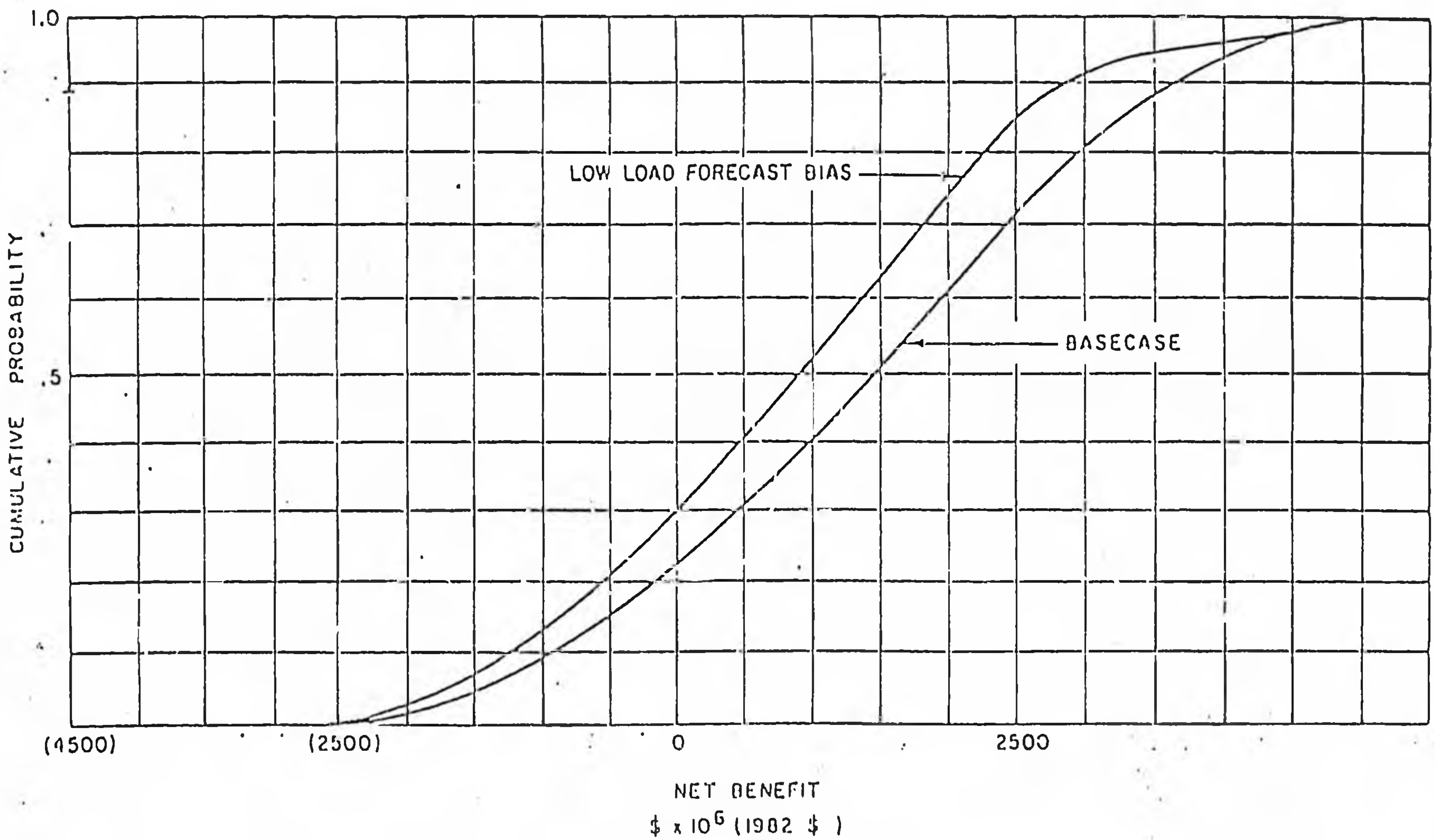
FEASIBILITY REPORT ASSUMPTIONS: BETWEEN 2.8% AND 4.7% GROWTH IN ENERGY DEMAND



LOAD FORECAST UPDATE

2.8% AND 4.7% GROWTH IN ENERGY DEMAND

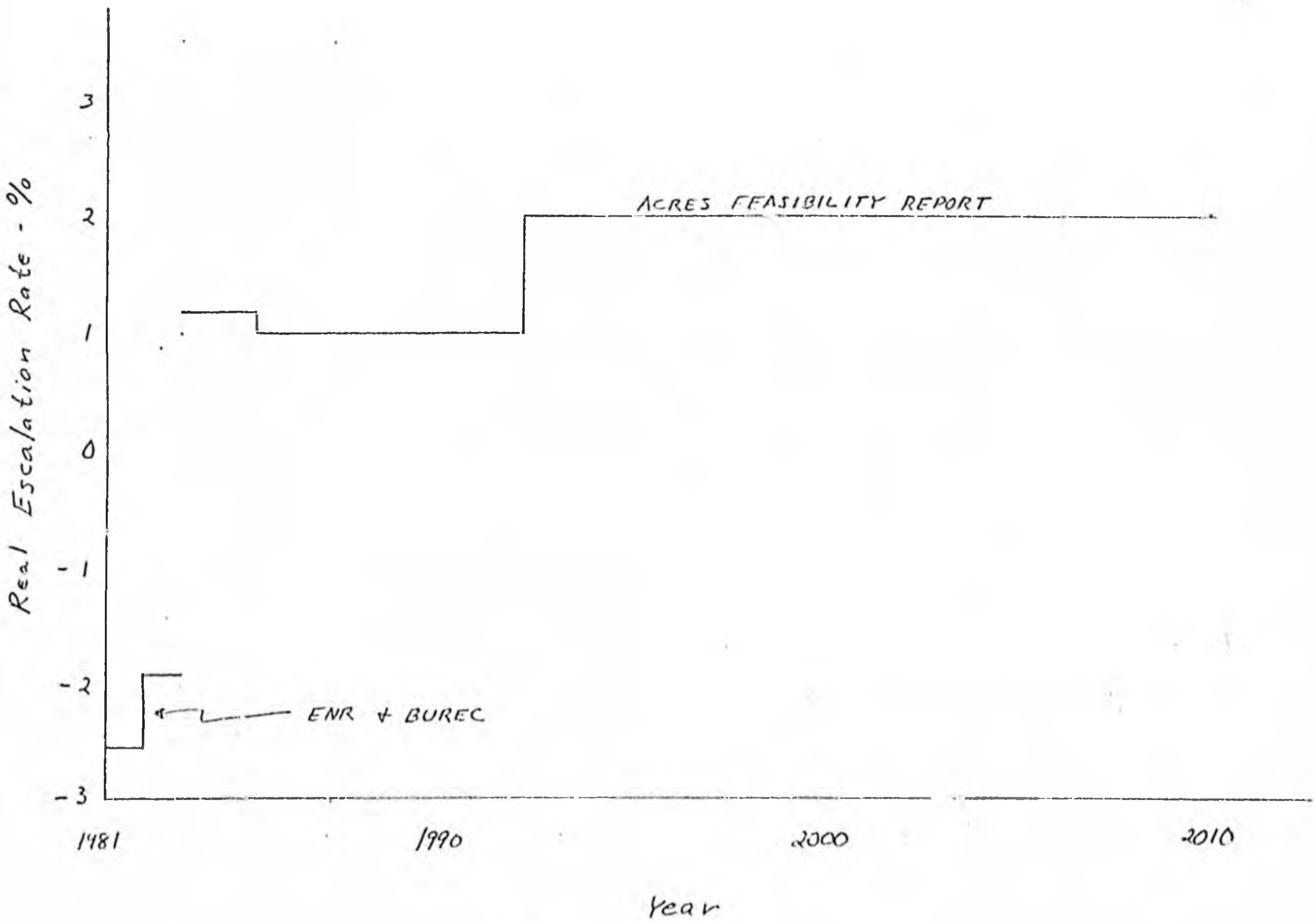


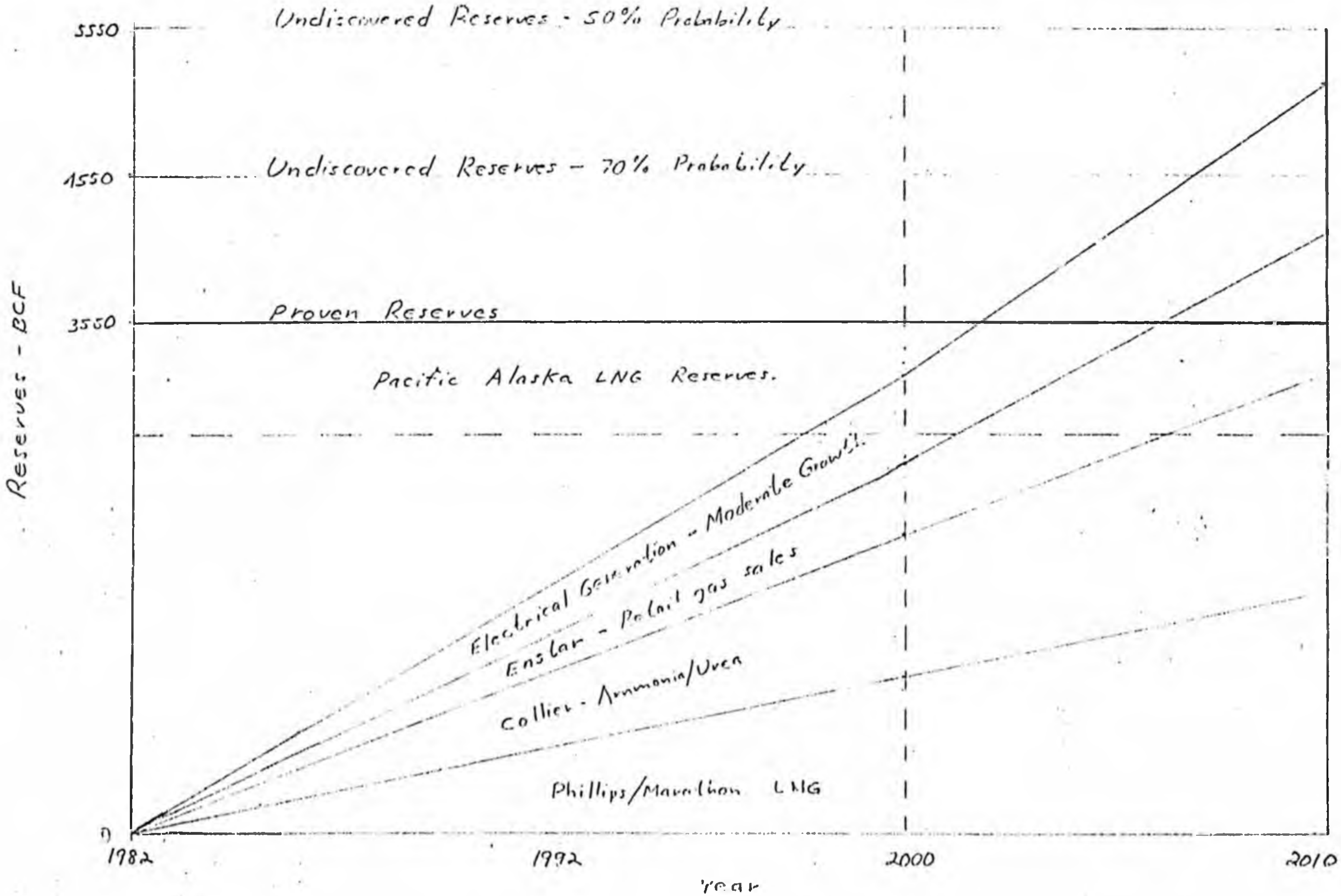


ASSIGNMENT OF PROBABILITIES

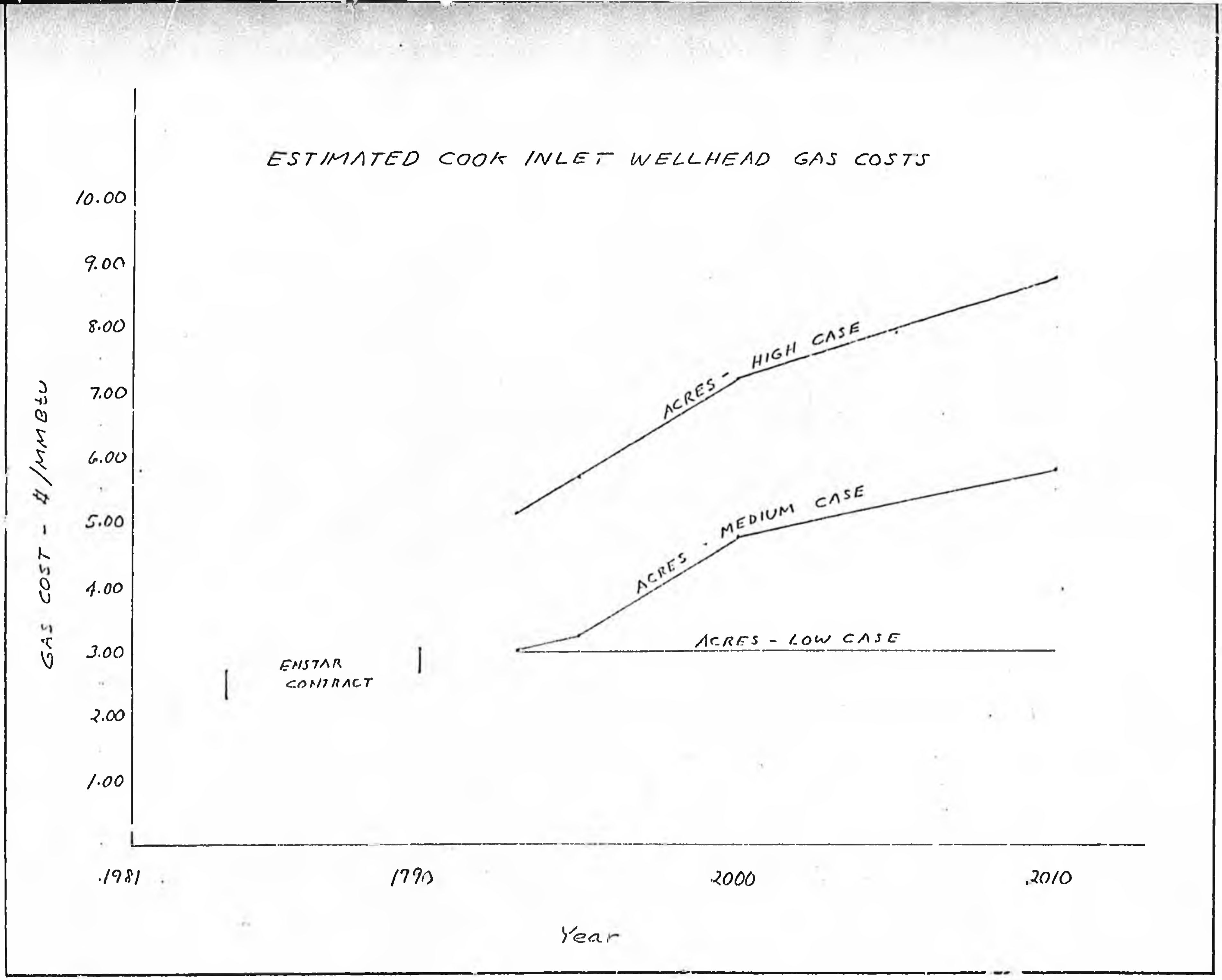
	Low	Medium	High
Feasibility Study	0.2	0.6	0.2
Alternative Outlook	0.6	0.3	0.1

CONSTRUCTION COST ESCALATION

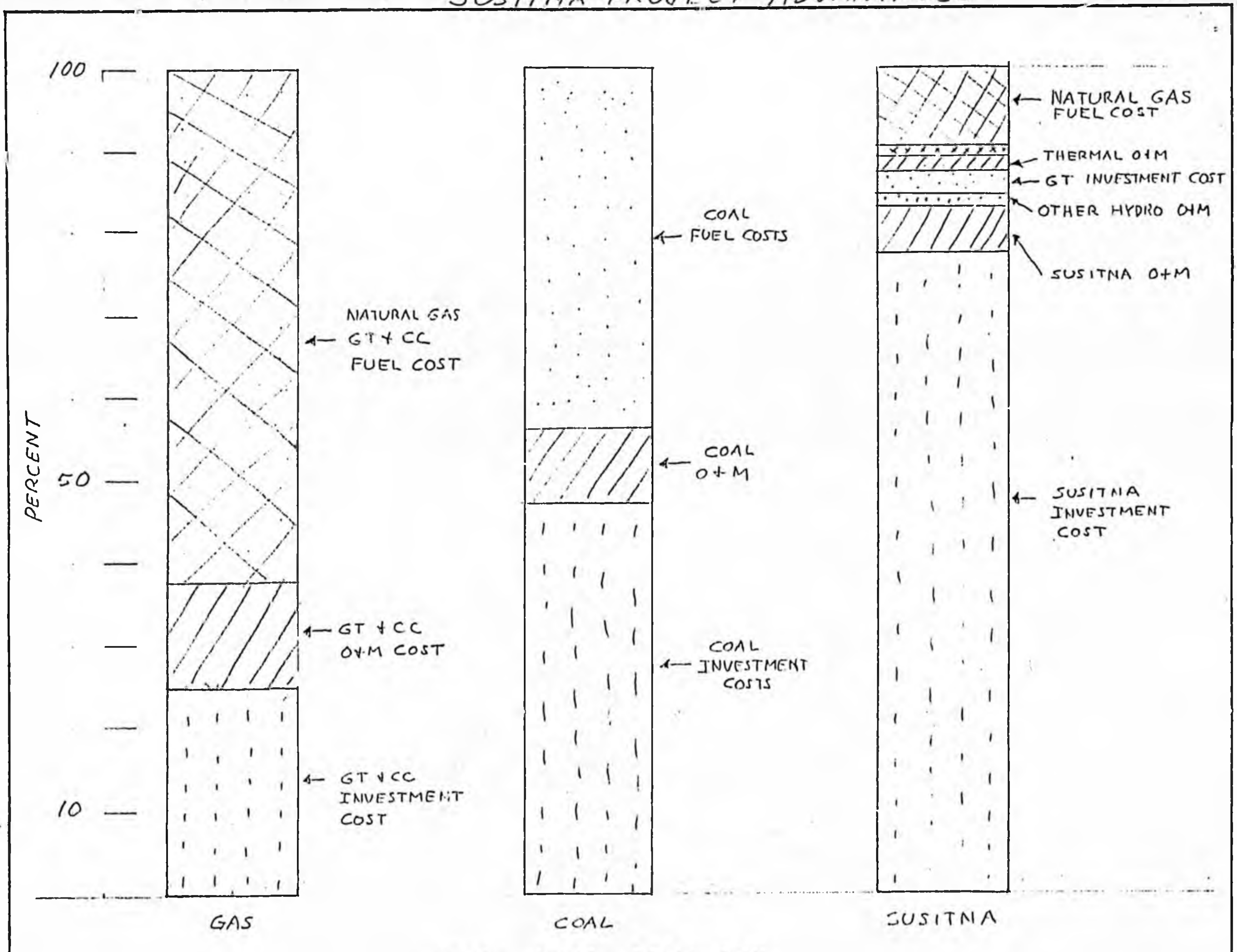




COOK INLET NATURAL GAS SUPPLIES
AND ESTIMATED CONSUMPTION


ESTIMATED COOK INLET WELLHEAD GAS COSTS
GAS COST - $/MMBtu
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
ACRES - HIGH CASE
ACRES - MEDIUM CASE
ACRES - LOW CASE
ENSTAR CONTRACT
1981
1990
2000
2010
Year

SUSITNA PROJECT ADVANTAGES



YEAR 2010 COST MIX

NORTH SLOPE GAS OPTION

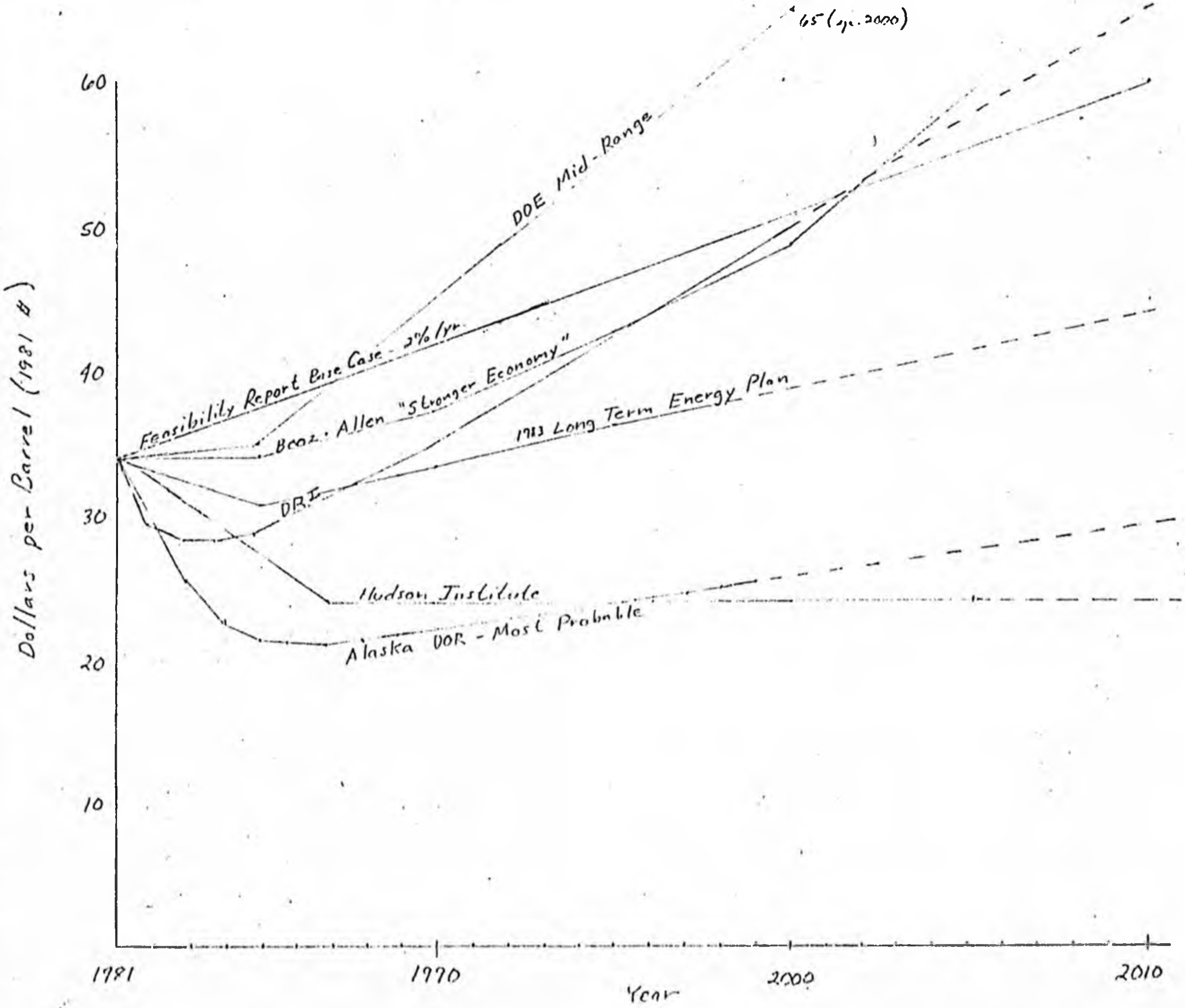
- DRAFT REPORT UNDER REVIEW
- THREE OPTIONS
- SITING, CONCEPTUAL DESIGN, FACILITY COST ESTIMATES

CHAKACHAMNA PROJECT

	FEASIBILITY STUDY	UPDATE
CAPACITY	330 MW	330 MW
FIRM ANNUAL ENERGY	1,374 GWh	1,236 GWh
ANNUAL GENERATION	1,446 GWh	1,301 GWh
TOTAL COST (1982 $)	$1.45 BILLION	$1.32 BILLION
TOTAL COST ENERGY*	43.5 MILLS/KWh	44.5 MILLS/KWh

* Includes 15 MILLS PER KWh FOR O+M

WORLD OIL PRICE FORECASTS



WATANA DAM HEIGHT REDUCTION
CURRENTLY UNDER STUDY

DAM HEIGHT	885 FEET	800 FEET	700 FEET
FILL QUANTITY	62 MILLION CY	46 MILLION CY	29 MILLION CY
TIME OF CONSTRUCTION	9 YEARS	8 TO 9 YEARS	7 TO 8 YEARS
ANNUAL ENERGY	3450 GWh	3040 GWh	2550 GWh
CONSTRUCTION COST ($1982)	3.58 BILLION	3.2 BILLION	2.8 BILLION
PROBABLE COST REDUCTIONS	--	10%	20%

TECHNIQUES FOR SUSITNA COST CONTROL

- EMPHASIS ON "HIGH CONFIDENCE" ESTIMATE
- INDEPENDENT ESTIMATE
- EARLY CM INVOLVEMENT
- MAXIMUM PRE-CONSTRUCTION SITE INVESTIGATION
- 100% DESIGN PRIOR TO BIDDING
- RIGOROUS CHANGE CONTROL PROCEDURE
- MASTER LABOR AGREEMENT
- FIRM FIXED-PRICE CONTRACTS

<u>POWER AUTHORITY RECOMMENDATIONS</u>

APRIL 1982

- CONTINUE PER-CONSTRUCTION DEVELOPMENTAL EFFORTS
- SUBMIT A FERC LICENSE APPLICATION
- INITIATE DESIGN

Dir

C

Anchorage
CHAMBER of COMMERCE

Crossroads of the Air World

RECEIVED
FEB 24 1983

February 1983

TO ALL LEGISLATORS:

The Susitna Hydro Project is certainly complex and requires a lot of background information.

Many of you have asked for a summation or outline of the project. The attached article by Dave Hutchens in the February issue of "Ruralite" is as good a one page summary as we've seen. It's caption "Decision Time" is really on target - you are the one's that must act now for our future needs.

Sincerely,

Robert C. Penney

RCP/mja

encl.

ANCHORAGE CHAMBER OF COMMERCE · 415 F STREET, ANCHORAGE, ALASKA 99501 · (907) 272-2401

Dave Hutchens
executive director,
Alaska Rural Electric
Cooperative Association

The Alaska Scene

RECEIVED
FEB 24 1983

Decision Time

The 1983 Legislature has a very important decision to make on behalf of electrical consumers throughout much of Alaska, from Homer to Fairbanks.

This decision deals with developing a financing plan for the Susitna Hydroelectric Project. Several facts make this decision critical.

Right now, natural gas provides the primary source of electric generation in this region. Only Golden Valley Electric Association and the Fairbanks Muncipal Utilities use coal to generate power. Golden Valley also uses oil-fired turbines for peak load generation. Two small hydroelectric facilities—Eklutna Lake and Cooper Lake—are the only other sources of electrical power.

According to the best estimates of utility managers, the proven gas supplies in Cook Inlet will begin running out of enough gas to generate electricity and heat homes in about 1995—only 12 years away. Without gas, another source of clean power to generate electrical energy must be developed and put into use before 1995.

The alternatives are known. Either coal-fired generation or hydroelectric power.

Coal-fired plants have some advantages. They are less expensive to build than hydroelectric plants and they can be built in about seven years as opposed to ten years for a project like Susitna. On the other hand, coal-fired plants have high maintenance costs, high labor costs and generate air pollution. Coal-fired plants also have to be replaced in about 35 years as their equipment ages and wears out. In the Cook Inlet area, coal is available but unless the coal mining companies can move larger quantities through export channels, the economics of developing a major coal field for one or two power plants are not favorable.

The hydroelectric potential of Susitna, on the other hand, is a source of clean power that will be available on a long term basis in excess of 50 years. It will also offer the advantage of stable prices. Coal-fired plants have somewhat variable costs for fuel since labor and machinery costs to extract the coal from the ground usually rise over the years. Hydroelectric facilities always have the same source of "free fuel"—the water in the river they are built on.

The Susitna project also appears to be relatively free from major environmental impacts. The river itself supports little fish life above the dam sites at Devil Canyon and Watana, and apparently there will be few long-term effects on salmon runs in Cook Inlet. Fishery resources can also be enhanced by construction of hatcheries. The dams themselves are designed to minimize changes in the character of the river water, another move associated with avoiding damage to fisheries resources.

The real benefits of Susitna lie in the area of economics. Susitna will provide stable power rates which will become less expensive in real terms as long as it lasts. From the $35 million study conducted by ACRES, there is no doubt that the savings to the consumers will be enormous over the useful life of the Susitna project. The trick is to finance it in such a way that some of those savings are received in the early years.

Employment associated with the Susitna Project is also a factor that must be considered. During the 20-year construction period for both dams there would be as many as 3,400 persons directly employed. The townsite at the dams would house the bulk of these workers, lessening the impact on communities such as Trapper Creek and Talkeetna. Over the long term, the northern Susitna Valley can expect a population increase due to dam construction and operation. The effects of this population increase remain a source of intense discussion in the Matanuska-Susitna Borough.

In short, construction of the Susitna Project is at a crossroads. Proven gas supplies for power generation in the Cook Inlet basin will begin running out in just twelve years. It will take ten years to finish the first part of the Susitna Project at Watana. If construction is not approved and a plan of finance approved within the next two years, *we* may be the ones freezing in the dark, not the people Outside.

Alaska Environmental Lobby, Inc.
419 6th Street, Suite 328 Juneau, Alaska 99801 907-586-2345

RECEIVED
FEB 23 1983

C

Susitna

21 February 1983

TO: All Legislators
FROM: Jay Nelson, Executive Director
Eric F. Myers, Energy Specialist
RE: Understanding Public Opinion on Susitna

The recent Dittman Research poll found widespread support for hydroelectric development in Alaska generally and Susitna specifically. These results are hardly suprising; it is a direct reflection of the massive media blitz sponsored by Susitna Power Now and the Anchorage Chamber of Commerce. The poll results would be similar if Dittman had asked if people were interested in a free car, a free house, or a free lunch. The answer is obvious.

The most significant finding of the poll is that it showed how virtually none of the respondents had even the remotest idea of what the Susitna project would cost. Even Eric Yould, Executive Director of the Alaska Power Authority and prime sponsor of the project, acknowledges that the total costs for the project will amount to upward of 15 billion dollars. This does not include any finance charges or the possibility of cost overruns.

Over 70 percent of the people polled indicated that they either didn't know what the project would cost or thought that it would cost less than 500 million dollars. Only 2 percent of the survey had a realistic notion of what the actual project costs would be (ie, over 10 billion dollars).

Also noteworthy is that those who indicated support for the project gave "cheapest source of power" and "need" as their main reasons. The project is neither cheaper than the alternatives, nor is it needed.

It is acknowledged by all parties to the Susitna debate that alternatives, primarily gas, will be less expensive than Susitna until well into the next century. In fact, the Alaska Power Authority feasibility study on Susitna by Acres American shows clearly that electricity from Susitna at 30¢/kwh would be more than twice as expensive as the gas alternative at 14.5¢/kwh if and when the project is brought on line as scheduled in 1993. Only with multi-billion dollar subsidies, the Acres study concluded, could Susitna possibly be competitive. The proponents of Susitna attempt to trivialize this need for multi-billion dollar subsidies as "a marketing problem."

Concerning the "need" for Susitna, the most recent comprehensive and up-to-date work on Railbelt power requirements by Battelle (1982, revised) shows that there will be a need (in the Moderate or "most likely" case) to add only some 200 megawatts to the Railbelt system by the end of the Century. By contrast, Susitna is a 1600 megawatt project. Some day Susitna may make sense, perhaps by the year 2050. But for the forseeable future, Susitna is clearly far oversized for our needs.

Contrary to popular belief, the official economic analyses of Susitna done to date have not found that Susitna offers any clear, cost-effective advantage over alternatives. In fact, the Acres feasibility study analysis prepared for the Alaska Power Authority <u>rejects</u> Susitna when the fundamental changes in world oil markets are taken into consideration. With world oil markets stable or falling, the Acres study observed, building Susitna would be a massive mistake. That is, a commitment to Susitna would cost over one billion dollars more than developing alternatives. Of considerable significance is the fact that the Alaska Power Authority Board of Directors has not endorsed the conclusion that Susitna is the most attractive Railbelt power option.

To raise questions about Susitna, as the Alaska Environmental Lobby has, must not be misconstrued as blanket opposition to Alaska hydroelectric power development. To the contrary, the Lobby has repeatedly spoken out in support of more modestly scaled hydro projects such as Bradley Lake which, together gas, offers a far more economically attractive, low risk native to Susitna. Individual projects, however, must be careful onsidered on their merits — not on the basis of the superficial Susitna Power Now public relations media hype.

The objective, of course, is to avoid a circumstance like the Tyee debacle. Although much smaller than Susitna, the Tyee project is in many ways similar to its Railbelt counterpart. Tyee was developed by the Alaska Power Authority and is far too large for the two communities (Wrangell and Petersburg) it is intended to serve. Now nearly completed, it is apparent that the price of power from the project may be as high as twice that currently faced by the communities — even with about seventy percent of the project's cost paid for with grants. Not surprisingly, the communities have refused this expensive Tyee power. And the Alaska Power Authority has a 120 million dollar white elephant.

The most critical issue underlying the Susitna debate is not whether you are "for" or "against" Susitna but, rather: How can we provide responsibly — economically and environmentally — for the reliably anticipated increases in Railbelt power demand? At some point in the distant future, the 1600 megawatt project may make sense but now is not the time.

This is particularly true in light of the revenue picture. It must be understood that the Energy Program for Alaska, with its multi-billion dollar subsidy scheme proposed for the Susitna hydro project, is a legacy from the past when revenues were coming into the State treasury faster (almost) than we could spend them. The "problem" in those days was to think up ways to spend money creatively. Now we are being forced to reckon quite soberly with dropping revenues. Even without the added financial burden of trying to provide 2-3 billion dollars in subsidies for Susitna, the State is facing a severe fiscal crisis in the early 1990's.

With regard to the Dittman poll once again, there is one question that was conspicuous by virtue of its absence: What are people willing to give up in order to subsidize Susitna?

Even if people were to express support for, say, a 5 or even 10 billion dollar expenditure for Susitna the question remains, what are they willing to trade away? To a great degree, the number would be irrelevant anyway because the real issue is: Are the people of Alaska willing to give up the Permanent Fund Dividend Program; abandon municipal revenue sharing and property tax relief; cut back on education funding; do without sewer, water and road improvements; pay income taxes?

These are the true costs of Susitna, the questions few are willing to talk about.

[illegible] SUBJ: [illegible]

[illegible] KERTTULA
[illegible]
REP. [illegible]
(COPY TO [illegible] LEGISLATORS)

FROM MRS. HAROLD LARSON
BOX 7-2 111, GOLD CREEK
C/O ALASKA RAILROAD
ANCHORAGE 99510
PHONE: 733.2329

PLEASE BE ADVISED THAT THE GOLD CREEK-SUSITNA NATIVE ASSOCIATION.WAS CERTIFIED BY THE BIA AS A >NATIVE GROUP< ON FEBRUARY 4, 1983, AND HAS VALID AND EXISTING RIGHTS AND CLAIMS AT THE SUSITNA HYDROELECTRIC DAM,SITE. PLEASE SEE THAT OUR REPRESENTATIVES ARE PRESENT AT ANY DELIBERATION AFFECTING OUT LAND AND RIGHTS.

RECEIVED
FEB 28 1983

Rep. Lindauer Brought this for You to See

(B)

References cited in SB 69 and 71

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

(b) A feasibility study shall include

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

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

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

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

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

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

(2) the issuance of

(A) general obligation bonds of the state; or

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

(3) an appropriation from the general fund

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

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

(4) a loan from the general fund;

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

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

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

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

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

(1) a market rate of interest, which is

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

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

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

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

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

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

Effect of amendments. — The 1982 amendment, effective June 26, 1982, inserted "the costs of transmission systems and reserve power requirements" in paragraph (1) of subsection (b).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Article 7. Susitna River Hydroelectric Project.

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

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

(1) minimize market area electrical power costs;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Article 7. Susitna River Hydroelectric Project.

Sec. 44.83.325. Restrictions on contracting.

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

D)

LOOKING AT SUSITNA ISSUES

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

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

Some Arguments Against

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

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

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

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

New Gas Price

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

(Continued on Page 6)

SUSITNA QUESTIONS . . . . (from page 3)

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

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

Actual Cost

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

Bonding Costs

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

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

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

Susitna Hearings

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

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

DATA:JMS.D11 WATANA (ON LINE 1993)-$1.8 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3:647 8-JAN-83

CASH FLOW SUMMARY
===($MILLION)===

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.05	154.81	165.65	177.24	189.65	202.92	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.0	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.7
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.2	369.8
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-15.2	50.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-15.2	50.4
446 STATE CONTRIBUTION	806.8	413.3	475.3	552.1	156.4	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	1275.1	1259.3	867.3	311.6	0.0
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	806.8	413.3	475.3	552.1	156.4	1275.1	1259.3	867.3	387.8	65.9
320 LESS CAPITAL EXPENDITURE	373.3	390.5	389.2	390.9	768.1	1390.1	1259.3	867.3	296.4	25.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	433.5	22.8	86.1	161.2	-611.7	-115.0	0.0	0.0	0.0	11.1
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	49.4
454 CASH SURPLUS RETAINED	456.6	479.4	565.5	726.7	115.0	0.0	0.0	0.0	0.0	11.1
370 CUM. CAPITAL EXPENDITURE	373.3	763.8	1153.0	1543.9	2312.0	3702.1	4961.4	5828.8	6125.2	6150.9
465 CAPITAL EMPLOYED	829.9	1243.2	1718.5	2270.6	2427.0	3702.1	4961.4	5828.8	6216.5	6260.8
461 STATE CONTRIBUTION	806.8	1220.1	1695.4	2247.5	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9
462 RETAINED EARNINGS	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	7.9	58.3
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.8
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	1275.1	2534.4	3401.8	3713.4	3699.7
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	769.7	710.5	457.3	153.6	0.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	769.7	1480.3	1937.6	2091.2	2091.2
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.96	1.10

Option D -- $1.8 Billion Dedicated From
Permanent Fund Income

ACRES

DATAIONS.D11 WATANA (ON LINE 1993)-$1.8 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 8-JAN-83

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	58.08	54.31	51.39	48.34	45.52	42.89	40.46	38.24	36.19	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.55	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	134.94	135.52	136.69	137.57	138.61	139.77	141.08	142.66	144.46	0.00
-----INCOME-----------------										
516 REVENUE	457.0	459.0	462.9	465.9	469.5	473.4	477.8	483.2	489.2	5040.9
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	427.2	426.4	427.4	427.1	427.1	427.1	427.4	428.1	429.2	4597.5
214 ADD INTEREST EARNED ON FUNDS	5.7	6.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	11.1	10.8	12.4	12.7	13.4	14.1	15.2	16.8	18.8	135.9
391 LESS INTEREST ON LONG TERM DEBT	368.5	367.0	365.3	363.5	361.5	359.3	356.9	354.2	351.3	3957.3
548 NET EARNINGS FROM OPERS	53.4	54.9	56.6	58.4	60.3	62.6	65.0	67.7	70.6	584.9
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	53.4	54.9	56.6	58.4	60.4	62.6	65.0	67.7	70.6	584.9
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2403.9
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3713.4
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
549 TOTAL SOURCES OF FUNDS	61.1	79.6	67.1	69.6	70.6	72.5	78.5	82.1	86.0	6926.3
320 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6480.4
448 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	15.0	16.6	18.2	20.0	22.1	24.3	26.7	29.3	32.3	218.1
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	10.8	8.9	6.9	4.6	2.3	-0.2	-2.9	-5.8	-8.9	1.6
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.8	75.0	79.4	82.2	83.9	88.6	93.3	98.0	98.0
454 CASH SURPLUS RETAINED	21.9	30.0	37.7	42.3	44.6	44.4	41.4	35.6	26.7	26.7
370 CUM. CAPITAL EXPENDITURE	6178.4	6207.8	6239.3	6273.0	6309.1	6347.7	6389.0	6433.2	6480.4	6480.4
465 CAPITAL EMPLOYED	6314.9	6377.8	6426.7	6476.3	6524.8	6573.1	6624.9	6677.6	6731.3	6731.3
461 STATE CONTRIBUTION	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9
462 RETAINED EARNINGS	111.7	166.6	223.2	281.6	342.0	404.6	469.6	537.3	608.0	608.0
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	3684.7	3668.2	3649.9	3629.9	3607.8	3583.6	3556.9	3527.6	3495.3	3495.3
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2091.2
543 CUM. DEBT DRAWDOWN $1982	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2
519 DEBT SERVICE COVER	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

(E)

Summary of 3 Volumn Report + 2 Volumns of appropriate regs.

REGULATORY IMPACT MANAGEMENT PLAN

FOR THE SUSITNA HYDROELECTRIC PROJECT

Presented to:

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

January 15, 1982

Contractor:

Ronald G. Birch
BIRCH, HORTON, BITTNER AND MONROE

Subcontractors:

S. John Byington
ROGERS HOGE & HILLS

Gerald R. Hill
REGULATORY IMPACT MANAGEMENT INC.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

9.2 A HISTORICAL PERSPECTIVE OF POWER PLANNING IN ALASKA

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

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

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

Legislative Finding and Policy

(a) The legislature finds, determines and declares that

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

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

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

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

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

The same legislation that created the Power Authority also created the Power Project Revolving Loan fund. The Power Authority administered this fund, which was set up as a "trust fund" to make loans to municipal or public utilities for feasibility studies, preconstruction engineering and design, and construction of hydroelectric and fossil fuel plants. For example, in 1977 $1.6 million was appropriated for the Green Lake Hydroelectric project at Sitka and $540,000 was appropriated to the Power Project Revolving Loan Fund. Through the fund, loans also could be made to cities, boroughs, village corporations, village councils and nonprofit marketing cooperatives for meeting their "energy requirements."

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

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

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

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

In addition to these direct appropriations, two resolutions authorized the issuance of a variety of revenue bonds. The revenues from those bonds would be used for constructing or acquiring generating facilities or for financing expansion of distributions systems by local utilities. The revenues used included the following:

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

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

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

In 1981 the legislature again passed electric power legislation, known as SB 25 and SB 26. The legislation, discussed in Section 9.3, relates to the Power Authority.

The above discussion is not intended as either a comprehensive review of history of electrical power planning and development in the State of Alaska or a detailed review of the legislation relating to the Power Authority. Nonetheless, several relevant observations can be drawn. First, involvement by legislative and executive branches of the state government in the planning, analysis, financing, and direct ownership of power generation and distribution facilities is a recent phenomenon. Second, although recently involved, the State has clearly assumed a major role in these activities. It has preempted significantly most other efforts by federal agencies and by individual utilities. Third, almost yearly the state's involvement has been expanding significantly, in terms of dollar volume, complexity, and geographic area. Fourth, the specific means and parameters that define that involvement have changed frequently.

These observations suggest that the analysis of the 1981 legislation and its impact upon alternative energy projects, which follows, must be viewed with some skepticism. Most likely, these laws will be changed before either the Susitna Project or some alternative can be implemented. Furthermore, because the State's involvement has been so fluid, if an alternative is perceived publicly as preferable to the Susitna Project, the alternative most likely could be implemented directly by changes in the current statutes.

Federal, state, or local governments have become involved in the construction and ownership of power generating facilities for four general reasons. First, government involvement in the decision making process and ownership of production facilities may be appropriate where market imperfections prevent a utility from building the generating capacity it needs to meet demand. Such imperfections do exist in the capital markets and also may be caused by regulatory risks. To address such imperfections, the simplest approach is for the government to make available to the utility a grant or loan to provide a direct source of capital. Normally, the government entity would not have to take over the decision making process or own the facility simply to correct capital market imperfections.

A second reason for government involvement is to give recognition to "externalities" that result in public benefits but which are not factored into an individual utility's decision making process. Many projects undertaken by the federal government are justified on this basis. For example, construction of Tennessee Valley Authority dams was undertaken when public sentiment viewed the creation of construction jobs as a public benefit in itself. In this instance, the government was willing to spend money to put people to work on a construction project even if a private entity was not willing to build the project. For dams built in the West, the externalities that constitute public benefits justifying the expenditure of public dollars include making water available for irrigation and for protection against flooding. Although a private utility might not chose construction of a hydroelectric plant if cheaper energy sources are available, the hydroelectric plant may be the "best" plant when consideration is given to the additional public benefits it creates.

A third reason for government involvement is the decision to effect income transfers through the distribution and consumption of power. If the government wishes to subsidize the consumption of power, it may construct a plant and sell the power below its free market price. The result will be a subsidy to electricity users. Such a subsidy can result in income transfer either to end-use consumers, to the utility distribution companies, or to both.

A fourth reason for government intervention in the decision making or production production process is simply to alter the free market result for political or policy reasons. Thus, if a private utility will generate electricity using methods "A" and "B" and the government prefers methods "C" and "D", it can intervene to ensure use of methods "C" and "D." The government's preference for "C" and "D" might result from objectives already discussed (such as income redistribution) or it might be the result of noneconomic objective. For one example, a noneconomic objective might be the desire to create a local market for coal. If this were a government objective, the government might wish to encourage coal-fired power generation even if that method was not the least-cost method.

9.3 THE CURRENT STATUTORY FRAMEWORK IN ALASKA

The legal authority for the state to implement the electric energy plans is contained in the recently adopted legislation that revises the legislation creating the Alaska Power Authority. The provisions creating the Alaskan Energy Program, A.S. 44.83.380 et seq (SB 25), are especially important. This statute creates a fund, the revenues of which may be used for, among other things, reconnaisance, feasibility and construction of power projects (including all related costs of such construction). The fund may not be used for operation and maintenance which, as discussed below, creates a significant bias in planning. Before the revenues can be used for constructing a project, the project must satisfy the following conditions:

1. The project must be economically feasible and after construction, must be able to provide revenue sufficient to return annually to the State five percent (5%) of the amount that the Power Authority has spent from the fund for the project.

2. The project must provide the lowest reasonable power cost to the utility in the market area for the estimated life of the power project, whether operated by itself or in conjunction with other power projects in the market area.

3. The project must operate either on renewable energy resources such as hydroelectric, wind, biomass, geothermal, tidal, solar, temperature differentials of the ocean, or coal, peat, waste heat, or fossil fuel.

4. The project must be approved by the legislature and funds appropriated by the legislature.

Because these limitations are defined primarily in economic and political terms and not in terms of engineering or hardware, the statute appears to have enough flexibility to permit the Power Authority to adopt any of the four alternative electric energy plans, provided that the plan meets the tests of the statute. The exception to this conclusion is the plan option that requires large expenditures for conservation of electrical energy. The statute appears to contemplate construction of facilities that will generate electricity. The statute may be interpreted so that certain types of conservation programs could be classified as "projects;" however, this approach is doubtful. Implementating the conservation option appears to require new authorizing legislation.

Although the requirements of A.S. 44.83.384 <u>et seq</u>. do not preclude implementing any of the energy option plans (except perhaps conservation as mentioned above), the circumstances under which the requirements dictate a particular option as the only authorized option cannot be determined with certainty. Lack of certainty results because the requirements are too general and sometimes contradictory to judge definitively how the courts will interpret the statute.

The relationship between the requirements set forth in A.S. 44.83.384 (conditions 1-3 above) and the requirement of legislative approval contained in A.S. 44.83.380 is not clear. Legislative approval appears to be a separate, independent requirement and therefore should not be sufficient to authorize construction of a project that does not also satisfy the requirements of A.S. 44.83.384. On the other hand, the legislative approval must be in accordance with A.S. 44.83.185, which requires passage of a law authorizing the project. Most likely the legislation authorizing approval will either make explicit or implied amendments, or if necessary, repeal the requirements of A.S. 44.83.384 as to the project the legislation authorizes. If the legislature takes this action, then any of the options are possible if it is approved by enactment of a law. While this analysis seems logical, it renders the requirements of A.S. 44.83.384 illusory, and for that reason, a court might conclude that a project is not properly before the legislature for approval until the requirements of A.S. 44.83.384 are met.

Application of the standards set forth in the statues requires interpretation by the Power Authority. For example, the requirement that a project "be able to provide revenue sufficient to return annually to the State five percent (5%) of the amount that the (Power Authority) has spent from the fund. . ." is ambiguous. If this requirement is interpreted to mean that a project must return five percent (5%) of the amount spent, almost no project could qualify because the price the Power Authority charges for power pursuant to section .490 expressly excludes capital recovery. This provision must mean that five percent (5%) would be returned if a full price is charged. However, even this interpretation raises questions. What price and demand assumptions should be made to determine if the project meets the requirement? Is it realistic that a project large enough to meet demand at a low price will also be able to sell enough power at a much higher price to return five percent (5%) per year? What rate of return should be assumed for invested capital? Also, if the State has a 100% equity position in the project, this requirement necessarily implies a 20-year amortization of the project.

The statute requires that a project must provide the lowest price by itself and when operated in conjunction with other power projects in the market area. However, a project may be lowest in only one situation, not both. All of these uncertainties are problems that are frequently encountered and handled by planners and engineers when making decisions about future generating additions. Once assumptions are made about market area, future demand, project lifetime and other parameters, conclusions can be drawn about which project will provide the "lowest" cost. In the current statute uncertainty exists, however, because it authorizes projects only when certain criteria, such as "lowest cost," are met. It does not provide guidance on the assumptions that are to be used when arriving at the final determination.

Because the statutory requirements are technical and require the Power Authority in determining whether they are met, its determination should be final unless a court finds that no reasonable basis exists for the their finding. This standard maximizes the Power Authority's flexibility to evaluate alternatives, but does not give the Power Authority complete freedom to select whatever option it wants. If the option or base case is not justified in terms of the statutory requirements, interpreted in a reasonable manner, the option or base case could not be implemented under the existing statute.

In the statute, other provisions that seemingly are unrelated to the statutory standards create bias in favor of a particular generation option. Because the Power Authority obtains the needed funds for a project from the legislature and because the project is expected to be subsidized partially with General Fund revenues, no direct market accountability exists for whatever option the Power Authority undertakes. On the other hand, the Power Authority, as an agency of the state, must be accountable to the legislature, the governor and the people of the state and, to the extent this political accountability is a direct substitute for market accountability, the Power Authority can be expected to seek out the least-cost approach just as a private utility would. Conversely, if the least-cost objective conflicts with other political objectives, the Power Authority may seek to accommodate both the economic and political goals to the maximum extent feasible.

Section .490(b)(2) of SB 25 states that if the legislature has not appropriated $5 billion to the fund, the wholesale power rate shall be the higher of either 10% of the amount the Power Authority has invested in power projects or the amount of revenues necessary to pay operation and maintenance (O&M) costs plus debt service plus safety inspections. If O&M costs, debt service and safety inspections are less than 10% of investment, which is quite likely, then purchasing utilities will want the legislature to appropriate the

$5 billion to satisfy the condition contained in (b)(2) since they then will avoid the risk of the higher wholesale power costs. To meet the $5 billion appropriation requirement, the legislature will have to select those power projects and energy options that have the greatest initial capital cost. Of the option plans identified in this study, only those including construction of Susitna appear to meet that requirement. The purchasing utilities can be expected to work aggressively, in their own self interest, to persuade the Power Authority to choose an energy option that includes construction of Susitna, even if Susitna is not the least-cost approach.

The pricing provision also creates a second kind of bias. Assuming the legislature does appropriate $5 billion, the wholesale price the Power Authority charges to purchasers is a function of O&M costs, safety inspections and the financing approach used by the Power Authority. Under this provision, the price to the purchasing utilities will be lowest for those projects having lowest O&M and safety inspection costs, regardless of capital cost, when the project is funded by direct appropriation. If the least-cost approach is one that includes projects with higher overall long-term O&M costs but less initial capital investment, the least-cost approch will not be favored by the purchasing utilities because it results in greater power costs to them (and less cost to the State). This bias in favor of the facility with the lowest O&M is significant when considering alternatives. Those facilities, such as hydroelectric projects, with high initial capital investment but low O&M costs, will be favored by purchasing utilities because the capital costs are subsidized by the State but O&M costs are not. On the other hand, projects, such coal-fired plants, which have lower front end costs but higher O&M costs, might be the least-cost project (in present dollars) but will not be favored by the purchasing utilities because it could result in higher cost power to them and to their customers because the State subsidy will be less.

The extent to which the statute's pricing provisions create, for the purchasing utilities, objectives that conflict with the criteria contained in other parts of the statute cannot be known until additional economic analyses of the options are undertaken. Likewise, the extent to which the Power Authority's analysis will be directly or indirectly inflenced by the desires of purchasing utilities is unknown. Note that the Power Authority is required to average prices statewide for all projects. This requirement means that all purchasing utilities, not just Railbelt utilities, will be impacted by the

Power Authority's decisions. All utilities which do, or may, purchase power from the Power Authority's, therefore, will have the same objectives of prefering those projects that receive maximum State subsidy whether they purchase power from a particular project or not.

The 1982 amendment (HB 9) changes the single, shared wholesale price to a project-specific cost based on each project's proportionate share of the outstanding debt for all projects. In addition, a "cap" assures that the early projects will "phase-in" to paying their proportionate shares, with other projects making up the difference.

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

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

January 5, 1983

MEMORANDUM

TO: Representative Brian Rogers

FROM: Jack Kreinheder
Research Staff

RE: Status of Susitna Project Studies
Financing and Power Sales Proposals
Research Request 82-157

You requested that we monitor and report on the progress of studies and on recent events related to the proposed Susitna hydroelectric project, particularly those studies dealing with alternatives to Susitna and Susitna fisheries impacts. You also asked that we review new developments in Susitna financing and power sales contracts.

THE KEY ROLE OF OIL PRICES AND STATE REVENUES

The outlook for future oil prices is one of the most important and controversial issues regarding the Susitna project today. As you know, the power demand forecasts and the power cost analyses presented in the Battelle Railbelt Electric Power Alternatives Study and the Acres Draft Susitna Hydroelectric Feasibility Report were developed before the recent downturn in oil prices and State revenues. According to Battelle and some other analysts, this downturn, coupled with State forecasts of oil prices which are much lower than earlier projections, indicates that Railbelt power demand and the cost of thermal generation are likely to be substantially lower than projected by Acres and the original Battelle report. These factors could reduce or eliminate the economic benefit of building the Susitna project, and also make power marketing and project financing more difficult.

Others, including Acres and the Power Authority, maintain that the consensus among nationally-recognized energy forecasters is for continued increases in the real price of oil averaging about 2 percent annually, which is the figure used in the Acres and Battelle reports. Thus, the analyses in these reports, which demonstrate that Susitna is the lowest cost source of electrical power for the Railbelt, remain valid.

The price of oil and other fossil fuels is important in evaluating any proposed hydroelectric development throughout the world because this price usually determines the "base case" cost of power against which a new hydro project is compared. However, petroleum prices are even more significant for the Susitna project because of the strong link between petroleum prices, State revenues, and economic activity in the Railbelt. In addition to affecting relative power costs, oil prices also influence load growth and the fiscal capacity of the State to appropriate the $2.3 billion (in 1982 dollars; $3.5 billion in actual appropriations) which was estimated by Acres to be necessary for financing Susitna.

The economic feasibility of the Susitna project, as it is currently proposed, depends not only on the increased cost of fossil fuels, but also on substantial growth in Railbelt electrical demand. The Watana and Devil Canyon dams would produce more than twice as much electricity as is now consumed in the Railbelt. Although the output from the Watana dam could be fully utilized with only a small increase in electrical load growth (combined with replacement of retired generating units), Acres has stated that a modified Devil Canyon dam appears to be the best single-dam development plan.

The economic and population growth which is necessary to create this level of electrical demand depends significantly on the level of State spending in the Railbelt over the next 20 years. As you know, nearly 90 percent of State revenues are currently derived from petroleum taxes and royalties. Increases or decreases in oil prices translate fairly directly into similar changes in State revenues and spending, inducing corresponding increases or decreases in economic and population growth, which in turn are the primary determinants of electrical power demand in the Railbelt. Thus, the increase in power demand which is necessary to realize the full benefits of the Susitna project is also substantially dependent on future increases in oil prices (although subsidized power costs could increase demand, as discussed below).

REVISED BATTELLE RAILBELT LOAD FORECASTS

In response to concern among State officials and others that the decline in current and projected State revenues made Battelle's original forecasts of demand for power in the Railbelt too high, Battelle revised these forecasts based on current (March 82) revenue projections. These updated forecasts were issued as an addendum to the executive summary of the Battelle report. The calculations for the updated projections are approximate and much less detailed than Battelle's initial work. However, Battelle now believes that Railbelt load growth is likely to be substantially lower than originally projected.

The revised Battelle forecasts contain a number of poorly documented assumptions and calculations. The most obvious case is in the projection of State petroleum revenues. Although Battelle states that their revisions were based on Department of Revenue forecasts (apparently the March 1982 report), the revenue figures listed in the Battelle report differ significantly fr m the Department's. In 1990 the Battelle revenue figure is 33 percent higher than the comparable Department of Revenue projection.

The revised "moderate" and "low" forecasts of power demand prepared by Battelle are about 20 percent lower than the original forecasts for the years 2000 to 2010. In addition, Battelle states that because of factors which were not quantified in the revised load forecasts, the most likely case probably lies between the revised low and moderate cases. The midpoint between the revised low and moderate cases is about 29 percent below the original moderate or most likely case over the 2000 to 2010 period. Battelle concludes that "while still the most resistant [energy plan] to inflation once it is completed, [Susitna's] power output would be larger than the Railbelt region could readily accommodate."[1]

It should be noted that the growth rate of electricity consumption in the Anchorage-Cook Inlet area during 1981 and 1982 has been considerably larger than was forecast by Battelle in their earlier work. This recent trend has raised concern over the accuracy of the forecasting models, and has been cited as evidence that the revised Battelle forecasts are too pessimistic.

One major factor favoring Susitna which was not mentioned in Battelle's revised summary, or in the Tussing/Erickson review (discussed below), is the effect which State investment in Susitna would have on Railbelt power demand. In their original analysis, Battelle estimated that demand for Susitna power would be approximately double the level otherwise expected by the year 2010 if the State appropriated the full $5.1 billion project cost, rather than using 100 percent market financing as assumed in the base case.[2] This analysis assumed that the cost of power to consumers would reflect only the operation and maintenance costs of the project, which are very low compared to the costs of debt service under the bond financing case.

---

[1] Battelle, Railbelt Electric Power Alternatives Study, Newsletter #4, December 1982, p. 13

[2] Dick Emmerman, Division of Policy Development and Planning, The Probable Effect of Lower State Revenue Forecasts on the Projection of Electricity Demand in the Railbelt, September 1982, pp. 5-6.

Based on this analysis and full State funding for Susitna, Railbelt power demand could be more than originally estimated in the Battelle Railbelt alternatives study, even with the decline in oil price and revenue forecasts. It now appears very unlikely that the State will fund the full cost of Susitna through appropriations; therefore, State investment in the project will probably have a more moderate effect on demand. In any case, this factor should be addressed in any re-evaluation of Susitna, as should the higher load growth rates discussed above.

The Power Authority is planning to contract with Battelle for a more detailed revision of their power demand forecasts, including an update of the historical power demand data used in the forecasting models. The Power Authority plans to submit a status report on Susitna to the Governor and the legislature in March 1983, as required by AS 44.83.340. The staff of the Authority believes that a more detailed revision of the Battelle forecasts is necessary to provide an accurate and realistic update on the status of the Susitna project. The contract amount would be about $30,000.

THE TUSSING/ERICKSON STUDY

In Alaska Energy Planning Studies, a report prepared for the Division of Policy Development and Planning by Arlon Tussing and Gregg Erickson, the authors review both the Acres and Battelle studies mentioned above. The principal conclusions of the report are: (1) the change in oil-price expectations since 1980 suggests that economic activity and load growth in the Railbelt will be substantially lower than projected by Battelle and Acres; (2) the Acres and Battelle estimates of Railbelt coal and gas prices are too high because they are based on export market values rather than regional market factors; (3) recent high interest rates and capital-market conditions raise concerns about the risks, costs, and financing arrangements of the Susitna project; and (4) the economic attractiveness of the Susitna project is significantly less favorable than indicated by Acres and Battelle.

While a thorough discussion of the Tussing/Erickson review is beyond the scope of this memorandum, a few observations may be helpful. On the whole, the report does a very good job of highlighting the key factors affecting the Susitna project, and generally appears factually correct. However, the authors sometimes draw conclusions based on limited data and overlook opposing viewpoints.

For example, the discussion of oil prices notes that the Department of Revenue forecasted in March 1982 that real oil prices would decline through 1998. While this is true, Tussing and Erickson did not mention that wellhead prices were projected to rise in real terms at 0.1 percent annually in the March forecast and 1.7 percent in the June forecast. Wellhead, rather than market prices, are the determining factor in the level of State oil revenues. The 1.7 percent figure is much lower than the 4.8 percent annual increase in wellhead value forecast in June 1981, so that the overall point made by the authors is still accurate. However, it would seem appropriate to discuss forecasted wellhead prices, as well as market values.

Tussing and Erickson also seem to misinterpret the meaning of the Department of Revenue 30th percentile or "risk adjusted" revenue estimates, which are now used as the basis for the executive budget. The report states that the use of the 30th percentile figure "indicates the Department's judgment about the probability that actual revenues will be less than the figure shown."[3] The use of the 30th percentile figure does not mean revenues are anticipated to be less than the mean forecast value. Instead the lower figures are used to adjust for the greater risk or impact associated with lower than expected revenues. The lower estimates simply reflect the fact that it is more disruptive to the budget process to have lower than expected revenues than to have higher revenues, and that it is prudent to base the State budget on a revenue estimate that is more certain than the mean "50-50" figure.

In the section on financing issues, Tussing and Erickson argue that the discount rate used by Acres (3 percent) is too low, and that at a discount rate corresponding to current real interest-rate levels, even the Acres analysis rejects Susitna. In Acres review of the draft report, the firm maintained that a project specific discount rate analysis, as recommended by Tussing and Erickson, resulted in a discount rate lower than 3 percent. The authors appear to ignore the Acres comments on the discount rate issue in the final report and reach the same conclusion stated above.

Acres and the Power Authority criticized the draft Tussing/Erickson report for relying almost exclusively on the Department of Revenue oil price forecasts in concluding that Railbelt electricity demand is likely to be lower than the lowest Acres and Battelle projections. Acres cited a number of oil price forecasts by major energy-oriented firms and agencies which generally supported the 2 percent annual real increase used by Acres and Battelle for their base case analysis. Eric Yould of the Power Authority stated that on the oil price issue, Tussing and Erickson "seem to have adopted a somewhat extreme position outside the mainstream of informed opinion."

---

[3] Tussing and Erickson, Alaska Energy Planning Studies, November 1982, p. 15.

Tussing and Erickson responded to these comments by noting that none of the forecasts cited by Acres were made by oil companies and that four of the eight forecasts were made by agencies with a stake in oil price increases. The authors also stated that internal forecasts by oil companies and oil-exporting nations, major decreases in drilling activity, and declines in the value of petroleum reserves all point to lower expectations of future oil prices.

Department of Revenue Forecasts

An important issue raised by this discussion is the accuracy of the Department of Revenue forecasts of oil prices and State revenues, and the role of these forecasts in evaluating the feasibility of the Susitna project. Acres and the Power Authority clearly imply in their comments on the Tussing/Erickson report that the Department or Revenue forecasts are too pessimistic, do not correspond with the projections of most reputable forecasting agencies or firms, and are not a valid basis for reevaluating the Susitna project. This situation is somewhat ironic, given the strong criticism of the Department of Revenue forecasts which was levied by the legislature and others just last spring because the forecasts were too high.

I spoke with Chuck Logsdon, Chief Petroleum Economist for the Division of Petroleum Revenue, regarding the apparent discrepancies between the Division's oil price forecasts and the much higher forecasts cited by Acres. Dr. Logsdon explained that the Division's projections are, in fact, more conservative than those of many other forecasters, in part because of the need for prudent revenue estimates in the State budget process, and because of the State's recent experience with revenue shortfalls. However, the oil price projections represent the best judgment of the Division's staff, and are not intentionally biased downward to provide a margin of error; this margin is provided by the use of the 30th percentile revenue estimates, as discussed above.

It would appear to be a difficult and confusing situation for the legislature (and the Governor) if the Power Authority's studies concluded that Susitna was feasible and properly sized, while the revenue projections on which the State budget is based suggested that excess capacity could prevent the project from being the lowest cost generation alternative.

While it may n[illegible] be possible, or necessarily desirable, to reach a consensus on the oil price issue, it is important to recognize that the forecast(s) used in Susitna feasibility updates will have a major effect on the evaluation of the project. The "base case" analysis must center on one rate of growth, but the sensitivity analysis should address the effect of a wide range of oil prices on both relative power generation costs and load growth. Ideally, the range of oil prices considered should be continuous, so that the "break-even" point can be easily determined, and so that the effect of new developments in the oil price area can be assessed.

I should mention that Susitna is not the only project affected by the oil price issue; nearly every Alaska hydro project, including those under construction, as well as planned projects like Bradley Lake, would show substantially lower benefits if projections of flat or declining real oil prices were used instead of the positive escalation rates used by the Power Authority.

Cook Inlet Gas Prices

The discussion in the Tussing/Erickson report concerning Cook Inlet fossil fuel prices, and natural gas prices in particular, emphasizes the importance of considering local market conditions and gas contracts, rather than the export opportunity values derived by Battelle and Acres. This point is supported by the recent announcement of the new Enstar gas contracts with Shell Oil Co. and Marathon Oil Co. for 470 billion cubic feet of gas at a base price of $2.32 per thousand cubic feet (MCF). Although this price is more than a three-fold increase from Enstar's current primary gas price of $0.65 per MCF, it is about 25 percent below the $3.00 per MCF figure estimated by Battelle and Acres for the cost of new gas.

The future gas price under the contracts is tied to the current ratio between gas and heating oil prices. Only if oil prices increase more than projected by Battelle and Acres would the contract gas price be more than 75 percent of the Battelle/Acres projections. Smaller oil price increases would mean lower gas prices. Thus, the future cost of gas-fired generation could be significantly less than estimated by Battelle and Acres.

In responding to the draft Tussing/Erickson report, Acres stated that the authors' rejection of Acres export valuation of Cook Inlet gas was a short-term view based on the lack of current gas export development, and did not reflect the long-time horizon for the Susitna project. It is true that it is difficult to project future gas markets and export opportunities, and it may well be appropriate to use the higher Battelle/Acres gas prices over the long term. However, the new Enstar contracts run until the year 2002, and would appear to be the most accurate indicator of Cook Inlet gas prices for this period.

The marketability of Susitna power may be more affected by the new Enstar contracts than is the economic feasibility of the project. The Enstar contracts and any new Chugach Electric contracts with similar terms could increase the difference in cost between Susitna power and the cost of thermal generation, particularly during the first few years of Susitna operation. It is these early years that are most difficult from a marketing standpoint (reference Acres' discussion of the "inflationary financing deficit").

It is important to note that the most recent Enstar contracts affect (with respect to electricity prices) primarily the Anchorage Municipal Light and Power utility, which buys nearly all of its gas from Enstar. Chugach Electric Association, Inc. (CEA) buys over 80 percent of its gas directly from producers. However, the Enstar contracts give a strong indication that producers are willing to sell gas under long-term contracts at a price substantially below the Acres and Battelle values.

I spoke with Tom Kolasinski, Production Manager for CEA, about the significance of the Enstar contracts for CEA's future gas prices. Mr. Kolasinski believes the Enstar contracts have effectively set a ceiling on Cook Inlet gas prices, and he expects CEA to be able to negotiate new gas contracts at prices less than or equal to the Enstar rates. CEA will be beginning negotiations this month with Chevron and Arco, who each have 220 BCF of proven, uncommitted reserves in the Beluga field.

According to the Acres Susitna feasibility study, a State appropriation of about $2.3 billion (1982 dollars) is likely to be required in order to bring the first-year power costs from the Susitna project down to the level of thermal generation costs. If gas is available in the early 1990's at a cost 25 percent below the Acres estimate, the State appropriation for Susitna may have to be significantly higher than $2.3 billion to maintain the marketability of Susitna power.

SUSITNA FINANCING PROPOSALS

Acres is currently developing a series of financing options for the Susitna project. These options are in preliminary draft form at this point and have not been approved by the Authority, but have been reviewed by the Authority's financial advisors, First Boston, John Nuveen, and First Southwest. The financing alternatives include a mix of general obligation and revenue bond issues and State appropriations, with the State contributions ranging from $100 million per year to $250 million per year (in real dollars) from 1985 to 1993-4. Another option would rely entirely on G.O. bonds until 1987 and then require a State appropriation of $306 million in 1988 (in 1988 dollars) continuing through 1994.

The financial advisors concluded in their review of the various options that the levels of borrowing proposed in all of the options could be achieved without material effect on Alaska's credit rating providing that a sufficient proportion of revenue bonds were issued, no other major State borrowing were attempted during periods of peak borrowing for the project, and the borrowing were phased to meet market conditions prevailing at the time. The group of advisors also indicated that the options are practicable methods for financing the project. However, the advisors emphasized the need for prudent and full reevaluation of financing alternatives with changing economic and financial conditions.

Acres noted that because all of the preliminary financing options appear to be technically feasible, the choice between the options depends on other criteria, the most important of which are:

(1) the financial viability of Watana in its early years under each option, and thus the level of revenue bonds which could be issued;

(2) the percentage of the State funds available for capital and loan appropriations which would be required for Susitna;

(3) the timing of the demands for State appropriations with regard to variations in the amount of funds available for capital projects and loans.

Although Acres did not recommend a particular financing plan to the Power Authority, they suggested that the three criteria listed above were best met by the two financing options which balance lower levels of appropriations before 1987 against higher amounts from 1988 to 1994.

Because of the preliminary nature of these financing options, it would not be appropriate to critique them in detail in this memorandum. In general, the options point out the trade-off between the amount of money appropriated by the State for Susitna and the amount of G.O. bonds required for the project, because lower State appropriations reduce the financial viability of the Watana phase and limit the amount of revenue bonds that the bond markets would be willing to purchase.

The financing discussion also indicates that there is a good deal of uncertainty about the proportion of the project cost that can be financed through revenue bonds because this proportion will depend on the financial position and credit rating of the State, the power sales contract which have been negotiated, and other factors. Finally, the options which Acres favors include higher amounts of State appropriations in the later years. This approach seems to run counter to current forecasts of State revenues, which are expected to decline in real terms after 1989.

FERC LICENSING/PROJECT DESIGN

The Power Authority currently plans to submit a license application for construction of the Susitna project to the Federal Energy Regulatory Commission (FERC) in February. The firm of Acres American, Inc., is overseeing the preparation of the license application up to the point of filing the application. After submission of the application to FERC, the joint venture of Harza and Ebasco will assume responsibility for project licensing and the next phase of project design. Acres estimated that it would take approximately 24 months for a FERC license to be issued after filing the application. Major litigation or a requirement for substantial additional information could extend this period.

SUSITNA FISHERIES STUDIES

I spoke with Dr. Richard Fleming, who is responsible for environmental studies for the Power Authority, regarding the research effort on the Susitna fisheries. The fisheries data collected during the summer of 1982 by the Alaska Department of Fish and Game (ADF&G) is now being compiled and will be released in a draft ADF&G report around January 31. A subsequent study to be completed by June will contain an analysis of the "raw" data included in the January report.

The Arctic Environmental Information and Data Center (AEIDC) is responsible for the analysis of probable fisheries impacts from the Susitna project. AEIDC is currently developing a model with which to evaluate these impacts. It is expected that the model will be completed by June, but no results from the impact analysis will probably be available until the fall and winter of 1983.

The firm of Woodward-Clyde is preparing "Exhibit E," which includes fisheries impacts and mitigation measures, for the Susitna license application to be submitted in February by the Power Authority to the Federal Energy Regulatory Commission (FERC). Although no analysis of the 1982 fisheries data will be available until June, the Authority plans to submit the tentative findings from the 1981 research program, plus a preliminary mitigation plan, to FERC in February. Additional submissions will be made as new information becomes available.

The 1982 summer research program was benefitted (although the salmon were not) by an unusually dry period in which the Susitna River flow dropped below 12,000 cubic feet per second (CFS) for part of the salmon spawning period. This flow compares to average summer flows in the 25,000-30,000 CFS range. This dry period allowed the researchers to observe the effects of lower flows, such as would occur from the operation of the Susitna project, on the spawning patterns of the Susitna salmon. A number of negative effects from the low flows were observed, including blockage of access in some sloughs and a reduction in the size of spawning areas. It should be noted that the effects of these low natural flows were more severe than the effects that would be caused by comparable flow reductions from the Susitna project. This is because the drought reduced flows from tributaries and ground water sources, as well as in the Susitna itself.

Summer river flows in the primary spawning areas during operation of the Susitna project would be about 8,000 to 10,000 CFS if the economic benefits of annual power production were to be maximized. The preliminary data from 1981 indicated that summer flows of about 19,000 CFS would be needed to avoid any significant impact on salmon reproduction (absent any other mitigation measures).

The preliminary mitigation plan to be submitted to FERC in February will be based on a combination of moderate flow increases and intervention measures to provide access to spawning areas at reduced flow levels. According to Dr. Fleming, the research conducted to date suggests that flows of 11-12,000 CFS during the critical spawning months of August and September, combined with habitat modifications, could avoid any decrease in salmon stocks. The intervention measures cover a broad range of possibilities and will not be defined on a specific area-by-area basis in the February FERC submission. Possible approaches include removal of obstacles, lowering of slough entrances, construction of small check dams to increase slough flows, and gravel substrate placement or improvement.

I checked with Carl Yanagawa, the Director of the ADF&G Habitat Division for the Southcentral Region, regarding the Department's response to the proposed mitigation measures and FERC license submission. Mr. Yanagawa is presently coordinating comments from the different divisions in the Department and stated that no response had yet been developed, but that a formal response would be provided to the Power Authority by January 15.

The fisheries research program for the summer of 1983 and the winter of 1983-84 has not yet been finalized, nor have funding levels been determined. Scoping meetings with ADF&G and other consultants will be held in January and February to determine what studies are needed. Dr. Fleming indicated that he expected the field research efforts to become more focused as a result of previous experience, and that the FY 84 budget may be reduced from the FY 83 level.

SUSITNA ALTERNATIVES STUDIES

North Slope Gas Studies

Task Force Study. Railbelt power generation is one of the options being evaluated by Booz-Allen & Hamilton in their study for the State Task Force on Alternative Uses of North Slope Natural Gas. The Phase I report, which was released in November, screened a wide range of potential transportation and utilization options and eliminated the options which did not pass the screening criteria. The Railbelt power generation option was selected as one of five alternatives for more detailed evaluation. However, this option would be in conjunction with one of the other alternatives, i.e., with a conventional gas pipeline such as ANGTS, a pipeline to the Kenai area for LNG production, or Fairbanks methanol production. This report should be completed in the next two months.

Alaska Power Authority Study

The Alaska Power Authority is analyzing the feasibility of three options for generating Railbelt power from North Slope gas:

(1) construction of a small-diameter gas pipeline from the North Slope to the Fairbanks area, with power generation in Fairbanks and transmission of power to Anchorage via the intertie now under development;

(2) generation of power on the North Slope and transmission via new high voltage lines to Fairbanks, and then to the remainder of the Railbelt.

(3) utilization for power generation of low-BTU waste gas from an LNG facility on the Kenai Peninsula, located at the terminus of an "all-Alaska" gas line.

This study, which is being conducted by Ebasco Services Inc. for the Authority, is due to be completed in February 1983. Two reports reviewing existing data and assumptions and system planning studies have been released. Ebasco has determined that only about 10 percent of the maximum daily Prudhoe Bay gas production would be required to meet all Railbelt power generation requirements, and that combined cycle gas turbines would be the most cost-effective generation system using North Slope gas. Ebasco estimates that the low-BTU waste gas option would be able to meet less than one-third of Railbelt power needs. No information on the cost of power or overall feasibility of electricity generation from North Slope gas has yet been released.

Chakachamna Hydro Studies

The Chakachamna project is not an alternative to Susitna in itself because of its much smaller generation capacity (330 megawatts versus 1660 megawatts for Susitna). However, it would be a major element, if constructed, of any Railbelt generation plan not including Susitna. The Power Authority has been conducting a study of the Lake Chakachamna hydro site since August 1981. According to Eric Marchegiani, the project manager, this is not a feasibility-level effort, but rather an interim study. The work is being done under contract to Bechtel and Woodward-Clyde and was funded by the Power Authority Board for $800,000 for the current fiscal year. Approximately $900,000 was spent on Chakachamna studies during FY 82.

The legislature appropriated $3.3 million for FY 83 Chakachamna studies as part of the $25.6 million authorized for continuation of the Susitna project studies. This figure was reduced by the Power Authority Board based on a recommendation from the staff that $800,000 was sufficient to carry out the FY 83 study efforts. Mr. Marchiagiani did not wish to comment on the adequacy of this funding level, but it appears from the program description that field studies and other portions of the study were constrained significantly by the limited funds available. Also, because FY 83 funds were not authorized until the end of June, study efforts during July were limited.

Approximately 80-90 percent of the Chakachamna study funds are being spent on fisheries research, primarily to determine salmon escapement levels, major spawning areas, and other baseline data. This funding allocation was based on the judgment that fisheries impacts were the area of primary concern for the Chakachamna site, with the cost estimate for the project another major concern. The development plan recommended by Bechtel and Woodward-Clyde would have a power generation capacity of about 330 megawatts and would involve a power tunnel from Lake Chakachamna into the McArthur River, which is one of the adjacent drainages.

Earlier studies had indicated that up to 480 megawatts of capacity could be developed at the Chakachamna site, but the current studies have found that mitigation of fisheries impacts and other factors limit the capacity of the site to the 330 megawatt figure. The current estimated cost for construction of the project is $1.2 billion (January 82 dollars), provided that the power tunnel can be bored rather than blasted. Blasting of the tunnel would add about $222 million to the project cost.

Bechtel and Woodward-Clyde will release a report on their findings to date in February 1983. However, because of the limited scope of the studies, no determination of project feasibility will be included in this report. Instead, the report will summarize the fisheries and geotechnic data collected, discuss potential project impacts and possible mitigation measures, and review the project cost analysis conducted by Bechtel.

The Power Authority requested $2.9 million for Chakachamna studies in FY 84. This has been reduced to $2.5 million by the Governor's Office.

* * * *

I hope this summary information on the Susitna project and related issues is useful. If you have any questions, please call. Also, if there are other legislators who you feel would be interested in this subject, we would be glad to provide this memorandum to them.

JK/sj

January 18, 1983

Addendum to Susitna Status Memorandum -- APA Comments

This memorandum was reviewed after its completion by Robert Mohn, Director of Engineering and Susitna Project Manager for the Alaska Power Authority. Mr. Mohn provided the following comments on the report:

Cook Inlet Gas Prices. Mr. Mohn indicated that there are several add-on charges to the $2.32 base price of the Enstar gas contracts which effectively boost its price to about $3.00/MCF. This is about the same as the current gas price used in the Acres and Battelle base case analyses of Railbelt thermal generation costs. The Power Authority therefore does not view the Enstar contracts as significantly altering the conclusions of the Battelle and Acres studies. Time did not permit additional research on this question by this agency; however, two analysts in the Governor's Office of Management and Budget are doing some work on the effect of the Enstar contracts which should be completed in the next several weeks.

Susitna Fisheries Studies. The memorandum states that no analysis of the 1982 fisheries data will be available to June, in reference to the Alaska Department of Fish & Game's report which is scheduled to be completed at that time. Mr. Mohn stated that although the full ADF&G analysis will not be completed until June, there has been a substantial amount of analysis conducted on the 1982 fisheries data by ADF&G and Woodward-Clyde. The February FERC licence application will include the results of the analysis conducted to date.

Chakachamna Study Funding. There appears to be some dispute on the legislative intent for FY 83 Chakachamna studies. Mr. Mohn's understanding is that there was no clear statement of intent by the legislature that $3.3 million of the $25.6 million in FY 83 Susitna funding be used for studies of the Chakachamna project. Rather, there was only a general directive that the $25.6 million include funding for the study of alternatives to the Susitna project, as necessary.

According to George Matz of the Office of Management and Budget, who handled this budget request, there was clear intent by the legislature that a feasibility level study of the Chakachamna project be conducted, as stated in a budget amendment document. Both the Power Authority Board and the Policy Review Committee overseeing the Battelle study recommended that $3.3 million be provided for this purpose; however, it was not expected that these funds would come out of the appropriation for Susitna studies.

(H)

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

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

February 11, 1983

MEMORANDUM

TO: Representative Don Clocksin

FROM: Jack Kreinheder JK
Research Staff

RE: Lake Tyee Power Costs and Project History
Research Request 83-39

You requested that we summarize the current status of contract negotiations for the sale of power from the Lake Tyee hydro project. You asked that we address the expected cost of power from the project, current power costs in Petersburg and Wrangell, and alternatives for reducing Tyee power costs to marketable levels..

The attached letter from the Alaska Power Authority outlines the sequence of construction cost estimates for the Tyee project and the decisions made by the Power Authority Board concerning project construction.

It is important to emphasize that the power cost projections in this memorandum are preliminary and are currently being revised by the Power Authority to reflect detailed financing arrangements for the Tyee project. These revised cost estimates will probably be somewhat lower than the figures cited here.

SUMMARY OF FINDINGS

The basic power marketing problem for the Tyee project is that the wholesale cost of power from the project in its first years of operation is projected to be about 40 percent higher than current power generation costs for Petersburg and Wrangell. The Power Authority estimates that Tyee power will cost about 16.5 cents per kilowatt hour (KWH) in FY 1986. Recent press reports have cited claims by Petersburg officials that the retail cost of power from Tyee would be 100 percent higher than current levels. However, these claims are disputed by the Power Authority, as discussed later.

Power generation in Petersburg and Wrangell now costs about 12 cents per KWH and this cost is not likely to increase substantially over the next several years unless oil prices increase more than expected by most forecasters. These communities are understandably not willing to sign contracts to purchase Tyee power at rates substantially higher than current generation costs.

If no action is taken by the legislature to reduce Tyee rates, it appears that power sales agreements could not be obtained and the Power Authority would not be able to sell the necessary revenue bonds to repay the interim financing for the project. Although I did not research the possible steps the Power Authority might take in this situation to avoid a default on the Tyee debt, the Authority would probably be in a precarious financial position.

There are several possible approaches to reducing power rates for the Tyee project, most of which require more State money:

(1) Make an additional lump sum appropriation to the hydro program to reduce the amount of debt financing required for Tyee and other projects. About $70-80 million may be required to reduce Tyee rates to the level of current power costs. If desired, this appropriation could be structured as a loan, to be repaid to the State after Tyee power becomes competitive with the cost of power from present generation facilities.

(2) Appropriate a smaller amount of about $20 million only to the Tyee project and enact temporary legislation which would reduce only the Tyee rates. (Under present law, an appropriation to any power project would reduce the power rates by an equal percentage for all projects.)

(3) Make annual appropriations of about $2-3 million to cover a portion of the debt service costs for the Tyee project, allowing power rates to be reduced until the project becomes competitive with diesel generation costs.

(4) Amend the rate structure under present law to spread the higher cost of Tyee power among other power projects.

(5) Restructure the long-term debt for the Tyee project to reduce debt service costs in the early years of project operation (the viability of this approach is uncertain).

TYEE POWER COSTS

The following table shows projected wholesale power costs for the Tyee project from FY 85 to FY 90.

PROJECTED TYEE WHOLESALE POWER COSTS
(Cents per Kilowatt Hour)

Fiscal Year	1985	1986	1987	1988	1989	1990
Power Cost	12.8	16.5	16.7	16.8	17.0	17.2
Power Sales (Millions of KWH)	32.0	32.8	33.6	34.5	35.3	36.2

Source: Alaska Power Authority for FY 85-86, adjusted by House Research Agency for FY 87-90 for 4 percent annual increase in debt service cap, 3 percent average annual load growth for all APA projects, and 5 percent annual inflation in operation and maintenance costs. Debt service calculations based on 35-year revenue bonds at 11 percent interest, with a 1.1 coverage level.

Again, these projections are preliminary, and more accurate figures will be available within a week. These projected rates are probably on the high side because they do not account for the interest earned on debt reserve funds or the lower-than-expected cost of the interim financing for the project. The Power Authority's financial advisors are now working to incorporate these and other adjustments to arrive at more accurate rate projections. One uncertainty in these rates is that they assume the Wrangell sawmill will buy about 7 million KWH per year -- about 20 percent of total projected power sales from the project. The sawmill was shut down for over a month this winter and could be an uncertain buyer of Tyee power.

The Tyee project is scheduled to be completed in early 1984, and may be on line as soon as October 1983 if work continues at its current pace. When the project begins generating power, the initial rate will be set to cover only operation and maintenance costs (4-5 cents/KWH) until the start of the 1985 fiscal year, when the rate will increase to cover the costs of long-term financing for Tyee and the Swan Lake project. The power rate will increase again in FY 86 to reflect the cost of revenue bonds issued for the Terror Lake project. After 1986, the Tyee power rate will probably increase by about two percent per year.*

PROJECT FINANCING

82 M/112 M

The completed cost of the Tyee project is now estimated at $115 to $125 million. Construction of the project has been financed by $82 million in appropriations from the legislature and $50 million in interim financing. This interim financing will have to be repaid in the spring of 1984 through the issuance of revenue bonds, additional State appropriations, or a combination of the two. The Swan Lake project also has $50 million in interim financing which will be repaid at about the same time. Terror Lake has $100 million in short-term debt which will be due in 1985.

HB 9 RATE STRUCTURE

The financing and power costs for Tyee are tied to those of other Power Authority hydro projects under legislation enacted in 1982 (CCSHB 9 -- Chapter 155). This statute requires each hydro project to pay its "proportionate share" of the total debt service costs for all projects, as determined under a formula in the statute. Basically, the statute means that if the construction cost of Tyee is 25 percent of the total cost of all projects in the system, Tyee must pay 25 percent of the total debt service costs for all projects. The wholesale power rate for each project is then determined by adding operation and maintenance expenses to debt service costs and dividing this sum by the expected power sales for each project.

The HB 9 rate structure replaced the "postage stamp" or single statewide rate formula which was enacted in 1981 by SB 25. The major purpose for the change in the rate structure was to increase the incentive for building cost-effective and properly sized projects, by linking power costs more directly with project construction costs.

When the conference committee on HB 9 reviewed rate projections for the four power projects, there was concern that the rates for the Tyee and Swan Lake projects would be excessive under the HB 9 rate structure. As a result, the committee included in the legislation a limit or cap on the debt service cost for each project. Under this cap, no project must pay more than the average debt service cost for all Power Authority

---

* The rate calculation is complex, but the three main factors that affect the project rates after 1986 are: inflation in O&M costs, the rate of growth in power sales, and the 4 percent annual increase in the HB 9 debt service cap. The addition of the Bradley Lake project or other projects could also affect Tyee rates substantially.

projects, plus a certain percentage which increases each year (8 percent in FY 85, 12 percent in FY 86, and so on). Although this debt service limit reduces the power rate for Tyee substantially, it does not reduce the rate to a marketable level.

Because the debt service costs are pooled for all projects in the system, an appropriation to Tyee or any other project would reduce the power costs for all projects by an equal percentage.

PETERSBURG AND WRANGELL POWER COSTS

Current Costs

Exact power costs for Wrangell and Petersburg were not readily available at this writing. However, the busbar generation cost (equivalent to the wholesale power cost from Tyee) for both communities is approximately 12 cents per KWH. Wrangell generates all of its electricity from diesels, while Petersburg obtains about half its power from the Crystal Lake hydro project, which was built many years ago. The Petersburg utility apparently has a higher level of debt than the Wrangell utility, which offsets the lower cost of power from the hydro facility.

While most of the recent publicity concerning the Tyee project has focused on the city of Petersburg, the Power Authority staff maintains that Wrangell would face a larger rate increase if Tyee power were purchased at current projected rates than would Petersburg. According to Mike Yerkes, who is negotiating the Tyee contracts for the Power Authority, this is because Wrangell would convert entirely from diesel generation to Tyee power, while Petersburg would continue to generate about half its power from the low-cost Crystal Lake hydro project, which was built decades ago.

Future Costs

The rate of increase in future generation costs for Petersburg and Wrangell is one of the basic questions to consider in determining what approach the State might take to the Tyee situation. The cost of diesel fuel is the largest expense component for these utilities, averaging about 9-10 cents per KWH generated over the past year. As you know, the future of world oil prices is highly uncertain and the range of forecasts is considerable. However, the most recent Department of Revenue forecast projects a 28 percent cumulative decrease in the real price of oil through FY 87. In nominal terms, oil prices in FY 88 are forecast to be about the same as today.

If this projection is accurate, it may be the early to mid-1990s before diesel generation costs would increase to the level of Tyee costs. However, an additional consideration is that Wrangell and Petersburg may have deferred expansion of their generation facilities in expectation of receiving Tyee power. Therefore, new generators might have to be added to meet increases in load growth during the 80s, which would increase power rates.

Retail Power Rates

Part of the publicity over the Tyee project centered on claims by Petersburg officials that they would have to add about 9 cents per KWH to the wholesale cost of power from Tyee for distribution and overhead costs, thus doubling the retail power costs from current levels. The Power Authority staff believe this figure is highly inflated and does not account for savings in diesel maintenance costs which would occur when Tyee comes on line. The staff is preparing documented estimates of what they feel are more realistic distribution and overhead costs.

Other Concerns

It is important to note that the cost of power from current projects is not the only concern of Petersburg, Wrangell, and other cities or utilities to be served by Power Authority projects. These groups are also concerned that under the current rate structure, their power rates could increase substantially as additional projects are added to the system. Whether this would occur depends on the level of State funding for the additional projects. If the ratio of State funding to bonded costs for new projects is lower than the average for current projects, the rates for current projects would rise.

The "Susitna Blackmail Clause" [AS 44.83.398(b)(2)] is an additional source of concern for municipalities and utilities, as the clause could dramatically increase power rates if not repealed. This clause would increase power rates by requiring a 10 percent annual return on investment to the State if $5 billion has not been appropriated for power projects by 1986.

POSSIBLE APPROACHES TO THE TYEE RATE PROBLEM

There are several possible approaches to the Tyee rate problem, as summarized earlier. The choice among them is complex and depends on basic policy issues relating to the power development program. Some of the more important factors to consider are discussed below.

Lump Sum Appropriation

This approach would be the most expensive; preliminary calculations indicate that $70-80 million would be necessary to lower the Tyee power rates to the cost of diesel generation.* Although the outstanding debt on the Tyee project is only $50 million, the pooling of debt service among all projects under the APA rate structure requires a larger appropriation to reduce Tyee rates sufficiently. A lump sum appropriation would also lower the power rates for Solomon Gulch, Swan Lake, and Terror Lake by an equal percentage (about 40 percent). This raises two questions.

First, is it necessary or desirable to reduce the power rates for other projects that already have reasonably price power? Second, what effect would lowering the rates for all projects now on line or under construction have on future projects? Lowering the average power rate would reduce the debt/equity ratio for current projects and require a higher level of State appropriations for future projects unless power rates were to be increased for all projects.

Special Tyee Legislation

If special legislation were passed so that a one-time appropriation would be used to reduce only Tyee power rates, roughly $20 million would be required to provide the necessary rate reduction. However, this approach could be viewed as creating a precedent for "bailing out" high-cost projects which might result in similar problems for future projects.

Annual Appropriation

In lieu of a one-time appropriation, the legislature could make annual appropriations of about $2.4 million to cover the debt service shortfall that will result if power is sold at 12 cents rather than 16.5 cents per KWH. These appropriations would continue and eventually diminish

---

* I have not included these calculations here for the sake of brevity, but can provide them if desired.

to zero as the cost of diesel generation increased to match the cost of Tyee power or the cost of Tyee power fell. Although it is uncertain how long these annual appropriations would be required, depending on fuel escalation rates and other factors, the total cost would probably be half or less the cost of a lump sum appropriation.

The Petersburg and Wrangell utilities would be eligible for rate relief under the power cost assistance program, but only for the portion of retail rates above 16 cents in FY 86. This floor increases by one cent each fiscal year. Also, cost assistance is available only for the first 600 KWH per month sold to each customer. Therefore, a separate appropriation specifically for Tyee debt service might be required each year in order to reduce power rates sufficiently.

Modification of Rate Structure

It would be technically possible to modify the statutory rate structure to reallocate at least part of the Tyee debt service to other lower cost projects, primarily Solomon Gulch and Terror Lake. The communities served by these projects would probably strongly oppose this change. In addition, the bond markets could view this juggling of the rate structure with some concern.

Restructure Project Debt

It may be possible to reduce the debt service costs for the first few years of operation of the Tyee project by borrowing additional funds with which to pay part of the interest on the bonds for several years. According to Sterling Gallager of John Nuveen and Associates, it is legally possible to have this type of arrangement for five years without violating federal arbitrage regulations. However, the financial viability of this approach is uncertain and would require additional research.

Another possibility would be to use a geometric financing approach, in which the debt service schedule would be shifted so that debt service costs would be lower in the early years and increase gradually as the project power sales increased. This approach has been used in a few utility bond issues, but it is uncommon and would also require more investigation to determine its viability for the Tyee situation.

IMPLICATIONS FOR OTHER POWER PROJECTS

A number of legislators and other observers have expressed concern about the possibility of the Tyee marketing problem occurring with Susitna or other hydro projects. This is a controversial issue with numerous points of view, but a few observations may be helpful in understanding the problem.

It is important to recognize the distinction between the economic feasibility of a hydroelectric project and the marketing feasibility of the same project. Although the economic feasibility of the Tyee project is an issue itself, the point is that even a clearly feasible hydro project will usually require some sort of grant or low-cost financing to lower power rates to marketable levels in its early years of operation. After a period of years, increasing power sales and higher fuel costs for the alternative generation source should result in a break-even point, after which the hydro power becomes less expensive. The initial subsidy to the project can then be repaid, if necessary.

In the case of the Tyee project, the continually increasing cost estimates for the project made it difficult to determine how much State money was required to achieve marketable power rates. The power marketing problem for Tyee is also accentuated by the fact that Tyee has the largest excess generation capacity of the four projects now on line or under construction -- only about 25-30 percent of the project's capacity will be used in the first years of operation. This lower level of utilization means that a higher proportion of State funds is necessary to obtain reasonable power rates.

A major element of the Tyee problem appears to be that neither the legislature nor the Power Authority placed sufficient emphasis until recently on the marketing of power from the projects under construction. Part of the reason for this apparent oversight is that in 1980 and 1981, State revenues were increasing rapidly and it was expected that most of the project costs would be funded through direct appropriations or low-cost loans, rather than by revenue bonds. With this expectation, power marketing was not an issue because of the low power costs. The sharp decline in State revenues has resulted in more reliance on debt financing, causing higher power rates and the marketing problem demonstrated by the Tyee project.

With respect to the Power Authority, an additional problem was the lack of staff with experience in marketing and rate issues. It was only about 10 months ago that the Power Authority hired someone with rate setting and utility experience. Until then, the focus of the staff was more on the feasibility, design, engineering and financing aspects of power development.

A final contributing factor to the Tyee situation was that the revisions to the Power Authority rate structure enacted in 1982 by HB 9 were not based on a full assesment of the effect of these rate revisions on the marketability of power from Tyee and the other projects.

The likelihood of the Tyee rate problem occurring with other power projects is difficult to assess. The Power Authority appears to have made good progress in dealing with the marketing issue. Several measures have been taken to avoid the recurrence of the Tyee cost escalation problem, and a number of recent bids for construction of the Terror Lake and Anchorage-Fairbanks projects have been substantially lower than engineering estimates.

In addition, the Authority has proposed changing its procedures to require power sales contracts to be signed before project construction begins, and this was done for the Terror Lake project. In the past it has been difficult to obtain contracts because it was uncertain how much funding would be provided by the legislature, and there is a natural incentive for communities to lobby the legislature for additional funds to reduce their power rates. It may also be difficult to obtain pre-construction power sales agreements for the Susitna project because of the long lead time of the project.

The chances of the Tyee power marketing problem occurring with future power projects would be reduced if the legislature made certain it had sound estimates of the maximum appropriation necessary for power marketing purposes before approving construction of a project, and committed itself to the appropriation of the necessary amount. Any changes in the rate structure should also be made only after detailed evaluation of the impact on project power rates and marketability.

* * * * *

I hope this information is useful. If you have any questions or would like additional information, please don't hesitate to call.

JK

Attachment

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE · ANCHORAGE, ALASKA 99501

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

February 9, 1983

Mr. Jack Kreinheder
House Research Agency
Pouch Y
Juneau, Alaska 99811

Subject: Tyee Hydroelectric Project-Summary of Estimated Total Costs

Dear Jack:

As per your request, following is a brief summary on the sequence of events on the Tyee hydropower project primarily relating to cost. The summary of Board actions was extracted from our corporate minutes. Most of the actions taken by the Board were based on advice from myself and my staff.

On December 19, 1979, the Alaska Power Authority submitted a revised 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 total cost of the project at that time at \$39,590,000 (1980\$'s). With an allowance for inflation and interest during construction the estimated total capital investment at that time came to \$53,333,000.

In September 1980, IECO submitted a revised cost estimate of \$50,976,000 (August 1980\$'s).

Early in 1981, the Power Authority retained EBASCO Services, Inc., to prepare an independent cost estimate. EBASCO subsequently estimated the total project cost at \$96,693,000 (May 1981\$'s). Escalated to the midpoint of construction, this would represent a completed cost of approximately \$110 million. After reviewing the EBASCO estimate, IECO conceded that its previous estimates were low and IECO raised its estimate to \$81,069,000 (June 1981\$'s). EBASCO refuted this revised estimate.

Procurement of long-lead-time turbines began in July 1981 in anticipation of a FERC license. The Board of Directors was realigned by Statute in the latter part of July 1981. The FERC issued a license on August 5, 1981 and the award of several additional procurement and one construction contract followed almost immediately thereafter.

IECO continued to make monthly reports on the status of the project, including estimated total project costs. It is important to note that by the end of March 1982, IECO had increased its project estimate to \$97,072,000, including engineering costs prior to construction. In the March report the overhead transmission line was estimated to cost $12,840,000 plus a $6,000,000 contingency. Less than two months later, during the bid opening for that contract, IECO provided an engineer's estimate of $23,280,887.00--an estimate that is 24 percent above any previous estimate, including contingency funds. The actual low bid was even higher at $24,901,466.

Starting with the IECO estimate from the March 1982, report, adjusting for the actual low bid on the transmission line, and adding the estimated cost for a proposed separate substation construction contract, the estimated total project cost was increased by IECO to $110,133,000 (May 1982). This did not include approximately $5 million for owner provided insurance.. During the months that followed, the total project cost has decreased and increased, slightly, as adjustments have been made for actual bids on relatively small procurement contracts..

In December 1982, and again in January 1983, senior staff of IECO and IECO's parent company, Morrison Knudson (M-K), met with representatives of the Power Authority to discuss construction management of the project, including total project costs. The latest information from IECO is that the total project cost will not exceed $124,886,100. The Power Authority has asked the parent company, M-K, to completely review this estimate. A report from the M-K staff is anticipated the second week of March 1983.

A summary of Board actions, as extracted from our corporate minutes, is as follows:

October 4, 1978 Board receives report on Tyee Project indicating that, according to the reconnaissance study by Robert W. Retherford Associates, (RWR) the Project looks favorable and that Thomas Bay Power Commission (TBPC) will soon enter into contract with RWR for Federal Energy Regulatory Commission (FERC) work and that TBPC may request the Alaska Power Authority to take over the project.

November 18, 1978 APA Board voted to make $120,000 loan to TBPC for Tyee FERC work and this would supplement the $300,000 available from the Water Resources Revolving Loan Fund (WRRLF) in order to cover the $475,000 contract with RWR.

June 21, 1979 Board makes a loan to TBPC of $60,000 for Tyee Project. TBPC and Representative E.J. Haugen request the APA take over Tyee. The Board directed staff to bring information back at next Board meeting for Project take-over.

September 27, 1979 Tyee Letter of Understanding with TBPC adopted by Board.

November 2, 1979 Board authorized Executive Director to submit FERC license application. Also passed "stop-the-clock" resolution needed for bonding.

February 7, 1980 Board agreed to extend contract for advanced Engineering and Design to IECO for Tyee but it was later decided with legal council to seek competitive proposals.

April 18, 1980 Board selects IECO for the Engineering and Design from among three proposals.

October 23, 1980 Board informed that costs have increased from $39,000;000 to $51,000,000 and has IECO explain to Board.

April 20, 1981 Board selects consultant panel as required by FERC.

May 14, 1981 Board awards Bids for Turbines.

July 6, 1981 Board considered awarding contract for Steel Towers and Conductors but defers "notice to proceed" until after opening of major Civil Contract so that the Board could get a better fix on the true cost of the Project.

August 18, 1981 FERC license has been received. Bids for Civil construction were reviewed as were the economics of the Project based on new cost estimates. Notice-to-proceed was given on Towers and Conductors. The Board was informed that existing funds were insufficient and that interim financing would be necessary. Board deferred action until the next meeting.

September 10, 1981 Board awards Civil Works contract to Southeast Harrison Western (SEHW) after lengthy debate.

October 2, 1981 Board informed on legal actions against Tyee construction contracts. Need for interim financing was discussed and indicated a proposal would be presented to the Board in December, 1981. Risk Management's desire to use "Wrap-up Insurance" on Tyee Project was discussed and actions that would be taken to effectuate such a program.

December 15, 1981 A Finance Plan was presented to the Board. It was recommended that the Board appoint a subcommittee to review the feasibility of the Tyee Project based on present knowledge of the costs. Commissioners Ward and Mueller and Dr. Weeden were appointed to the subcommittee. The Board moved that final financing documents for financing be prepared. The economics of the Project was reviewed.

January 22, 1982 Senator Dankworth and Representative Haugen addressed the Board and recommended proceeding with interim financing. Board authorized securing of $50,000,000 in interim financing. Board awarded a contract for Underwater Cables.

May 25, 1982 The Board awarded the Overhead Transmission Line contingent upon the Legislature not passing a piece of legislation that was being considered but that subsequently was not passed. Thus on June 3, 1982 the Executive Director informed the Board of his intent to issue the award for Transmission Tower construction.

October 22, 1982 The Board awarded contract for Transformers.

I trust this information is of assistance to you. If there is any further information you need, please call on me.

Sincerely,

Eric P. Yould

Eric P. Yould
Executive Director

CC:
C. Conway
Comm. D. Lyon

MARKETS & INVESTMENTS

A fiasco that may rock municipal bonds

When a delegation of top Washington State officials traveled to New York City recently to drum up interest in a bond sale, institutional money managers turned out in force. Despite the unusually large crowd, the obligatory call for questions following the briefing was greeted with silence. "Finally, someone asked about 'Whoops,'" recalls one attendee, "and all hell broke loose."

Washington Public Power Supply System, better (if unaffectionately) known as Whoops, is giving Wall Street a severe case of the jitters. WPPSS, which is the nation's largest single issuer of tax-exempt debt, is perilously close to defaulting on $2.25 billion of the $8.3 billion in bonds it has sold to finance a massive nuclear construction program. "The worst is beginning to come true," sighs a municipal bond portfolio manager for a big mutual fund.

A WPPSS default would be the biggest in municipal bond market history, and analysts say it could prove more disruptive than previous financial collapses. Unlike the typical tax-exempt issue, WPPSS bonds are in the hands of investors throughout the country. And in contrast to New York City and Cleveland—both of which had delayed repayment of short-term debt—WPPSS is on the verge of defaulting on long-term bonds. "It is an unparalleled situation," says Howard Sitzer, municipal research director for Thomson McKinnon Securities Inc.

Bad timing. WPPSS's predicament, moreover, is entering the crisis stage just as the health of the municipal bond market is becoming more crucial than ever. Sales of long-term tax-exempt bonds, which have hovered at $45 billion since 1977, shot up to $76 billion in 1982. Another record is expected this year as states and cities rush to finance long-delayed building projects.

"Any problem with Whoops will have an effect on the whole muni market," says a senior executive at a top brokerage house. "I really shouldn't say any more about it," he adds. "Just say we are very concerned." Investment bankers are particularly loath to discuss Wall Street's role in the WPPSS debacle. At the urging of four Northwestern congressmen, the Securities & Exchange Commission recently began looking into allegations of fraud in the underwriting and sale of WPPSS bonds. And John D. Dingell (D-Mich.), chairman of the House Energy & Commerce Committee, is considering holding hearings.

The syndicates put together to underwrite WPPSS bonds were headed by some of the premier names in public finance—Merrill Lynch, Goldman Sachs, Salomon Bros., Smith Barney, Blyth Eastman, and Paine Webber. Virtually every brokerage house of any consequence participated in these huge offerings. "Everybody sold Whoops bonds," says one analyst. To the dismay of investors, a long series of setbacks has depressed many WPPSS bond issues (chart).

The battering down of a WPPSS issue

Average weekly trading price of a 1974 issue of WPPSS 4 and 5 bonds maturing in 2015. By mid-September trading in this and other 4 and 5 issues was too light to permit computation of an average price

Upward revisions. WPPSS was forced to abandon two partially constructed nuclear plants a year ago; estimates had soared after Robert Ferguson took charge as WPPSS managing director and ordered a recalculation of costs. On Jan. 25, the 88 Pacific Northwest utilities that joined in this project were required to begin paying off the $4.8 billion in interest due over 30 years on the $2.25 billion in bonds sold to finance the plants.

Although each participant signed a contract obligating it to pay its share even if the plants were never completed, WPPSS received payments from only two utilities—totaling $9,435 of the $19 million it had coming. Five other utilities set aside funds in escrow accounts.

WPPSS needs the funds to make monthly payments to Chemical Bank, the bond fund trustee, which in turn makes semiannual distributions to investors. Unless WPPSS begins collecting by March, it will not have enough money to cover the $93.9 million payment due bondholders on July 1. Chemical holds $102 million in reserves, but tapping them might trigger a technical default.

'We're stretching.' Moreover, by the end of March, WPPSS expects to exhaust the funds set aside to pay up to $490 million due contractors on the ill-fated plants. It might be able to buy more time by selling off assets and delaying payments to contractors. "We're stretching," says James Perko, WPPSS's treasurer.

The participants, most of which are small public utilities, are under intense pressure from angry ratepayers. Crowds have marched on, and in some cases occupied, headquarters of public utility districts. Although many major participants are willing and able to fulfill their WPPSS contracts, they are unlikely to begin paying unless their legal obligation to do so is clarified in court. (Otherwise, they could be sued by ratepayers—and in Washington, public utility officials are personally liable.)

In fact, the 11 participants from Oregon are barred from paying by a state court ruling that found they exceeded their authority by entering into contracts with WPPSS in the first place. That decision is being appealed. Similar challenges are before courts in Idaho and Wyoming. In Washington, home to [illegible] of the participants, a suit to force utilities to pay WPPSS will not go to trial until April at the earliest. A half dozen other WPPSS cases—including one not expected to reach a federal court until summer—are pending.

No sympathy. Northwestern political and business leaders have tried in vain to jawbone recalcitrant utilities into paying. Attempts to seek a solution outside the region have proved similarly ineffective. California utilities have demonstrated little interest in buying WPPSS plants or any future output, and neither the Rea-

Director Ferguson and one of the two nuclear power plants (right) WPPSS decided to leave unfinished after getting new cost estimates.

gan Administration nor Congress is sympathetic to pleas for federal help.

Last fall, Shearson/American Express Inc., a major institutional owner of WPPSS debt, was unable to muster even token support on Capitol Hill for a bailout plan. "The federal government is waiting to receive guidance from the states to see what, if anything, they want done," says Lawrence S. Hobart, deputy executive director of the American Public Power Assn.

Efforts to reach an out-of-court compromise have gotten nowhere. "A lot of people would like to see all the parties sit down together and work something out," says Robert Greening, director of the Public Power Council, a utility trade group that counts many participants as members. "But as long as the lawyers are advising everyone not to give an inch, it won't happen. A lot of people are becoming fatalistic."

Thinking the unthinkable. Default, once unthinkable, increasingly is being viewed in the Northwest as a legitimate political option. Two recent studies contended that the impact of default on Washington's economy would not be as catastrophic as had earlier been predicted. Washington Governor John Spellman in mid-January commissioned an independent study of the effect on the state.

Although many observers cling to the hope that default can somehow be averted, some veteran WPPSS analysts already have concluded that it is virtually inevitable. "Under the most streamlined circumstances imaginable, there is the potential for an interruption in payment of interest, conceivably for two years or greater," says Eileen Titmuss, an analyst for Drexel Burnham Lambert Inc. Adds Jeffrey Whitehorn, an analyst for Dreyfus Corp.: "There is no way bondholders are going to come out whole."

If WPPSS is forced into receivership or bankruptcy, creditors might be able to get at funds—including bond reserves—meant for the three other plants it is building. WPPSS still needs to raise $1.1 billion to complete two of these plants (work on the third has been halted). But it is not clear that the Supply System will be able to return to the bond market for additional financing this spring as planned unless the legal uncertainties surrounding the impact of a default have been resolved.

The $6.2 billion in bonds WPPSS has sold to finance these plants are backed by the Bonneville Power Administration (BPA), a federal agency that markets the output of U.S. government-owned dams in the Northwest. But the BPA, too, is under mounting financial strain. Standard & Poor's Corp. recently downgraded the bonds for the three plants to AA.

A default also is likely to trigger an investor backlash against other Pacific Northwest tax-exempt issuers—even those not directly involved in WPPSS. "The precedent is really bad," says Edward Hosinger, municipal research director for Oppenheimer & Co. "I don't think a portfolio manager can risk owning a general obligation bond within these states."

'The old story.' Investors also may demand an additional risk premium to buy the securities offered by the nation's other 31 major regional public-power agencies, many of which employ "take or pay" contracts of the sort that WPPSS relied on. As a result, they may have to pay more for the $24 billion that John Nuveen & Co. estimates they will need to raise by 1990. One lesson of the WPPSS debacle, Titmuss says, is that "a project financing is only as good as the economics which underlie it."

But some analysts foresee an even stronger investor reaction. Although individuals now account for as much as 75% of all municipal bond purchases, "they are relatively unknowledgeable about munis," Sitzer argues. "If you had a Supply System default, people are going to be reluctant to buy more."

"It will affect people's assessment of the safety of all similar investments or even of all dissimilar investments," says Sterling Munro, former chief administrator of the BPA and Nuveen's national director of public power. "It is the old story—once the cat has been burned, it won't sit on the hot stove again, and it won't sit on a cold stove, either." ■

(J)

Alaska State Legislature

Senator Vic Fischer • Pouch V • Juneau, Alaska 99811 • (907) 465-4954

RECEIVED
JAN 27 1982
ALASKA POWER AUTHORITY

January 20, 1983

Eric Yould, Executive Director
Alaska Power Authority
344 W. 5th Avenue.
Anchorage, Alaska 99501

Dear Eric:

As you know, developments in recent months have significantly altered the outlook for future oil and gas prices and for energy demand. It now appears that some of the assumptions made by Acres and Battelle in their evaluations of the proposed Susitna project and alternatives are inaccurate. For example, it now appears that supplies of Cook Inlet natural gas will be available as fuel for the southcentral part of the state, and that they may be considerably less expensive than previously anticipated. (The intertie will make gas-fired electricity available to the interior as well.)

I have heard, though, that your understanding of the \$2.32/mcf contracts recently signed by Enstar is that they do not differ significantly for the \$3.00/mcf assumed in the Acres study, because the Acres price includes some additional costs that must also be added to the \$2.32 to compare them on an equal basis. I would very much appreciate it if you could provide me with a written explanation of this, as I believe it's critical to an understanding of the impact of the Enstar contracts.

Perhaps more important than the initial price, however, is the expected price escalation. Acres, I noted, in their medium forecast, assumes a real price escalation to \$4.80/mcf by the year 2000. Since the Enstar contracts are tied to changes in the price of locally-produced fuel oil and, since at least some experts in the field expect those prices to drop, it seems very possible that the escalation rate assumed by Acres is too high.

I understand further that people within the industry expect the Enstar contracts to act as a ceiling, and that future contracts are expected to be equal to or lower than the Enstar prices.

Given these developments, I would very much like to know how the up-dated Susitna-related work will reflect them. It seems to me that new net benefits calculations comparing Susitna to the base thermal case and to alternatives is called for. It would be most helpful to the legislature if such calculations could include a sensitivity analysis or, at the very least, a careful explanation of how changes in oil and gas prices will affect the net benefits.

I understand that Acres has in the past insisted on valuing the thermal alternatives at their "opportunity costs," or the prices they could bring on the export market if they could be sold. Although there may be some value in providing such a comparison, it seems to me obvious that we have at work some local market conditions that must be considered when deciding on the relative costs and merits of competing sources of energy. In fact, the market value of Cook Inlet gas is not the price it might bring in Japan if Japan wanted to buy it, but the price that the producers are willing to sell it for. It would be fiscally irresponsible to develop an energy project that would cost more than an available alternative; I would not want to face the prospect of building Susitna and then having the utilities opt to purchase Cook Inlet gas instead. Even disregarding such as extreme event, an accurate net benefits calculation is critical to determining how much state funding will need to be appropriated to Susitna so that its initial costs are lower than the thermal alternative, assuring that there will, in fact, be a market for the power. I would therefore very much appreciate it if Acres, or the APA, would, in addition to its "net-back" approach, provide a net benefits calculation based on actual costs available in Alaska.

Because of changing economic conditions, I have previously stressed to you what I felt was a need for updated load forecasts. I understand that Battelle was to do some revised forecasts, but that the contract has been both altered and delayed. I again stress the importance of this information to future decisions regarding Susitna. Further, I hope that new forecasts will include information on the effect of pricing on demand and some analysis of the energy demand "bubble" experienced by Anchorage in the last year.

I understand that the APA is apparently still expecting to submit a FERC license application for Susitna in February. It seems to me that there's a great deal of new information (including environmental field data for the 1982 season) that needs to be integrated into the application. Will a license application submitted in February take into account the recent pricing and demand developments and include this year's data and update? If it does not, how will the information later be incorporated?

I thank you for your attention to these matters and look forward to your early response.

Best regards,

Vic

Senator Vic Fischer

cc: Governor Bill Sheffield
Dick Lyon, Commissioner, DCED
Chuck Conway, APA Board Member
Robert Weeden, APA Board Member
John Schaeffer, APA Board Member
Peter McDowell, Director, OMB

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE - ANCHORAGE, ALASKA 99501

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

February 10, 1983

The Honorable Vic Fischer
Senator
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Dear Senator Fischer:

Thank you for your thoughtful inquiry into matters affecting the economic feasibility of the Susitna Hydroelectric Project.

In being associated with the project, I have noted that various people frame the arguments for or against Susitna in very different ways. Some concentrate on the environmental issues; others focus on the alternative uses for state funds. Some emphasize the risks inherent in building Susitna; others concentrate on the risks of relying on the alternatives and not building Susitna. Some base their judgement on the economic analysis, while others prefer to take a long term view of the project's potential contribution.

It is my personal opinion, and one which I have passed on to Governor Sheffield, that the issue is whether or not, at this juncture in the State's history, the State has sufficient discretionary funds to develop a secure renewable energy resource, at some risk regarding project cost, to satisfy power needs of about 70 percent of the State's population for more than 100 years.

Philosophy aside, there is no doubt that the economic analysis (with all its limitations) is a useful indicator that should contribute to a well reasoned decision. I will try to respond to each of your points.

The feasibility study, for purposes of the economic analysis, assumed unlimited supplies of Cook Inlet gas. I believe this to be a potentially dangerous assumption, but it nonetheless underlies the cost comparison. Mr. Dale Teel, of Enstar, continues to advise, in the strongest terms, that Cook Inlet gas supplies should not be depended upon for power generation beyond the mid 1990's. You may want to speak with him to gain insight into his view of the future.

With respect to Cook Inlet gas prices, the recent Enstar contracts provide an extremely valuable data point in the forecast of gas value. Previously contracted supplies will be exhausted by the time Watana could come on line in 1993. Therefore, the pertinent price for evaluating Susitna is the marginal value of new supplies. I have no reason to believe that the recent Enstar contracts are other than accurate indicators of the present day marginal price of Cook Inlet gas. The Alaska Power Authority's review of the contracts and our discussions with Mr. Teel lead us to the conclusion that the 1993 price of Cook Inlet gas delivered to Anchorage Municipal Light & Power (ML&P), in 1982 dollars and excluding any escalation between now and 1993, is about $3.00. This figure is arrived at by adding the severance tax (0.06/MCF), the delivery system fixed charges (0.30/MCF) and the demand charge (0.35/MCF) to the base price of $2.32/MCF. The estimates of severance tax and delivery system cost were provided by Mr. Teel. He was also the source of the forecast as to when the demand charge would go into effect (1990).

If an electric utility manages to negotiate an equally attractive contract and is able to burn the gas closer to the field than can ML&P, at least a portion of the delivery costs could be eliminated. Of course, that would mean increased electrical transmission facilities.

The Susitna Feasibility Report uses a 1993 cost of Cook Inlet gas (1982 dollars) of $3.03/MMBTU. Thus, the indicated cost based on the Enstar contracts would be virtually identical to the feasibility study estimate, as long as there is no real escalation in the gas prices between now and 1993. If there is real escalation over the next decade, Acres' estimate would prove too low; if there is de-escalation, the opposite would be true.

With this fairly close agreement on initial year prices between forecasted values and costs recently contracted, I agree with you that the expected price escalation is probably more important than the initial price. Acres assumed several escalation rates. In the low case, the price was assumed constant at $3.00/MMBTU throughout the study period (i.e., no escalation). The high case escalation rate was set at five percent to the year 2000, two percent for the next decade and zero thereafter. The resulting set of long-term system costs are presented in the Feasibility Report.

I am not privy to industry expectations that the Enstar contracts will serve as a ceiling for future price agreements. Please transmit any such information so that we can take it into account in our planning.

At my insistence, the Feasibility Report has been prepared to reflect and highlight the uncertainties and risks associated with both proceeding and not proceeding with the Susitna Project. Pages 46-49 of the March 1982, Summary Report offer a vivid presentation of the sensitivity of the economic evaluation to assumptions different than those that were assumed as the base case. Section 18, Volume 1 of the Feasibility Report provides more detail.

Your letter goes on to ask for economic (net benefits) and financial (yearly cost of thermal power) calculations based on actual costs available in Alaska. With respect to the latter, the actual generation cost (fuel, O&M and new capital investment) facing the utilities when Watana goes into operation is a very critical number in formulating the finance plan. The estimate is very dependent on inflation over the next decade and is also sensitive to the rate of demand growth. The first year alternative cost facing the utilities is one of several items that must receive periodic review.

You suggest that the market value of a fuel is not a function of the price it could bring in the Far East, but rather the price the Alaskan producers are willing to sell it for. Why would the producers want to sell the fuel locally at a price less than could be received from exporting? As long as the net-back procedure is performed properly and cost estimates are reasonably accurate, the procedure should yield good fuel price forecasts. If there is no interested overseas buyer, than the estimated market price should reflect that situation. If the forecast of world demand and markets proves incorrect and an export opportunity turns out not to exist, then the Alaskan production cost would become the controlling price.

To summarize, the net-back export price is the appropriate yardstick, but it is admittedly difficult to estimate world market conditions a decade and more into the future. The lowest price at which Alaskan fuels could possibly be valued is the local cost of production. I will include a sensitivity test where production based fuel costs are used for those fuel types where there is presently no established markets.

Battelle's RED model for Railbelt load forecasting has now been transferred to the State, under the custodianship of the Division of Energy and Power Development. Rather than hire Battelle to exercise the model for a forecast update, the project team will be using it directly. By so doing, we will be able to provide the necessary coordination of the forecasting and project evaluation to satisfy Federal Energy Regulatory Commission (FERC) requirements and can eliminate an extra player. The updated forecasts, like those prepared by Battelle, will show the sensitivity of demand to varied prices. They will also incorporate actual 1982 demand in the historical base.

You are correct that the Susitna license application will be submitted to FERC this month. It will have had the benefit of FERC and agency review and will be more thorough as a consequence. It will incorporate much of the results of the 1982 field season and will be accompanied by Alaska Department of Fish and Game's (ADF&G) 1982 data report. It will represent the largest amount of environmental information ever assembled for a FERC license application.

The "need for power" sections of the application will present the same analytical tools for load forecasting and project evaluation that are contained in the Feasibility Report. The application will also include the sensitivity testing methodology of the Feasibility Report and the full range of sensitivity test results. As the license processing proceeds, the Power Authority will be transmitting periodically updated load forecasts, fuel price assumptions and revenue projections. The FERC staff can be expected to critically review these and develop their own independently.

The FERC staff will initially concentrate on understanding and evaluating the analytical tools; only then will FERC turn to the actual evaluation of the project itself. By that time, the update presently in progress should be complete. FERC is well aware of the changing outlook for Alaskan revenues and is sensitive to their impact on demand.

As you consider the merits of the Susitna Project, it might be helpful to keep in mind that only the second phase, Devil Canyon, is predicated on load growth. The Watana phase is being planned to displace thermal generation and can be utilized from its first day of operation. Of course, the finance plan must result in competitive power costs to support this approach.

I hope I have adequately responded to your questions.

Sincerely,

Robert A Mohn
for Eric P. Yould
Executive Director

Attachment: Vic Fischer's letter dated January 20, 1983

cc: Governor Bill Sheffield
Richard Lyon
Charles Conway
Robert Weeden
John Schaeffer
Peter McDowell
Ray LaRusso
Henry Chen
Jane Drennan

POLICY ANALYSIS PAPER 82-14

Potential for Industrial Development in the Railbelt Region of Alaska Based on the Availability and Cost of Electric Power

December 1982

Prepared by: SRI International
333 Ravenwood Ave
Menlo Park, CA 94025

SRI International

POTENTIAL FOR INDUSTRIAL DEVELOPMENT IN THE RAILBELT REGION OF ALASKA BASED ON THE AVAILABILITY AND COST OF ELECTRIC POWER

Prepared for:

State of Alaska
Office of the Governor
Division of Policy Development
and Planning
Juneau, AK 99811

Submitted by:

Ralph J. Richardson
Michael D. Kimball
Jeffrey H. Barber
Technology and Innovation Management Center
SRI International

December 1982

SRI International

333 Ravenswood Ave. • Menlo Park, CA 94025
(415) 859-6200 • TWX: 910-373-2046 • Telex: 334 486

EXECUTIVE SUMMARY

The potential of new Alaskan hydroelectric and tidal power projects to provide large amounts of electrical power suggests that such hydroelectric capacity might serve as a magnet for industrial development and would help expand Alaska's economy. To assist the Office of the Governor in evaluating the potential for industrial development in Alaska based on inexpensive power, SRI International has reviewed available information on the proposed hydroelectric and tidal power projects and examined the issues related to an Alaskan location for a group of identified electrically intensive industries.

In addition to addressing particular industrial segments, SRI has examined other nonindustrial uses for low-cost electrical energy. These include electrification of the Alaskan Railroad, the possibility of an intertie to electrical grids in the lower 48 states, and expansion of electric space heating.

To determine the scope and timing of the proposed facilities, SRI used several studies on electric power development in the Railbelt region of Alaska. These include:

- Preliminary Assessment of Cook Inlet Tidal Power (Acres American/Governor's Office).
- Susitna Feasibility Study (Acres American/Alaska Power Authority) (Final Draft).
- Railbelt Electric Power Alternatives Study (Battelle Northwest Laboratories/Governor's Office) (Comment Draft).
- Energy Intensive Industry for Alaska (Battelle Northwest Laboratories/Division of Energy and Power Development).
- Various feasibility, engineering, and design studies on the Railbelt region by the Alaska Power Authority.
- Economic Development in Alaska--A Sectoral Analysis (Arthur D. Little/Alaska Department of Revenue).

In reviewing these studies of the Susitna hydroelectric and Cook Inlet tidal power projects, SRI collected data by project and in total for the following factors:

(a) Project location, likely completion date, power output, and other relevant system characteristics.

(b) Estimated project cost range.

(c) Forecast of service area demand.

(d) Estimated electric power price based on a, b, and c above.

(e) Nonutilized or surplus power availability through 2010, including a definition of "surplus" power and analysis of the impact of load growth on surplus power availability over time.

(f) Surplus or nonutilized power price ranges, including four cases: 100% market financing, 50% market financing and 50% state grants, 100% state loans with the rate of return equal to the inflation rate, and 100% state grants. The effect of potential wholesale and retail rate structures on surplus power price ranges was considered.

In addition, to place the hydroelectric and tidal power projects in perspective, SRI tabulated information about hydroelectric and other electric power developments worldwide that affect Alaska's competitive position compared to alternative industrial locations.

After reviewing the reports listed above, SRI concludes that for many of the proposed financing methods and demand scenarios, the projected capacities and price of power of electricity from the Susitna and Eagle Bay projects will not be major incentives for electrically intensive industries to locate in the Railbelt region.

Energy projects are usually phased to balance supply with expected demand. Significant quantities of nonutilized power are unlikely to be available as an inducement for industry to locate in Alaska unless the state chooses to adopt a construction schedule and plant mix that result in excess capacity.

More importantly, even though the annual operating costs of these projects may be low relative to alternative power sources, the high carrying costs associated with the initial construction of these projects, financed at prevailing interest rates, will offset such savings. As a result, unless the state is able to obtain low interest rates or provide the majority of capital costs at no or very low interest rates, the cost of excess power, even if available, will not be sufficiently low to attract industry.

Table 1 summarizes the pertinent data of the reviewed reports and to indicate the likely completion dates. The actual completion dates will depend on the demand for electric power and the potential for financing the projects.

Table 1

CHARACTERISTICS OF HYDROELECTRIC AND TIDAL POWER PROJECTS

Project Location	Earliest Completion Date, Medium Demand Forecast	Installed Capacity (MW)	Energy (GWh)	Capital Costs (billion 1982 $)	Projected Electricity Cost (mills/kWh)	Forecasts for Nonutilized Energy, 2000-2010 (GWh)	
						Medium Demand	Low Demand
Hydroelectric							
Susitna--Watana	1993	680					
Subtotal				$3.647		0	0
Susitna--Devil Canyon	2002	600		$1.470		0	900-1,300
Total		1,280	6,790	$5.117	58		
Tidal							
Eagle Bay	2010	1,440	4,000	$3.825[2]	48	4,000	4,000
Directly usable power			1,600		121		
Available power for retiming			2,400		79		

[1]Actual costs will include any additional interest to finance each project.

[2]Does not include any costs for retiming or storage.

To identify potential industries that might be attracted to Alaska by the long-term availability of inexpensive electrical energy, SRI compared U.S. Department of Commerce data on the value of purchased electrical energy with the value of shipped product for over 960 4-digit Standard Industrial Classification (SIC) code industries.

The screening process identified nine industries that might benefit from inexpensive power. Four are in Category I, for which electricity costs exceed 10% of product value. Two are in Category II, for which electricity costs are between 5% and 10% of product value; these were combined with three in Category III, for which total energy costs are greater than 10% of product value and electricity may be substituted for thermal energy sources.

In addition to the Category I, II, and III industries retained for further screening, four other potential large-scale electrical energy uses were considered as specified in the statement of work. The list of industries and "other industrial applications" evaluated are listed in Table 2.

Of the nine potential candidate industries and four additional application areas considered, only residential space heating and processing of certain primary metals are likely to take advantage of the low-cost power in the Railbelt region. Expanded space heating usage has the best potential to utilize any excess power produced in the Railbelt. Investment in an aluminum plant appears to be likely only if the construction costs of the hydroelectric projects are subsidized by the state, and then it is questionable that there will be sufficient excess power available to serve a single "world-class" plant. Although the tidal project might provide sufficient power, the power from this project will not be low cost. Other metal processing plants are likely to be considered only if feedstocks are found in Alaska. The construction of an intertie with the Lower 48 does not appear to be cost-effective without state grants to finance the power projects, but there is no rationale for Alaska to subsidize power delivered to other states.

SRI's findings are predicated on 10% interest rates, continued high Alaskan labor costs, and little real increase in petroleum prices during the next 25 years.

The major findings of the study are:

- The cost of power from the Susitna project will not be competitive without a very substantial state subsidy, in the form of either grants or subsidized interest rate (until the capital cost obligation is paid off in 2010).
- The Cook Inlet project will not produce power at competitive rates because of the intermittent nature of tidal power.

Table 2

INDUSTRIES AND OTHER INDUSTRIAL APPLICATIONS EVALUATED AS POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL POWER

Category I

- The Aluminum Industry (SIC 3334, Primary Production Aluminum)
- The Chlor-Alkali Industry (SIC 2812, Alkalies and Chlorine)
- Industrial Gases (SIC 2813, Industrial Gases)
- Ferroalloy and Miscellaneous Metal Alloy Production (SIC 3313, Electrometallurgical Products)

Categories II and III

- Pulp and Paper Industry (SIC 2661, Building Paper and Building Board Mills; 2611, Pulpmills; and 2621, Papermills, Excluding Building Paper)
- Cement Industry (SIC 3241, Hydraulic Cement)
- Chemical Industry (2719, Industrial Inorganic Chemicals, NEC)
- Primary Metals Industry (SIC 3339, Primary Smelting and Refining of Nonferrous Metals, NEC; SIC 3333, Primary Zinc)
- The Fertilizer Industry (SIC 2873, Ammonia Production, Nitrogenous Fertilizers; 2874, Phosphate Fertilizers)

Other Applications

- Agglomerations of Small Industrial Facilities
- Residential Space Heat
- Electrification of Alaskan Railroad Intertie with the Lower 48
- Intertie with the Lower 48.

- There is not likely to be excess power available from Susitna alone unless the Alaskan economy stagnates or declines.

- There is unlikely to be sufficient excess power to serve a single world-class aluminum plant.

- Other than aluminum, electrically intensive industries are unlikely to derive sufficient cost savings from subsidized power to consider an Alaskan site on the basis of low-cost electricity alone.

- The availability of low-cost power might improve the economics of processing materials, provided the major feedstocks are native to Alaska.

- Without a tiered rate structure to discourage use for residential space heating, subsidized power is likely to increase electric space heating use sufficiently to absorb any excess power from the Susitna project.

- The relatively high state corporate income tax is a barrier to industrial development in the state.

- Although the SRI study is predicated on stable energy prices through 2002, the findings of the study are not greatly affected by an increase in fuel prices of 50%, since transportation costs will escalate commensurately.

CONTENTS

CONTENTS (Concluded)

ILLUSTRATIONS

TABLES

TABLES (Continued)

TABLES (Concluded)

I PROPOSED RAILBELT HYDROELECTRIC AND TIDAL POWER PROJECTS

The potential of new Alaskan hydroelectric and tidal power projects to provide large amounts of electrical power suggests that such hydroelectric capacity might serve as a magnet for industrial development and would help expand Alaska's economy. To assist the Office of the Governor in evaluating the potential for industrial development in Alaska based on inexpensive power, SRI International has reviewed available information on the proposed hydroelectric and tidal power projects and examined the issues related to an Alaskan location for a group of identified electrically intensive industries.

In addition to addressing particular industrial segments, SRI has examined other nonindustrial uses for low-cost electrical energy. These include electrification of the Alaskan Railroad, the possibility of an intertie to electrical grids in the lower 48 states, and expansion of electric space heating.

To determine the scope and timing of the proposed facilities, SRI used several studies on electric power development in the Railbelt region of Alaska. These include:

- Preliminary Assessment of Cook Inlet Tidal Power (Acres American/Governor's Office)
- Susitna Feasibility Study (Acres American/Alaska Power Authority) (Final Draft)
- Railbelt Electric Power Alternatives Study (Battelle Northwest Laboratories/Governor's Office) (Comment Draft)
- Energy Intensive Industry for Alaska (Battelle Northwest Laboratories/Division of Energy and Power Development)
- Various feasibility, engineering, and design studies on the Railbelt region by the Alaska Power Authority
- Economic Development in Alaska--A Sectoral Analysis (Arthur D. Little/Alaska Department of Revenue).

In reviewing these studies of the Susitna hydroelectric and Cook Inlet tidal power projects, SRI collected data by project and in total for the following factors:

(a) Project location, likely completion date, power output, and other relevant system characteristics.

(b) Estimated project cost range.

(c) Forecast of service area demand.

(d) Estimated electric power price based on a, b, and c above.

(e) Nonutilized or surplus power availability through 2010, including a definition of "surplus" power and analysis of the impact of load growth on surplus power availability over time.

(f) Surplus or nonutilized power price ranges, including four cases: 100% market financing, 50% market financing and 50% state grants, 100% state loans with the rate of return equal to the inflation rate, and 100% state grants. The effect of potential wholesale and retail rate structures on surplus power price ranges was considered.

In addition, to place the hydroelectric and tidal power projects in perspective, SRI tabulated information about hydroelectric and other electric power developments worldwide that affect Alaska's competitive position compared to alternative industrial locations.

The economics of the proposed hydroelectric and tidal power plants are highly dependent on future oil prices and lower interest rates. Increasing oil prices will provide more state revenue, enabling the Legislature to consider grants or low-interest loans. More importantly, increased oil prices are more likely to force electric energy costs higher and induce electric-energy-intensive industries to build new facilities in regions with low-cost electric power. Industry is also more likely to finance the construction of new plants if interest rates are low.

After reviewing the reports listed above, SRI concludes that for many of the proposed financing methods and demand scenarios, the projected capacities and price of power of electricity from the Susitna and Eagle Bay projects will not be major incentives for electrically intensive industries to locate in the Railbelt region.

Energy projects are usually phased to balance supply with expected demand. Significant quantities of nonutilized power are unlikely to be available as an inducement for industry to locate in Alaska unless the state chooses to adopt a construction schedule and plant mix that result in excess capacity.

More importantly, even though the annual operating costs of these projects may be low relative to alternative power sources, the high carrying costs associated with the initial construction of these projects, financed at prevailing interest rates, will offset such savings. As a result, unless the state is able to obtain low interest rates or provide the majority of capital costs at no or very low interest rates, the cost of excess power, even if available, will not be sufficiently low to attract industry.

SRI International prepared Table I-1 to summarize the pertinent data of the reviewed reports and to indicate the likely completion dates. The actual completion dates will depend on the demand for electric power and the potential for financing the projects.

Susitna Hydroelectric Development

Project Location

The Susitna basin development plan recommended by Acres American, Inc., indicates that the proposed 1,280 MW Watana-Devil Canyon dam project is the optimum plan from an economic, environmental, and social point of view. The proposed plan develops approximately 91% of the total basin potential.

The Susitna River system is the sixth largest in Alaska. The main stream of the Susitna River originates about 90 miles south of Fairbanks, where melting glaciers contribute much of its summer flow. For more than 30 years, the vast hydroelectric potential of this river has been recognized and studied. Strategically located in the heart of the south central Railbelt, the Susitna could be harnessed to produce more than twice as much electrical energy per year as is now being consumed in the Railbelt. Figure I-1 illustrates the location of the proposed Watana and Devil Canyon dams.

The main Watana dam is projected to be an earth/rockfill structure constructed primarily with locally excavated materials. The maximum height of the dam above the foundation will be approximately 880 feet, and the crest elevation will be 2,225 feet. The overall volume of the dam is estimated at approximately 63 million cubic yards.

The main Devil Canyon dam is currently proposed as a thin concrete arch structure with an overall height of 650 feet and developed crest length of 1,230 feet. The crest width will be 20 feet, and the base width at the crown cantilever will be 90 feet. The geometry of the arch corresponds to a two-center configuration compatible with the asymmetric transverse profile of the valley. The development at Devil Canyon will be located at the upper end of the canyon at its narrowest point.

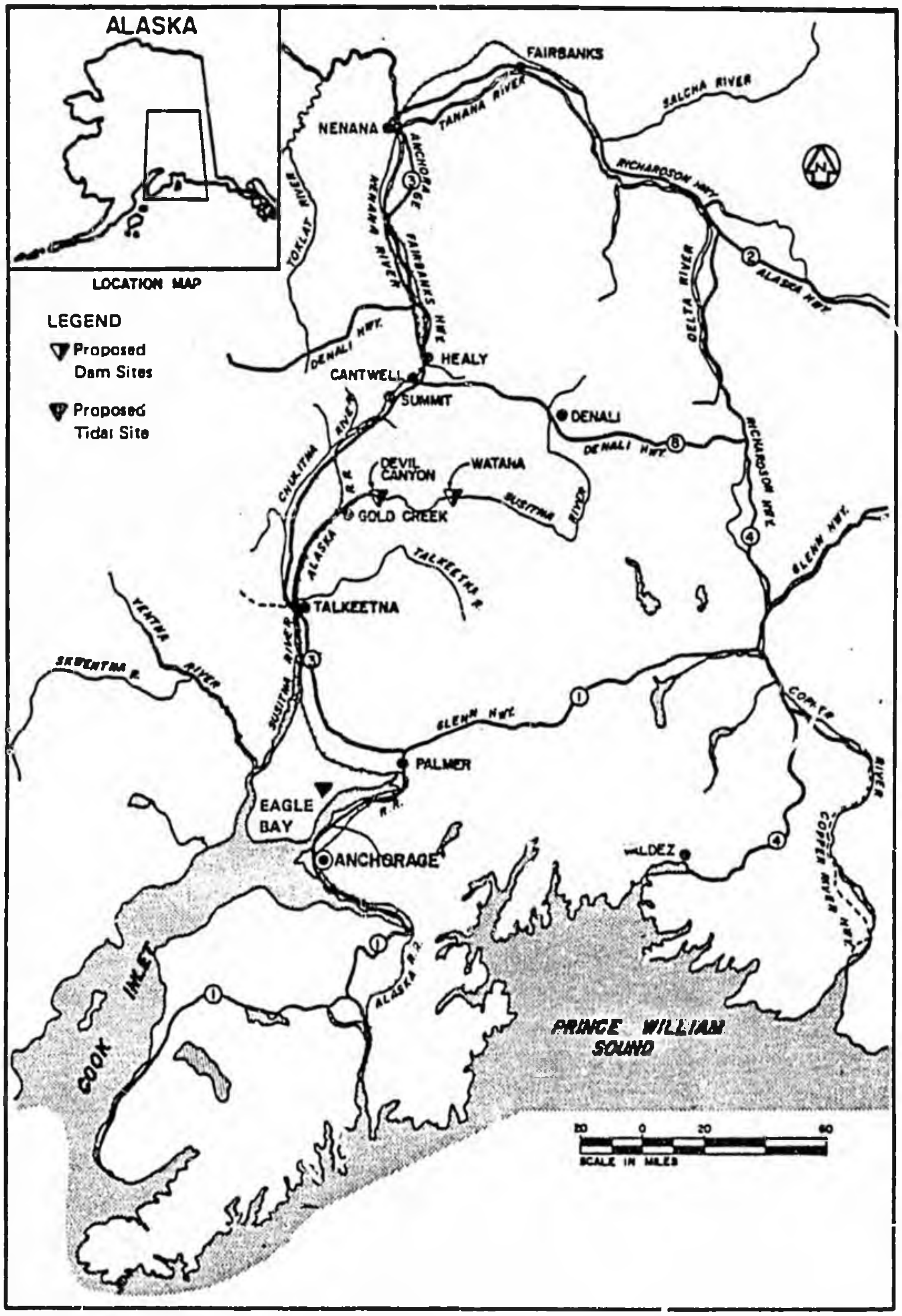
Table I-1

CHARACTERISTICS OF HYDROELECTRIC AND TIDAL POWER PROJECTS

Project Location	Earliest Completion Date, Medium Demand Forecast	Installed Capacity (MW)	Energy (GWh)	Capital Costs (billion 1982 $)	Projected Electricity Cost (mills/kWh)	Forecasts for Nonutilized Energy, 2000-2010 (GWh) Medium Demand	Low Demand
Hydroelectric							
Susitna--Watana	1993	680					
Subtotal				$3.647		0	0
Susitna--Devil Canyon	2002	600		$1.470		0	900-1,300
Total		1,280	6,790	$5.117	58		
Tidal							
Eagle Bay	2010	1,440	4,000	$3.825[2]	48	4,000	4,000
Directly usable power			1,600		121		
Available power for retiming			2,400		79		

[1]Actual costs will include any additional interest to finance each project.

[2]Does not include any costs for retiming or storage.



SOURCE: Acres American Incorporated, *Susitna Hydroelectric Project, Task 11 Economic, Marketing and Financial Evaluation*, prepared for Alaska Power Authority (March 1982)

FIGURE I-1 LOCATION OF PROPOSED PROJECTS

Completion Dates

The Watana rockfill dam is expected to take approximately 11 years to complete from the start of the access road to the testing and commissioning of all generating units. The earliest date that power production from the Watana dam could start is January 1993, based on construction of the access road beginning in early 1985 as soon as the Federal Energy Regulatory Commission (FERC) license is received. The Devil Canyon thin arch dam will take approximately 9 years and will be completed by 2000 at the earliest.

Power Output

The selected Susitna Basin development plan involves the construction of the Watana dam with a 680-MW powerhouse scheduled to commence operation by 1993, the earliest that a project of this magnitude can be brought on line. The final stage involves the construction of the Devil Canyon dam with an installed capacity of 600 MW.

Should the load growth rate increase more slowly than the current medium growth forecast, then Alaska would have to consider postponing both the capacity expansion proposed at Watana and the construction of the Devil Canyon dam to the year 2002 or later. If Watana were delayed to the late 1990s, Devil Canyon would be delayed to 2010. This slippage corresponds to the low load forecast with an increased level of load management and conservation. For actual load growth rates higher than the medium load forecasts, construction of the Devil Canyon dam could be advanced to 1998.

Although this development plan is economical for a wide range possible future energy growth rates, the actual scheduling for various stages should be continuously reassessed. In addition, am heights and installed capacities should be considered represen at this stage of project planning.

Project Cost Estimates

The total projected capital cost (1982 dollars) for the selected Susitna hydroelectric development project is $5.117 billion, with Watana costing $3.647 billion and Devil Canyon an additional $1.470 billion. The annual operating costs are projected to be $10 million for Watana and $5.42 million for Devil Canyon--a total of $15.42 million per year. Other forecast financial parameters are shown in Table I-2.

Cook Inlet Tidal Power Development

Tidal power was selected for consideration in Railbelt electric energy plans because the substantial Cook Inlet tidal resource is among the largest in the world and because of the renewable character of this energy resource.

Tidal power plants typically consist of a tidal barrier extending across a bay or inlet that has substantial tidal fluctuations. The barrier contains sluice gates to admit water on the incoming tide and turbine-generator units through which the outgoing tide passes to generate power. Tidal power is intermittent, requiring a power system with an equivalent amount of installed capacity capable of cycling its output. Hydroelectric plants and/or energy storage facilities (pumped hydro, compressed air, storage batteries) could be used to regulate the power output of the tidal facility.

Project Location

The Acres American study, "Preliminary Assessment of Cook Inlet Tidal Power" (September 1981), evaluated three tidal power plant alternatives, identifying Eagle Bay in Knik Arm northeast of Anchorage as the most economically attractive site based on preliminary results of its technical evaluation. SRI analyzed the price and availability of power only at the Eagle Bay site because of its compatibility with Railbelt load projections and avoidance of some environmental problems common to sites farther down the Knik Arm in Cook Inlet. The other two sites, Rainbow and Point Mackenzie-Point Woronzof, are not included in the SRI comparative analysis.

Completion Date

The overall tidal project at Eagle Bay is estimated to require 10 years to complete once the FERC license application is received. A license probably would not be awarded by FERC before late 1989 at the earliest. The process could be accelerated by performing the detailed design and engineering specifications (with a model of the ter~ turbines) during the federal license process. Although construction could begin as early as 2000, the State of Alaska is unlikely to undertake the tidal project until the Susitna project is nearing completion. The phasing of economic cycles, in combination with the financial drain of the large capital outlays required by both tidal and hydroelectric projects, precludes them from being constructed concurrently. In light of the periodic nature of tidal energy output, the hydroelectric projects at Susitna built before the development of the Cook Inlet tidal basin could assist in leveling the output of a tidal generation facility by idling Susitna generators during tidal plant output periods. Alternatively, thermal power plants could be disengaged while the tidal power plant was generating. However, even with Susitna on line, not all tidal power would be used. With the Devil Canyon dam being completed by 2000 at the earliest, the Eagle Bay project would be ready to start up by 2010.

Table I-2

FORECASTS OF SUSITNA FINANCIAL PARAMETERS

	Watana	Devil Canyon	Total
Project completion date	1993	2002	
Costs (1982 $)			
Capital costs (billion $)	$ 3.647	$ 1.470	$ 5.117
Operating costs (million $/year)	$10.0	$ 5.42	$15.42
Provision for capital renewals* (million $/year)	$10.94	$ 4.41	$15.35
Operating working capital	15% of operating costs plus 10% of revenue		
Reserve and contingency fund	100% of operating costs plus 100% of provision for capital renewals		
Real rate of increase in operating costs			
1981 to 1987	1.7% per annum		
1986 to 1992	1.0% per annum		
1993 on	2.0% per annum		

*0.3% of capital costs.

Power Output

The planned Eagle Bay tidal plant could have an installed capacity of 1,440 MW and could produce about 4,000 GWh annually when the project is in full operation. In the Railbelt system, the value of the installed capacity of a tidal power plant operating strictly on tidal cycles cannot be fully realized. The periodic nature of the tidal plant's generation cycle and the very substantial output of energy in comparison to the Railbelt demand provides a unique problem in fitting the supply to match the pattern of demand.

Previous tidal power studies estimated that, in theory, the energy output from a tidal plant must be less than 10% of the total system requirements for it to be directly absorbed without "retiming" of energy. The 4,000 GWh produced at Eagle Bay would be as much as 90% of total system energy needs in the Railbelt projected by Battelle for the year 2010. SRI is not aware of any major industrial users of electricity that could utilize the intermittent power. Some type of retiming or energy storage is necessary if the full tidal power plant output is to be absorbed effectively.

If the energy usable in the system is defined as that portion of the tidal power plant production that meets system demand, the usable portion varies from about 30% of the total energy produced in summer months, to about 35% in the spring and fall months, to more than 50% in the winter months. Overall, about 1,600 GWh, or 40% of the Eagle Bay plant total of 4,000 GWh, can be classified as directly usable in the system.

Because of the magnitude of the directly unusable energy--about 2,400 GWh--three options should be considered to increase utilization of the tidal power: (1) installation of an energy storage system designed to balance the tidal fluctuations, (2) providing a balancing power supply source, or (3) attracting an industrial base to take advantage of unretimed tidal output. The penalty for not using the full output of tidal power is major. The cost of the usable energy goes up by a factor of 2.5 at Eagle Bay if the unretimed and directly unusable energy is not utilized.

Project Cost Estimates

Cost estimates for the tidal project of Eagle Bay are taken from the study prepared by Acres American. The Eagle Bay project is expected to have a capital cost of $3.825 billion (1982 dollars), which does not reflect the additional costs for retiming or any other costs associated with integration of the intermittent phased output pulses of tidal power.

II RAILBELT FORECASTS OF ANNUAL PEAK LOAD AND ELECTRIC ENERGY REQUIREMENTS

Historical Electricity Demand Profiles

Between 1940 and 1978, electricity sales in the Railbelt grew at an average annual rate of 15.2%, roughly twice the national average. However, the gap between national and Alaskan energy consumption has been narrowing due to the maturing of the Alaskan economy. Growth in the Railbelt has exceeded the national average for two reasons: the population growth in the Railbelt has been higher than the national rate, and the proportion of Alaskan households served by electric utilities was initially lower than the U.S. average so that some growth in the number of customers occurred independently of population growth.

The 1980 annual energy requirement of the Railbelt utility system was estimated to be 2,790 GWh and the peak demand 515 MW. Near-term future demands can be satisfied by the existing generating system, the committed expansion at Bradley Lake (hydroelectric), and the combined-cycle (gas-fired) plant at Anchorage. These facilities are expected to meet the demand until 1993, provided an Anchorage-Fairbanks intertie of adequate capacity is constructed.

Demand Forecasting

The feasibility of a major hydroelectric project depends partly on the extent to which the available capacity and energy are consistent with the needs of the market to be served by the time the project comes on line. Therefore, load forecasts are a most important factor in selecting the type and timing of generation units.

The Battelle Northwest study, "Railbelt Electric Power Alternatives Study" (February 1982), produced forecasts of annual electric energy and peak electric demand requirements for the Railbelt region and its three principal load centers: the Anchorage-Cook Inlet area, the Fairbanks-Tanana Valley area, and the Glennallen-Valdez area. These forecasts are designed as internally consistent estimates of power needs that take into account the following effects on the Railbelt region:

- Future economic and population growth.
- Future changes in the age, size, and energy-use characteristics of households.
- Future growth in commercial building stock.
- Future price and availability of fuel oil, natural gas, and wood.
- Cost of power from specific combinations of conservation and electrical generation that could be used to meet power demands.

- Public policy actions directly affecting energy demand or the cost of power.
- Possible new major uses of electric power, such as industrial use in manufacturing.

Because groups of these factors may interact in complex ways to produce a range of possible (but not equally plausible) forecasts, computer models of the interaction process were developed to determine how these factors individually and jointly affect demand estimates. The models, together with certain key assumptions concerning Alaska's economy, Alaskan public policy, and world prices for fossil fuels, produced contingent forecasts of electricity demand at 5-year intervals beginning from 1980. The demand forecasts were used as the basis for power plant planning in the Battelle study.

The forecasting process consisted of two steps: (1) combining sets of consistent economic and policy assumptions (scenarios) with economic models from the University of Alaska Institute of Social and Economic Research (ISER) to produce forecasts of future economic activity, population, and households in the Railbelt region and its three load centers; and (2) combining these forecasts with data on current end uses of electricity in the residential sector, data on the size of the Railbelt commercial building stock, data on the cost and performance of conservation, assumptions concerning the future prices of electricity and other fuels, and future new uses of electricity to produce demand forecasts.

Specifically, three basic scenarios for private economic activity and state spending were combined to give three overall economic scenarios: (1) high private economic activity and high state spending (high economic growth case); (2) medium private economic activity and medium state spending (medium economic growth case); and (3) low private economic growth and low state spending (low economic growth case). Increased industrialization and unsustainable state spending were investigated by Battelle but are not included in the three major growth scenarios. The Battelle forecasting model, the Railbelt Electric Demand (RED) model, is based on the linkage between economic growth scenarios and electricity consumption.

Peak demand and annual energy forecasts for the low, medium, and high economic growth cases, as developed by Battelle, are presented in Table II-1.* The medium growth scenario is established in the Battelle

---

*Note that the forecasts used by Acres American, Inc., in the Susitna hydroelectric project were initial projections derived from December 1981 computer runs of the various scenarios. The final forecasts produced in February 1982 by Battelle are approximately 20% lower. The result is that the Acres American low growth case corresponds to the latest Battelle medium growth forecast.

study as the base-case. The projected annual growth rate in base-case demand for electric energy is approximately 3.0% between 1980 and 2010, for an increase in per capita use of approximately 0.9% per year. Demand in the low economic growth case increases at 2.2% per year. Demand in the high economic growth case shows an average increase of 4.3% per year. The corresponding Railbelt system peak load (expressed in megawatts) corresponds basically to growth rates in annual energy demand.

Table II-1

PEAK DEMAND AND ANNUAL ENERGY REQUIREMENTS FOR THE LOW, MEDIUM, AND HIGH ECONOMIC GROWTH CASES*

	Low Economic Growth		Medium Economic Growth		High Economic Growth	
Year	Peak (MW)	Energy (Gwh)	Peak (MW)	Energy (Gwh)	Peak (MW)	Energy (Gwh)
1980	520	2,550	520	2,550	520	2,550
1985	620	3,030	640	3,140	670	3,240
1990	800	3,850	880	4,260	1,060	5,414
1995	840	4,060	990	4,880	1,180	6,060
2000	820	3,990	1,020	5,030	1,230	6,380
2005	870	4,280	1,090	5,420	1,440	7,430
2010	1,000	4,940	1,260	6,260	1,760	9,010

*The peak demand and annual energy requirements in this table do not assume a subsidy of the electric rate. The demand for electricity would increase if rates were subsidized.

III ELECTRIC POWER PRICE RANGES

Susitna Project

Electricity cost estimates depend directly on the ability to correctly forecast electricity demand. If electricity consumption drops by one-third, the cost per kilowatt-hour more than doubles. As the unit price of power increases (decreases), consumption rates tend to decrease (increase). This elasticity of demand for electric power has proven to be a major factor in the economic health of domestic utilities. Clearly, to assure an economical match between electricity production and consumption, the timing of a major project like Susitna and the cost of power are extremely critical. The issue of full utilization of Susitna capacity is complicated by the present system of decentralized independent utilities which can be expected to bargain for rates no higher than the cost of energy from the best thermal option available to them.

Unless Susitna is completely financed by the state, residual bond financing will be required, at interest rates determined by complex political and economic forces. Acres American developed a financing plan based on interest rates of 10% to 12% to arrive at estimates of project financing characteristics. Analysis of this plan indicates that the costs of supporting the Susitna project on a 100% market-financed basis are higher than its projected revenues during the early years of the project. The cost of 100% market financing would result in electric rates which vary over time but are 9 to 15 times the level that would result from 100% state grants. These multiples result from high debt-servicing costs associated with the 100% market-financed scenario.

Table III-1 illustrates overall power costs, and the fraction of those costs attributable to operational costs and debt servicing for the four basic scenarios under consideration for the year 1995 (2 years after Watana's earliest power production), 2003 (2 years after Devil Canyon's earliest power production), and 2010 (at which point Susitna power costs should be relatively level). Price ranges were taken directly from published Acres American financial data, except for the 100% state loan scenario. The power price for this scenario was calculated from yearly plant expenses in the absence of capital cost debt servicing as determined by the 100% state grant case, and from debt-servicing data used in the 100% market-financed case.

With 100% state grants and a total capital cost of $5.1 billion (in 1982 dollars), the price for hydroelectric power of $.01 per kWh would be very competitive worldwide. This plan represents the simplest financing option.

Table III-1

ELECTRIC POWER PRICE RANGES
(Mill/kWh, Constant 1982 Dollars)

Scenario	Amount of Power Cost Attributable to Debt Servicing			Annual Operational Expense*			Total Cost		
	1995	2003	2010	1995	2003	2010	1995	2003	2010
100% state grant	N/A	N/A	N/A	8.24	8.84	8.35	8.24	8.84	8.35
100% state loan	78.47	49.05	26.72	8.24	8.84	8.35	86.71	57.89	35.07
50% market financing 50% state grant	47.14	51.06	25.11	8.24	8.84	8.35	55.38	59.90	33.46
100% market financing	112.10	70.07	38.17	8.24	8.84	8.35	120.34	78.91	46.52

*Assumed constant for all scenarios; see Table II-1.

Source: Acres American Susitna Feasibility Study

If Susitna is built with 100% state grants, the implication is that only the relatively small annual costs necessary for successful operation would be charged as the cost of output. The energy developed by Susitna would thus be supplied to utilities at a fraction of the cost of power from alternative sources. It has been assumed that no financing or marketing problems will exist for this case. The major problem may be arriving at an equitable allocation of the low-cost power among the consuming utilities whose normal demand may well exceed the supply of heavily subsidized power. The 100% state grants case would result in rates of about $.01/kWh (in 1982 dollars), which are comparable to but slightly lower than the $.0125 industrial rates for Le Grande Complex in Canada.*

Another possible scenario is for the state to provide 100% of the capital costs in the form of a state loan to be repaid at an interest rate based on inflation. Assuming repayment at an average interest rate of 7%, this scenario would result in a rate of $.09/kWh in 1995, which decreases to $.035/kWh by 2010 (in 1982 dollars). If the state provides about half ($2.3 billion) of the capital costs as a grant, with the remaining portion being market financed, the electric rate would vary from $.05/kWh in 1995 to $.06 in 2003 and then decrease to $.033/kWh by 2010, somewhat higher than the current industrial rates in the Pacific Northwest. This rate is fractionally lower than the state loan case, reflecting the effect of the $2.3 billion grant. If the Susitna hydroelectric project is 100% market financed, then the rates would be $.12/kWh in 1995, decreasing to $.08/kWh in 2003 and $.046/kWh by 2010.

Cook Inlet Tidal Project

As illustrated in Table III-2, estimated production costs of an unretimed tidal power facility ($.048/kWh) would be competitive with principal alternative sources of power, such as coal-fired power plants, but this cost can be realized only if all the available power could be used effectively by a specialized industry established to absorb the predictable but cyclic output of the plant. Alternatively, if it is assumed that only the portion of the power output that could be absorbed by the Railbelt power systems could be classified as usable, the cost of this energy ($.121/kWh) would be extremely high relative to other power-producing options because only a fraction of the raw energy production could be used. An additional alternative would be to construct a retiming facility, such as a pumped storage facility. Because of the increased capital costs and power losses inherent in this option, busbar power costs ($.079/kWh) would still be substantially greater than for nontidal generating alternatives.

If the power production capability of the proposed 1,440-MW Eagle Bay plant were halved, using 30 instead of 60 turbines, the energy costs, when the excess energy cannot be used, are still relatively high.

---

*LeGrande Complex rates for small power users vary between $.026/kWh and $.045/kWh.

Table III-2

TIDAL GENERATION ENERGY COSTS AT [illegible]
($/kWh)

Installed Capacity (MW)	Production Cost of Unretimed Energy	[illegible]	
		Excess Energy Not Used	Excess Energy Retimed
1,440	.048	.121	.079
720	.058	.087	.076

*Assumes a 3% real rate of return on the capital invested.

Source: Preliminary Assessment of Cook Inlet Tidal Power, Phase I Report, Acres American, Incorporated, September 1981.

IV AVAILABILITY OF NONUTILIZED POWER THROUGH 2010

Nonutilized power can be the result of seasonal variations, insufficient demand in the short term (3 to 5 years), or long-term low energy demand. The actual demand for electricity in the Railbelt varies seasonally. The capacity of new generation facilities is designed to meet peak loads, even if some surplus capacity results during certain time periods. Little can be done with short-term excess capacity when the normal demand growth will consume it within a few years. Only long-term surpluses of a generation system like the Susitna hydroelectric or the Eagle Bay tidal project would have the potential for attracting electrically intensive industry. These industries require reliable energy sources at low cost for periods exceeding 10 to 15 years.

According to Table I-1, in their final configuration the proposed Susitna hydro projects at Watana and Devil Canyon are expected to produce 6,790 GWh of energy annually. Under the Battelle-derived medium demand electric energy forecast, all of this energy will be consumed through normal load growth and displacements of existing generation facilities. Nonutilized power would only become available if the low growth forecast occurs. Should the low growth scenario prevail, approximately 1,200 to 1,800 GWh of nonutilized power, when Devil Canyon comes on line in 2002, could then be consumed annually by electrically intensive industries.

The mere availability of inexpensive electrical energy is not sufficient to ensure that the managers of electrically intensive industries will elect to locate new facilities in Alaska. Companies are reluctant to invest the required capital in a new plant to take advantage of inexpensive electric energy if large quantities of electricity cannot be guaranteed beyond 10 to 15 years. For example, the Acres American report states that even under their medium demand scenario some Susitna energy output (about 350 GWh) will not be used during the summer in 2010 (medium demand, summer). This seasonal energy output could be available to industry in the summer months. However, since most manufacturing processes require year-round operation, this power would not be attractive to most industries and cannot really be classified as a "surplus." In addition, the projected cost of the power from the unsubsidized facility is high when compared to other large hydroelectric power facilities like Le Grande Complex in Canada. If the state provides 100% of the capital for the project and does not expect any return on capital, then the cost of electricity will be very low, but this lower rate is likely to increase domestic demand significantly, resulting in little power availability for industry.

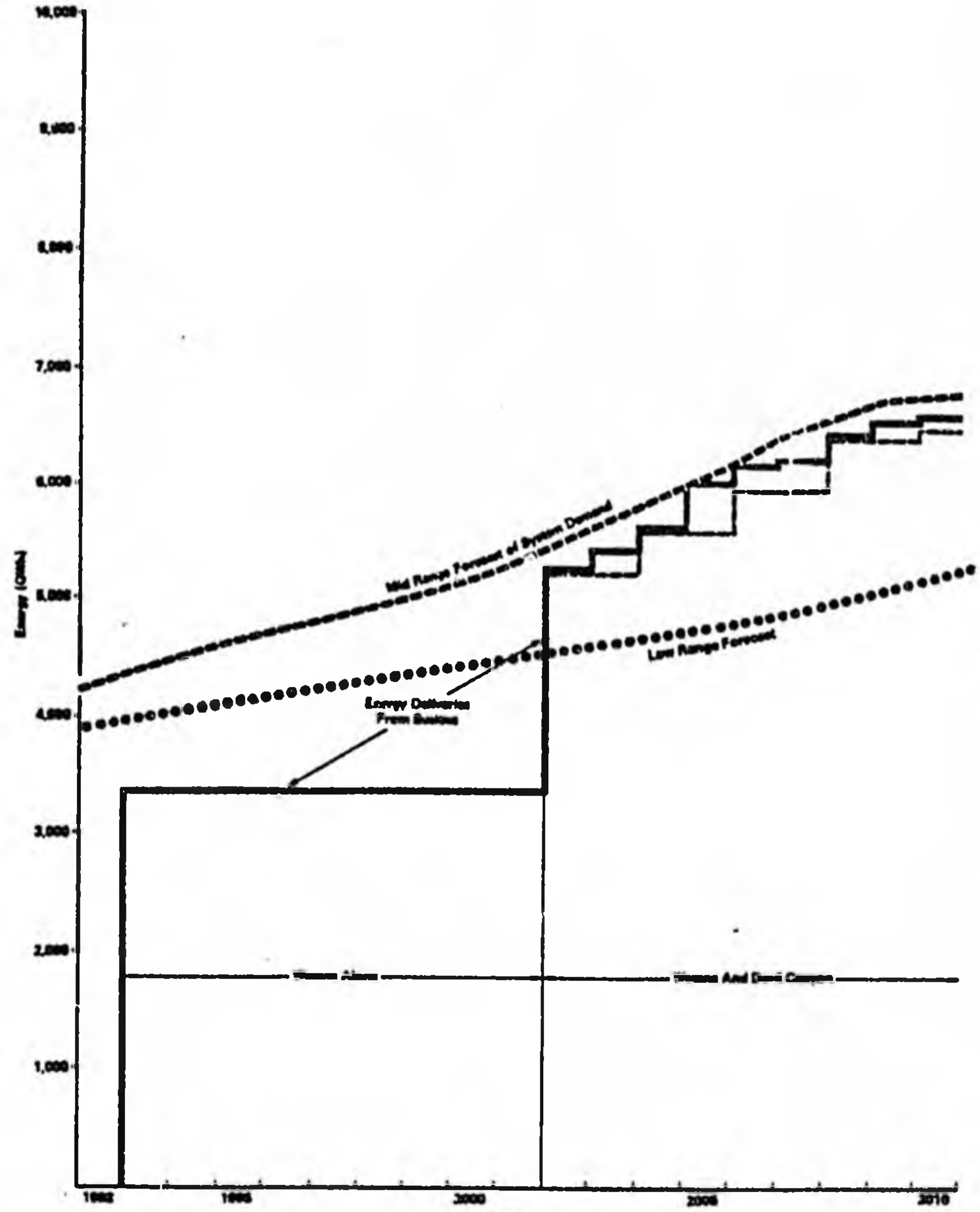
If the proposed Eagle Bay tidal power facility is approved, construction is expected to begin after 2000, when the Susitna project is about ready to go on line. This schedule would most effectively use Alaskan labor supply and is not likely to overtax the Alaskan economy. The required 10 years of construction would bring the tidal-generated power on line in 2010 or 2012. Even for the medium demand forecast, very little if any Eagle Bay output is expected to be required in 2010-2012. All of the output of this facility could be available, therefore, for additional industrial consumption. Because the generation of tidal power is intermittent, the energy produced will be in excess of the demand at certain periods, resulting in power that is not directly usable by the power grid without a large energy storage facility for retiming. The additional costs for retiming would make the project uneconomical. If only the directly usable power is included in the overall project, the cost for Eagle Bay power is estimated at $0.12/kWh.

Optimum economic use of the Watana and Devil Canyon hydroelectric plants requires that they be operated as close as possible to full capacity. Large users of electric power could be offered blocks of power at a reduced rate to encourage full utilization of the capacity of the dam with maximum payback on the high capital costs and fixed operation and maintenance.

Potential for Nonutilized Electric Power

By comparing the forecast of system demand for the Railbelt with the energy deliveries from Susitna and Eagle Bay, the projected quantity of nonutilized electric power can be derived. The medium forecast of system demand and capacity is used as the base case in most of the studies that were compared. This comparison is shown in Figure IV-1 for both the medium and low case scenarios used by Acres. The wholesale energy cost from the hydroelectric and tidal plants is assumed to be less than the cost of the best thermal option and also less than the avoided operating costs of electricity supplied by existing equipment so that existing facilities are displaced. These assumptions would result in Railbelt utilities purchasing the majority of their power requirements from the hydroelectric and tidal projects. If the wholesale energy cost from the hydroelectric and tidal plants is not competitive with the cost of the thermal options, then there is little justification to undertake the large water projects. If the wholesale price is substantially less than the thermal alternatives because of financing subsidies, then the quantity of nonutilized power (excess capacity) would decrease as a higher "normal" demand consumes the lower-cost energy.

Figure IV-1 compares energy demand projections from Acres and projected deliveries from the Susitna hydroelectric projects. When Watana comes on line in 1993, the total energy output would not exceed the expected demand. No surplus is expected to be available for large-scale industrial usage, at least until Devil Canyon comes on line in



SOURCE: Acres American Incorporated, *Susitna Hydroelectric Project, Task 11: Economic, Marketing and Financial Evaluation*, prepared for Alaska Power Authority (March 1982)

FIGURE IV-1 ENERGY DEMAND AND DELIVERIES FROM SUSITNA

2000-2002. Under the medium growth forecast, little if any nonutilized power would be available. However, the low range forecast projects that 1,200 to 1,800 GWh of energy would be available annually for at least 10 years.

If the Eagle Bay tidal power plant comes on line in 2010, then the complete output of the project would be available for industrial use in the near term, although only 1,600 kWh would be directly usable.

The State of Alaska and the Corps of Engineers are considering two additional hydroelectric projects, Chackachamna and Bradley Lake. Chackachamna would be completed no earlier than 1995; its installed capacity of 330 MW would produce 1,500 GWh of energy annually. The 90-MW Bradley Lake project, which could be completed in 1988, would produce 350 GWh of energy annually. This plant has a 90-MW base load and 135-MW peak load capacity. By 1995 these plants would make an additional 1,850 GWh available for industrial use.

Fiscal Crisis Scenario

The various scenarios that have been discussed assume that any nonutilized or excess power capacity above normal reserve margins is the general result of a conscious decision to build such capacity for attracting industry and that massive excess capacity will not occur unintentionally. One additional scenario that SRI was asked to address concerns a worst-case fiscal crisis situation in which dams are constructed and even the low growth economic projection fails to materialize. This scenario is similar to the situation in which the utilities that make up the Washington Public Power Supply System found themselves when building what turned out to be excess nuclear capacity. They were forced to terminate at least two plants of five under construction, one of which was more than 24% complete. Under the fiscal crisis scenario, the state would have approximately 3,800 GWh available to attract industry.

In all financing scenarios except the 100% state grant, the ability or nonability to repay financing debt has serious consequences. In cases with fixed capital costs and falling demand, management is likely to increase power prices to maintain revenue. In any event, this scenario would result in an increase in the range of power available for industrial development if capacity is built before the Alaskan economy enters stagnation or downturn.

Summary of Potential for Surplus Energy

Table IV-1 summarizes the potential for surplus energy that might develop in the Railbelt. The data in the table indicate that if all the contemplated projects are built and if the Railbelt region experiences a low growth rate (2.2% per year), up to 5,350 GWh of annual output could be available by 2010 to attract electrically intensive industries. Even if the Cook Inlet and Chackachamna facilities are not built, 2,000 GWh of annual output could be available by 2000 if Devil Canyon is built and the "fiscal crisis" scenario develops.

Table IV-1

SUMMARY OF POTENTIAL SURPLUS ENERGY*

	2000	2010
Watana/Devil Canyon[1]	1,300 GWh	
Watana/Devil Canyon and Cook Inlet Tidal[1]	1,300 GWh	5,300 GWh
Watana alone[2]	2,500 GWh	
Watana/Devil Canyon[2]	3,800 GWh	

*Without consideration of project financing.

[1]Assumes Acres low demand case.

[2]Assumes Battelle "Fiscal Crisis" case.

V WORLDWIDE POWER PROJECTS COMPETITIVE WITH ALASKA'S HYDROELECTRIC DEVELOPMENT

Roughly half of the world's hydropower potential (approximately 1,200 GW) is in developing countries. Only 10% of the potential projects have been developed. Tables V-1 and V-2 show the status of worldwide hydroelectric development. Given the large increases in oil prices, many previously uneconomical hydroelectric sites have become more attractive. Developing countries are funding hydropower surveys and feasibility studies to explore these possibilities, but because of the long lead time for such projects and high financing cost, very few large projects will be completed during the present decade. Nevertheless, about 100 GW of hydroelectric capacity are expected to be completed over the next decade in some 60 developing countries. At fuel oil prices of \$20-\$25 per barrel, hydropower costing \$2,500 to \$3,000 per kilowatt of installed capacity can be competitive with oil-fueled steam units or large diesels. At this investment cost, assuming financing at 10%, hydroelectricity would cost about \$0.07/kWh. Several sites, particularly in Canada and Brazil, have projected rates of about \$.015/kWh. With power costs of \$.0125/kWh for large industrial users, Le Grande Complex in Quebec will be a competitor of the Railbelt for electrically intensive industries. Moreover, significant amounts of power are expected to be available for industrial use from this facility.

Industry is a major user of commercial energy in the developing world. In countries for which data are available, the industrial sector accounts for one-fifth to two-thirds of total commercial energy consumption, with an average at around 35%.

Those developing countries with relatively high levels of energy consumption are also major producers of the more energy-intensive industrial products, such as steel (Brazil, India, Republic of Korea, Mexico, Romania, Turkey, Yugoslavia), cement (Brazil, India, Republic of Korea, Romania, Turkey), ammonia (India, Indonesia, Republic of Korea, Mexico, Romania), aluminum (Brazil, India, Yugoslavia), pulp and paper (Brazil, Republic of Korea, Mexico, Romania), fertilizers (India, Brazil, Romania, Turkey), and chemicals (Brazil, India, Portugal, Romania). These countries are potential competitors of Alaska as industrial sites.

Table V-1

HYDROELECTRIC DEVELOPMENT STATUS
(MW)

Country	Installed Capacity	Under Construction	Planned	Other Probable
Australia (1981)	6,113	-	2,350	9,765
Argentina (1979)	3,900	3,872	33,717	8,340
Brazil (1979)	23,842	26,163	14,096	100,000
Chile (1979)	1,480	950	6,595	6,781
Venezuela (1979)	3,000	2,620	13,565	-
India (1979)	9,908	6,820	1,978	42,000
Indonesia (1979)	450	-	2,500	31,000
Nepal (1979)	37	90	80,000	-
Colombia (1979)	3,120	1,150	23,350	23,600
Iceland (1979)	3,069	-	-	28,000
Honduras (1979)	69	600	-	3,000
Nigeria (1979)	600	1,145	1,200	8,000
Guatemala (1977)	121	600	1,635	4,000
Thailand (1977)	910	185	19,602	-
New Zealand (1978)	3,766	-	-	-

Table V-2

INTERNATIONAL DEVELOPMENT STATUS OF HYDROELECTRIC POWER SITES--INSTALLED OR INSTALLABLE CAPACITY (MW)

Country	Operating	Under Construction	Planned	Other Probable	Total
World	402,294	122,137	247,105	457,850	1,229,386
Canada	40,810	17,522	4,050	37,397	99,779
U.S.	68,933	8,200	2,013	103,477	182,623
Asia and Pacific					
Australia	5,695	1,660	2,350	-	9,705
New Zealand	3,617	868	1,320	5,000	10,805
Nepal	36	-	-	-	36
Philippines	725	2,085	-	4,778	7,588
Sri Lanka	335	-	-	-	335
Thailand	910	185	19,602	-	20,697
India	9,353	6,820	1,978	-	18,151
Indonesia	976	-	2,500	28,500	31,976
Malaysia	350	348	838	1,150	2,686
Latin America					
Argentina	1,945	5,872	33,717	8,340	49,874
Brazil	19,038	26,163	14,096	44,734	104,031
Chile	1,474	950	6,595	6,781	15,800
Colombia	2,801	1,150	23,350	23,600	50,901
Guatemala	121	20	1,635	4,881	6,657
Honduras	69	-	-	-	69
Paraguay	265	-	-	-	265
Peru	1,412	488	-	37,140	39,040
Uruguay	236	1,245	20	42,520	1,926
Venezuela	2,353	2,620	13,565	0	18,538
Africa					
Angola	368	80	300	9,000	9,748
Ghana	792	-	140	527	1,459
Madagascar	40	-	-	-	40
Mozambique	937	3,700	2,500	5,000	12,137
Nigeria	420	440	3,930	-	4,790
Zaire	1,159	289	-	32,000	33,448
Zambia	1,669	-	-	-	1,669

Source: Yearbook of World Energy Statistics, United Nations (1979).

VI INDUSTRIAL LOCATION DECISIONS

General

Business location decisions depend on a variety of site-specific factors, the objectives of the particular company involved, and the changing business environment and health of the relevant industry. Justification for specific facilities is an outgrowth of specific corporate strategies. The compelling reasons behind the search for new sites include:

- Expansion of existing production capacity
- New product manufacturing
- Cost reduction of production and distribution
- Expansion of market area
- Replacement of obsolete facilities.

Table VI-1 lists typical site selection criteria. Five broad categories--labor costs, transportation costs, utility costs, construction and other occupancy costs, and tax costs--represent about 90% of the total geographically variable cost factors associated with a typical plant location study. Usually treated as recurring expenses, these costs are therefore annualized; their totals represent a major input into locational decisions by most companies.

Usually a number of noncost, or subjective, factors are investigated during the course of a facility location project. The list may be as short as a half-dozen or as long as 100 or more. However, most company lists include at least labor issues (unionism, attitudes, availability), electric power and natural gas availability and dependability, physical site suitability, community attitude toward business development, and living conditions.

The specific measures used by an industry to determine each location's degree of compliance with the general location criteria consist of two types of screens: (1) thresholds or minimum requirements that must be met by any location to be considered suitable for a plant, such as those relating to environmental regulations or availability of required utilities, transportation facilities, and land and buildings; and (2) relative measures that provide a basis for comparing locations that meet all minimum requirements, such as those relating to production factors and quality of life issues.

Once the list of alternative locations is narrowed, specific cost analyses of total facility costs attributed to labor, transportation, amortization, utilities, taxes, and other costs are often conducted.

Table VI-1

GENERAL SITE SELECTION CRITERIA

Financial Considerations

- Overall cost of living
- Cost of transportation for feedstock and parts to plant and for product to marketplace
- Cost of direct and indirect labor
- Utility costs
- Salary levels
- Taxes on industry
- Availability of industrial development assistance
- Availability of capital
- Overall operating costs
- Employee relocation costs
- Cost of land and buildings
- Construction costs, including expense of added time for permit approval

Locational Considerations

- Availability and reliability of utilities
- Proximity to transportation, including airports, rail lines, trucking, shipping, and mass transit
- Proximity to like industries
- Proximity to materials, vendors, and services
- Start-up training and facilities
- Stability of regulatory and political climate
- Labor union presence
- Environmental sensitivities
- Recruitment potential and labor availability
- Legal status of land ownership

Quality of Life Considerations

- Quality of public schools
- Availability and cost of housing; potential neighbors
- Cultural activities
- Presence of major university--4-year, 2-year, vocational
- Recreational activities
- Climate
- Community attitudes
- Alternative employment potential
- Proximity to resource centers for professional development

Compromises are almost always necessary in locating a new facility. For example, a company may have extensive requirements for electricity that would cause it to select a second-best site. Many site selections result from arbitrary corporate decisions that contradict purely economic analyses. This situation most often occurs when economic variations between competing sites show few significant differences and personal preferences by corporate management become the deciding factor. A list of the site selection factors considered by industry in analyzing energy issues is presented in Table VI-2.

Electrically Intensive Industries*

The cost of electric power, like the cost of any input to production, will affect Alaska's attractiveness as a location for new production facilities, but low-cost electricity by itself is insufficient to attract industry. For example, although a typical aluminum plant incurs electrical energy costs from 14% to 18% of product value, the extra construction costs (1.6 times U.S. average) and other additional expenditures associated with an Alaskan location may outweigh the benefit of reduced electricity costs.

Plant Location Factors

New forces are emerging that are shifting the weight of the relative measures for comparing locations. Cost factors are changing significantly, making future cost projections difficult. Figure VI-1 shows that transportation, electric power, and occupancy costs have increased much more dramatically during the past 10 years than the cost of labor or local property taxes.

Changes in transportation costs during the past 10 years have been closely linked to escalating fuel costs. As transportation costs increase, the importance of strategic markets and raw material availability increases for new plant sites.

Electric power costs have escalated rapidly during the past 10 years and can be expected to continue to increase over the next 10 years. Electricity rates for large industrial users rose by 18% between 1980 and 1981 alone, and recent increases in the Northwest have dramatically shifted the economics of existing plants.

---

*Derived from A. R. Tussing in "Introduction to Electric Power Supply Planning," Tussing and Associates, May 1980.

Table VI-2

SITE LOCATION FACTORS RELATING TO
ELECTRIC ENERGY AND UTILITIES

Power Source

- Thermal--coal, natural gas, propane, fuel oil, lignite
- Hydroelectric
- Other--nuclear, geothermal, solar

Electric Power Supply

- Company or public agency serving area
- Interconnection with other systems
- Capacity--present and planned
- Recent record of shortages or interruptions
  - Average number of interruptions per year
  - Maximum duration
- Vulnerability to natural disasters
- Location of nearest electric substations and whether interlocking
- Voltage, phase, and cycle available
- Size of connection at proposed site
- Two-way feed
- Rates based on demand for services
  - Lighting
  - Machine operation
  - Air conditioning
  - Welding
  - Furnaces
- Cost of extending service
- Typical residential rates
- Off-peak possibilities
- Fuel adjustment provisions

Potential for On-Site Independent Energy Source

- Gas well
- Coal mine
- Nuclear reactor
- Cogeneration
- Waste burning

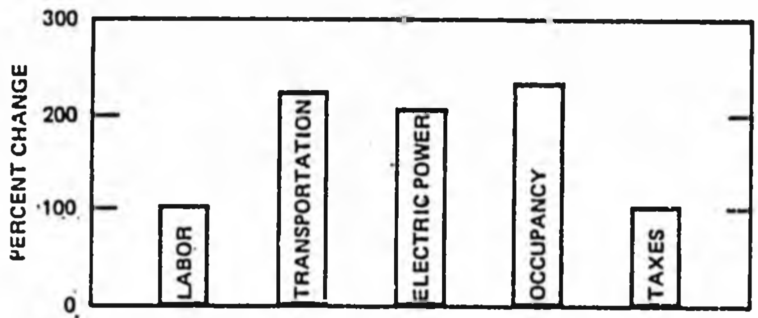


FIGURE VI-1 PERCENT CHANGE IN KEY COST FACTORS, 1970-1980

As competition among the states for new facilities increases, more and more states are seeking to improve their business climates to attract new industries. Although median tax rates have increased from about 2% to 4% of total investment during the past 10 years, more states are granting full or partial exemption to various classes of property to lure new facilities. Similarly, state levies on corporate income have remained relatively stable. Only two states have increased corporate income taxes during the past 5 years.

Occupancy costs have risen faster than any other costs during the 1970s. Both of the key elements that make up this cost, construction costs and interest rates, have doubled during the past 10 years. A $2 million building in 1970 cost $4,444,000 in 1980. A typical revenue bond interest rate in 1970 of 7% nearly doubled to 13% by 1980. The annual cost to amortize a 25-year loan jumped more than 250% between 1970 and 1980.

A review of site location studies written during the early 1970s reveals a concern with unionism, natural gas availability, proximity to interstate highways, and proximity to various support services. By 1980, additional factors such as state and community attitude toward industry, environmental concerns, living conditions, airline and truck service, and electric power availability and reliability are equally important.

Companies are becoming more concerned, in making their siting decisions, about living conditions, community attitudes, and political stability. In addition to forecasting geographically variable costs, corporations will become more adept at evaluating noncost or subjective factors. These concerns could become significant when comparing an Alaskan site to a site in a developing country with competing low-cost hydroelectric power. The relative political stability offered by Alaska represents a real asset when compared to the political uncertainty in many developing countries, although this asset may be offset by the economic uncertainty resulting from the expected decline in oil revenues in the 1990s.

During the next 10 years, additional issues such as water availability are expected to increase in importance. The availability of grants, subsidies, and inducements will also be a major locational criterion. The aggressive worldwide competition for new industry, exemplified by Japanese aluminum smelters in Brazil and by U.S. microelectronics industry in Scotland, are becoming increasingly important as U.S. manufacturers look in both developed and developing countries for sites which lower their production costs.

VII CHARACTERISTICS, RESOURCES, AND LIMITATIONS OF THE RAILBELT REGION

Characteristics of the Railbelt region critical to industry-specific location decisions are:

- Labor costs and supply
- Taxation
- Construction costs
- Transportation cost and infrastructure
- Land status
- Climate
- Environmental considerations and land use plans
- Basic services and secondary industry
- Natural resources
- Existing industry
- Geographical location and proximity to markets

Alaska's principal economic attractions are its potential supply of undeveloped raw materials and fuel and its power availability. These attractive features must be weighed against those factors of the Alaskan economy which will prevent certain types of development in the state for the foreseeable future.

Labor Costs and Supply

As indicated in Table VII-1, the Railbelt has only limited supplies of labor in the construction, mining, and manufacturing (industrial) sectors. Any major developments in those sectors would require a significant labor influx. The most recent, accurate data concerning labor supplies in the Railbelt region are the employment figures for the third quarter of 1980. The data in Table VII-1 represent the averages for that year and are given by sector and by subregion (census division).

Table VII-1

NUMBER OF EMPLOYEES BY SECTOR IN THE RAILBELT

Sector	Anchorage	Kenai	Mat-Su	Subtotal South Central	Fairbanks/ SE Fairbanks	Cordova/ Valdez	Total Railbelt	Percent Total
Government	20,356	1,169	1,281	22,806	7,460	1,100	31,366	26%
Services	17,182	1,023	511	18,716	4,554	686	23,956	20
Retail trade	13,324	1,048	792	15,164	3,662	332	19,158	16
Transportation, communication, utilities	8,318	671	306	9,295	2,882	608	12,785	11
Construction	7,190	902	267	8,359	2,374	360	11,093	9
Finance, insurance, real estate	4,900	203	115	5,218	698	123	6,039	5
Manufacturing	2,532	2,022	27	4,581	502	532	5,615	5
Wholesale trade	4,230	272	53	4,555	679	51	5,285	4
Oil & gas extraction	2,671	793	--	3,464	6	--	3,470	3
Other mining	244	--	53	297	74	152	523	--
Other	804	82	36	922	103	--	1,025	1
Total	81,751	8,185	3,441	93,337	22,994	3,944	120,315	100%
Percent Total	68%	7%	3%	78%	19%	3%	100%	

Source: U.S. Bureau of Labor Statistics

Alaskan wage rates for industrial occupations tend to be substantially above U.S. averages. For example, in 1982 the average construction worker's weekly wage in Anchorage was approximately 1.52 times the average of 27 other U.S. metropolitan areas (Table VII-2). Other industries such as services and manufacturing are somewhat closer to national averages. Hourly manufacturing wage rates in Alaska in 1980 were about 1.37 times higher than those for the U.S. as a whole and are expected to remain at least 1.3 times higher in most sectors throughout the study horizon of 1982-2010. In the specific industry analyses, which are contained in Section IX, labor data for the individual industries are used where available.

Not only are prevailing wage rates in Alaska relatively high, but Alaska does not have a large pool of highly skilled workers. Many of the recent unemployed are construction workers. Workers with specific skills in the oil industry and other specialized skills are generally recruited outside of the state.

In general, extractive and primary processing operations are less labor intensive than final product manufacture. In addition, the increased use of automation and robotics in manufacturing will decrease the importance of labor in this sector. Nevertheless, labor costs, especially for construction, will remain an inhibiting factor to any industry that does not gain an offsetting economic advantage from an Alaskan location (e.g., lower material or energy costs).

<u>Taxation</u>

Recent changes in Alaskan taxation policies have made the state more attractive to both individuals and corporations, although corporate income taxes remain high.

Most states levy corporate income and/or corporate franchise taxes as significant sources of state revenues. For 1982, the income tax rate for large corporations was significantly reduced in Alaska, to 9.4% from the previous maximum rate of 11%. This reduction makes Alaska more competitive with states such as California (9.6%), but the rate remains high relative to many Sunbelt states which have either no corporate income tax (Nevada, Texas) or rates in the 5% to 6% range (Alabama, Florida, Georgia, South Carolina, North Carolina, etc.). Alaska is also high relative to Pacific Northwest states. Washington has a business occupation tax of 1%, and Oregon has a 7.5% corporate tax rate.[2]

The retroactive repeal of personal income tax, in combination with the absence of a general sales tax, is a significant attraction to individuals and may eventually have a positive impact on Alaskan labor rates.

Table VII-2

HOURLY AVERAGE WAGE RATES IN CONSTRUCTION
FOR ANCHORAGE AND 27 U.S. METROPOLITAN AREAS
($ 1982/hr)

Albuquerque	15.10	Indianapolis	17.78
Anchorage	27.28	Kansas City	18.13
Atlanta	13.89	Miami	15.74
Baltimore	15.49	Minneapolis	17.52
Birmingham	13.41	New Haven	17.70
Boston	18.31	New York	19.33
Buffalo	18.39	Philadelphia	17.33
Chicago	19.25	Phoenix	19.28
Cincinnati	19.05	Pittsburgh	17.88
Cleveland	19.24	Portland, OR	20.51
Dallas	16.21	St. Louis	17.63
Denver	16.19	San Diego	22.30
Detroit	19.71	San Francisco	22.96
Houston	17.73	Seattle	21.06

Source: Engineering News-Record, September 23, 1982.

Construction Costs

Location adjustment factors computed to account for added construction costs in Alaska typically range from 1.5 to 2.0. Location adjustment factors increase as site locations move inland and northward. They are also dependent on the extent to which prefabrication can be performed in the lower 48 states.

Many estimates of Alaskan construction escalation factors were based on pipeline construction experience and reflect the high rates of inflation which occurred during that period. There is evidence that the Alaskan labor rate differential is moderating. Cost of living indexes for various Alaskan areas are not growing as rapidly as some other U.S. regions.[3] Nevertheless, 1982 hourly construction labor rates in Anchorage are approximately 1.52 times those of 27 other U.S. metropolitan areas (see Table VII-2).

Material costs also contribute to high construction costs in Alaska because of the necessity to import many materials. Some materials, such as sand and gravel, may be at or below national average prices because of their availability in Alaska. However, cement prices are approximately 2 times higher in Anchorage than in Seattle due to transportation charges. A general materials cost factor of 1.7 was assumed by SRI and is reasonable for the Railbelt region during the time frame of the study. Labor costs generally constitute about 1/3 of direct construction costs, with materials and project management costs accounting for the remainder. An overall construction factor of 1.5 can be derived for the Railbelt region based on current rates.

This factor is consistent with recent estimates obtained by SRI for specific plant construction cost factors in the Railbelt region. The engineering firm C. F. Braun recently quoted 1.5 as the construction offset factor, and Chevron (a component of Standard Oil of California) suggested 1.6 as a construction factor for a hypothetical ammonia/urea plant constructed in the Railbelt. Wherever possible, construction cost factors for specific plants have been used in the SRI study. These location factors would probably decrease over time, assuming that Alaska economic development continues.

Transportation Costs and Infrastructure

The Railbelt region has the only comprehensive transportation system in the state. All of the urban centers are connected by air, rail, and highway links and have good access to ocean shipping. Specialized oil ports exist in Valdez and Cook Inlet. A coal terminal is planned for Seward, and grain terminals are being planned for Seward and Valdez. A specialized coal terminal is also contemplated for the Beluga coal fields.* Specific areas set aside for energy, industrial, and port development activities include the Port of Anchorage, Point MacKenzie (Mat-Su Borough), and the Port of Seward.

Transportation costs are high both within Alaska and between Alaska and its markets and suppliers. Because the state's transportation infrastructure is limited, low-cost intrastate transportation is scarce. Many areas can only be reached by air, or by sea in ice-free months. The costs of transportation to areas outside of the Railbelt are high because of their remoteness and because of the small quantities shipped and lack of backhaul. The cost of shipping equipment to or product from a mine or plant off the established transportation routes places the additional burden of road construction on any prospective developer.

Until additions to this infrastructure are made, most development will be limited to the coastal and immediate Railbelt areas. Only projects with immense economic potential will be able to finance their own transportation facilities (e.g., the oil/gas pipelines, coal facilities) and those projects will occur only as dictated by world market and national policy considerations. Beyond the Anchorage/ Fairbanks corridor, little infrastructure is available to serve industries and their employees. Any mining or manufacturing activities outside of the Anchorage/Fairbanks corridor will have to provide housing and other population-serving infrastructure—either temporary camps or permanent new towns—for workers.

Because of the lack of a major inland waterway transportation infrastructure, locations in Alaska near coastal areas can be expected to be favored for process plants. Pulp, chemicals, and primary metals are all industries that typically require waterborne transport access.

Industries whose transportation costs are low relative to the value of product have more flexibility in location decisions than those with comparatively high transportation costs. Industries that produce high-value, low-weight products may choose locations that minimize power, labor, or other costs.

---

*The transportation network is described in detail in ISER, Alaska's Unique Transportation System (June 1980), and Booz, Allen, Strategic Marketing Plan for Port of Anchorage, Chapters II and III and Appendix B (February 1981).

In summary, transportation costs will remain a major factor in Alaska's future economic development because of the costs involved in transporting natural resources and feedstocks to processing facilities and the costs of transporting goods to international markets.

Land Status

A great deal of important land in the Railbelt is still under federal ownership, a fact that will limit certain resource extraction and industrial activities. Much of the Anchorage coastline, for example, is owned by the Alaska Railroad (a federal entity) and the Department of Defense. The Fairbanks area also has large military reservations and other federal holdings.

Land status is currently in flux because of the slow pace of selection by, and conveyance to, the state and native corporations. Site-specific information about particular land areas is available from federal, state, and local authorities for areas under their respective jurisdictions and from private holders, including native corporations.

Although land availability is a negative factor for firms seeking to exploit mineral resources, most land that might be desired for industrial development in the Railbelt region could be leased for the economic life of the facility, which should be a satisfactory arrangement to most firms.

Climate

Not only is the Railbelt region's climate severe, but Fairbanks often has extensive ice smog created by air inversions trapping sediments and particles from burning fuels in the river valleys of the area, and active volcanoes are located in the Cook Inlet region. Permafrost is a unique subsurface characteristic of the Arctic that poses special problems for construction.

Alaska's climate limits most construction and extraction activities to the summer months and curtails transportation to northern parts of the state in winter. The limitations imposed by the weather raise the overall cost of doing business in the state (e.g., creating a need for substantial summer overtime hours and premiums in construction or for costly air freight transport in the winter). Weather conditions in the Railbelt region are a severe inhibitor to the location of manufacturing industries in Alaska, not only because of construction and operating cost considerations but also because it restricts freedom of movement for personnel and material during much of the winter.

Environmental Considerations and Land Use Plans

Uncertainty over the state's future environmental policies, especially for pristine wilderness areas, may inhibit new industry. An example of such uncertainty is the state's mineral tax policy. The question of whether royalties and severance taxes (similar to those on oil and gas) should be imposed on hardrock minerals and the rates of such taxes remain unsolved. In addition, opinions on what the state should seek to gain through industrial development are contradictory and unresolved.

The Anchorage and Matanuska-Susitna boroughs (Mat-Su) have standards for energy facility siting. Anchorage has a formal coastal management plan. Mat-Su, Kenai/Cook Inlet, and Valdez have written plans which are currently being reviewed and are in the approval process. All permit—and encourage--industrial location in designated areas. The state also has a natural resources plan for its lands. Most intermediate product manufacturers and bulk material producers require large sites to accommodate plants and facilities. The effect of land use plans must be considered on a project-by-project basis once the initial threshold requirements have been met.

Basic Services and Secondary Industry

Local representation of major infrastructure (e.g., insurance firms, repair services, banking) and secondary industry firms (e.g., emergency resupply for mechanical or electrical failure) can be an important factor in plant location decisions. The perceived lack of secondary support facilities is likely to be a major inhibiting factor for the location of new industries in Alaska.

Many aspects of developed industrial infrastructure, such as specialized industrial supplies and services, apart from petroleum extractors and transportation services, do not currently exist in Alaska. Repair services, machine shops, parts depots, and other complementary firms will have to be established concurrently with industrial development, or such supplies and services will have to be imported at high cost.

Natural Resources

The major natural resources of the Railbelt include coal, minerals, and metal ores (although no bauxite reserves for aluminum production), oil and natural gas, fish and shellfish, forests (soft and hardwood), nonfuel minerals; and water (for hydroelectric generation and for consumption). Historically, economic development in any region has usually begun with some type of resource extraction. Mineral resources that have not yet been extensively developed can become the basis for primary processing industries, including mining and smelting. Timber and fishing resources have supported most of Alaska's manufacturing activity to date, and it is likely that manufacturing based on these resources can be expanded.

A special category of natural resources includes hydrocarbons, which can serve as raw materials as well as fuels for manufacturing processes. Industries such as food processing, pulp and paper, petrochemicals, primary and fabricated metals, and electrometallurgical processes require stable and/or low-cost supplies of oil, gas, or coal as process fuels or as feedstocks as well as the appropriate materials, minerals, and metals for processing. The potential of Alaskan oil and gas as industrial feedstocks is widely recognized and proposals for in-state processing of royalty oil have been considered. If oil and natural gas (including LNG) become more expensive and scarce, the availability of petroleum feedstocks will become an increasingly attractive factor.

While oil and particularly natural gas have traditionally been used as industrial process fuels, this use will become less widespread as costs continue to increase and regulatory actions encourage use of other fuels (primarily coal). In this regard, Alaska also has vast quantities of low-sulfur steam coal available for industrial use. The ready avail- ability of water in the south central region could be particularly important for those industries that require significant amounts of process water (e.g., food products, particularly beverages, pulp and paper, chemicals), particularly in view of the shortfalls in water availability predicted for many regions of the U.S.

The presence of important natural resources is not sufficient to guarantee development. For example, extensive high-grade strategic metals and minerals are present in the Brooks Range, but development of the transportation infrastructure for extraction is economically prohibitive.

Existing Industry

Government is the major employer in the Railbelt (see Table VII-1), and most of the employment in the region is associated with services. Although relatively small, the petroleum industry has the character of a true basic industry in that the Railbelt includes the people and facilities for administration (primarily in Anchorage), transportation (primarily in Valdez and Kenai), and processing (North Pole refinery near Fairbanks and Tesoro and Chevron Oil refineries, Phillips LNG plant, and Union Chemicals nitrogen fertilizer plant, all located at Nikiski, Kenai), as well as exploration and development.

Employment statistics for the petroleum industry are aggregated by reporting agencies to avoid disclosure of individual business reporting units. The labor force in the petroleum sectors is estimated, however, to include about 3,650 to 4,900 persons.

Petroleum production capacities are as follows:

	Capacity (barrels/day)
Kenai	
Tesoro oil refinery	48,000
Chevron oil refinery	22,000
Fairbanks	
Mapco North Pole refinery	47,000

Another major plant is the Union chemical fertilizer plant, which produces 1 million tons of liquid ammonia per year and 800,000 tons of urea per year. The Phillips LNG plant produces 140 million cubic feet of LNG per year for the Japanese market.

Other than those associated with the petroleum industry, there are few industry groupings already in Alaska to naturally attract similar firms or suppliers.

Geographical Location and Proximity to Markets

Alaska's remoteness and the requirement to use U.S. registered ships for U.S.-bound goods results in high shipping costs between Alaska and the rest of the United States. The state's vastness also increases the likelihood of future developments being remote from the state's population centers or from the principal resource base. If a primary processing facility is located near a mine to minimize ore handling and shipping, for example, provisions will have to be made to provide housing and related facilities for workers. Alternatively, a firm performing processing near the population centers will have to transport bulk ores from the mine. Similarly, the distance from Anchorage, the commercial center, to the many outlying towns and villages will make it very difficult for even an Anchorage-based producer to supply the in-state market at reasonable prices. In addition, Alaska's remoteness from the Lower 48 may discourage small or medium-sized firms from even considering Alaska as a potential site.

Alaska's local market is quite small (approximately 400,000 people) and is further limited by the difficulties of distributing products to the more remote areas. Furthermore, unlike other states with relatively small markets, no neighboring states can absorb excess production of local market-oriented goods. The most basic local market industries do exist in Alaska--bakeries and newspapers, for example--but the population is too small to support other consumer-product makers. The need to ship excess production at possibly high cost will inhibit development of locally oriented consumer or industrial suppliers until local demand is sufficiently sustained to support such industries.

Service industries, which are the fastest growing segment of the U.S. economy, locate near the population centers or companies they serve. Intermediate product industries, such as concrete producers, metal forgers, commercial printers, and glass container makers, tend to locate near industrial or commercial purchasers of their products. In many of these industries, industrial development must occur sequentially. For example, a plastics manufacturer may logically locate near a petrochemical complex as long as product transportation costs to the marketplace are relatively low. The sequencing or downstream integration of production facilities depends on upstream materials being available.

Alaska's geographic location on the Pacific Ocean is tantalizing. As the international procurement of materials and the international manufacturing of products increase, Alaska's location may be more beneficial than previously assumed. The ports in the south central region of the Railbelt are closer to Japan and Korea than the Lower 48 ports; unfortunately, this factor is currently largely offset by higher construction, labor, and operating costs in the Railbelt region.

<u>Summary</u>

The major advantages of developing an Alaskan industrial site are the state's vast supplies of natural resources and its fuel and feedstocks for extraction and initial processing industries. As natural resources and fuel or power shortages develop, Alaska will become an increasingly attractive site. Alaska is also favorable in comparison to many developing countries, which have the potential for political instability.

Deterrents to an industry's siting its facilities in Alaska arise from the state's economic environment, as well as industry-specific resource development constraints. Inhibiting factors are generally those that raise the costs of operating in Alaska, making Alaska-produced goods less competitive in U.S. and world markets, or that contribute to an adverse business climate (e.g., highly publicized environmental lawsuits and Teamsters Union activities have had a detrimental effect on corporations contemplating expansion into Alaska).

The principal inhibitors to development in Alaska are:

- High labor costs (1.3 to 1.5 times U.S. average) and lack of skilled labor.

- Lack of transportation and other infrastructure.

- High construction costs (1.5 times U.S. average is typical).

- Remoteness from major markets (transportation costs--highly dependent on product and destination).

- Limited local market.

- Institutional and regulatory issues:

  - Uncertain land status
  - Environmental constraints
  - Federal government influence.

- Climate.

- Relatively high corporate taxes.

The relative importance of inhibiting factors to economic development and industry-specific location decisions varies, depending on the proposed industrial facility, the economic health of the industry, and world market trends. Most of the Railbelt characteristics that presently inhibit industrial development increase the operating costs for industry. The advantages of an Alaskan location, such as proximity to specific resources and Pacific markets, are insufficient to offset these additional operating costs for most industries. The special case of electrically intensive industries will be examined in the next section.

VIII IDENTIFICATION OF POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL POWER

To identify potential industries that might be attracted to Alaska by the long-term availability of inexpensive electrical energy, SRI compared U.S. Department of Commerce data on the value of purchased electrical energy with the value of shipped product for over 960 4-digit Standard Industrial Classification (SIC) code industries. The four SIC industries for which electrical energy costs exceed 10% of the value of the shipped product are listed in Table VIII-1. Firms in these Category I industries are considered the most likely to consider an Alaskan site for new plant facilities if long term, low cost electrical power becomes available in the Railbelt region.

Additional industries considered as secondary candidates are listed in Table VIII-2. For these Category II industries, electrical power costs range between 5% and 10% of the value of shipped product. The lure of inexpensive energy will generally be less important for firms participating in the industries listed in Table VIII-2 than those in Category I.

Finally, the value of total (not just electrical) energy used was compared with the value of shipped product for all 4-digit SIC code industries to identify energy-intensive industries that might consider substituting inexpensive electrical energy for other forms of energy. These Category III industries identified during this process are listed in Table VIII-3, which does not include industries already listed in Table VIII-1 and Table VIII-2. Firms participating in Category III industries are considered to be less likely candidates for a Railbelt location than firms from the industries listed in Table VIII-1 and Table VIII-2, because of the largely unexplored issues associated with energy substitution.

Based on this initial screening, all four Category I industries were further evaluated to determine the potential additional costs of a Railbelt location for new plants in these industries. Of the Category II industries, manufactured ice, hydraulic cement, iron foundries, and reclaimed rubber were not considered likely candidates because of the obvious tradeoff between low product value and high transportation costs associated with these industries. An analysis of the transportation costs for cement is included in the study for comparison purposes and is considered to be representative of these low-value products. Malleable iron foundries and reclaimed rubber both depend on close proximity to associated industries (e.g., heavy machinery, automobile) and are unlikely to consider any locations which lack these supporting industries.

Table VIII-1

CATEGORY I: ELECTRICALLY INTENSIVE INDUSTRIES
(Electrical Energy Costs as Percentage of Product Value, 1980)

SIC Code	Description
2812	ALKALIES AND CHLORINE (18.8)

Establishments primarily engaged in manufacturing alkalies and chlorine.

Alkalies	Potassium hydroxide
Carbonates, potassium and sodium	Sal soda
Caustic potash	Soda ash
Caustic soda	Sodium bicarbonate
Chlorine, compressed or liquefied	Sodium carbonate (soda ash)
Potassium carbonate	Sodium hydroxide (caustic soda)

SIC Code	Description
2813	INDUSTRIAL GASES (23.3)

Establishments primarily engaged in manufacturing gases for sale in compressed, liquid, and solid forms. Establishments primarily engaged in manufacturing fluorine and sulfur dioxide are classified in Industry 2819, household ammonia in Industry 2842, and other ammonia in Industry 2873, and chlorine in Industry 2812. Distributors of industrial gases and establishments primarily engaged in shipping liquid oxygen are classified in trade. Ammonia and chlorine production are considered separately. Fluorine, sulfur dioxide, and liquid oxygen are expected to have production economics similar to the gases listed in SIC 2813.

Acetylene	Helium
Argon	Hydrogen
Carbon dioxide	Neon
Dry ice (solid carbon dioxide)	Nitrogen
Gases, industrial: compressed, liquefied, or solid--mfpm	Nitrous oxide
	Oxygen, compressed and liquefied

Table VIII-1 (Concluded)

SIC Code	Description
3313	ELECTROMETALLURGICAL PRODUCTS (14.1)

Establishments primarily engaged in manufacturing ferro and nonferrous additive alloys by electrometallurgical or metallothermic processes, including high-percentage ferroalloys and high-percentage nonferrous additive alloys.

Additive alloys, except copper: not produced in blast furnaces
Electrometallurgical products, except aluminum, magnesium, and copper
Ferroalloys, not made in blast furnaces
Ferrochromium
Ferromanganese, not produced in blast furnaces
Ferromolybdenum
Ferrophosphorus
Ferrosilicon, not produced in blast furnaces
Ferrotitanium
Ferrotungsten
Ferrovanadium
High-percentage ferroalloys, not produced in blast furnaces
Manganese metal, not produced in blast furnaces
Molybdenum silicon, not produced in blast furnaces
Nonferrous additive alloys, high percentage: except copper
Steel, electrometallurgical

SIC Code	Description
3334	PRIMARY PRODUCTION OF ALUMINUM (15.4)

Establishments primarily engaged in producing aluminum from alumina, and in refining aluminum by any process. Establishments primarily engaged in rolling, drawing, or extruding aluminum are classified in Industries 3353, 3354, and 3355 and are not classified as electrically intensive.

Aluminum ingots and primary production shapes, from bauxite or alumina
Extrusion ingot, aluminum: primary
Pigs, aluminum
Slabs, aluminum: primary

Source: U.S. Commerce Department Data

Table VIII-2

CATEGORY II: ELECTRICALLY INTENSIVE INDUSTRIES
(Electrical Energy Costs as Percentage of Product Value, 1980)

SIC Code	Description
2097	MANUFACTURED ICE (8.0)

Establishments primarily engaged in manufacturing ice for sale. Ice plants operated by public utility companies are included in this industry when separate reports are available. (Establishments primarily engaged in manufacturing dry ice are classified in Industry 2813 and have not been analyzed.)

Block ice
Can ice
Ice cubes
Ice, manufactured or artificel: except dry ice
Ice plants, operated by public utilities

SIC Code	Description
2661	BUILDING PAPER AND BUILDING BOARD MILLS (5.6)

Establishments primarily engaged in manufacturing building paper and building board from wood pulp and other fibrous materials. Pulp mills combined with building paper and building board mills, and not separately reported, are also included in this industry; where separately reported, they are classified in Industry 2611.

Asbestos paper and asbestos-filled paper, mitse
Asphalt board and sheathing, mitse
Asphalt paper: laminated--mitse
Board, building: composition, cellular fiber, and hard pressed--mitse
Board, building; except gypsum--mitse
Building board, mitse
Building paper: sheathing, insulation, saturating, and dry felts--mitse
Construction paper, mitse
Dry felts, mitse
Felts, building: unsaturated--mitse
Fiber board, wood or other vegetable pulp: mitse
Insulating siding, paper or board, mitse
Insulation board, cellular fiber or hard pressed (without gypsum): mitse
Kraft sheathing paper, mitse
Lath, fiber: mitse
Paper, building: mitse
Paperboard, building (containing no gypsum): mitse
Roofing board and felt stock, unsaturated: mitse
Roofing, wood fiber: mitse
Saturated felts, mitse
Tar paper, building and roofing: mitse
Wall tile, fiber board: mitse
Wallboard, except gypsum: cellular fiber or hard pressed--mitse

Table VIII-2 (Continued)

SIC Code	Description
2819	INDUSTRIAL INORGANIC CHEMICALS, NEC (8.7)

Establishments primarily engaged in manufacturing industrial inorganic chemicals, not elsewhere classified. Important products of this industry include inorganic salts of sodium (excluding refined sodium chloride), potassium, aluminum, calcium, chromium, magnesium, mercury, nickel, silver, tin; inorganic compounds such as alums, calcium carbide, hydrogen peroxide, sodium silicate, ammonia compounds (except fertilizers), rare earth metal salts and elemental bromine, fluorine, iodine, phosphorus, and alkali metals (sodium, potassium, lithium, etc.). Establishments primarily engaged in mining, milling, or otherwise preparing natural potassium, sodium, or boron compounds (other than common salt) are classified in Industry 1374, which is not electrically intensive. Establishments primarily engaged in manufacturing household bleaches are classified in Industry 2842, which is not electrically intensive; phosphoric acid in Industry 2874; and nitric acid, anhydrous ammonia, and other nitrogenous fertilizer materials in Industry 2873 are discussed separately.

Activated carbon and charcoal	Bromine, elemental
Alkali metals	Cesium metal
Alumina	Calcium carbide, chloride, and hypochlorite
Aluminum chloride	Calcium compounds, inorganic
Aluminum compounds	Calcium metal
Aluminum hydroxide (alumina trihydrate)	Calomel
Aluminum oxide	Carbide
Aluminum sulfate	Catalysts, chemical
Alums	Cerium salts
Ammonia alum	Charcoal, activated
Ammonium chloride, hydroxide, and molybdate	Chlorosulfonic acid
Ammonium compounds, except for fertilizer	Chromates and bichromates
Ammonium perchlorate	Chromic acid
Ammonium thiosulfate	Chromium compounds, inorganic
Barium compounds	Chromium salts
Bauxite, refined	Cobalt chloride
Beryllium oxide	Cobalt 60 (radioactive)
Bleaching powder	Cobalt sulfate
Borax (sodium tetraborate)	Copper chloride
Boric acid	Copper iodide and oxide
	Copper sulfate
	Cyanides

Table VIII-1 (Continued)

2819 INDUSTRIAL INORGANIC CHEMICALS, NEC (8.7) (Continued)

Boron compounds, not produced at mines
Borosilicate
Brine
Fissionable material production
Fluorine, elemental
Fuel propellants, solid: inorganic
Fuels, high energy: inorganic
Glauber's salt
Heavy water
High purity grade chemicals, inorganic: refined from technical grades
Hydrated alumina silicate powder
Hydrochloric acid
Hydrocyanic acid
Hydrofluoric acid
Hydrogen peroxide
Hydrogen sulfide
Hydrosulfites
Hypophosphites
Indium chloride
Inorganic acids, except nitric or phosphoric
Iodides
Iodine, elemental
Iodine, resublimed
Iron sulphate
Isotopes, radioactive
Laboratory chemicals, inorganic
Lead oxides, other than pigments
Lead silicate
Lime bleaching compounds
Lithium compounds
Lithium metal
Luminous compounds, radium
Magnesium carbonate
Magnesium chloride
Magnesium compounds, inorganic
Manganese dioxide powder, synthetic
Mercury chlorides (calomel, corrosive, sublimate), except U.S.P.
Mercury compounds, inorganic
Mercury oxides
Mercury, redistilled
Metals, liquid

Desiccants, activated: silica gel
Dichromates
Ferric chloride
Ferrocyanides
Potassium iodide
Potassium metal
Potassium nitrate and sulfate
Potassium permanganate
Propellants for missiles, solid: inorganic
Radium chloride
Radium luminous compounds
Rare earth metal salts
Reagent grade chemicals, inorganic; refined from technical grades
Rubidium metal
Salt cake (sodium sulfate)
Salts of rare earth metals
Scandium
Silica, amorphous
Silica gel
Silicofluorides
Silver bromide, chloride, and nitrate
Silver compounds, inorganic
Soda alum
Sodium aluminate
Sodium aluminum sulfate
Sodium antimoniate
Sodium bichromate and chromate
Sodium borates
Sodium borohydride
Sodium bromide, not produced at mines
Sodium chlorate
Sodium compounds, inorganic
Sodium cyanide
Sodium hydrosulfite
Sodium, metallic
Sodium molybdate
Sodium perborate
Sodium peroxide
Sodium phosphate
Sodium polyphosphate
Sodium silicate
Sodium silicofluoride

Table VIII-2 (Continued)

2819 INDUSTRIAL INORGANIC CHEMICALS, NEC (8.7) (Concluded)

Mixed acid
Muriate of potash, not produced at mines
Nickel ammonium sulfate
Nickel carbonate
Nickel compounds, inorganic
Nickel sulfate
Nuclear cores, inorganic
Nuclear fuel reactor cores, inorganic
Nuclear fuel scrap reprocessing
Oleum (fuming sulfuric acid)
Oxidation catalyst made from porcelain
Perchloric acid
Peroxides, inorganic
Phosphates, except defluorinated and ammoniated
Phosphorus and phosphorus oxychloride
Potash alum
Potassium aluminum sulfate
Potassium bichromate and chromate
Potassium bromide
Potassium chlorate
Potassium chloride and cyanide
Potassium compounds, inorganic: except potassium hydroxide and carbonate
Potassium cyanide
Potassium hypochlorate
Sodium stannate
Sodium sulfate--bulk or tablets
Sodium tetraborate, not produced at mines
Sodium thiosulfate
Sodium tungstate
Sodium uranate
Stannic and stannous chloride
Strontium carbonate, precipitated, and oxide
Strontium nitrate
Sublimate, corrosive
Sulfate of potash and potash magnesia, not produced in mines
Sulfides and sulfites
Sulfocyanides
Sulfur chloride
Sulfur dioxide
Sulfur hexafluoride gas
Sulfur, recovered or refined, including from sour natural gas
Sulfuric acid
Tanning agents, synthetic inorganic
Thiocyanates, inorganic
Tin chloride
Tin salts
Uranium slug, radioactive
Water glass
Zinc chloride

Table VIII-2 (Continued)

SIC Code	Description
3031	RECLAIMED RUBBER (6.9)
	Establishments primarily engaged in reclaiming rubber from scrap rubber tires, tubes, and miscellaneous waste rubber articles by processes which result in devulcanized, depolymerized, or regenerated replasticized products containing added ingredients. These products are sold for use as a raw material in the manufacture of rubber goods with or without admixture with crude rubber or synthetic rubber. Establishments primarily engaged in the assembly and wholesale sale of scrap rubber are classified in trade industries.
	Reclaimed rubber (reworked by manufacturing processes)
3241	CEMENT, HYDRAULIC (7.4)
	Establishments primarily engaged in manufacturing hydraulic cement, including portland, natural, masonry, and pozzolan cements.
	Cement, hydraulic: portland, natural masonry, pozzolan
3322	MALLEABLE IRON FOUNDRIES (5.6)
	Establishments primarily engaged in manufacturing malleable iron castings.
	Castings, malleable iron; Foundries, malleable iron; Pearlitic castings, malleable iron

Table VIII-2 (Concluded)

SIC Code	Description
3339	PRIMARY SMELTING AND REFINING OF NONFERROUS METALS, NEC (5.4)

Establishments primarily engaged in smelting and refining nonferrous metals, not elsewhere classified. Establishments primarily engaged in rolling, drawing, and extruding these nonferrous primary metals are classified in Industry 3356, which is not electrically intensive, and the production of bullion at the site of the mine is classified in the mining industries.

Antimony refining, primary
Beryllium metal
Bismuth refining, primary
Cadmium refining, primary
Chromium refining, primary
Cobalt refining, primary
Columbium refining, primary
Germanium refining, primary
Gold refining, primary
Ingots, magnesium
Iridium refining, primary
Magnesium refining, primary
Nickel refining, primary
Nonferrous refining, primary: except copper, lead, zinc, and aluminum
Pigs, magnesium
Platinum-group metals refining, primary
Precious metal refining, primary
Primary refining of nonferrous metal: except copper, lead, zinc, aluminum
Primary smelting of nonferrous metal: except copper, lead, zinc, aluminum
Refining of nonferrous metal, primary: except copper, lead, zinc, aluminum
Rhenium refining, primary
Selenium refining, primary
Silicon, epitaxial (silicon alloy)
Silicon, pure
Silicon refining, primary (over 99% pure)
Silver refining, primary
Slabs, magnesium: primary
Smelting of nonferrous metal, primary: except copper, lead, zinc, aluminum
Tantalum refining
Tellurium refining, primary
Tin base alloys, primary
Tin refining, primary
Titanium metal, sponge and granules
Zirconium metal, sponge and granules

Source: Commerce Department Data

Table VIII-3

CATEGORY III: ENERGY-INTENSIVE INDUSTRIES
(Total Energy Costs as Percentage of Product Value, 1980)

SIC Code	Description	Energy Costs As Percent of Product Value
2046	Wet Corn Milling	8.7
2063	Beet Sugar	8.3
2083	Malt	6.7
2261	Finishing Plants, Cotton	7.4
2492	Particleboard	6.8
2611	Pulpmills	10.1
2621	Papermills, Excl. Building Paper	10.3
2631	Paperboard Mills	14.4
2816	Inorganic Pigments	8.8
2822	Synthetic Rubber	5.1
2823	Cellulosic Manmade Fibers	8.0
2824	Organic Fibers, Noncellulosic	5.2
2861	Gum and Wood Chemicals	7.1
2865	Cyclic Crudes & Intermediates	6.9
2869	Industrial Organic Chemicals, NEC	7.1
2873	Nitrogenous Fertilizers	18.2
2874	Phosphatic Fertilizers	6.0
2895	Carbon Black	10.7

Table VIII-3 (Continued)

SIC Code	Description	Energy Costs As Percent of Product Value
2951	Paving Mixtures and Blocks	6.4
3211	Flat Glass	9.8
3221	Glass Containers	10.3
3229	Pressed and Blown Glass	8.1
3251	Brick & Structural Clay Tile	20.1
3253	Ceramic Wall & Floor Tile	6.2
3255	Clay Refractories	8.0
3259	Structural Clay Products	17.3
3261	Vitreous Plumbing Fixtures	5.5
3263	Fine Earthenware Food Utensils	6.8
3269	Pottery Products, etc.	6.3
3274	Lime	31.3
3275	Gypsum Products	9.3
3295	Minerals, Ground or Treated	7.7
3296	Mineral Wool	9.1
3297	Nonclay Refractories	6.1
3312	Blast Furnaces & Steel Mills	9.7
3321	Gray Iron Foundries	7.5

Table VIII-3 (Concluded)

SIC Code	Description	Energy Costs As Percent of Product Value
3325	Steel Foundries, NEC	5.4
3333	Primary Zinc	10.3
3398	Metal Heat Treating	6.9
3624	Carbon & Graphite Products	6.6

The three remaining industries in Category II are building paper and building board mills; industrial inorganic chemicals, not elsewhere classified; primary smelting and refining of nonferrous metals, not elsewhere classified. These industries were considered further as potential candidates because of possible Alaskan feedstocks.

Industries identified in the Category III screening that are associated with food processing (e.g., wet corn milling, beet sugar, malt); textile finishing (e.g., cotton finishing plants, man-made fibers); or heavy, low-value materials (e.g., paving mixtures, lime, glass containers, brick and structural clay tile and clay products) are unlikely candidates because of the remoteness of an Alaskan location from both feedstocks and markets for these commodities. Carbon black production is energy intensive only because petroleum-based feedstocks are used in the manufacturing process and is therefore precluded from further consideration. Although ammonia production is energy intensive for the same reason, electrically driven compressors can be substituted for gas-fired turbines in the production process. Furthermore, the major feedstock for ammonia production, natural gas, is available in Alaska. For these two reasons, ammonia production was selected for limited consideration. The construction of new processing facilities of most primary metals (e.g., copper, steel) is unlikely in the Railbelt region primarily because these industries are dependent on nearby feedstocks and are likely to remain depressed in the U.S. economy in the foreseeable future. In addition, the consequences of energy conservation (e.g., automobile downsizing) have caused the heavy manufacturing industries that are supplied by the primary metal industries to permanently reduce their requirements for feedstock. Although selected primary metals (e.g., zinc) might benefit from the combination of Alaskan feedstocks and low-cost electrical energy for thermal processes, most of these industries are unlikely candidates for expansion throughout the remainder of this century. The only industries in Category III that were retained for further consideration were ammonia production, nonferrous metals, and paperboard mills.

In addition to the Category I, II, and III industries retained for further screening, four other potential large-scale electrical energy uses were considered as specified in the statement of work. The list of industries and "other industrial applications" evaluated in Section IX are listed in Table VIII-4.

Table VIII-4

INDUSTRIES AND OTHER INDUSTRIAL APPLICATIONS EVALUATED
AS POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL POWER

Category I

- The Aluminum Industry (SIC 3334, Primary Production Aluminum)
- The Chlor-Alkali Industry (SIC 2812, Alkalies and Chlorine)
- Industrial Gases (SIC 2813, Industrial Gases)
- Ferroalloy and Miscellaneous Metal Alloy Production (SIC 3313, Electrometallurgical Products)

Categories II and III

- Pulp and Paper Industry (SIC 2661, Building Paper and Building Board Mills; 2611, Pulpmills; and 2621, Papermills, Excluding Building Paper)
- Cement Industry (SIC 3241, Hydraulic Cement)
- Chemical Industry (2719, Industrial Inorganic Chemicals, NEC)
- Primary Metals Industry (SIC 3339, Primary Smelting and Refining of Nonferrous Metals, NEC; SIC 3333, Primary Zinc)
- The Fertilizer Industry (SIC 2873, Ammonia Production, Nitrogenous Fertilizers; 2874, Phosphate Fertilizers)

Other Applications

- Agglomerations of Small Industrial Facilities
- Residential Space Heat
- Electrification of Alaskan Railroad Intertie with the Lower 48
- Intertie with the Lower 48.

IX EVALUATION OF POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL ENERGY

To evaluate the real potential of the candidate users of electrical energy, the likely characteristics of representative process plants in the selected industries must be considered. Because of the increasing importance of energy costs in recent years, much of the research and development in the candidate industries is devoted toward reducing process energy costs. The effect of these efforts should be to increase the likelihood of the construction of new process facilities in the candidate industries, but to reduce the importance of a regional location based on low cost electrical energy. The industry averages used to select candidate industries undoubtedly overestimate the importance of the costs of electrical energy for new facilities because they include marginal facilities that might be replaced by more efficient plants during a period of economic expansion. In the specific industry analyses which follow, the most recent available data on plant efficiency were used to evaluate the attractiveness of low-cost electrical energy. In each case the reduced costs of an Alaskan location attributable to inexpensive power must be balanced against the increased costs associated with an Alaskan location.

A range of electric energy rates, including a most probable competing energy rate (where possible), was assumed when comparing energy savings with additional transportation, construction (e.g., capital) and labor expenses associated with a Railbelt location. Because of industry infrastructures and market locations, the competitiveness of given electrical energy prices to attract new industry varies with the industry. Aluminum smelters are typically sited in lower-cost energy locations than chlor-alkali plants, which are more dependent on local resources. Since the availability of the low-cost electric power is highly dependent on the demand scenario associated with Alaskan population growth and petroleum-derived state revenues, SRI assumed for the purposes of the study that sufficient capacity would be available for at least one "world-class" plant in each category (e.g., 2,700 GWh annually for an aluminum smelter).

In addition to energy requirements, a major consideration for prospective Alaskan industries is the cost of transporting raw materials to Alaska and the resultant products to user markets. Materials and products which are subject to mass handling techniques and bulk shipment are preferable because lower handling costs associated with such materials reduce the overall cost of transportation. Transportation costs were considered for a "typical" facility to determine the additional expense of this factor associated with an Alaskan location. Related to transportation costs is the important consideration of the ability of the candidate industries to utilize indigenous Alaskan raw materials.

Primary industries with relatively simple input requirements may be most easily sited initially. As will be described in the industrial analyses which follow, however, synergistic relationships can form as an industrial base develops and industries are able to utilize locally produced materials. As an example, caustic soda from chlor-alkali production is an important input to alumina production, or facilities producing bulk commodities such as caustic soda might provide a partial return cargo for Alaska-bound alumina carriers serving aluminum smelters in the state.

Other important factors are the relatively high costs for labor and construction in the state, the degree of labor intensiveness of candidate industries, the relative proximity of markets, and the overall projected demand for candidate industry products.

The Aluminum Industry

Of the industries which have been examined, aluminum has, at .154, the third highest ratio of purchased electrical energy costs to value of shipped product. In spite of the high energy costs associated with aluminum production, the metal increasingly contributes to energy efficiency in other products, particularly in the transportation sector. As a result, projections for aluminum demand indicate annual growth of 4-6%[4,5] over the next decade. As the aluminum industry continues to expand, areas offering low-cost electricity will be considered as locations for new plants.

Currently, the industry is dominated by six multinational corporations which collectively account for over 66% of the world's bauxite/alumina production and 54% of aluminum metal production.[6] As shown in Table IX-1 and Table IX-2, these corporations are:

- The Aluminum Company of America (Alcoa, U.S.A.)
- Pechiney Ugine Kuhlmann (France)
- Swiss Aluminum (Alusuisse, Switzerland)
- Aluminum Company of Canada (Alcan, Canada)
- Reynolds Metals Company (U.S.A.)
- Kaiser Aluminum and Chemical Corporation (U.S.A.).

Table IX-1

INVESTORS IN THE ALUMINUM INDUSTRY: ALUMINA REFINERIES, 1979
(Thousands of Tons; Percentage)

	Capacity in Developed Countries	Capacity in Developing Countries	Total Capacity		
			Thousands of Tons	As Percentage of Market Economy Countries' Capacity	As Percentage of World Capacity
Six Major Transnational Corporations					
Alcan	2,208	1,344	3,552	12.2	10.3
Alcoa	4,135	1,966	6,101	20.9	17.8
Alusuisse	1,265	36	1,301	4.5	3.8
Kaiser	2,645	471	3,116	10.7	9.1
Pechiney	2,169	130	2,299	7.9	6.7
Reynolds	2,318	430	2,749	9.4	8.0
Total	14,740	4,377	19,118	65.6	55.7
Other TNCs with Private Investors in Developed Market Economy Countries	5,772	738	6,510	22.3	18.9
Governments of Developed Market Economy Countries	1,569	18	1,587	5.4	4.6
Governments of Centrally Planned Countries	5,208	-	5,208	-	15.2
Governments of Developing Countries	-	1,590	1,590	5.5	4.6
Private Investors in Developing Countries	-	355	355	1.2	1.0
World Total	27,289	7,078	34,368	100.0	100.0

Source: United Nations Centre on Transnational Corporations, as published in *Transnational Corporations in the Bauxite/Aluminum Industry*, United Nations, 1981, p. 37.

Table IX-2

INVESTORS IN THE ALUMINUM INDUSTRY: ALUMINUM SMELTERS, 1979
(Thousands of Tons; Percentage)

	Capacity in Developed Countries	Capacity in Developing Countries	Total Capacity: Thousands of Tons	Total Capacity: As Percentage of Market Economy Countries' Capacity	Total Capacity: As Percentage of World Capacity
Six Major Transnational Corporations					
Alcan	1,355	154	1,509	11.2	8.6
Alcoa	1,673	131	1,804	13.4	10.3
Alusuisse	649	-	649	4.8	3.7
Kaiser	884	227	2,222	8.2	6.3
Pechiney	973	71	1,044	7.7	6.0
Reynolds	1,043	82	1,125	8.3	6.4
Total	6,577	665	7,242	53.6	41.3
Other TNCs and Private Investors					
Europe	686	13	699	5.1	4.0
United States and Canada	1,218	32	1,251	9.3	7.1
Other	1,652	26	1,678	12.4	9.6
Total	3,556	71	3,628	26.8	20.7
Governments of Developed Market Economy Countries	1,569	-	1,569	11.6	9.0
Governments of Developed Centrally Planned Economies	3,[illegible]2	-	3,732	-	21.2
Developing Country Governments	-	979	979	5.2	5.6
Developing Country Private Investors	-	378	378	2.8	2.2
Market Economy Countries, Total	11,703	1,821	13,522	100	
World, Total	15,434	2,093	17,528		100

Source: United Nations Centre on Transnational Corporations, as published in Transnational Corporations in the Bauxite/Aluminium Industry, United Nations, 1981, p. 37.

Collectively, these corporations have aluminum smelters in virtually all developed countries. Historically, smelting facilities have been located in developed countries, which have imported bauxite (or alumina), the primary feedstock for aluminum production. As energy prices have risen, smelters are being built with increasing frequency in countries with indigenous bauxite and lower-priced electric power.

The effect of high energy costs on aluminum production is particularly evident in both Japan and the United States, as is the effect of worldwide recession on the demand for aluminum. It is estimated that Japan's internal smelting capacity will decrease 40% by mid decade from the level of 1,204,000 metric tons of 1981, largely as a result of increased electricity costs in Japan. In 1981, Japanese smelters were facing electrical rates 2 to 23 times those available in the United States and Canada. As production has decreased in Japan, Japanese companies have increasingly participated in joint refinery projects overseas and are building smelters in Australia, Brazil, and Indonesia.[7] In the United States, aluminum producers have also been faced with escalating electrical energy costs at a time when plants are operating at approximately 40-60% of capacity, largely due to the current recession. In the Northwest, for example, the Bonneville Power Administration indicated that electrical rates for aluminum smelters would increase 49.7% to 25.9 mills/kWh, up from 17.3 mills, effective October 1, 1982. Initial industry reaction has been to indicate that such rate increases will seriously affect plans for capital investment and plant modernization in the area, which currently accounts for about 1/3 of U.S. production capacity.[8]

The most recently constructed U.S. aluminum smelter, the Alumex plant at Mt. Holley, South Carolina, is reported to use 6.24 kWh/lb of metal produced. A representative of Kaiser Aluminum indicated, during a telephone interview, that major breakthroughs in electricity usage are not expected and that 6.24 kWh/lb should be regarded as representative for plants which will come on line in the early 1990s.

In spite of the rising cost of energy in the developed nations, some experts believe that a large-scale shifting of aluminum production to developing countries will not occur. Indigenous electrical energy needs of the developing countries will compete for available power and may make other energy sources in developed countries, such as U.S. western coal reserves, economically attractive. There are also concerns about political stability in some of the developing countries, the higher costs associated with construction in remote areas, and the distance of such facilities from aluminum markets.

As noted in a recent United Nations report on the aluminum industry, "finance charges contribute about as much as do alumina and power to the cost of a ton of aluminum metal for a new smelter. Cheap power will not make a smelter competitive."[9] Since Alaska offers the potential combination of political stability and low-cost power, it remains to examine the importance of other costs which may be pivotal in decisions to site aluminum production facilities in the state.

Foremost among these other costs is the cost of transporting both raw materials to Alaska and aluminum ingot or finished products to markets in the United States and the Pacific basin. Primary aluminum production consists of two steps. The first is the mining and subsequent refining of bauxite into alumina, which is followed by smelting into primary aluminum ingots. The principal producers of bauxite are Australia, Guinea, and Jamaica as shown in Table IX-3. These countries, however, produce only a small fraction of the world's aluminum. Aluminum production is dominated by the United States, the U.S.S.R., Japan, and Canada (Table IX-4). Thus, the aluminum industry has historically transported bauxite/alumina over long distances to smelting facilities.

Transportation Costs

Both bauxite and alumina can be shipped using bulk handling procedures. Although alumina transportation costs are generally higher than for bauxite, there are advantages to refining bauxite into alumina at the mine since 2 to 2.5 tons of bauxite are required to produce 1 ton of alumina. This process requires only small amounts of caustic soda and other materials and consumes only 300 to 350 kWh of electrical energy per ton of alumina, as compared to the refining of aluminum, which requires 14 to 16 MWh (industry average) of electrical energy per ton of aluminum produced (Table IX-5 and Table IX-6).

Many exporting countries are increasingly shipping alumina rather than unrefined bauxite. Australia is an example of this trend. Approximately 74% of alumina imported by the United States is obtained from Australia, but no bauxite has been imported from Australia in recent years. It should also be noted that relative sizes of world-class alumina plants and aluminum smelters are significant in determining the structure of the industry which might develop in Alaska. Most new alumina plants have capacities in excess of 500,000 tons/year, and at least 10 have capacities in excess of 1,000,000 tons. Aluminum smelters tend toward capacities above 100,000 tons, usually around 200,000 metric tons. As a result, a single world-class alumina facility can support a number of smelters. This fact, in combination with the distances which bauxite would have to be transported, suggests that one or more aluminum smelters, as opposed to alumina processing plants, would be the most likely facilities located in Alaska, with alumina feedstocks coming from Australia.

Although our analysis indicates that the Alaskan smelting site might incur increased transportation charges compared to the Pacific Northwest, Alaskan sites may not incur significantly higher charges than most other U.S. smelting sites. Alaska is closer to Australia than east coast smelters such as the newly completed Mount Holly plant in South Carolina, which is importing alumina from Alcoa of Australia. In addition, Alaska is less than 1,600 miles above smelters in the Pacific

Table IX-3

BAUXITE AND ALUMINUM PRODUCTION IN 1980
(Metric Tons x 1000)

	Bauxite	Aluminum
Australia	27,584	369
Guinea	14,000	-
Jamaica	12,261	-
USSR	4,600	2,167
U.S.	1,460	5,463
Japan	-	1,323
Canada	-	1,295
World Total	89,933	16,940

Source: 1980 Minerals Yearbook

Table IX-4

1980 ALUMINUM PRODUCTION PERCENTAGE

U.S.	30.3
Canada	6.9
Japan	7.1
Western Europe	23.3
Eastern Europe	16.2
Australia & New Zealand	3.0
Rest of World	13.2

Source: 1980 Minerals Yearbook

Table IX-5

REPRESENTATIVE INPUTS FOR 1 METRIC TON OF ALUMINA

Bauxite, dry	2.0 to 2.5 tons
Caustic soda	0.07 to 0.17 tons
Fuel oil (steam and calcinating)	0.28 to 0.38 tons
Electric energy	300 to 350 kWh
Total labor and supervision	2.5 to 5 hours

Source: United States Bureau of Mines, Mineral Commodity Profile, May 1978, as reported in Transnational Corporations in the Bauxite/Aluminum Industry, United Nations, 1981.

Table IX-6

REPRESENTATIVE INPUTS FOR 1 METRIC TON OF ALUMINUM

Alumina	1.92 - 1.95 tons
Calcined petroleum coke	0.40 - 0.45 tons
Pitch	0.14 - 0.16 tons
Fluoride salts (with dry scrubbers)	0.02 - 0.03 tons
Electric energy	14 - 16 MWh
Labor and supervision	10 - 20 hours

Source: Transnational Corporations in the Bauxite/Aluminum Industry, United Nations, 1981, p. 17.

Northwest. Transportation costs on a per mile basis tend to decrease with distance, because the relatively fixed costs of time spent in terminals and handling charges are spread over the larger distances. Thus, the added expense associated with this extra distance may not be significant compared to the cost savings of inexpensive power.

Transportation charges for bauxite to the U.S. mainland averaged $5.77 per metric ton in 1980, although charges from some countries were in excess of $10.00 per ton. Alumina shipping charges averaged $16 per ton; however, as a fraction of product value, bauxite transportation charges averaged 18% as opposed to 9% for alumina, reflecting the added value associated with alumina.

An analysis of the additional transportation costs associated with an Alaskan location is complex. A major consideration is the suitability of harbor facilities in Alaska. Although 35,000-ton shipments are common, bauxite vessels are projected to increase in size to 60,000-100,000 dwt because efficiencies increase for bulk materials as vessel size increases and because of bauxite's low value per unit weight. Alumina vessel capacities are expected to remain under 50,000 dwt. Harbor facilities at Kenai, for example, might accommodate such tonnages, but it is not clear that access to these private harbor facilities is possible. Use of the port of Anchorage would require the smaller 35,000-ton vessels, while construction cost for a new port would be on the order of $28,000,000.[10]

Weather is another important factor. In the 1960s, Alcoa stockpiled materials during the ice-free season on the St. Lawrence and subsequently developed a large shipping business in Canada to effectively utilize its shipping capacity during the off-season. Thus, potential delays associated with use of the port of Anchorage or other harbors due to dredging or ice formation could affect overall transportation costs.[11]

Other factors which influence transportation cost calculations are the degree to which carriers are owned by the aluminum companies and their accounting practices. Rates can also vary markedly depending on the destination of the shipping run, independent of the distance traveled. For example, lack of return cargos can have a significant effect on shipping costs.[12]

Even more important than feedstock transportation costs are the costs associated with transporting aluminum metal. Approximately 90% of aluminum is produced in the developed countries where it is consumed. On a per weight basis it is estimated that aluminum transportation is 4 to 5 times more costly than bauxite or alumina because of added handling costs associated with the discrete ingots. Thus, the location of smelting facilities geographically close to metal users in the developed countries may have helped to offset rising electrical energy costs. As aluminum smelters are located near bauxite resources, overall transportation charges can increase.

Based on current U.S. averages for transportation costs in the aluminum industry, SRI estimates that transportation costs are approximately 7% of the primary aluminum value.[13] While Alaska may be more distant from U.S. aluminum users than other smelters in the U.S., it is closer to Japanese and other Pacific basin markets. As such, Alaskan transportation costs may not be higher than those of other U.S. smelters. Some increase in transportation costs may result from the need for additional alumina storage and delays associated with weather. SRI estimates that a transportation adjustment factor of 0% to 10% of the average U.S. rate is appropriate for computing additional transportation costs associated with an Alaskan site.

Capital Cost

An estimate of the capital costs for a smelter in Alaska can be made by using a location adjustment factor and data on cost of construction for a similar facility operating in the Lower 48. As stated previously, SRI estimates an adjustment factor of approximately 1.5 for construction of plants in the Anchorage area relative to the Lower 48. Only one new smelter facility has been constructed in the United States since 1973. This is the Mt. Holly plant, built by Alumax, Inc., at Mt. Holly, South Carolina, which went into operation in 1980. This plant cost $350,000,000, of which $40 million was attributed to environmental controls (that might be inadequate for an Alaskan location). The plant occupies 300 acres, receives over 35,000 short tons of alumina from Australia per month, and produces approximately 197,000 metric tons of aluminum product annually. It has an alumina storage capacity of approximately 40,000 tons and is located 14 miles from its port facility in North Charleston. The plant employs approximately 700 persons.[14]

Labor Costs

Since there are no nonferrous metal smelters in operation in Alaska, the differential in labor cost to be expected, relative to other U.S. sites, must be computed by comparison with other published industry labor data. The method used compares the ratio of hourly wages for primary metal production to general manufacturing, modified by specific plant data published for the Mt. Holly facility. As shown in Table IX-7, primary metal workers' hourly earnings are consistently higher than general manufacturing workers'. The variation is highest in the southern states at about 40% but decreases in the Northwest to less than 20%. Total annual payroll reported for the Mt. Holly plant in 1980 was $16,000,000 or an average hourly rate per employee of $10.98. This average, unlike Table IX-7 data, includes salaried professions. Based on an average 42% higher salary paid primary metal workers over general manufacturing in the Southeast, the average hourly rate for the Mt. Holly plant is estimated at $7.94 using the data in Table IX-7 on general manufacturing labor rate in South Carolina. The additional $3.04 ($10.98 minus $7.94) per employee in South Carolina accounts for the salaried management component of the overall plant payroll.

Table IX-7

1980 AVERAGE HOURLY MANUFACTURING WAGES FOR PRIMARY METALS AND MANUFACTURING
($ in Millions)

	Manufacturing	Primary Metals	Ratio (Primary Metals/Manufacturing)
U.S. Total	7.27	9.77	1.34
Alaska	10.22	-	-
South Carolina	5.59	-	-
Washington	9.41	10.74	1.14
Oregon	8.65	10.24	1.18
Texas	7.15	8.99	1.26
Kentucky	7.34	10.44	1.42
Tennessee	6.08	8.58	1.41
West Virgina	8.08	11.73	1.45

Source: U.S. Bureau of Labor Statistics as reported in the "Geo-Economic Index," Site Selection Handbook, May 1982, Conway Publications, Inc.

Although average U.S. hourly rates are 42% higher than in the Southeast, it is assumed that the Mt. Holly plant is paying above the prevailing wage in the region. Assuming that the U.S. rate is only one-third greater than the Mt. Holly rate. It is estimated that a hypothetical 1980 overall hourly rate in the U.S. for Mt. Holly type plants would have been $14.64. Overall plant payroll in Alaska, assuming a similar percentage of management personnel as at Mt. Holly and a factor of 1.4 (ratio of Alaska to U.S. average labor rates in Table IX-7), would thus be:

(1.4) x (700 employees) x ($14.64) x (1,920 hours) = $27.5 million.

Adjusted for inflation, this would amount to $30.3 million in 1982 dollars for an Alaskan smelter as opposed to $17.6 million in the Mt. Holly facility. (A hypothetical U.S. average plant would have a $21.6 million payroll.) Thus, the additional labor cost for an Alaskan smelter would be approximately $12.7 million annually. If a lower differential of 1.3 is used for Alaska labor costs, the additional labor costs would be only $10.5 million annually.

Construction Costs

If a Mt. Holly type plant were constructed today, it is estimated that it would cost between $450 million and $500 million. In Alaska, a similar plant would cost approximately $675 million to $750 million, assuming a construction adjustment factor of 1.5. The cost differential is between $225 million and $250 million. Over 30 years, assuming a 10% interest rate, this differential produces an additional annual cost of approximately $25 million per year.

Electricity Rates

Average U.S. industrial electrical power costs have been escalating rapidly since 1970. After many years of constant real costs, large power user rates jumped from an average of about $0.015/kWh in 1970 to an average of $0.046/kWh in 1980 and $0.054/kWh in 1981.[15]

Aluminum smelters are generally located in regions with industrial electricity rates well below the average. Using the published electricity rates for aluminum smelters plus other published rate data, it is estimated that Alaskan power must compete with average current rates of $0.026/kWh to $0.029/kWh (1982 dollars).

Alaskan Site Sensitivity Summary

In Table IX-8 are summarized some of the major additional-cost differentials which are expected to be incurred in siting an aluminum smelter in the Railbelt region near an existing port facility. Additional construction expenses associated with taxes, housing, or harbor modification are not included.

Table IX-8

ANNUAL COST DIFFERENTIALS ASSOCIATED WITH ALASKAN SMELTER
($ 1982)

	Increase
Labor	$10.5 to $12.7 million
Construction	$25 million
Transportation	$0-$2.2 million
Total	$35.5-$39.9 million

Table IX-8 indicates that electrical power savings associated with Susitna power must be in excess of $35-$40 million annually to offset other higher costs associated with location in the state. Based on plant usage of 6.24 kWh per pound of product and 197,000 metric tons of output, the plant requires 2,700 GWh annually. Susitna power must therefore be $.014/kWh to $.016/kWh cheaper than competing sites to reach "break-even" against the added differential costs computed above. Table IX-9 shows the maximum prices at which Susitna power can be sold to achieve "break-even." Thus only the 100% state grant case could provide power at a sufficiently low price to compete effectively (see Table III-1). It is questionable that sufficient power (2,700 GWh) would be available for a single large aluminum facility at this rate since demand would increase significantly from domestic users at this low rate.

Table IX-9

POWER COST SENSITIVITY OF SMELTER FACILITY*
($/kWh)

Competing site power rates	.029	.035	.050
Susitna power rates at "break-even"	.015	.021	.036

*Assumes $40 million must be saved to offset costs.

The Chlor-Alkali Industry

The ratio of purchased electricity to value of shipments for the chlor-alkali industry in 1980 was 18.8%. The primary electrically intensive products of the chlor-alkali industries are sodium hydroxide (NaOH) and chlorine (Cl_2). Chlorine is produced commercially through the electrolysis of brine, with sodium hydroxide (also known as caustic soda) as a byproduct. Table IX-10 contains a comparison of U.S. chlorine capacity and production. Sodium hydroxide production follows a pattern similar to chlorine production, with some variation.[16] Sodium hydroxide capacity and production are compared in Table IX-11.

The top five producers, shown in Table IX-12, account for over 65% of U.S. capacity. Dow Chemical, the major producer of chlorine, accounts for almost one-third of U.S. production. In the world production of chlorine, the U.S. share, second to Europe, is 36% (see Table IX-12). Approximately 54% of total U.S. chlorine production is liquefied for sale or in-plant transport; the remainder is used captively by producers to make chlorinated products or transferred via pipeline as a gas. Geographic distribution of chlorine production is listed in Table IX-14.

Table IX-10

U.S. CHLORINE CAPACITY AND PRODUCTION
(Thousands of Metric Tons)

Year	Capacity	Production	Operating Rate (Percent)
1977	14,281	11,630	80.9
1978	15,243	12,157	79.8
1979	15,725	13,520	86.0
1980	15,815	12,563	79.4
1981	15,860	11,615	73.2

Source: Current Industrial Reports,
U.S. Department of Commerce

Table IX-11

U.S. SODIUM HYDROXIDE CAPACITY AND PRODUCTION
(Thousands of Metric Tons)

Year	Capacity	Production	Operating Rate (Percent)
1977	12,532	9,979	79.6
1978	13,082	10,275	78.5
1979	13,604	11,242	82.6

Source: Current Industrial Reports, U.S. Department of Commerce

Table IX-12

THE TOP FIVE U.S. CHLORINE PRODUCERS

	Percent
Dow Chemical U.S.A.	31.3
PPG Industries, Inc.	10.4
Diamond Shamrock Corp.	8.8
Occidental Petroleum Corp.	7.9
Olin Corp.	6.8
Others	34.8

Source: SRI

Table IX-13

WORLD PRODUCTION OF CHLORINE

	Percent
Europe	47
United States	36
Asia	11
Canada	4
South America, Oceania, and Africa	2
Total	100

Source: Encyclopedia of Chemical Technology

Table IX-14

U.S. CHLORINE PRODUCTION
BY GEOGRAPHIC AREA

Geographic Area	Metric Tons (000s)	Percentage
New England	656.2	5.0
Middle Atlantic	505.9	3.9
North Central	858.3	6.6
South Atlantic	942.2	7.2
East South Central	1,531.1	11.7
West South Central	7,640.1	58.5
Mountain & Pacific	935.2	7.2

Source: The Chlorine Institute

Chlorine is primarily used for the manufacture of organic chemicals. Other uses include pulp, paper, and textile bleaching, the production of inorganic chemicals, water and waste treatment, cleaning and sanitation products, and metallurgical processing (see Table IX-15). Of the 12,563,000 metric tons of chlorine produced in 1980, 564,058 tons (4.5%) was shipped as a gas. Out of the 7,774,565 tons produced as a liquid, 4,621,980 tons were commercially shipped; of this, only 128,626 tons were exported.[17] This low figure is primarily due to the risk of chlorine transportation.

Though the pulp and paper industry has been a significant user of chlorine, there is a trend to move away from chlorine dependence by way of substitutions. Due to a tightening of Cl_2 and NaOH supply,[18] prices have risen faster than inflation. The imbalance has became worse as pulp and paper producers (who spend $600 million on bleaching chemicals a year) substitute other bleaching agents for chlorine. For example, the replacement of conventional Cl_2 processes by oxygen-using processes is one trend. Another trend is the substitution of chlorine dioxide, which possesses 2.63 times the oxidizing equivalent of chlorine. Mills using hardwood feeds are said to decrease chlorine consumption by almost 30%. In addition, chlorine-base products also face competition from hydrogen peroxide.

According to the data in Table IX-16, chemical manufacturers consume almost half of the sodium hydroxide used (in 1979 this amounted to approximately 5 million metric tons). The production of alumina from bauxite by the Bayer process is one of the major chemical uses of sodium hydroxide. The volume of NaOH is approximately 9% of the alumina produced; in 1979, for example, 540,000 metric tons were consumed to produce 6 million tons of alumina. A large portion of sodium hydroxide exports in liquid form has been to countries that are major manufacturers of alumina (e.g., Australia, Jamaica, and Surinam). Destinations for most caustic exports will continue to be tied to trends in alumina production. Unfortunately, because it is more economical to produce alumina at the site where it is mined, it is unlikely that this potential infrastructural synergism could develop between the two industries in Alaska.

The pulp and paper industry, however, may provide a potential interaction. Because of the limited supplies and high prices, the pulp and paper industry (which consumed over 2 million tons of caustic soda in 1979) has turned to other sources. Several mills, for example, are using sodium sulfate as a substitute. Now, however, partly due to regional shifts to alternative chemicals such as sodium sulfate and soda ash, caustic supplies have become more plentiful and prices have fallen. As a result, production rates have dropped from 80.2% in June 1981 to as low as 65% in June of 1982.[19]

Table IX-15

U.S. CONSUMPTION OF CHLORINE
(1979)

	Metric Tons Consumed	Percent
Organic Chemicals	7,834,000	71.1
Pulp & Paper Production	1,215,000	11.0
Inorganic Chemicals	648,000	5.9
Water Treatment	500,000	4.5
Other	830,000	7.5

Source: SRI International

Table IX-16

U.S. CONSUMPTION OF SODIUM HYDROXIDE
(1979)

	Metric Tons Consumed	Percent
Chemical Manufacturing	5,000,000	49.7
Pulp & Paper Manufacturing	2,050,000	20.4
Cleaning Products (Soaps, Bleaches, etc.)	634,000	6.3
Petroleum & Natural Gas	495,000	4.9
Cellulosics (Rayon, etc.)	267,000	2.6
Cotton Mercerizing	170,000	1.7
Other		14.4

Source: SRI International

Another contribution to the decrease in price has been the contribution of energy-saving production technology. Previous chlor-alkali production has been dependent on various designs based on the diaphragm or mercury intermediate electrode. A new generation of electrolytic cells is now being developed which promises to cut energy consumption by 20% and more.[20]

PPG is converting the diaphragm chlor-alkali cells to the more efficient (by 25%) bipolar electrolyzer technology that the company has developed.[21] (Other companies, such as Diamond Shamrock, Chemetics, and Occidental Research, are also installing electricity-cutting technologies involving new catalysts and separation membranes.) These new methods can be expected to reduce the importance of the cost of electricity.

In the economics of the production process, investment costs for a 1-billion lb-per-year chlorine plant in the U.S. are approximately $260 million. Based on the typical escalation factor for construction in Alaska, the investment in a Railbelt site would be expected to be approximately $395 million in 1982 dollars. At 10% interest, the annualized cost differential for an Alaskan location would be approximately $14 million. Electricity consumption using diaphragm cells is approximately 1.28 kWh/lb of Cl_2 produced. For each pound of Cl_2 produced, approximately 1.128 lb of NaOH is produced. For a typical plant producing 1 billion lb of Cl_2 annually, electricity consumption is equal to 1,280 GWh annually. At the current average price of $0.045/kWh, annual electricity costs are $57.6 million.

Labor operating costs for the facility will be approximately $7.5 million annually. For an Alaskan location, the operating labor cost differential would be $2.25 million based on an adjustment factor of 1.3. Estimates of the costs associated with transporting the product to market were obtained from shipping firms. The cost of transporting the Cl_2 and NaOH from Anchorage to Seattle by container ship range from $0.042/lb to $0.059/lb for Cl_2 and $0.031/lb to $0.043/lb for NaOH (50% solution). If the additional cost of transporting salt from Baja to Anchorage and distributing the product from Seattle is ignored, the annual transportation penalty for an Alaskan location would be approximately $92 million.

Table IX-17 summarizes the pertinent data for a large Cl_2 plant. Table IX-18 summarizes the cost differential for an Alaskan location. The $108 million cost penalty can only be offset if Alaskan electricity is $0.084/kWh below the prevailing rates in competing regions. The high cost of transportation makes the production of Cl_2 an unlikely candidate industry for an Alaskan location.

Table IX-17

DATA FOR A LARGE (1 BILLION LB/ANNUALLY)
Cl_2 PLANT LOCATED IN ALASKA

Capital Cost	$260 million
Electricity Usage	1,280 GWh
NaOH Product	1.13×10^9 lb
Raw Material Costs	$.75 million
Direct Operating Costs (including Labor)	$15.4 million
Indirect Operating Costs	$41.9 million
Electricity Costs	$57.6 million
Other Utility Costs	$16.7 million

Source: SRI International

Table IX-18

COST SAVINGS AND PENALTIES
ASSOCIATED WITH AN ALASKAN LOCATION FOR A Cl_2 PLANT

Construction Differential	$ 14 million
Labor Differential	$ 2.25 million
Transportation Differential	$ 92.0 million
Total	$108.25 million

Source: SRI International

The Industrial Gases Industry

As a group, industrial gases had the highest ratio of electrical energy purchases to product value, .233. Gases within this classification include:

Acetylene	Neon
Argon	Nitrogen
Carbon dioxide	Nitrous oxide
Helium	Oxygen
Hydrogen	

Based on the value of U.S. shipments, oxygen and nitrogen are the most economically significant, as shown in Table IX-19.

Acetylene, carbon dioxide, and hydrogen are all made from hydrocarbon refining processes. Carbon dioxide and hydrogen are both largely produced by steam reforming of natural gas. Nitrogen, oxygen, and argon are more energy intensive and are produced by the cryogenic separation of air into its elemental constituents.

The primary producers of industrial gases are:

- Airco Industrial Gases Division of Airco Inc.
- Industrial Gases Division of Air Products and Chemicals, Inc.
- Linde Division of Union Carbide Corp.

Currently, Alaska has a 30-ton/day air separation plant owned by Liquid Air Corporation. Acetylene is also produced in the state. Production of the other hydrocarbon-derived gases in Alaska was not confirmed but is certainly feasible with the abundant feedstocks available.

After World War II, large air separation plants were constructed in the United States, primarily to supply oxygen to the steel industry. Most large facilities are near their primary users and utilize pipelines for product transportation. Until recently, the synfuels industry seemed likely to emerge as a major oxygen consumer. Based on SRI energy price projections, it now seems unlikely that the synfuel industry will emerge as a major user of oxygen by the year 2000.

The co-product of air separation, nitrogen, is expected to show continued strong growth for secondary oil recovery. At least one company, Ingersoll-Rand Enhanced Recovery Company, builds cryogenic air separation plants with compression capability at oil and gas field sites substituting hydrocarbon-based energy for electricity. Table IX-20 shows a breakdown of market share for various oxygen and nitrogen producers.

Table IX-19

1979 VALUE OF U.S. SHIPMENTS OF INDUSTRIAL GASES
(In Millions of Dollars)

Oxygen	502.4
Nitrogen	407.3
Acetylene	175.2
Argon	136.5
Carbon Dioxide	130.4
Hydrogen	119.0

Source: U.S. Department of Commerce, 1979 Industrial Gases Report issued November 1980.

Table IX-20

OXYGEN AND NITROGEN
ON-SITE AND MERCHANT CAPACITY
(Tons per Day)

	Oxygen Gas	%	LinLox	%	Oxygen Gas	%	LinLox	%
Linde	27,158	43.3	13,000	36.0	50,000[a]	34.6	26,700	35.6
Airco	8,935	14.3	6,100	17.0	20,500[b]	13.8	13,000	17.3
Air Products	10,180	16.3	5,900	16.3	25,000[c]	17.3	14,000	17.7
Big Three	7,883	12.6	3,600	10.0	15,000	10.4	6,500	8.4
Liquid Air	4,000	6.3	3,600	10.0	7,000	4.8	8,000	10.7
Liquid Carbonic	0	0.0	1,400	3.9	3,000	2.1	2,500	3.3
Burdox	630	1.0	800	2.2	1,000	0.8	1,500	2.0
Burdett	400	0.6	1,200	3.3	1,500	1.0	2,000	2.7
Others	3,465	5.5	500	1.3	22,000	15.2	800	1.0
Capacity (billion cubic feet)	393		263		916		520	
Demand (billion cubic feet)	292		163		780		410	
Operating Rate	73%		62%		85%		80%	

Note: Oxygen gas: on-site. LinLox (liquid nitrogen and oxygen): merchant.

[a] 6,000 tpd synfuel on-site.

[b] 6,000 tpd synfuel on-site.

[c] 8,000 tpd synfuel on-site.

Source: Smith Barney Harris Upham & Co., as quoted in Chemical Business, May 4, 1981.

In the last two decades, two trends have been in evidence in the industrial gas industry. The first is a shift toward bulk liquefied gas transportation with a commensurate decrease in the use of small gas cylinders as a major transportation mode, and the second is an increase in the number of small plants and on-site production facilities. Both of these trends are brought about by the high cost of transporting compressed and liquefied gases. Currently, no industrial gas is shipped from Alaska. Nationwide, the industry is operating below capacity, particularly in the Pacific Northwest.

Since there are no bulk shipments of industrial gases from Alaska, precise transportation charges are not available. Using current classification rates for liquid nitrogen, however, transportation costs relative to product value were examined.

All industrial gases are subject to widely varying prices depending on the quantity of gas required, location of the user, length of contract, supplier competition, and availability of feedstocks. Prices on the west coast for nitrogen are approximately \$.40 per 100 ft^3 of gas based on a 3-year contract and usage of 700,000 ft^3 per month. This figure does not include vaporization charges or storage tank leasing fees. Currently, rail barge service is available from Anchorage to Seattle, and it is assumed that liquid nitrogen could be transported by railcar. An average tank car weighs approximately 111,000 lb and has a liquid nitrogen capacity of 82,000 lb (or 840,000 ft^3 of gas when vaporized). Southbound transportation costs, Anchorage to Seattle, for 80,000 lb of nitrogen are quoted, using class rates, at \$4.60/100 lb. Thus, for a typical rail car, the ratio of transportation costs to product value would be 1.10.[22]

Given regular shipments, this class rate could be greatly reduced, however, even if it were reduced by 50%, transportation costs alone would outweigh the advantage of inexpensive electricity, even if it cost as little as \$0.005/kWh. Thus, while indigenous Alaskan gas producers would certainly benefit from lower industrial power rates, even free energy would not overcome the cost of transportation outside the state.

The Ferroalloy Industry

The production of ferro and nonferrous additive alloys is electrically intensive (electric energy/shipped product value ratio of .141). These alloys are primarily utilized in steel production to remove undesired elements and to form alloys with improved strength and corrosion properties. These additives also are used to form alloys with improved temperature performance and to neutralize undesirable characteristics of other elements within the metal. Alloys within this group are listed in Table IX-21.

Table IX-21

SIC CODE 3313 ELECTROMETALLURGICAL PRODUCTS

Additive alloys, except copper: not produced in blast furnaces
Electrometallurgical products, aluminum, magnesium, and copper
Ferroalloys, not made in blast furnaces
Ferrochromium
Ferromanganese, not produced in blast furnaces
Ferromolybdenum
Ferrophosphorus
Ferrosilicon, not produced in blast furnaces
Ferrotitanium
Ferrotungsten
Ferrovanadium
High percentage ferroalloys, not produced in blast furnaces
Manganese metal, not produced in blast furnacnes
Molybdenum silicon, not produced in blast furnaces
Nonferrous additive alloys, high percentage: except copper
Steel, electrometallurgical

The ferroalloy industry, like other metals industries in the developed countries, is being adversely effected by high energy and labor costs. Ferroalloys are not end products, but are in turn dependent on the health of the steel industry they support. In recent years, both the U.S. steel industry and the ferroalloy industry have been under continual pressure from foreign imports and the economic recession.

In 1980, ferroalloy imports into the United States were valued at $644 million while U.S. exports were only $93 million, a 6 to 1 ratio of imports to exports. The principal imported alloys are manganese alloys, ferrosilicon, chromium alloys, and ferronickel alloys as shown in Table IX-22.

The availability of feedstock ores in Alaska will be a major factor in any decision to locate a ferroalloy processing plant there.

From 1917 to 1957 chromite was produced at three main sites: the Star and Chrome Queen claims at Red mountain, and the Reef mine at Claim Point in Seldovia, all on the Kenai Peninsula.

There has been no domestic production of chromium since 1961, and no production of manganese since 1973. The United States currently imports chromium from the Republic of South Africa (44%), the Philippines (16%), and the Soviet Union (18%).

Red Bluff Bay, in southeast Alaska, contains high-grade deposits with a good chromium-to-iron ratio. Reserves of 570 tons of more than 40% chromium and 29,000 tons of 18-35% chromium have been noted. These deposits could be valuable national reserves; however, they are not major occurrences on the world scale.

Manganese is imported from Gabon (40%), Brazil (19%), Australia (15%), and South Africa (14%).

Approximately 40% of mined tungsten is consumed by ferrous alloys; when added to iron or steel it improves high-temperature strength and hardness. 38% of all tungsten produced is used as tungsten carbide in many die and drilling applications. On Gilmore Dome, east of Fairbanks, the Yellow Pup mine has produced tungsten concentrates at its small gravity mill.

Molybdenum is a strategic metal used in the production of high-strength alloy steels where minimum weight is required. Reserves of molybdenum have been either proved or inferred at Bond Creek (500 Mt at .03%), Stepovak Bay (100 Mt at .03%), and Nunatak (8.5 Mt at .125%). The most widely known and important reserves, however, can be found in Alaska at Quartz Hill, 45 miles east of Ketchikan. This deposit, discovered in 1974 by U.S. Borax and Chemical Corp., contains an orebody of 1.5 billion tons of ore and a gross value of $18 billion; it is believed to be one of the largest molybdenum deposits in the world. Quartz Hill will produce 40 million lb of molybdenum a year, and is expected to come on stream in late 1987. U.S. Borax estimates that half its output will be exported to markets in the Pacific Basin and Europe.

The United States is heavily dependent on external sources for many of the vital elements listed in Table IX-21, as shown in Table IX-23. There were 32 U.S. ferroalloy producers in 1980 (Table IX-24), many of which are foreign owned. The pattern of plant locations in the United States is an indication that proximity to markets is a more important factor in this industry than electricity costs.

An estimated 15,000 to 20,000 kWh is needed to produce 1 ton of ferroalloy. Based on industry averages, a "typical" ferroalloy plant might produce 1,600 tons of product annually. Pertinent data for a representative ferroalloy production facility are listed in Table IX-25. The differential costs associated with an Alaskan facility are listed in Table IX-26. Because of the varying points of origin of feedstocks, average transportation costs will vary widely, but based on the parameters estimated in Table IX-25, Railbelt electricity would have to be $0.0625/kWh less expensive than competing sites before the region would be considered on the basis of inexpensive electricity alone. Transportation costs for input feedstocks and product would make an Alaskan plant site less competitive than in the eastern U.S. Unless Alaskan producers can identify and economically process local feedstock resources, there is little potential for ferroalloy production in the state based on inexpensive electricity alone.

Even if plants are built, this industry is unlikely to utilize significant quantities of electrical energy, based on the total average annual electrical energy usage for individual plants (32 GWh) in this industry. Such plants would be candidates for the agglomeration of small facilities discussed later in this section.

Table IX-22

1980 U.S. IMPORTS OF FERROALLOYS
AND METALS USED IN FERROALLOYS
($ in Thousands)

Manganese alloys	240,833
Ferrosilicon	42,639
Chromium alloys	155,803
Ferronickel	104,156
Ferromolybdenum	243
Ferrophosphorus	10
Ferrotitanium and Ferrosilicon titanium	1,679
Ferrotungsten and Ferrosilicon tungsten	4,039
Ferrovanadium	3,477

Source: 1980 U.S. Minerals Yearbook.

Table IX-23

1980 NET IMPORT RELIANCE AS A PERCENTAGE OF APPARENT CONSUMPTION

Manganese	98%
Chromium	90%
Silicon	20%
Nickel	73%
Titanium	Data withheld by the Bureau of Mines to avoid disclosing company proprietary data
Tungsten	52%

Source: "Mineral Commodity Summaries 1982," U.S. Department of Interior, Bureau of Mines

Table IX-24

PRODUCERS OF FERROALLOYS IN THE UNITED STATES IN 1980

Producer	Plant Location	Products[1]	Type of Furnace
FERROALLOYS (EXCEPT FERROPHOSPHORUS)			
Alabama Alloy Co., Inc.	Bessemer, AL	FeSi	Electric
Aluminum Co. of America, Northwest Alloys, Inc.	Addy, WA	Si, FeSi	Do.
Autlan Manganese Corp.	Mobile, AL	SiMn	Do.
AMAX Inc., Climax Molybdenum Co. Div.	Langeloth, PA	FeMo	Metallothermic
Cabot Corp., KBI Div. Penn Rare Metal Div.	Revere, PA	FeCb	Do.
Chromasco Ltd., Chromium Mining & Smelting Corp. Div.	Woodstock, TN	FeCr, FeSi	Electric
Dow Corning Corp.	Springfield, OR	Si	Do.
Engelhard Minerals & Chemicals Corp., Minerals and Chemicals Div.	Strasburg, VA	FeV	Metallothermic
Foote Mineral Co., Ferroalloys Div.	Cambridge, OH Graham, WV Keokuk, IA	FeSi, FeV, silvery pig iron, other[2]	Electric
Hanna Mining Co., The:			
Hanna Nickel Smelting Co.	Riddle, OR	FeNi, FeSi	Do.
Silicon Div.	Wenatchee, WA	Si, FeSi	Do.
Interlake, Inc., Globe Metallurgical Div.	Beverly, OH Selma, AL	FeCr, FeCrSi, Si FeSi, SiMn	Do.
International Minerals & Chemical Corp.,	Bridgeport, AL	FeSi	Do.
Industry Group, TAC Alloys Div.	Kimball, TN	Do.	Do.
Macalloy Inc.	Charleston, SC	FeCr, FeCrSi	Do.
Metallurg, Inc., Shieldalloy Corp.	Newfield, NJ	FeAl, FeB, FeCb, FeTi, FeV, other[2]	Metallothermic
Ohio Ferro-Alloys Corp.	Montgomery, AL Philo, OH Powhatan Point, OH	FeB, FeMn, FeSi, Si, SiMn	Electric
Pennzoil Co., Duval Corp.	Sahuarita, AZ	FeMo	Metallothermic
Reseco Co., The	Newton Falls, OH Solon, OH Pulaski, PA Fort Worth, TX	FeAl, FeB, FeCb FeMo, FeNi, FeTi, FeV, FeW, other[2]	Electric, metallothermic

Table IX-24 (Concluded)

Producer	Plant Location	Products	Type of Furnace
FERROALLOYS (EXCEPT FERROPHOSPHORUS)			
Reactive Metals and Alloys Corp.....	W. Pittsburgh, PA	FeTi, other[2]	Electric,
Reading Alloys, Inc.................	Robesonia, PA	FeCb, FeV	Metallothermic
Reynolds Metals Co..................	Sheffield, AL	Si	Electric
Satra Corp., Satralloy, Inc. Div....	Steubenville, OH	FeCr, FeCrSi	Do.
SEDEMA S.A., Chemetals Corp.........	Kingwood, WV	FeMn	Fused-salt electrolytic
SKW Alloys, Inc.....................	Calvert City, KY.. Niagara Falls, NY.	FeMn, FeSi, SiMn	Electric
South African Manganese Amcor, Ltd.. Roane Ltd.	Rockwood, TN	FeMn, SiMn	Do.
Teledyne, Inc., Teledyne Wah Chang, Albany Div	Albany, OR	FeCb	Metallothermic
Union Carbide Corp., Metals Div.....	Alloy, WV Ashtabula, OH Marietta, OH Niagara Falls, NY Portland, OR Sheffield, AL	FeB, FeCr, FeCrSi FeMn, FeSi, FeV, FeW, Si, SiMn, other[2]	Electric
Union Oil Co. of California, Molycorp, Inc.	Washington, PA	FeB, FeMo, FeW	Electric and metallothermic
FERROPHOSPHORUS			
Electro-Phos Corp..................	Pierce, FL	FeP	Electric
FMC Corp., Industrial Chemical Div	Pocatello, ID	Do.	Do.
Monsanto Co., Monsanto Industrial Chemicals Co.	Columbia, TN Soda Springs, ID	Do. Do.	Do. Do.
Occidental Petroleum Corp., Hooker Chemical Co., Industrial Chemicals Group	Columbia, TN	Do.	Do.
Stauffer Chemical Co., Industrial Chemical Div.	Mt. Pleasant, TN Silver Bow, MT Tarpon Springs, FL	Do.	Do.

[1]FeAl, ferroaluminum; FeB, ferroboron; FeCb, ferrocolumbium; FeCr, ferrochromium; FeCrSi, ferrochromium-silicon; FeMn, ferromanganese; FeMo, ferromolybdenum; FeNi, ferronickel; FeP, ferrophosphorus; FeSi, ferrosilicon; FeTi, ferrotitanium; FeV, ferrovanadium; FeW, ferrotungsten; Si, silicon metal; SiMn, silicomanganese.

[2]Includes specialty silicon alloys, zirconium alloys, and miscellaneous ferroalloys.

Source: U.S. Minerals Yearbook, 1980.

Table IX-25

DATA FOR REPRESENTATIVE 1600-TON/YEAR FERROALLOY PLANT

Investment Costs for New Plant Construction	$10-$20 million
Labor Costs (200 employees)	$4 million
Electricity Costs ($0.045/kWh)	$1 million

Source: SRI International

Table IX-26

ANNUALIZED DIFFERENTIAL COSTS ASSOCIATED WITH AN ALASKAN SITE FOR A FERROALLOY FACILITY

Construction Costs	\$0.5 - \$1.0 million
Labor	\$1.2 million
Transportation Costs	\$0.2 - \$0.3 million
Total	\$1.9 - \$2.5 million

Source: SRI International

The Pulp and Paper Industry

In 1979, paper mills (excluding building paper) ranked as the fourth largest energy-consuming industry in the United States, using 592.2 trillion Btu costing $1.689 billion. Of this total, 32% ($536.7 million) was for electric power. For the building board and building board mills, purchased electrical energy represented 5.6% of the value of shipped product in 1980. Much of this industry produces a major portion of its own electricity through cogeneration. The United States ranks first in the world in both production and consumption of paper, board, and pulp. In 1981, the U.S. produced over 57 million metric tons of paper and board alone. A breakdown by grade of U.S. paper and board production for 1970-1981 is given in Table IX-27. The increase in annual demand expected by SRI through the 1980s, though far below growth in the 1950s and 1960s, will be about 65 million tons, or an annual increase of 3.3% per year. Growth of demand in developing countries is expected to be greater than in the U.S. U.S. exports have been increasing from 65,000 metric tons in 1979 to 159,000 in 1980 and 245,000 in 1981.[23,24]

The paper/forest products industry, like many other industries, is currently depressed by the recession and high interest rates. Some of the biggest companies, such as Boise Cascade, Champion International, and Crown Zellerbach are having a difficult time meeting interest payments.[24] Although the industry is currently depressed (see Table IX-28), it can be assumed that the economic recovery will lead to expansion of the industry comparable to historic trends. In the timeframe of interest (1990-2010), the industry can be expected to add capacity, particularly if new markets are developed, such as the People's Republic of China.

Because a newsprint facility[25] using thermomechanically processed pulp (TMP) possesses the least ability to generate its own internal sources of electricity, and because it is representative of the predominant paper commodities, this segment of the industry was selected by SRI as an example of the most likely of the pulp and paper industry segments to benefit from low-cost Alaskan electricity.

Industry estimates of plant energy costs vary from 12% to 30% of shipment value. Canadian plants, which produce the preponderance of newsprint, report purchased energy costs at 12% of the value of shipment. An Alaskan site would compete with the most efficient alternative sites, so the Canadian data are the most pertinent for comparison purposes. Based on industry averages, electricity costs

Table IX-27

PAPER AND BOARD PRODUCTION IN THE UNITED STATES
(Thousands of Short Tons)

	Paper							Paperboard				Construction[1]			
Year	News-print	Coated Printing	Publicat. & Print.[2]	Writing & Relat.	Coarse[3]	Sani-tary	All Paper Total	Other Bleached Paper-board	Corru-gating Material	Unbleached Kraft[4]	All Paper-board Total	Wet Ma-chine Board	Con-struc-tion (Paper)	All Cons-struction Total	Total All Types
1970	3,345	3,279	2,646	2,937	5,439	3,548	23,625	1,856	4,332	11,436	25,477	139	1,594	4,276	53,516
1971	3,321	3,251	2,758	2,996	5,442	3,660	23,811	1,938	4,596	11,700	26,135	138	1,837	5,001	55,086
1972	3,451	3,546	3,010	3,329	5,713	3,796	25,435	1,964	4,992	13,030	28,522	148	1,915	5,352	59,457
1973	3,459	3,814	3,116	3,817	5,694	3,726	26,483	1,971	5,285	13,139	29,267	149	1,858	5,406	61,304
1974	3,395	3,974	2,832	4,102	5,731	3,800	26,674	1,957	5,093	12,755	28,017	144	1,845	5,118	59,930
1975	3,476	3,318	2,400	3,244	4,805	3,669	23,306	1,792	4,411	11,170	24,452	115	1,616	4,648	52,521
1976	3,400	3,967	2,984	3,910	5,661	3,936	26,612	1,894	5,045	12,501	27,840	130	1,771	5,316	59,898
1977	3,525	4,215	3,316	4,170	5,930	4,045	28,096	1,968	5,485	105,902	29,006	N.A.	1,552	5,492	62,722
1978	3,489	4,513	3,507	4,277	5,778	4,036	28,506	1,634	5,792	N.A.	30,033	N.A.	1,915	5,625	64,300
1079	3,778	4,580	2,048	4,596	5,708	4,403	29,580	1,841	5,918	13,857	31,168	144	1,868	5,436	66,329
1980[5]	4,660	4,751	2,127	4,793	5,327	4,298	30,164	1,794	5,864	14,249	31,143	138	1,369	4,390	65,034
1981[6]	5,000	4,900	2,000	4,900	5,700	4,600	31,500	1,900	6,000	14,800	32,000	150	1,200	4,600	68,000

[1]Paper and Board. [2]Prior to 1979 data are for book paper, uncoated. [3]Packaging & industrial converting paper. [4]Prior to 1979 data are for linerboard. [5]Preliminary. [6]Estimate.

Source: Bureau of the Census

Table IX-28

U.S. PAPER/FOREST PRODUCTS FIRST-QUARTER RESULTS
($000)

Paper Companies	Sales	Change 1982/81	Earnings[1]	Change 1982/81
Chesapeake	$ 59,600	-6.6%	$ 1,900	-67.8%
Clevepak	31,079	5.9	949	0.1
Consolidated	135,816	-1.1	10,905	-29.7
Crown Zellerbach	725,000	-5.3	5,600	-69.6
Diamond	264,979	-14.4	2,204	-73.1
Federal Paper	123,015	8.0[2]	5,348	8.1[2]
Fort Howard	120,295	8.4	21,803	10.2
Glatfelter	68,696	29.3	5,774	150.7
GN Nekoosa	367,900	0.5	22,000	3.8
Hammermill	325,916	5.7	7,080	-34.1
Intl. Paper	1,002,700	-23.2	60,000[3]	-59.3
James River (1/24)[4]	184,250	-1.6	4,391	-5.9
Kimberly-Clark	734,300	0.1	57,700	-4.2
Longview (1/31)[4]	92,912	11.0	(2,185)	n.m.
Mead	689,866	2.6	13,803	-54.0
Mosinee	22,021	-6.1	1,022	-41.6
Pentair	67,865	17.0	2,223	-19.5
St. Regis	672,230	9.8	19,430	-61.0
Scott	580,156	2.5[2]	18,639	-27.9[2]
Sonoco	122,953	-4.2[2]	6,667	-13.8[2]
Sorg	19,932	-8.8	(98)	n.m.
SW Forest	144,948	-27.6	(4,603)	n.m.
Stone Container	105,442	2.3	2,556	-58.6
Union Camp	372,433	-10.6	32,241	-19.4
Wausau (2/18)[4]	44,833	-5.6	(864)	n.m.
Westvaco	342,644	-5.4	8,323	-57.4
Willamette	214,305	-12.2	(4,652)	n.m.
Total	$7,906,086	-3.1%	$298,156	-42.3%

Table IX-28 (Continued)

Forest Products	Sales	Change 1982/81	Earnings[1]	Change 1982/81
Boise Cascade	$ 713,960	-9.0%	$ 5,560	-85.2%
Champion Intl.	905,913	-9.5	617	-97.8
Georgia-Pacific	1,199,000	-11.1	15,000	-51.9
Louis.-Pacific	196,570	-26.4	(11,750)	n.m.
Popo & Talbot	59,633	-4.0	857	39.3
Potlatch	201,308	-7.9	4,485	-43.6
Weyerhaeuser	1,057,457	-3.7	56,952	-0.1
Total	$ 4,333,841	-9.3%	$ 81,721	-59.3%
U.S. Total	12,239,927	-5.4	379,877	-47.1

CANADIAN PAPER INDUSTRY RESULTS

Abitibi	C$414,618	0.9%	C$22,019	-21.5%
B.C. Forest	198,300	-2.9	(4,700)	n.m.
B.C. Resources	143,200	-35.9	(13,000)	n.m.
Con-Bathurst	362,600	1.6	17,600	-32.8
Donam	30,600	-1.0	(7,700)	n.m.
Fraser	102,734	8.4[2]	143	-97.0[2]
Great Lakes	132,275	-4.7	12,179	-42.0
Mac/Bloedel	505,000	-17.5	(10,400)	n.m.
Scott	52,900	9.3	2,200	10.0
Weldwood	99,700	-23.2	(4,047)	n.m.
Total	C$2,041,927	-9.2%	C$14,294	-87.1%

Note: n.m. = not meaningful

1. Income after taxes, from continuing operations, excluding most significant nonrecurring items in both years.

2. 1981 figures restated by company.

3. 1982 results include after-tax gain of $17.2 million from sale of tax benefits. 1981 results include after-tax gain of $57 million from land transactions.

4. Period ended. Figures for James River are for third quarter, Wausau for second quarter.

Source: Pulp and Paper, June 1982

are approximately 32% of energy costs, and the cost per metric ton (based on a production cost of $425.25/Mt) in Canada is equal to $16.33. For marginal plants where electricity is 20% of the total operating costs of an integrated facility, the costs might be as high as $85/ton. Alternatively, if electricity were substituted for all other energy uses, costs might be as high as $50/ton, even for a Canadian plant.

Average costs for construction of new forest products facilities are given in Table IX-29. Construction of a typical large newsprint facility is estimated at $330 million with a capacity of approximately 200,000 metric tons per year. At 10% interest over 30 years, finance charges on such a plant are approximately $712 million, for a total cost of $1,042 million. A similar plant in Alaska using a 1.5 location adjustment factor is estimated to cost $1,564 million over 30 years, of which $1,068 million is interest. These costs represent an annual cost differential for an Alaskan location of $17.3 million (1982 dollars).

Although input feedstock transportation costs are expected to be comparable to those for competing sites, output transportation costs will be greater for an Alaskan location than for an average site in Canada or the Pacific Northwest. At bulk shipment rates, annual costs for shipment of 200,000 tons of newsprint from Anchorage to Oakland, California, are expected to be $33.6 million (see Table IX-30). This value represents an added expense of approximately $168/ton, compared to average U.S. transportation charges of $64.50/ton. For a 200,000-ton production plant, the annual transportation differential is approximately $20.6 million (1982 dollars). Although export to Asia might be comparable for an Alaskan site and a U.S. west coast site, competing low-cost Asian labor rates make shipment of finished paper products to Asian users unlikely for all U.S. sites.

The labor cost differential can be calculated using published pulp and paper hourly rates for the Northwest and the United States as a whole and using the assumption that Alaskan labor rates are approximately 1.2 times higher than in the Northwest, and approximately 1.68 times higher than the U.S. average for the paper and pulp industry.[25] This results in an overall labor differential for an Alaskan plant of $13.5 million.

As shown in Table IX-31, the overall annual cost differential for a typical plant, which must be offset by energy rates, is $51.4 million, or $257/ton, which compares unfavorably with the $85/ton cost of electricity for even marginal plants.

Using an average of $.02/kWh price for electricity in Canada, the energy usage per pound of product can be estimated at approximately 1.28 kWh. Based on this estimate, Susitna power would have to be approximately $.09/kWh cheaper than competing sites in order to achieve a break-even with the annualized added cost of construction, labor, and transportation associated with an Alaskan site. An analysis of other

Table IX-29

TYPICAL U.S. MILL CONSTRUCTION COSTS

Grade	Capacity (metric tons/day)	Costs (million $)
Newsprint	550	330
Linerboard	1,100	Less than 200
Kraftboard	550	300
Printing & Writing Paper	550	600
Tissue	550	300

Source: Composite taken from interviews with industry officials.

Table IX-30

NEWSPRINT TRANSPORTATION COSTS

	Mode	Annual Cost (million $)
Newsprint from Anchorage to Seattle; $116.38/metric ton x 200,000 tons	Container vessel	23.3
Newsprint from Seattle to Oakland; $51.70/metric ton x 200,000 tons	Rail	10.3
Solid wood from British Columbia to Anchorage; $20/cubic meter x 483,000 cubic meters	Container vessel	9.7
Total Transportation Costs		43.3

Source: SRI International

Table IX-31

ANNUAL COST DIFFERENTIAL ASSOCIATED WITH AN ALASKAN SITE FOR A PULP AND PAPER PLANT

	Total	$/Ton
Construction	$17.3 million	86.5
Labor	13.5 million	67.5
Transportation	20.6 million	103.0
Total	$51.4 million	257.0

Source: SRI International

segments of the pulp and paper industry can be expected to produce similar results, since newsprint production is characteristic of the energy intensity of the pulp and paper industry processes, and this segment of the industry is less able to take advantage of cogeneration.

The Cement Industry

Because of the low value-to-weight ratio of cement, transportation charges are a major factor in its production. Most cement is used within 150 miles of where it is produced. Overall, cement industry capacity has not changed in recent years, but because of extreme competition within the industry, numerous older, obsolete plants have been retired and new, more efficient plants constructed. In the period 1980 through 1981, 22 plants were closed while 9 million tons of capacity were added in 1981.[26]

Four companies dominate the current cement industry.[27] These are:

- Lone Star Industries
- Ideal Basic
- Kaiser Cement
- Texas Industries.

Overall, there are 48 companies and 159 plants producing cement in 39 states. Most energy (90%) associated with cement production is used in the drying of cement clinker, which is then ground into the final product. There are two processes, wet and dry, which are used in the industry, although most new plants employ the dry process. Dry process plants typically are 20% lower in energy consumption than wet process plants.[28,29]

Although the cement industry is a high user of electrical energy, the preponderance of energy usage is from fossil fuels. In 1979, 76% of kiln energy was fueled by coal, 16% was natural gas, and 8% was oil. Since low-cost hydropower might be used to displace fossil fuel in thermal processes, the cement industry could be a candidate for energy substitution.[30]

Currently, there are no cement plants in Alaska. Product is shipped at a cost of approximately $60/ton from plants in Seattle which receive their raw materials from British Columbia.[31] Because of these added transportation costs, the cost of cement in Anchorage is twice the cost relative to the average U.S. price. Fifty percent of U.S. cement production currently comes from six states: Texas, California, Pennsylvania, Michigan, Missouri, and Florida. In general, the high cost of transportation from Alaska (approximately 100% of product value) appears to overshadow any possible energy saving associated with Alaskan cement production.

The Chemicals Industry

The industrial inorganic chemicals in SIC 2819 are a potpourri of diverse products and dissimilar industries. Contained within this group are a number of materials discussed in this report in conjunction with other industrial processes, such as alumina and bauxite as feedstocks to the aluminum industry. Of the remainder, the importance of energy costs varies markedly. The classification of this group as electrically intensive is somewhat misleading, since uranium production is included in this classification group.

The U_{235} isotope occurs in small concentrations in uranium ore, and the ore must be enriched in this isotope to produce nuclear fuel. In the currently used diffusion process, uranium oxide (U_3O_8) is converted into uranium hexafluoride (UF_6). This gas is then passed through diffusion tubes in an iterative process resulting in an increase in the concentration of the fissionable isotope. The entire process is extremely electrically intensive. Production of uranium fuel is controlled by the federal government, and no new diffusion plants are planned. Future isotope separation plants will utilize either centrifuge or laser separation techniques, both of which are less energy intensive.

Many of the other energy-intensive products are associated with production of low volumes of elemental metals, propellants, and elemental gases, which do not require large facilities. This SIC code also contains a number of high-volume, low-energy products. Eight chemicals within this SIC code are among the top 50 chemical products in the United States on a weight basis, as shown in Table IX-32. The production of these chemicals is, however, not very electrically intensive. Sulfuric acid production is an example of this class. Phosphate fertilizer production accounts for about 2/3 of sulfuric acid production, but other uses could be significant to Alaska. Its use in chloro-alkali production has been discussed previously. About 1.8 million metric tons is used annually in petroleum refining, and 1.7 million tons is used annually in recovering copper from low-grade ores.

In the production of sulfuric acid, sulfur dioxide reacts with excess air in an exothermic reaction which requires cooling. The resultant sulfur trioxide reacts with water to form sulfuric acid. The energy produced in this exothermic reaction can be used in a cogeneration steam process to produce electrical energy. Plants built in the 1980s will be able to generate 1.3 lb of steam per pound of acid. Significantly, this will occur at higher pressures (900 psi as opposed to 300 psi) and thus be more suitable for energy recovery than in older plants. Addition of a turbo generator to recover this energy would add \$5,000,000 to the plant capital costs of \$25,000,000 but would generate 15,000 kWh of energy.[32]

Table IX-32

RANKING OF SELECTED U.S. INORGANIC CHEMICALS ON PRODUCTION BASIS

	Rank	1980 Production (billions of pounds)
Sulfuric acid	1	80.7
Sodium hydroxide	7	22.6
Sodium carbonate	12	16.6
Hydrochloric acid	26	5.5
Sodium sulfate	35	2.5
Aluminum sulfate	37	2.4
Calcium chloride	40	2.0
Sodium tripolyphosphate	47	1.4

Source: Standard & Poor's Industrial Surveys, "Chemicals," November 5, 1981

Three general conclusions can be made concerning SIC 2819 industries. Energy usage is heavily skewed by radioactive material production; many other high-volume chemicals are actually not energy intensive; and finally, of those that remain, most represent small markets and are secondary products associated with developed industry infrastructures and not primary industries, a factor which SRI regards as important in identifying candidate industries for Alaska. SRI has not identified any candidate industries within the group which appear to be likely candidates to benefit from low-cost Alaskan power.

The Primary Metals Industry (Excludes Steel, Copper, and Aluminum)

Five metals (gold, silver, zinc, nickel, and tin) within these SIC codes either are in production in Alaska, are the subject of exploration, or are known to exist in potentially significant quantities. In the case of precious metals, Alaska has approximately 13 principal producers working placer gold deposits within the state. Overall, about 65,000 troy ounces of gold were recovered by over 200 operators in 1979. Approximately 6,500 troy ounces of silver were also recovered alloyed with the placer gold. At least 3 tin mining facilities are operating within the state. Zinc and nickel are the subject of exploration by a variety of multinational corporations, and various reserves have been reported. Unfortunately, of 244 known major mineral areas catalogued by Resource Associates of Alaska, over 80% are in closed lands. Of the 13 most economically viable deposits identified by RAA, 9 are closed to exploitation by the Alaska National Lands Interest Conservation Act.

Some of the larger known deposits that contain economically recoverable metals are:

- Lik - sulphides of Pd (8.5%), Zn (25.5%), Ag, Cd (0.25%)
- Cominco - very similar to Lik
- Artic - sulphides of Cu (4.0%), Zn (5.5%), Pg (1.0%), Ag
- Picnic Creek - similar to Artic
- Lost River - tin, fluorite, tungsten, and beryllium
- Brady Glacier - Ni-Cu
- Bohemia Basin - Ni (0.4%), Cu (0.25%), Co (0.04%)
- Green's Creek - Pb (1.94%), Zn (7.71%), Cu (0.4%), Ag, Au
- Quartz Hill - molybdenite (0.15% MoS_2).

Zinc, copper, and silver ores are the most prevalent, but significant deposits of strategically important cobalt, chromite, titanium, molybdenum, and tungsten ores are located throughout Alaska.

Nickel is used in the production of stainless steel and other corrosion-resistant alloys. The deposit at Brady Glacier, at Glacier Bay National Park, is considered to be a major nickel reserve for the U.S. Probable reserves are estimated to be between 100 million and 300 million tons of 0.5% Ni. On Yakobi Island, Inspiration Development Co. has conducted drilling and geological detailing at its claims covering the Bohemia Basin and Takanis deposits. These deposits, together with the Flapjack deposit, contain in excess of 20.7 million tons of 0.33-0.51% Ni and up to 0.04% Co.

Tin concentrates are produced as a by-product of molybdenum mining in Colorado and from placer deposits in Alaska. Only one tin smelter is in operation in the U.S., at Texas City, Texas. Although the U.S. is 80% dependent on tin imports and Alaska contains the primary U.S. reserves, the U.S. reserves are only 0.5% of the world total. Tin is, however, available from a number of world suppliers, including Southeast Asia, Australia, Bolivia, Brazil, Mainland China, and the USSR. Overall, U.S. tin usage is expected to grow at less than 1% annually through 1990.[34]

Zinc mining in the U.S. was a $306-million industry in 1981, with 25 mines producing 99% of total output. Tennessee, Missouri, New York, and Idaho accounted for 79% of total production. Although the United States is a net importer, its reserve base is approximately 20% of the world total. Demand is expected to grow at about 1.1% annually through 1990.

Energy costs for processing these ores as a percent of value are generally less than 10% of the final product value. The unknown costs of extraction in an Alaskan setting and transportation of finished products are expected to be a significant fraction of the final cost for these metals. Low-cost Alaskan electricity would enhance the economies of extraction of these minerals but is not likely to be an overriding factor in the decision to exploit them. Detailed economic analysis is required for each site before the impact of low-cost electricity can be determined, especially since many of these deposits are precluded from exploitation in the foreseeable future.

It is not practical to examine the economies of processing at all the sites for minerals in this category, but zinc smelting is representative of the group and will be examined in some detail.

Commercially valuable zinc-bearing ores occur predominantly in sulfide form. Valuable impurities in zinc ores, from which the zinc is extracted via specific metallurgical operations, include lead, iron, copper, silver, gold, antimony, and occasionally tin.

The process of extracting zinc from the ore takes place in three operational steps:

- Concentrating - where ores, after being mined, are separated into a concentrated mineral and a waste rock.

- Smelting - where the concentrate is reduced to the metal in a metallurgical works.

- Refining - where the metal is further refined and alloyed to commercially usable form.

The concentration of zinc sulfide ores usually takes place adjacent to the mine site. First, the ore must be crushed and ground in order to free the mineral lattices from those of the waste rock (gangue). Next, the finely divided ore is mixed into a slurry with water, and the mineral and gangue particles are separated utilizing the effect of gravity. This separation usually takes place by way of the froth flotation process, where the gangue is discarded as waste (tailings). During the last step in concentration (or beneficiation), the mineral slurry is separated into solids and water via a filtration process. The resulting zinc sulfide concentrates contain 50% to 64% zinc.

The preparation of the concentrate for smelting involves a process (roasting, sintering, or pyroconcentration) in which the source material is made into a crude zinc oxide form and specified particle size. During roasting, the sulfide is heated and burned with oxygen to form ZnO and gaseous SO_2 (which is generally converted to sulfuric acid). Sintering may take place to further treat the ZnO to increase density and particle size before feeding into the smelter. In pyroconcentration, the zinc-bearing material is mixed with coal, heated, and turned into a vapor, which is carried via a gas stream to a baghouse (filter) and condensed.

In the reduction step, the zinc is reduced from its oxide to its elementary form. Several different thermal processes may be used: horizontal retort, vertical retort, electrothermic furnace, and blast furnace (all of which use carbon as a reducing agent). The electrolytic process uses the passage of electric current for reduction to metal from a liquid bath. This hydrometallurgical (electrolytic) process for zinc smelting, rather than using heat for the reduction, relies on electrodeposition of the metal from a zinc sulfate solution prepared from the crude zinc oxide and sulfuric acid. Virtually all impurities remaining from the preparation step are eliminated in this process.

The quality of zinc produced by the various carbon reduction processes mentioned is suitable for hot-dip galvanizing, continuous-line galvanizing, and in some cases for brass manufacture and rolled (wrought) zinc. For sizable usage in die-casting alloys, however, output from this type of smelter must undergo a refining step. The major method of upgrading the lower-purity zinc metal is fractional distillation in reflux refining columns, which is capable of producing 99.995% pure zinc.

Sulfuric acid, one of the major byproducts of the zinc industry, is used by the chemical and oil industries (e.g., for chemical cleaning of steel; in making phosphates for fertilizers).

Identified world resources of zinc are estimated to be about 1.8 billion tons. (Metal Statistics, 1980, American Metal Market, Fairchild Publications, New York, 1980). Canada, the largest producer of zinc, is also the country with the largest known reserves. Other important producers are Peru, Australia, the U.S., and Mexico. In 1980, Peru produced 72,000 Mt; Australia, 300,000 Mt; United States, 325,300 Mt; Mexico, 165,000 Mt; and Canada 550,000 Mt. Major U.S. companies producing zinc include:

- Amax, Inc. (Greenwich, Conn.).
- Asarco, Inc. (New York).
- Bunker Hill Co. (Kellogg, Idaho), a unit of Gulf Resources and Chemical Corp.).
- National Zinc Co. (Bartlesvillle, Okla.; a unit of Engelhard Minerals and Chemicals Corp.).
- New Jersey Co. (Nashville; a unit of Gulf and Western Industries, Inc.).
- St. Joe Zinc Co. (Pittsburgh; a unit of St. Joe Minerals Corp., which closed its Monaca, Pa., electrothermic zinc smelter at the end of 1979).

A zinc smelter employing the electrolytic reduction process can be expected to use about 3,500 kWh per ton of finished product. Free electricity might produce a savings of $200 per ton, but this would be offset by $60 per ton in additional capital costs ($180 million for an Alaskan site) and $54 a ton for additional labor costs (300 workers) associated with an Alaskan location. Transportation costs cannot be evaluated without consideration of a specific site. In conclusion, the availability of inexpensive electricity makes an Alaskan zinc smelter more favorable but is clearly not a deciding factor.

The Fertilizer Industry

Although the chemical fertilizer industry is currently suffering from overcapacity, SRI projects a growth rate of 2% to 3% over the next 20 years for this industry, and there is potential for expansion of the industry in the 1990s. The industry has reduced the electric energy "content" of its product in recent years and has generally converted from mechanical compressors to the reforming process, which involves combustion of natural gas at 1,800°F to produce H_2 and steam for turbines. Siting issues are primarily associated with the availability and price of natural gas, which is used as feedstock for these plants. A new ammonia plant produces a product with an electric energy content of only 25 kWh/ton, compared to [illegible] kWh/ton for a plant using mechanical compressors. To determine the value of conversion back to electricity, the cost of the displaced gas ($28/ton of product, assuming $3.75 per million Btu) must be balanced against the electricity cost and the other costs associated with an Alaskan location.

Electrical energy (compressors) would only be substituted for natural gas (gas-fired turbines) if the electric energy content of the product did not exceed $25 to $30 per ton. SRI estimates the investment required to build a 1,500-metric-ton-per-day plant in Alaska at $[illegible]39 million, based on an investment of $166 million for a similar facility at a Gulf Coast site. Differential carrying costs associated with the capital investment in an Alaskan site are therefore approximately $10 per ton. Differential transportation costs can be expected to add another $35 to $45 per ton. Based on the increased construction costs and transportation costs of an Alaskan site, inexpensive energy alone will not attract investors to Alaska interested in siting a new ammonia plant.

If, however, an Alaskan location is considered because of economically priced natural gas, a decision between the gas-fired plant and a mechanical plant will be made on the tradeoff between the cost of displaced gas (7 billion Btu) and the electricity costs. Electricity prices below $0.026/kWh would be required before the mechanical plant would have lower operating costs than a gas-fired plant, assuming a gas cost of $3.75 per million Btu. If operation of the reciprocating-compressor ammonia plant proved economical, it would require approximately 550 GWh annually.

Electric Space Heat in the Residential/Commercial Markets of the Railbelt

In addition to major industrial development and activity, commercial and residential space heat offer market opportunities for utilizing low-cost electrical energy. Electric pricing policies and marketing programs could provide incentives to displace a portion of fuel oil and gas space heaters in both existing and new units. If electric rates were low enough relative to other space heating options, there would be a shift from fossil fuel to electric-generated space heating.

At present, electricity supplies approximately one-third of all residential end-use energy in the Railbelt. Commercial use is also large. The current and forecast use in both markets by fuel type predicted by Applied Economics Associates, adjusted and amplified by SRI as noted, are shown in Table IX-33.

Residential Electricity Demand

Total demand for residential energy (taken here as heat demand) is shown as growing to 57.844 trillion Btu by 2010 (see Table IX-33, Table IX-34). Likely conservation factors, estimated as reducing overall demand by 10%, 20%, and 30% in 1990, 2000, and 2010, respectively, result in a demand of approximately 40.5 trillion Btu in 2010 (see Table IX-34). If it is assumed that all savings are in the fossil fuel component, the fossil fuel usage after conservation would be approximately 30 trillion Btu (equivalent to approximately 18 trillion Btu of electricity). This quantity must be added to the original forecast for electricity of 12.5 trillion Btu. Accounting for conservation, this gives a total potential residential all-electric demand of approximately 30.5 trillion Btu. Assuming a favorable price advantage for electricity, conversion of existing facilities and the total electrification of all new construction in the Railbelt can be expected to approximate the conversion from coal to natural gas for space heating that occurred in the Midwest and Northeast during the late 1940s and 1950s. Because of transmission and distribution limitations, market penetration of approximately 80% is assumed at equilibrium in the Railbelt. The estimated potential residential electrical usage in 2010 is therefore approximately 24 trillion Btu (7,000 GWh). For 1990 it was assumed that the price differential between electricity and fossil fuels would be smaller, leading to a smaller equilibrium market share; that the market would be half way to equilibrium; and that only 90% of the potential market can be reached because of geographical factors. These assumptions imply that 25% of residential demand would be met by electricity. Similar considerations lead to a 45% share in 2000.

Table IX-33

ENERGY CONSUMPTION IN THE RAILBELT:
RESIDENTIAL/COMMERCIAL[1,2]
(10^9 Btu)

	1979	1990	2000	2010
Electric				
Residential	3,572	5,427	8,240	12,500 (3)
Commercial	2,544 (4)	3,998	6,618	10,060
Petroleum				
Residential	14,355	18,533	23,722	
Commercial	3,481	5,345	6,231	
Natural gas				
Residential	7,178	9,266 (5)	11,[illegible] (5)	
Commercial Heat	3,221	4,810 (6)	5,[illegible] (6)	
Total liquid fuels				
Residential				45,300
Commercial				17,800
Total energy				
Residential	25,105	33,226	43,823	57,844 (1)
Commercial	9,246	14,153	18,457	27,860

[1]Basic data from Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

[2]Coal excluded.

[3]Extrapolated by SRI International.

[4]Taken from energy balances, Long Term Plan, as 2,544 x 10^9 Btu. Other figures in row extrapolated at rate indicated on p. C-66 (4.2%).

[5]Inferred by SRI from 1979 data as 50% of petroleum use.

[6]Inferred by SRI from 1979 data as 90% of petroleum use.

Table IX-34

ESTIMATES OF POTENTIAL ELECTRIC DEMAND FOR
RAILBELT RESIDENTIAL END USE
(10^9 Btu Unless Otherwise Noted)

	1979[1]	1990	2000	2010[2]
Forecast usage				
Electricity	3,573	5,427	8,240	12,500
Fossil	21,533	27,799[3]	35,583[3]	45,346
Total	25,106	33,226	43,823	57,846
Total with conservation	25,106	29,903	35,058	40,492
Energy demand if all electric	16,493	20,113	24,331	29,295
Likely fraction of demand electric	0.217	0.25	0.45	0.8
Resulting electricity usage				
Btu	3,573	5,028	10,949	23,730
GWh	1,047	1,474	3,209	6,955

[1]Actual.

[2]Extrapolated by SRI International.

[3]Natural gas taken as 50% of petroleum values.

Source: Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

Commercial Electricity Demand

Similar considerations apply to commercial conversion to electricity and total potential electricity use. For the commercial sector it is assumed that some activities preclude the use of electricity, resulting in an arbitrary limit of 70% maximum market penetration. If the same market share approach* used in the residential estimates is assumed, the fractional shares indicated in Table IX-35 can be calculated. These values lead to the electricity demand forecasts presented at the bottom of Table IX-35.

Supply and Demand

The forecast[20] generation and generation capability are contrasted with the potential residential and commercial electricity use projected above in Table IX-36.

It is apparent that unless use for space heating is discouraged by a tiered rate structure, increased residential and commercial use of electricity could result in near saturation of the proposed Susitna-based generation system without any increase in industrial demand above the current 600 GWh per year. If long-term favorable electric rates are offered to residential and commercial consumers, a substantial substitution of electricity for fossil fuels will occur since electrical space heating equipment is generally less expensive than fossil-fuel-fired space heating equipment. The conversion will take place over a 20-year period as old space heating equipment is replaced. Electrical heating equipment will be specified in both the new construction and replacement markets, if the prospect for long-term favorable electric rates is widely perceived and accepted.

If the same analysis is performed for the fiscal crisis scenario, where the population is assumed to grow only by a factor of 1.25 by 2010 and conservation reduces per capita demand so that total usage is comparable to 1980 usage, the projected demand is reduced accordingly (approximately 3,900 GWh). In this scenario, substantial excess capacity is projected.

Agglomerations of Small Industrial Facilities

One alternative to attracting a single enterprise that utilizes large quantities of electric power is to attract a group of small energy-intensive businesses to an industrial park. The industrial park setting has been widely adopted as a way to attract business development to a region and to provide planned commercial development. As a job creation mechanism, there are advantages to a strategy that attracts small

---

*With slightly different equilibrium share and penetration figures.

Table IX-35

ESTIMATE OF POTENTIAL ELECTRIC DEMAND FOR RAILBELT COMMERCIAL END USE
(10^9 Btu Unless Otherwise Noted)

	1979[1]	1990	2000	2010[2]
Forecast usage				
Electricity	2,544	3,998	6,618	10,060
Fluid fuels	6,702	10,155[3]	11,839[3]	17,800
Coal	825	na	na	na
Total	10,071	14,153[4]	18,457[3]	27,860[3]
Total after conservation		12,738	14,766	19,502
Energy demand if all electric	7,060	9,242	11,507	20,740
Fraction of demand electric	0.360	0.400	0.441	0.567
Electricity use				
Btu	2,544	3,697	5,075	11,759
GWh	746	1,084	1,487	3,447

[1]Actual.

[2]Extrapolated by SRI.

[3]Natural gas taken as 90% of petroleum.

[4]Without coal.

Source: Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

Table IX-36

POTENTIAL ELECTRICITY USE IN THE
RESIDENTIAL AND COMMERCIAL SECTORS COMPARED TO SUPPLY
(GWh)

	1990	2000	2010
Residential	1,474	3,209	6,955
Commercial	1,084	1,487	3,447
Total projected demand[1]	2,558	4,696	10,402
Projected demand[2]	2,440	3,100	3,921
Projected supply[3]	4,846	5,107	7,031
Projected supply[4]	5,578	9,473	12,383

[1] 4.2% annual growth.

[2] Fiscal crisis scenario.

[3] Battelle (4.2% annual growth in population).

[4] Arbitrary retention of all existing and projected fossil capacity operating at previous maximun yearly rate.

Source: Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

businesses rather than large process plants. Large capital-intensive process plants tend to require fewer workers than small businesses per dollar invested. Moreover, large businesses are less likely to expand further in a single location than smaller businesses, which have a better potential for growth. Finally, large plants based on a single commodity are vulnerable to worldwide market changes, whereas a diversified business base can more easily adjust to changing market realities.

There are negative aspects of an agglomeration strategy. Large process plants can be planned as independent entities with waste treatment facilities, fire protection, and other services designed to satisfy the needs of the plant. For planned industrial parks, these services are often provided by the surrounding community. It will be more difficult for Alaska to provide the support facilities for a group of small businesses in an economically timed development program since the first tenant will require full services and it might take 20 years to fill the development. The projected energy requirements for a typical industrial park are not large, and it is difficult to envision any strategy (short of extremely favorable industrial development bonds for financing) that would enable Alaska to compete effectively with the large number of regional industrial development programs and commercially developed industrial parks in a way that would fill a large number of industrial parks.

The successful development of industrial parks designed for energy-intensive small businesses might be feasible if other aspects of an Alaskan location are exploited in addition to the potential availability of inexpensive electrical power. Materials processing, especially of Alaskan minerals, is the most likely type of business activity to be attracted to an Alaskan industrial park setting. The secondary processing of scarce high-value minerals is usually feasible only on a small scale. One approach for an integrated processing park would be to target the processing of critical or strategic materials like cobalt, chromium, molybdemum, manganese, zinc, nickel, tin, and fluorspar, and this possibility has been briefly discussed under "Ferroalloy Production."

SRI has found no meaningful way to quantitatively assess the potential for the development of small business industrial parks based on inexpensive electrical energy. SRI could find no examples of such parks that have been attracted to existing regions by the availability of inexpensive hydroelectric power. Since electrically intensive potential candidates, large or small, are considered throughout Section IX, potential candidates for the agglomeration strategy have been considered during the study. Based on this screening process, the most likely candidates appear to be associated with electrometallurgical processing (SIC 3313) or the processing of inorganic chemicals (SIC 2819).

Electrification of the Alaskan Railroad

Electrification of the Alaskan Railroad might be an attractive alternative to continued use of diesel-electric locomotives if low-cost plentiful electrical power becomes available. Two questions must be answered to determine the viability of electrification of the Alaskan Railroad:

- What approximate quantity of electric power would be consumed each year?
- What annual savings in the cost of energy would be available to repay the capital cost of electrification plus a return on investment?

Facilities and Equipment

The Alaskan Railroad has 654 miles of mainline, branch, yard, and other track for which traction power must be supplied. At present, the railroad owns 65 diesel-electric locomotives, including 21 classed as switchers. Thirty-eight locomotives are in service, 9 are undergoing heavy repair, 13 are stored in serviceable condition, and 1 is leased.[35]

If electrification were undertaken, some tracks such as yards and some branch lines would not be converted. Also, the Portage-Seward mainline has very low traffic density and would probably not be converted. For present purposes we will assume that 450 miles of track would be considered for electrification. This includes 419 miles of single track mainline between Whittier and Fairbanks and unspecified branch lines.

Construction of overhead electric lines, substations, and power distribution lines account for most of the capital cost of electrification. Electric locomotives would have to be purchased, but in the long run electric and diesel-electric locomotive fleets have similar capital costs.

Operations

Traffic on the Alaskan Railroad has varied greatly from year to year. In FY 1980 the railroad carried 271 million revenue ton-miles. In FY 1981 the traffic increased to 407 million revenue ton-miles, mainly because of increases in shipments of sand and gravel.[36]

Electrification is usually regarded as an interesting possibility only on lines that carry many trains each day and have high traffic densities—e.g., 40 million gross tons per year. The mainlines of the Alaskan Railroad have a low rate of utilization (Reference 3). In summer there are only 14 freight and passenger trains per week, each way, between Anchorage and Fairbanks, and the most heavily traveled line—between Anchorage and Matanuska—carries a total of only 37 round-trip trains per week. Traffic densities for mainline links in FY 1981 were as follows:

	Million Gross Tons Per Year
Fairbanks - Menana	3.1
Menana - Healy	3.2
Healy - Matanuska	2.2
Matanuska - Anchorage	5.9
Anchorage - Portage	1.8
Portage - Whittier	1.0
Portage - Seward	0.3

Energy Requirements

The Alaskan Railroad consumed 3,060,000 gallons of diesel fuel in 1981. In April 1981, at about midpoint in FY 1981, the average price paid for diesel fuel by U.S. railroads was $1.04 per gallon.[37] If we assume that the Alaskan Railroad paid $1.04 per gallon throughout FY 1981, its fuel cost was about $3.2 million.

In Reference 38, SRI developed factors for diesel fuel and electric power which indicate that an electrified system would require about 10.4 kWh to do the work of 1 gallon of diesel fuel in a diesel-electric system. Thus, in FY 1981, 100% conversion of the Alaskan Railroad would have generated a demand for about 32 million kWh of electric power, Actual demand would be somewhat less because some track would not be converted. If electric power had been available for $0.01/kWh, the cost of electric power would have been less than $320,000, or about 1/10 the cost of diesel fuel.

The difference between the costs of diesel fuel and electric power is the principal economic advantage of electrification. According to the foregoing estimates, the potential saving from 100% conversion would be about $2.9 million per year for the volume of freight carried in 1981 and at the price of diesel fuel in 1981. Savings from conversion of 450 miles would be somewhat less, of course. In future years savings would be higher if more freight were carried or if the difference in the prices of electric power and diesel fuel were higher.

Economics of Electrification

SRI's assessment of railroad electrification[38] indicates that the average cost of electrifying single track mainline without automatic signaling equipment was about $100,000 per mile at 1974 price levels. Costs in Alaska would be higher, and inflationary factors from 1974 to the 1990s would further increase costs. If these two factors are included, it would cost, on average, approximately $250,000 per mile for 450 miles, for a total cost of $110 million for electrification. If it is further assumed that the investment should be recovered in 40 years at a return of 10% per year, annualized capital costs will be approximately $11.2 million per year. This amount compares unfavorably with the estimate of the potential savings from electrification, which are estimated at less than $2.9 million per year.

It seems unlikely that the conclusions of the analysis will be altered in the future by changing conditions. Savings in operating costs would increase if the cost of diesel fuel increased or if the volume of traffic increased. However, based on the rough estimates presented above, the annualized capital cost of electrification would barely be recovered if the average cost of diesel fuel increased to $4 per gallon (in 1980 dollars) or if the average volume of freight increased to 1.6 billion revenue ton-miles. Neither event is considered likely by SRI in the time frame of interest (i.e., 1990-2010). The price of electricity has little influence. The merits of electrification would not be changed greatly if the cost of electricity were $.02/kWh or if it were free.

Electric Intertie to the Lower 48

Exporting electric power from the proposed Alaska hydroelectric and/or tidal power plants to the Lower 48 is one option in utilizing the full production capacity of these plants. As shown in Figure IX-1, the overland route would run from Fairbanks or Anchorage to Everett, Washington, where it could tie into the Pacific Northwest power grid. Since the electric power systems of the Pacific Northwest are now interconnected with those of British Columbia, another option for consideration is to interconnect Alaskan, Canadian, and Pacific Northwest power sources and markets through exchange and load displacement. However, since additional transmission capacity through British Columbia and the Pacific Northwest would be required, the costs associated with an interconnection to British Columbia are expected to be comparable with the costs associated with a direct intertie to the Lower 48, if the ultimate destination of the power is the Lower 48.

Physical Factors

Routes considered for the intertie involve an impressive variety of terrain, geology, and climate settings. Most route locations lie in remote, sparsely settled areas.

A potential 1,810-mile route from Fairbanks to Everett, Washington, involves only two elevations greater than 3,000 ft.

Canadian portions of the route are map locations for study purposes only. Generally, use is made of protected mountain trenches and relatively low inland plateaus, thus avoiding the rugged, wet coastal mountains. Existing roads and railroads now use predominantly these terrain features.

Several studies have been made of road and rail routings through Northern British Columbia and the Yukon Territory.

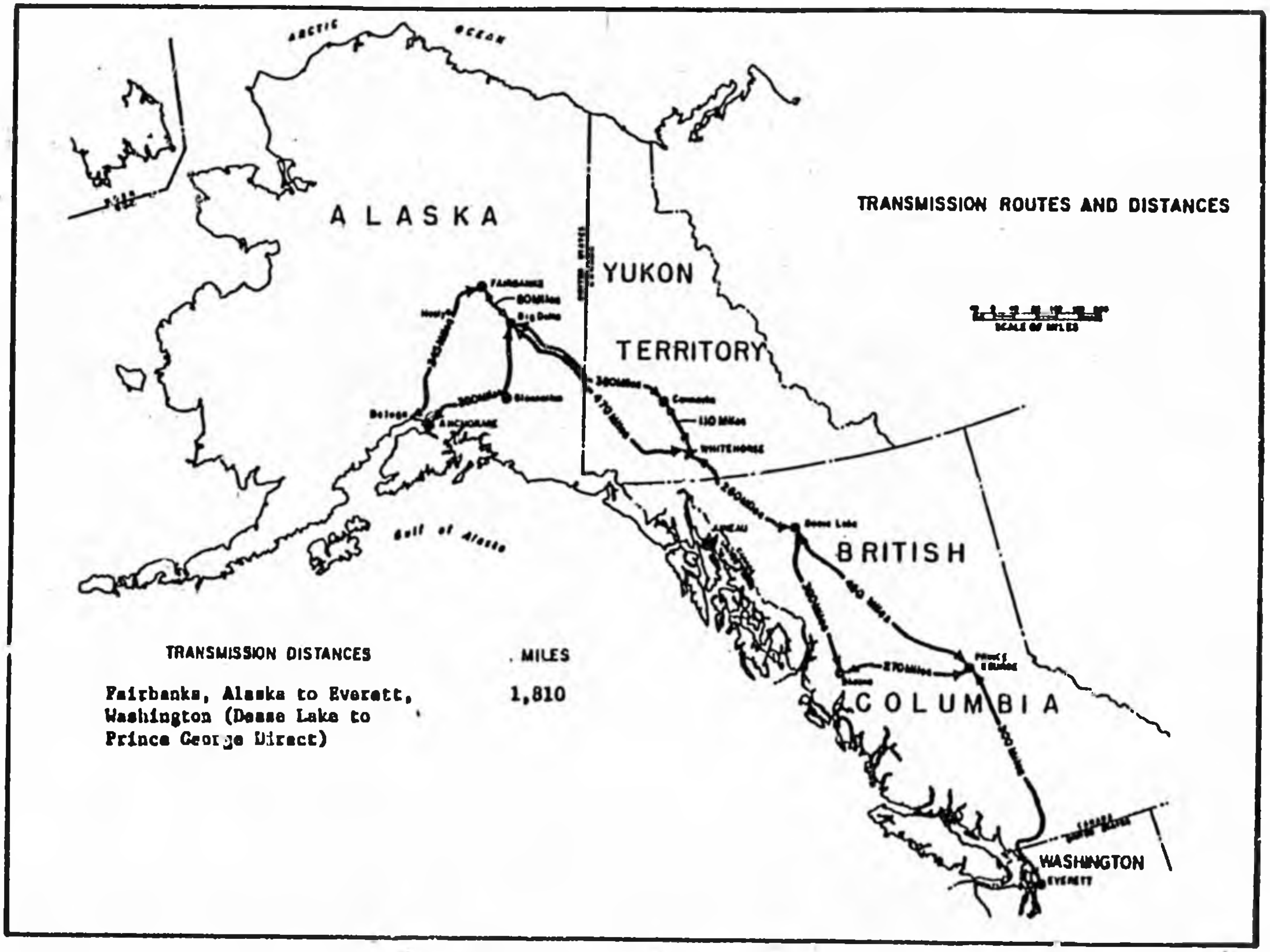


FIGURE IX-1 TRANSMISSION ROUTES AND DISTANCES

Existing 138-kV transmission systems near Fairbanks and Whitehorse, plus the extensive B.C. Hydro system extending as far North as the Peace River Project, provide an invaluable experience base. The Healy-Fairbanks 138-kV line experiences many of the environmental factors expected for the intertie, including exposure and operation in -70°F weather and tower foundations in fragile, discontinuous permafrost. From a design viewpoint, the southern portions of British Columbia may have the most difficult combination of terrain, snow, and icing problems encountered in the entire route.

Permafrost is known to exist as far south as the Yukon-British Columbia border and is a factor in foundation and access road design. Except for extremes of cold and duration of cold, the available climate data indicate few unusual design problems. Winds, snow, icing, and electrical storms all seem well within the range of climate conditions routinely handled in transmission systems in the Lower 48.

The route areas appear unusually free of earthquake dangers, considering the proximity to active areas of the Pacific Rim. Of the regions involved, the Puget Sound area has the most severe earthquake hazard.

Limited access presents problems for construction, operation, and maintenance. Routing generally along existing and developing transportation corridors should meet these concerns.

In summary, the available data support a tentative conclusion that no physical impediments exist which preclude construction of high voltage electric transmission lines along the routes considered. Careful attention to foundations and full use of existing knowledge of Arctic conditions appears to ensure physical feasibility.

A detailed study would involve careful consideration of the actual route selection, including soils and terrain, plus study of critical points such as the divides and mountain passes and full attention to the unique operation and maintenance situations in the Arctic.

Technology

Significant advances in high voltage transmission capabilities have been made in the last decade. Extensive alternating current transmission systems now exist at 500 kV, and some major Canadian and U.S. lines are operational at 735 and 765 kV.

Parallel advances in high voltage direct current (HVDC) technology include the 846-mile dc circuit of the Pacific Northwest-Southwest Intertie, which has a rated capacity of 1,440 MW. The Russian government has under study 1,500- and 1,800-mile lines at 750 kV dc for capacities up to 6,000 MW.

Existing and assured near-future transmission technology is adequate. This appears to be no technical barrier for the contemplated intertie.

Transmission towers would likely be of steel. Environmental effects of possible concern include esthetic impacts, direct effects of construction, increased activities in presently remote areas, and potential health effects of high voltage transmission lines. Interception of wildfowl by transmission lines has been experienced in some areas.

Transmission line clearing and weed control programs would be of possible concern. Differences would be expected in vegetation patterns and snow accumulation in cleared areas. Possible effects on wildlife, such as availability of feed, would need to be anticipated in location and clearing design.

It is assumed that any Canadian decisions on possible transmission routes in Canada would reflect full consideration of environmental effects. At this time, no environmental aspects of the transmission line preclude its development.

<u>International Aspects</u>

Transmission of the electric power would involve an international element in the feasibility of exporting Alaskan surplus power to the Lower 48. We assume appropriate arrangements with Canada can be reached if the U.S. and Canada determine there is a mutual interest. It should be noted, however, that B.C. Hydro is presently undertaking studies concerning exporting surplus electricity from British Columbia to potential markets in the Pacific Northwest and California. The interest by British Columbia in selling its own hydroelectric-generated power may place it in a competitive position with Alaska-generated electricity.

<u>Design and Cost Assumptions</u>

Adapting the Department of Interior North Slope Transmission Study Analysis,[39] the costs of an intertie with the Lower 48 were scaled according to the differences in transmission distances between the North Slope and the Railbelt (i.e., 2,249 miles vs. 1,310 miles). All estimates are based on routes and distances shown in Figure IX-1.

The analysis was based on Pacific Northwest construction costs, adjusted by a factor of 1.9 to reflect higher labor and transportation costs for Alaskan and northern Canadian construction. The transmission routes generally follow existing and planned roads and railroads, so no added costs were assumed for access roads or right-of-way. Costs were included for a service road suitable for 4-wheel-drive vehicles along those portions of the route where soil conditions permit. The service road would be used for construction and operation and maintenance.

For permafrost areas, such primitive service roads would be suitable only where soil conditions are ideal. For frost-susceptible soils and suspected high-ice-content permafrost, it is assumed that overland access for both construction and operation and maintenance would be limited to winter transport on frozen soils. Helicopters would be used extensively.

Tower foundations in permafrost areas require a departure from normal practice. Estimates for this study assume free-standing structural steel towers with foundations on timber grillage and gravel pads for permafrost areas, based on successful Canadian experience with this design.

Rough estimates of clearing costs were based on regional forest cover types and required width of rights-of-way. The costs do not include any allowance for right-of-way acquisition. System voltage and conductor configurations were selected by rule-of-thumb methods, and rough approximations were made of line capabilities, losses, and series compensations.

The estimates include substation (or terminal) costs to deliver power to regional transmission systems. The costs do not include subtransmission or distribution facilities within the regions. Unit transmission costs reflect assumptions of 50-year life for transmission lines and 20 years for terminals and substations, and an assumption of public financing. The estimated costs for transmission of electricity from the Railbelt region to the Lower 48 are expected to average $0.022/kWh in 1981 dollars (Table IX-37).

Under the proposed bulk transmission of electric power to the Pacific Northwest, the power must satisfy an unmet demand and be cost competitive in the potential market areas.

The increased cost of transmission to the Lower 48 compares unfavorably with current industrial market prices, which range from $0.01/kWh to $0.025/kWh in the Pacific Northwest. Although the price of subsidized Alaskan electricity transported to the Northwest ($0.035/kWh) might compare favorably with the projected prices of electricity in the Northwest and California in the 1990s, Alaska would have to assure power availability throughout the lifetime of the transmission line, and there seems to be little incentive for Alaska to subsidize power delivered to the Northwest.

Established HV and EHV transmisson grids in the Pacific Northwest interconnect the region's federal and investor utility generating plants and load centers. A recent report on potential markets in the Pacific Northwest and California for surplus electricity from British Columbia in the late 1980s concluded that:

Table IX-37

ESTIMATED COSTS FOR TRANSMISSION OF ELECTRICITY FROM RAILBELT TO LOWER 48 FOR 4,000 MW WITH 90% LOAD FACTOR AND 7% LOSSES (2.6×10^{10} kWh at market)

Construction cost (1981$)	$\$4.7 \times 10^9$
Interest during construction $\left(\frac{\text{cost} \times 10\% \times 4 \text{ yrs}}{2}\right)$	$\$0.9 \times 10^9$
Investment	$\$5.6 \times 10^9$
Annualized cost (10%)	$\$0.56 \times 10^9$
Operation and maintenance	$\$ .01 \times 10^9$
Total cost	$\$0.57 \times 10^9$
Energy cost for transmission	$0.022/kWh

Utility forecasts indicate that the Pacific Northwest states will have a net SURPLUS of electrical energy under most foreseeable circumstances through the mid-1990s.

...the Pacific Northwest is NOT a promising market for surplus British Columbia electricity, except under extremely infrequent (and certainly unpredictable) "critical" water conditions.*

In the 1990-2010 time frame, power from Alaska would be a supplement to the hydro-thermal program in lieu of nuclear installation near the Pacific Northwest load centers. There are many uncertainties as to probable future costs of new baseload electric energy in the Pacific Northwest. Increasing construction costs, siting questions, and a range of environmental considerations all point to higher cost of energy from future plants. Independent analyses by SRI of the supply and demand in the Pacific Northwest confirm that supplies should be adequate in this region through the 1990s. There is some potential to market Alaskan electricity in California if it can be made available below prevailing industrial rates.

The export to the Pacific Northwest of power generated with the proposed hydroelectric or tidal facilities through a direct bulk power delivery system is fully feasible from a physical and engineering standpoint. However, it is unlikely at this time to have sufficiently favorable financial feasibility to merit priority consideration in the use of surplus hydroelectric power. More detailed investigations of transmission systems to deliver energy generated by hydroelectric or tidal power in the 1982-1995 time frame do not seem merited. Potential delivery to California markets on a regular basis through the Pacific Northwest grid may be feasible beyond 1995.

---

*A. R. Tussing, S. A. van Vactor, C. C. Barlow, "Potential Markets in the Pacific Northwest and California for Surplus Electricity from British Columbia." ARTA, Inc., Seattle, Washington, November 1981.

X CONCLUSIONS

SRI has evaluated the potential of low-cost power in the Railbelt region to attract energy-intensive industries. Of the nine potential candidate industries and four additional application areas considered, only residential space heating and processing of certain primary metals are likely to take advantage of the low-cost power in the Railbelt region. Expanded space heating usage has the best potential to utilize any excess power produced in the Railbelt. Investment in an aluminum plant appears to be likely only if the construction costs of the hydroelectric projects are subsidized by the state, and then it is questionable that there will be sufficient excess power available to serve a single "world-class" plant. Although the tidal project might provide sufficient power, the power from this project will not be low cost. Other metal processing plants are likely to be considered only if feedstocks are found in Alaska. The construction of an intertie with the Lower 48 does not appear to be cost-effective without state grants to finance the power projects, but there is no rationale for Alaska to subsidize power delivered to other states.

SRI's findings are predicated on 10% interest rates, continued high Alaskan labor costs, and little real increase in petroleum prices during the next 25 years.

The major findings of the study are:

- The cost of power from the Susitna project will not be competitive without a very substantial state subsidy, in the form of either grants or subsidized interest rate (until the capital cost obligation is paid off in 2010).
- The Cook Inlet project will not produce power at competitive rates because of the intermittent nature of tidal power.
- There is not likely to be excess power available from Susitna alone unless the Alaskan economy stagnates or declines.
- There is unlikely to be sufficient excess power to serve a single world-class aluminum plant.
- Other than aluminum, electrically intensive industries are unlikely to derive sufficient cost savings from subsidized power to consider an Alaskan site on the basis of low-cost electricity alone.

- The availability of low-cost power might improve the economics of processing materials, provided the major feedstocks are native to Alaska.

- Without a tiered rate structure to discourage use for residential space heating, subsidized power is likely to increase electric space heating use sufficiently to absorb any excess power from the Susitna project.

- The relatively high state corporate income tax is a barrier to industrial development in the state.

- Although the SRI study is predicated on stable energy prices through 2002, the findings of the study are not greatly affected by an increase in fuel prices of 50%, since transportation costs will escalate commensurately.

REFERENCES

1. State Government Tax Collections in 1980, U.S. Department of Commerce, Bureau of Census, 1981.

2. 1981 State Tax Handbook, Commerce Clearing House, Inc.

3. University of Alaska, "Prices and Incomes--Alaska and the U.S., 1967-1980," Alaska Review of Social and Economic Conditions, Vol. XVIII, No. 2, June 1981.

4. Stewart R. Spector, "Price and Availability of Energy in the Aluminum Industry," Journal of Metals, June 1981, p. 139.

5. Transnational Corporations in the Bauxite/Aluminum Industry, United Nations, 1981, p. 19.

6. Ibid., p. 28.

7. Spector, p. 138.

8. Chemical Marketing Reporter, August 23, 1982, pp. 7, 27.

9. Transnational Corporations in the Bauxite/Aluminum Industry, p. 27.

10. Ibid., pp. 4-27.

11. Sterling Brubaker, Trends in the World Aluminum Industry, Johns Hopkins Press, 1967, pp. 155-162.

12. Ibid.

13. Average U.S. price of aluminum ingot in 1980 = 71.6¢/lb
= $1,575 $/metric ton

Average shipping cost for alumina = $16/ton

2 tons alumina/ton aluminum = $16 x 2 = $32/ton input shipping charge

Export shipping of ingot = 4.5 x $16 = $72/ton

Total average shipping charge per ton aluminum = $72 + $32
= $104

Fraction of value attributable to shipping = $104/ton shipping
÷ $1,575/tons value
= 6.6%

14. "Alumax on Stream at Mt. Holly, South Carolina," Engineering and Mining Journal, December 1980, pp. 84-85.

15. "Typical Electric Bills," January 1, 1981, U.S. Department of Energy, Energy Information Agency, 1982.

16. Variations in operating rates are due to data including Cl_2 producers not producing NaOH, as well as varying rates of recovery and finishing of NaOH.

17. Current Industrial Reports, U.S. Department of Commerce.

18. Chemical Week, April 15, 1981.

19. Chemical Marketing Reporter, August 1982.

20. Chemical Week, June 10, 1981.

21. Chemical Marketing Reporter, March 16, 1981.

22. Telephone interview of personnel of Liquid Air Corporation, San Francisco.

23. 1979 Annual Survey of Manufacturers.

24. Business Week, September 13, 1982.

25. Conversation with personnel from American Paper Institute.

26. Standard & Poor's Industry Surveys.

27. Ibid.

28. Mineral Commodity Summaries 1982, U.S. Department of Interior, Bureau of Mines.

29. U.S. Minerals Yearbook.

30. Ibid.

31. Conversations with cement producers in Seattle.

32. "The Changing Sulfuric Acid Industry," Chemical Week, February 10, 1982, pp. 40-43.

33. Mineral Commodity Summaries, 1982, U.S. Department of Interior, Bureau of Mines.

34. Ibid.

35. The Alaska Railroad, FY 1981 Annual Report.

36. Ibid.

37. Association of American Railroads, Yearbook of Railroad Facts, 1981.

38. SRI International, Railroad Electrification in America's Future: An Assessment of Prospects and Impacts, 1979.

39. "North Slope Transmission Study," U.S. Department of Interior, Alaska Power Administration, July 1972, Update March 15, 1982.

SUSITNA HYDROELECTRIC PROJECT

SUMMARY REPORT

MARCH, 1982

DRAFT

ACRES

ALASKA POWER AUTHORITY

TABLE OF CONTENTS

FRONTISPIECE — WATANA DAMSITE

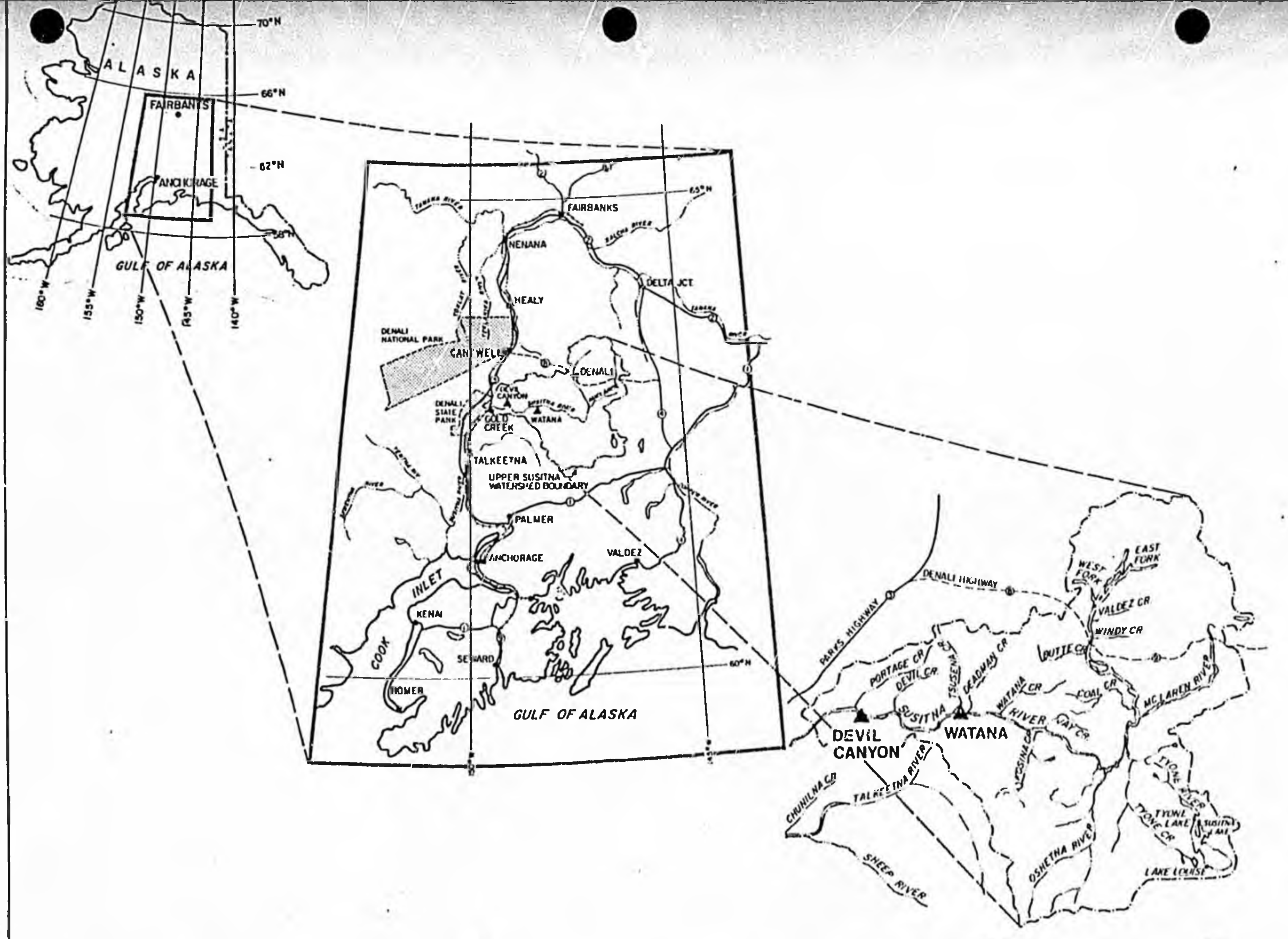


PLATE 1 LOCATION PLAN

INTRODUCTION

1

The Susitna River, with a drainage area of more than 19,000 square miles, is the sixth largest in Alaska. (See Plate 1.) Rising in the glacier-topped mountains of the Alaska Range about 90 miles south of Fairbanks, the river meanders across a broad alluvial fan for about 50 miles in a southerly direction before it turns westward and begins a 75-mile plunge between essentially continuous canyon walls. Turning once again to the south, it flows for another 125 miles before discharging into the upper reaches of Cook Inlet west of Anchorage. An important and productive fishery resource, the Susitna also contributes to the support of significant wildlife populations in the virtually untouched and relatively inaccessible lands across which it flows.

Contained entirely within the southcentral Railbelt region, the Susitna basin is strategically situated between the two largest Alaskan population centers of Anchorage and Fairbanks.

The extensive hydroelectric potential of the Susitna River first came to public attention in 1948 when the Bureau of Reclamation issued a report of its initial investigations there. Since that time, various development schemes have been advanced by public agencies and private organizations. A common thread in the many earlier reports is a virtually unanimous agreement that some project should proceed.

Acres American Incorporated was commissioned by the Alaska Power Authority, in December 1979, to conduct a detailed feasibility study in order to determine technical feasibility, economic viability, and environmental impacts of an optimal development in the basin. A rigorous program of field investigations, alternative plan evaluations, design studies, environmental studies, and economic analyses led to the production of a final draft feasibility report issued for public comment in March 1982. This document provides a summary of the detailed report.

Throughout the study period, an agressive public participation program was conducted by the Alaska Power Authority. Comments from interested organizations and individuals have greatly influenced the work. In addition, coordination with federal and state resource agencies has resulted in the selection of design criteria, project features, and operation plans which appear to offer balanced solutions to sometimes conflicting objectives.

A separate and independent study of alternatives to the Susitna project has been prepared by Battelle Pacific Northwest Laboratories under the terms of an agreement with the Office of the Governor, State of Alaska. Both the Battelle Report and the detailed feasibility study are available for public review at libraries throughout the Railbelt.

THE EXTENSIVE HYDROELECTRIC POTENTIAL OF THE SUSITNA RIVER FIRST CAME TO PUBLIC ATTENTION IN 1948...

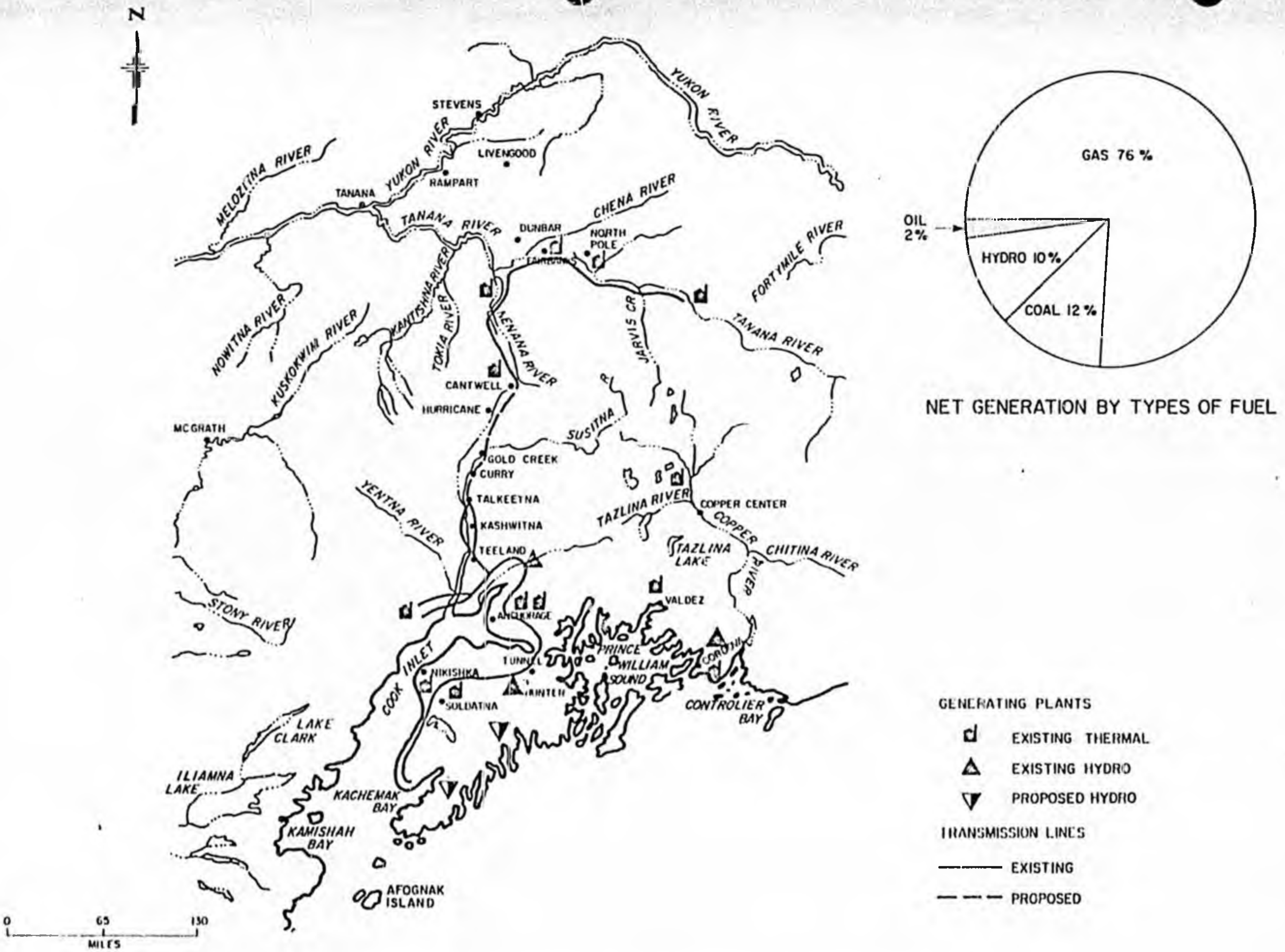


PLATE 2 GENERATING AND TRANSMISSION FACILITIES

Current Generation System

About 90 percent of the current total net generation of electricity in the Railbelt depends upon the use of fossil fuels. Anchorage and other communities in the south now enjoy relatively low-cost energy because of their proximity to Cook Inlet gas fields and to existing small hydroelectric plants. In the north, the Fairbanks-Tanana Valley area depends primarily upon coal (which is mined near Healy) and a small amount of oil. Plate 2 provides a breakdown of generation by fuel types.

At the present time, the northern and southern load centers are not interconnected. Thus, generating systems have evolved independently over the years in these two areas. The total installed capacity in the Railbelt, exclusive of military generation, is nearly 1000 MW.

Five electric utility companies serve the Anchorage-Cook Inlet area. The two largest, Achorage Municipal Light and Power and Chugach Electric Association, operate the bulk of the generating resources. Alaska Power Administration, a federal agency, operates the 30-MW Eklutna hydroelectric plant, marketing wholesale power to several of the utility companies. Aside from the Eklutna plant, most generating resources in the south are concentrated around urban areas or near Beluga, west of Anchorage, where natural gas is piped from various wells. Transmission interconnections between utility systems generally exist in the Anchorage-Cook Inlet area.

The Fairbanks-Tanana Valley area is served by two utility companies: Golden Valley Electric Association and Fairbanks Municipal Utilities System. A coal-fired plant operated near the mine mouth at Healy supplies energy to communities to the north through a 138-kV transmission line.

Military bases in the Railbelt independently operate generating units, as does the University of Alaska at Fairbanks. The Glennallen-Valdez area, east of Anchorage, is served by the Copper Valley Electric Association.

Scheduled Additions

An intertie permitting transfer of up to 70 MW of power between Anchorage and Fairbanks is currently planned by the Alaska Power Authority. It will provide an opportunity for economic interchange of energy and will permit sharing reserve capacity. Provisions have been made for integrating the intertie into a future larger transmission system in the event that the Susitna project or other regional-scale facility is constructed.

THE TOTAL INSTALLED CAPACITY IN THE RAILBELT, EXCLUSIVE OF MILITARY GENERATION, IS NEARLY 1000 MW.

Five new generating units are currently planned in the Railbelt. Two hydroelectric plants will provide about 97 MW with perhaps another 45 MW of spinning reserve. The larger of these is the Bradley Lake Project east of Homer, now being considered at alternative capacities of either 90 MW or 135 MW. Grant Lake would add a further 7 MW. One gas-fired combined-cycle unit and two gas turbines will add another 160 MW. When scheduled retirements and new additions are accounted for, the total system capacity in the early 1990s is expected to be about 1200 MW.

Historical Trends

Between 1940 and 1978, electricity sales in the Railbelt grew at an average annual rate of 15.2 percent - roughly twice that of the nation as a whole. Plate 3 illustrates the historical growth in electric energy demand between 1965 and 1980. Although the rate of demand increase in the Railbelt has consistently exceeded the national average, the gap has narrowed in recent years as the Alaskan economy has matured. Past high growth rates can be attributed both to rapid population increases and to installation of electric service in households which had not previously been served.

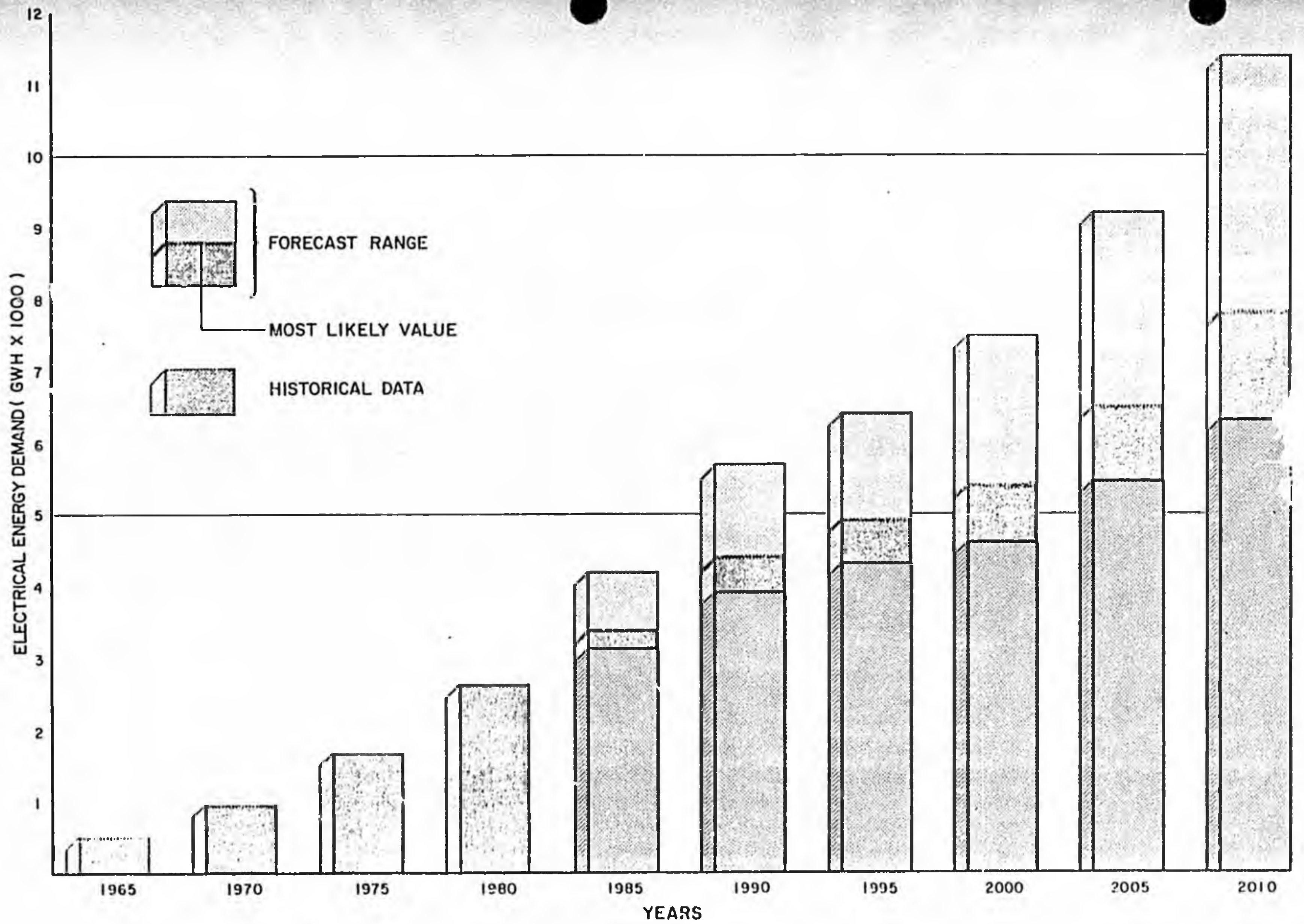


PLATE 3 RAILBELT ENERGY DEMANDS

Currently, about 47 percent of utility sales are to residential customers, 1 percent for miscellaneous use (e.g. street lighting), and the remaining 52 percent to the commercial-industrial-government sector. This split has been relatively constant during the past decade.

Forecasts of Future Demand

A great deal of uncertainty is necessarily associated with the preparation of demand and load forecasts. Population growth, industrial activity, government expenditures, energy prices, conservation measures and a variety of other factors will affect — and are frequently affected by — future demand. To ensure objectivity, a range of load forecasts was independently derived. Initial work accomplished by the Institute for Social and Economic Research, University of Alaska, was subsequently updated by Battelle Pacific Northwest Laboratories (Battelle). Plate 3 illustrates the December 1981 Battelle forecasts used in the final evaluation of Susitna project viability. Between 1981 and 2010, the mid-range forecast suggests that electrical and energy demand will grow at an annual rate of about 3.5 percent, with the high and low range limits at about 4.6 percent and 2.8 percent, respectively. The mid-range value was selected as the base case for planning future generation needs in the Railbelt. Sensitivity tests were conducted for the high and low cases (see Section 10).

All forecasts include substantial electricity conservation due to the cost of power. In the low case, industrial developments such as mining Beluga coal, U.S. Borax mining, a petrochemical plant, and a Valdez refinery are assumed not to occur. These developments do appear in the high case, but no additional major capital projects for which planning has not yet commenced are assumed. In each case, demand was sensitive to energy costs. Thus, more energy demand is assumed to occur for the least cost alternative than for higher cost alternatives.

Military bases and self-supplied industries are assumed to continue to generate electricity for their own needs and they are not included in the demand forecast.

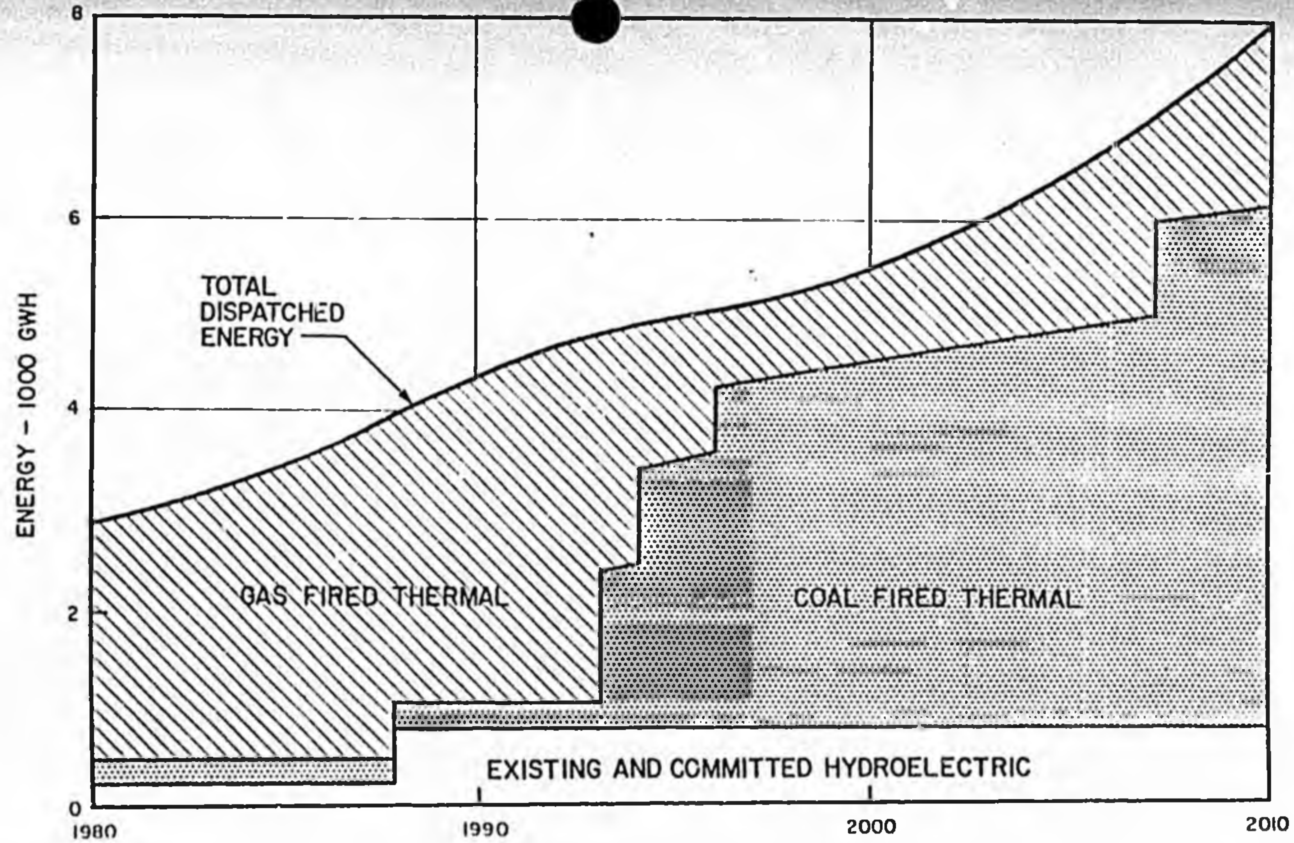
Electric space heating which now warms about 21 percent of the households in Anchorage and 9 percent in Fairbanks is assumed to change in relation to price differences between electricity and alternative heating fuels. Growth in population and tourism varies from case to case. Battelle indicated that the chances of realizing lesser and greater demand than the mid-range forecast are equal.

Requirements for Additional Capacity[1]

Under the mid-range forecast, currently scheduled additions are sufficient until 1993 to meet rising demand as well as to replace aging units which must be retired. Between 1993 and 2010, about 1400 megawatts of capacity must be added to the system to meet additional demand as well as to replace aging units.

. . . THE MID-RANGE FORECAST SUGGESTS THAT ELECTRICAL ENERGY DEMAND WILL GROW AT AN ANNUAL RATE OF ABOUT 3.5 PERCENT.

If required system expansion occurs by continued use of the thermal generating plants, a shift toward increased use of coal will be necessary not only because the Cook Inlet gas reserves may be insufficient to sustain long-term reliance upon natural gas in the face of increased demand but also because sharp increases in gas prices will occur in the next decade as old supply contracts expire. The installation of thermal (coal- or gas-fired) plants to meet the demand would offer the consumer no protection against rising costs, since fuel prices will continue to be exposed to inflation and to extraordinary escalation occasioned by world market conditions. Thus, it is appropriate to consider what other options may exist, as well as to ponder important implications and risks which might be associated with them.



VALUES OF SELECTED PARAMETERS

	200 MW COAL - FIRED PLANT (BELUGA)	70 MW GAS-FIRED COMBUSTION TURBINE
FUEL PRICE (1982 $/MMBTU)	$1.43	$3.00
ANNUAL FUEL PRICE ESCALATION:		
1982-2000	2.6%	2.5%
2000-2010	1.2%	2.0%
CAPITAL COSTS (1982 $/KW)	$2,242	$636
ANNUAL CAPITAL COST ESCALATION	1.8%	1.8%
INFLATION RATE	0%	0%
DISCOUNT RATE	3%	3%
ANNUAL OPERATING AND MAINTENANCE COSTS		
FIXED (1982 $/KW)	$16.83	$2.70
VARIABLE (1982 MILLS/KWH)	0.60	4.84
ASSUMED USEFUL LIFE (YEARS)	30	30

PLATE 4 | BASE CASE INSTALLATION SEQUENCE

OPTIONS

In Battelle's preparation of load and demand forecasts, consideration was given to the extent to which reasonable and extreme conservation measures might be taken to minimize growth in electricity consumption. Indeed, conservation assumptions contributed in part to the earlier noted major decrease in growth rate from historical trends to alternative future expectations. It follows that the post-1993 demand must be met by physically installing additional generating units. An additional consideration, regardless of load growth, is the possible value of substituting new generation modes for existing fossil fuel-fired facilities subject to significant cost increases.

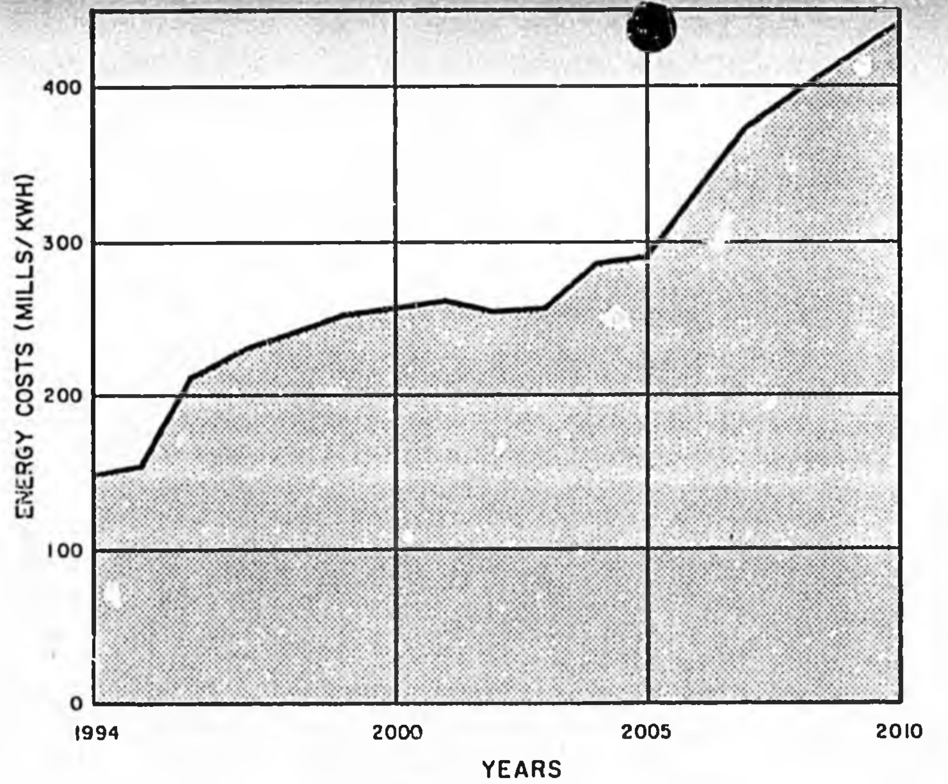
While it was not the purpose of the Susitna feasibility study to define the preferred alternative to Susitna development, it is nonetheless true that a reasonable "without Susitna" plan had to be developed as the basis for determining the nature, phasing, and economic viability of the apparent optimum Susitna project.

A computerized generation planning model, Optimized Generation Planning (OGP), is commonly used in the utility industry to assist in making decisions about future system expansion. This tool was employed to develop an apparent least-cost non-Susitna thermal generation plan. Given a list of possible additions — each with associated capacity, capital costs, fuel requirements and costs, operating and maintenance costs, reliability and availability data — the model selects appropriate additions on an annual basis throughout the planning period. Plate 4 illustrates the installation sequence developed for the "all thermal" non-Susitna plan, together with a tabulation of selected additions and key cost parameters. It is this plan which provides a base case for comparing alternative Susitna developments and for evaluating net benefits.

Although different methodologies and planning models were employed, the base case thermal plan shown on Plate 4 is similar to that produced by Battelle as Plan 1A in the independent alternatives study.

Certain non-Susitna hydroelectric options are available in the Railbelt. Of these, the most attractive from an economic standpoint would appear to be the Chakachamna project, located about 80 miles west of Anchorage. Chakachamna does not appear in the base case plan primarily because it may have a substantial fishery impact and because studies to date have been insufficient to determine expected capital costs with precision. Even so, as will be seen in Section 10, sensitivity analyses were conducted to determine the extent to which Chakachamna development would change net project benefits.

... THE BASE CASE THERMAL PLAN ... IS SIMILAR TO THAT PRODUCED BY BATTELLE ...



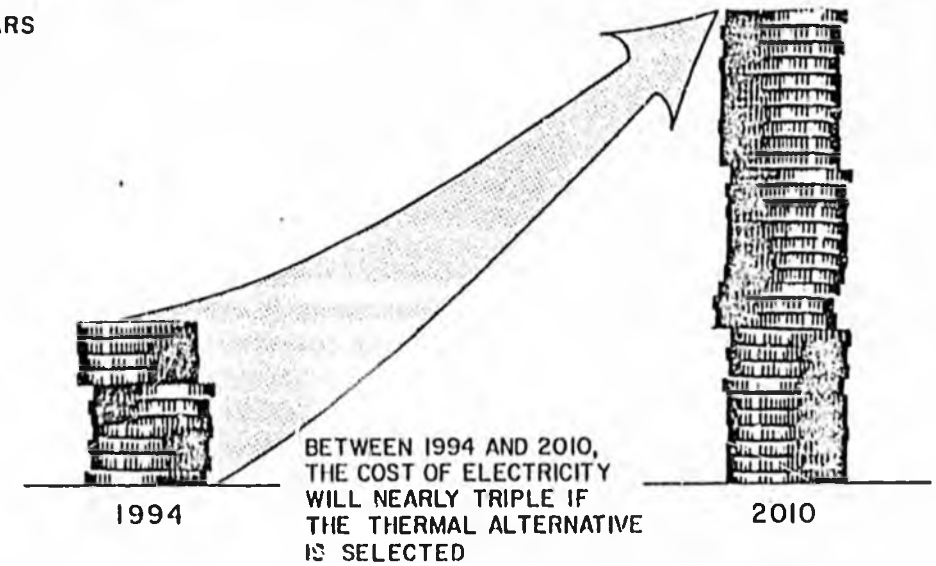


PLATE 5 | **ANNUAL COSTS - BASE CASE**

Future Electric Energy Costs

If the base case plan is implemented, certain relatively dramatic changes in Railbelt energy costs will occur during the study period, as shown on Plate 5. In part, the expected electricity price rise can be ascribed to the insidious effects of inflation, assumed to average about 7 percent per annum through 2010. In part, the compounding effects of continuing fuel cost escalation over and above inflation will be translated into higher electricity bills. But other influences come into play as well, and they represent important considerations.

Not shown on Plate 5, but nonetheless significant to the consumer, particularly in Anchorage, is the fact that between 1982 and 1993, many of the long-term contracts now held by utility companies for very favorably priced Cook Inlet gas will expire. Not only will major increases in electric energy costs result from the requirement by local utility companies to purchase gas at market prices, but also known Cook Inlet gas reserves may have been depleted in the early 1990's to the point that reliance upon natural gas as the principal fuel for electric energy generation would no longer be possible. The availability during the study period of North Slope gas near Fairbanks remains uncertain. Even if the gas pipeline is built, however, the gas price is projected to be higher than that for the Cook Inlet resource. For these reasons, use of North Slope gas for electric energy generation is not considered a viable alternative.

The base case plan calls for the addition of two 200-MW coal-fired steam plants at Beluga in 1993-94. Coal mining is assumed to occur at Beluga and an export market for Beluga coal is assumed to exist. To recover the investment in these plants and to account for anticipated major increases in gas costs, as well as inflation and fuel price escalation above the underlying inflation rate, the wholesale price per kWh for electricity will have risen by 1994 to 145 mills (14.5¢) per kWh and will continue to rise thereafter. It is this price trend against which any proposed hydroelectric development on the Susitna River must compete.

If the mid-range forecast is realized, another 200-MW coal-fired plant will be required, probably near Nenana, in 1996 — accounting for the sharp increase between 1995 and 1996 shown on Plate 5. By 2007, a 200-MW coal-fired plant must be added, probably at Beluga. In the meantime, a number of gas turbines must be installed to maintain system peaking capability, to satisfy reserve requirements, and to replace similar units which will have reached the end of their useful operating life. Existing and planned hydroelectric plants are included in the base case plan and no hydroelectric units are assumed to retire during the study period. If the Bradley Lake Project is not constructed, costs for the non-Susitna plan will be greater than those shown on Plate 5.

An important assumption in the development of the base case plan has been that coal mining operations in the Beluga fields will have been conducted on a commercial scale within the next decade. Even with the assumed transition from gas to coal as the principal fuel for Railbelt electricity generation, coal demand within Alaska will have to be supplemented by substantial coal export requirements before opening the Beluga fields becomes an economically wise decision. Thus, there is some risk associated with reliance upon the Beluga coal scenario. The energy prices reflected on Plate 5 would rise dramatically if Healy fields were to represent the only reasonable coal source or if the only market for Beluga coal were to be for electric energy generation in Alaska.

AN IMPORTANT ASSUMPTION . . . HAS BEEN THAT OPERATIONS IN THE BELUGA FIELDS WILL START WITHIN THE NEXT DECADE.

It may be anticipated that, if primary dependence is placed upon fossil fuels for energy generation, electricity costs will rise after 2010 at a rate similar to that reflected in the last five years shown on Plate 5. As will be seen in Section 11 of this report, development of the upper Susitna basin could result in suppression of long-term growth in energy prices and a true saving to consumers. Even so, important potential risks and environmental impacts must be pondered.

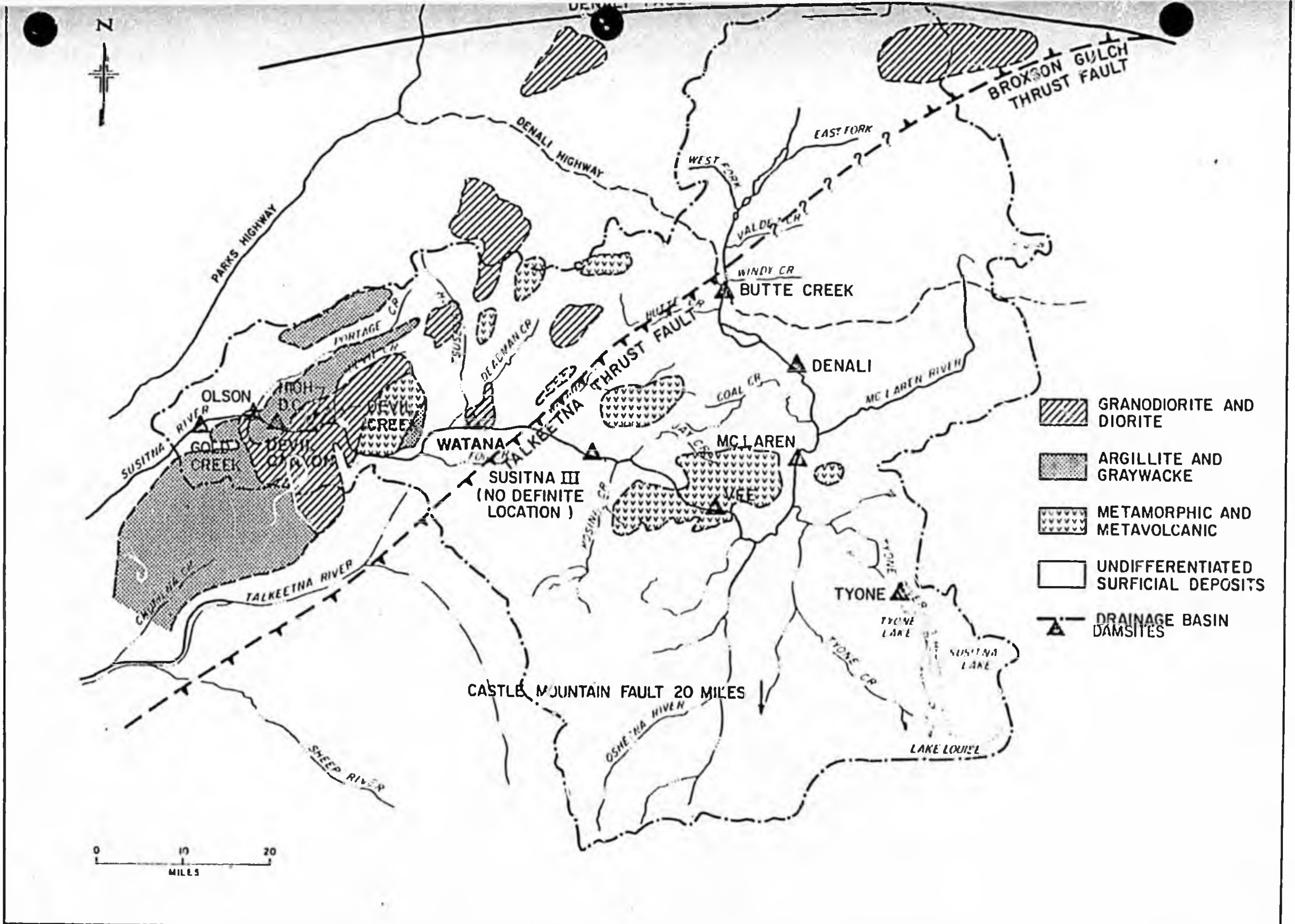


PLATE 6 **UPPER SUSITNA BASIN**

Basin Characteristics

The Susitna River exhibits two distinct seasons of flow. Between May and October, snow and glacial melt, together with heavy rainfall, contribute about 90 percent of the annual total flow. Modest winter flows occur in the mainstem, and many smaller tributaries freeze solid in the coldest months. Less than 20 percent of the total Susitna discharge into Cook Inlet is contributed by the Susitna river above Devil Canyon. As the river turns in a southerly direction after leaving the steep narrow canyons of its westerly leg, major tributaries, including the Chulitna, Talkeetna and Yentna Rivers, contribute to the bulk of the total discharge which ultimately reaches the mouth.

Occasional high flows in the Susitna contribute to the formation of productive habitat both for fisheries and for wildlife as land is alternately inundated and exposed and as sedimentation and debris is picked up and redeposited. However, Portage Creek, just west of Devil Canyon (see Plate 6), is the furthest point to which salmon migrate. Raging torrents in the canyons beyond Portage Creek present a natural barrier to further upstream movement. Floods with return periods of 50 to 10,000 years range from 48,000 cfs to 200,000 cfs at Devil Canyon. The probable maximum flood (expected never to occur) is 366,000 cfs at Devil Canyon.

The upper Susitna basin has a complex geology, as will be seen on the overlay for Plate 6. A history of at least three periods of major tectonic deformation contributes to this complexity. Volcanic flows and limestones, formed 250 to 300 million years ago, are overlain by sandstones and shale. A tectonic event dated approximately 150 million years ago resulted in the intrusion of large diorite and granite plutons. Marine deposition of silts and clays followed. Faulting and folding of the Talkeetna Mountains area in the late-Cretaceous period (65 to 100 million years ago) resulted in the formation of argillites and phyllites near Devil Canyon. The diorite pluton that forms the bedrock of the Watana site was intruded into sediments and volcanics about 65 million years ago. Andesite and basalt flows nearby were intruded after this plutonic intrusion.

A third regional uplift about 20 to 40 million years ago raised portions of the basin as much as 3000 feet. Since then, erosion, glaciation, and active downcutting of streams and rivers have combined to form the current topography.

The upper basin lies in a highly seismic region. Historical earthquakes within 200 miles of the upper Susitna River have generally originated from deep within the earth (the Benioff Zone) and from the crustal seismic zone. Major faults include the Denali fault system and the Castle Mountain fault. The Denali fault lies 30 to 40 miles north of potential dam sites and it is capable of causing earthquake magnitudes of 8.0 on the Richter scale. The Castle Mountain fault is 60 to 70 miles to the south and could cause earthquakes of magnitude 7.5. The most dominant earthquake source, however, is the Benioff Zone, which itself contains two distinct segments separated by a transition zone of low seismic activity. The shallower portion could produce earthquakes of 8.5 magnitude within about 57 miles of Devil Canyon and 40 miles of Watana. The deeper segment could generate 7.5 magnitude about 19 miles closer to Devil Canyon. The absence of faults with recent displacement in the vicinity of the sites sets an upper limit on the magnitude of an event that could have occurred in the crustal zone without detection. However, a remotely possible "terrain" earthquake occurring with a magnitude of 6.25 less than 6 miles from the sites must also be considered.

It follows that if hydroelectric development does proceed in the basin, proposed projects must be sufficiently robust to withstand occasional high floods and major earthquakes. At the same time, impacts on important downstream fishery resources and on wildlife populations in general must be minimized.

THE UPPER BASIN LIES IN A HIGHLY SEISMIC REGION.

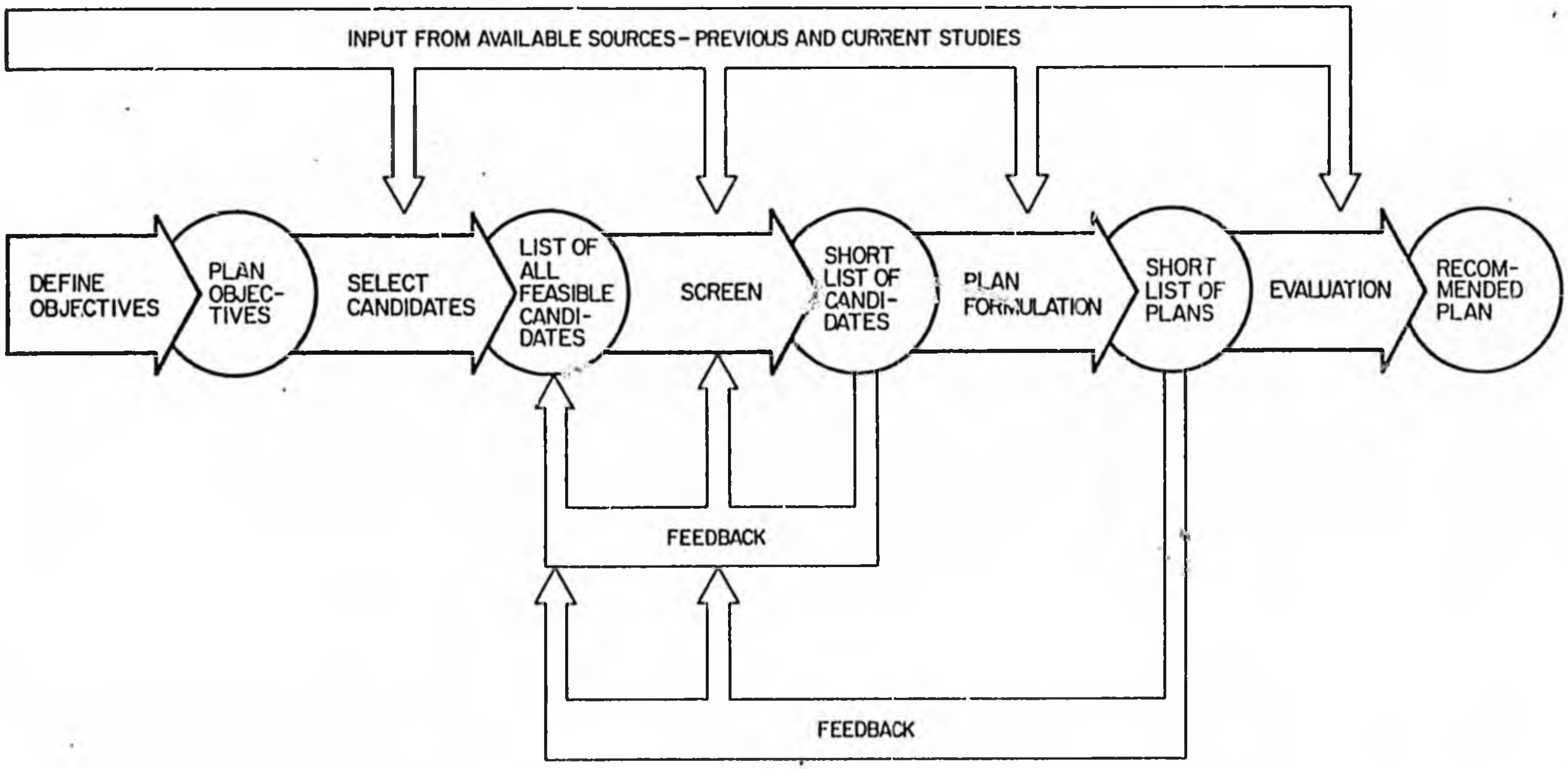


PLATE 7 | **DEVELOPMENT SELECTION PROCESS**

Plan Formulation

A generalized plan formulation and selection process was developed to guide the various planning studies. Plate 7 illustrates the procedure. Of the numerous planning decisions made, perhaps the most important were the selection of the preferred Susitna basin development plan and appropriate routes for access and transmission lines. In broad terms, a large number of possible choices was subjected to successively tighter criteria screens until a preferred plan was defined.

The steep narrow canyons in the upper basin offer an unusually large number of possible dam sites. They offer opportunities as well for considering a range of alternative developments at any single site. Plate 6 locates the many sites which were reviewed in the development selection process.

After detailed screening to account for important technical, economic, and environmental criteria, three general plans emerged as being appropriate for more detailed evaluation: (1) the Watana and Devil Canyon sites, (2) High Devil Canyon and Vee sites, and (3) a combination of a dam at Watana, a relatively low regulation dam midway between Watana and Devil Canyon, and a tunnel from the low dam to a downstream portal near Devil Canyon.

A technically sound preliminary design was produced for each plan, and preliminary cost and energy production estimates were prepared. The OGP model was run to evaluate economic viability as well as to determine optimum dates upon which the various stages of alternative Susitna developments should be operable. Quantitative and qualitative environmental and social data were compiled and comparisons were made. Sensitivity tests were conducted to determine the extent to which differences between expectations and the potential extreme values of certain key parameters affected each plan.

The Watana-Devil Canyon plan was found to be clearly superior to development of the High Devil Canyon and Vee sites on economic, energy contribution, and environmental grounds; and it was found marginally better in terms of social criteria. Both plans are technically feasible.

The Watana development is common to both remaining plans. When compared to the tunnel alternative, the Devil Canyon dam was found to be significantly better in terms of economic and energy contribution criteria, and marginally favored for social criteria. The tunnel scheme was moderately favored environmentally. While both plans appear to be technically feasible, however, a greater degree of technical uncertainty was associated with the tunnel plan. A clear economic advantage of the Devil Canyon dam was judged to outweigh the reduced environmental impact associated with the tunnel scheme.

Thus, the selected arrangement involves construction of dams at the Watana and Devil Canyon sites. It lends itself well to staged development since the second dam can be deferred or accelerated as a function of actual future growth in Railbelt energy demand.

. . . THE SELECTED ARRANGEMENT INVOLVES CONSTRUCTION OF DAMS AT THE WATANA AND DEVIL CANYON SITES.

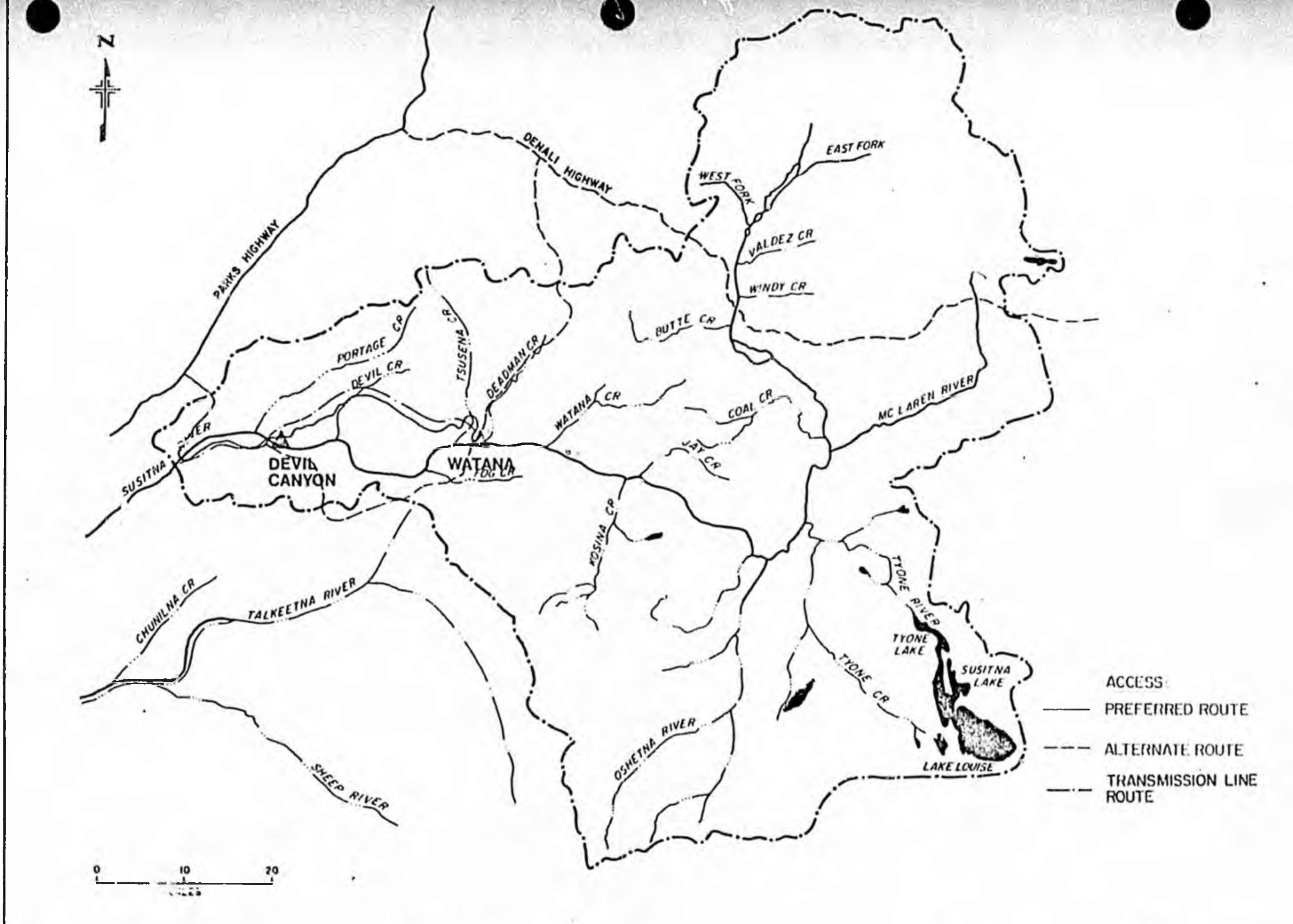


PLATE 8 **ACCESS ROUTES**

Access Route Selection

The generalized plan formulation and selection process illustrated on Plate 7 was also applied to the selection of important access and transmission line routes. Plate 8 displays various candidate choices considered in the upper basin.

Three main access corridors emerged after initial screening. Each was assessed by conducting environmental and engineering studies, reviewing aerial photography, and preparing geologic maps. Important objectives included allowing construction to proceed on schedule, minimizing construction and logistics costs, facilitating operation and maintenance, minimizing adverse biological impacts, accommodating preferences of local communities and Native landowners, and accounting for the concerns of interested resource agencies.

A total of eleven different plans was produced from the three main corridors.

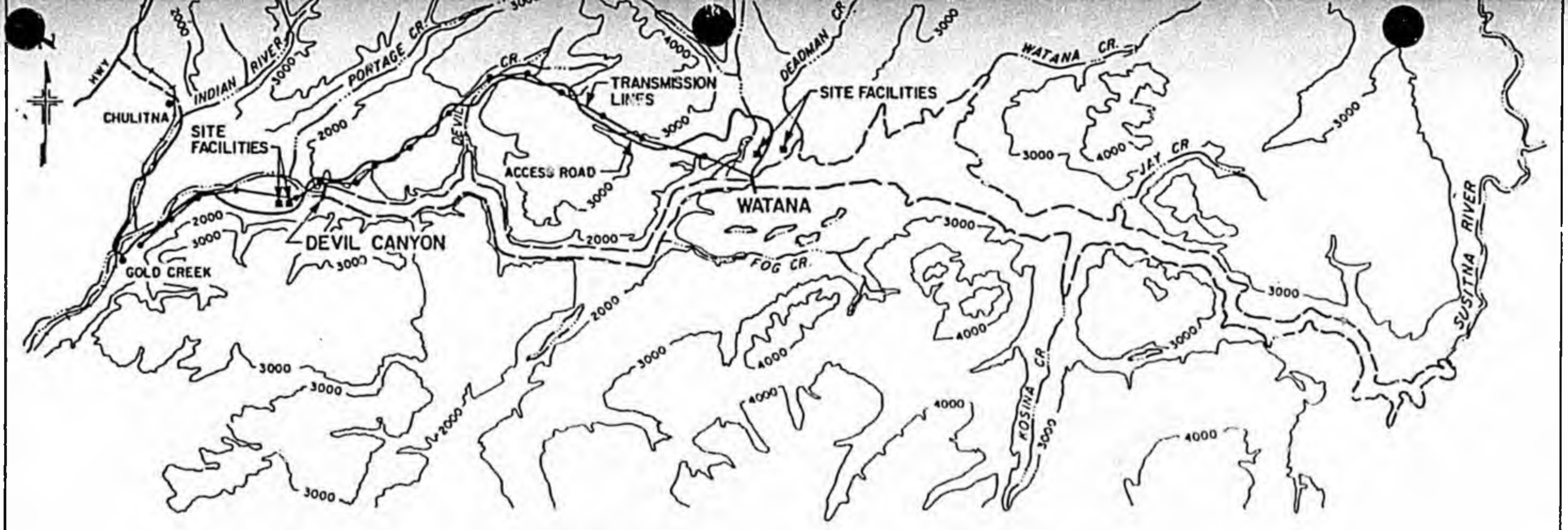
No single plan was found to be consistently best in meeting all objectives. Even so, tradeoffs were made between environmental impacts and socio-cultural impacts, and a preferred access plan was selected. Plate 8 traces this route. Important features include: provisions for limited access between Gold Creek and the Watana site by way of a pioneer road to commence in mid-1983; deferment of road access from the Parks Highway until after award of a federal license for the project; rendering the pioneer road impassable in the event that the project does not proceed; use of special construction techniques to minimize environmental damages; controlling public access; and special mitigation recommendations, such as a full service construction camp, to minimize undesired changes in local communities.

Transmission Line Routes

Transmission line route selection followed a similar pattern to that for access routes. Initial corridor selection resulted in narrowing the options from 22 possible choices to three which reasonably met established objectives. The selected transmission line route generally parallels the Alaskan Railroad between Willow and Fairbanks. Between Willow and Anchorage, the route extends in a southerly direction to a point west of Anchorage, where undersea cables will cross Knik Arm. Between Willow and Healy, the route would utilize the transmission corridor previously selected by the Power Authority for the Railbelt Intertie.

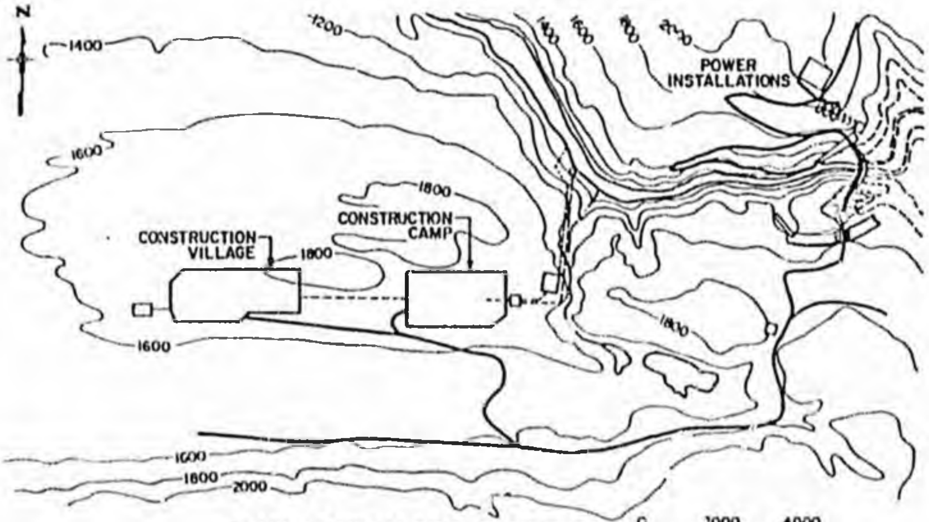
Plate 8 displays that portion of the transmission line route which lies within the upper basin.

NO SINGLE ACCESS PLAN WAS FOUND TO BE CONSISTENTLY BEST IN MEETING ALL OBJECTIVES.



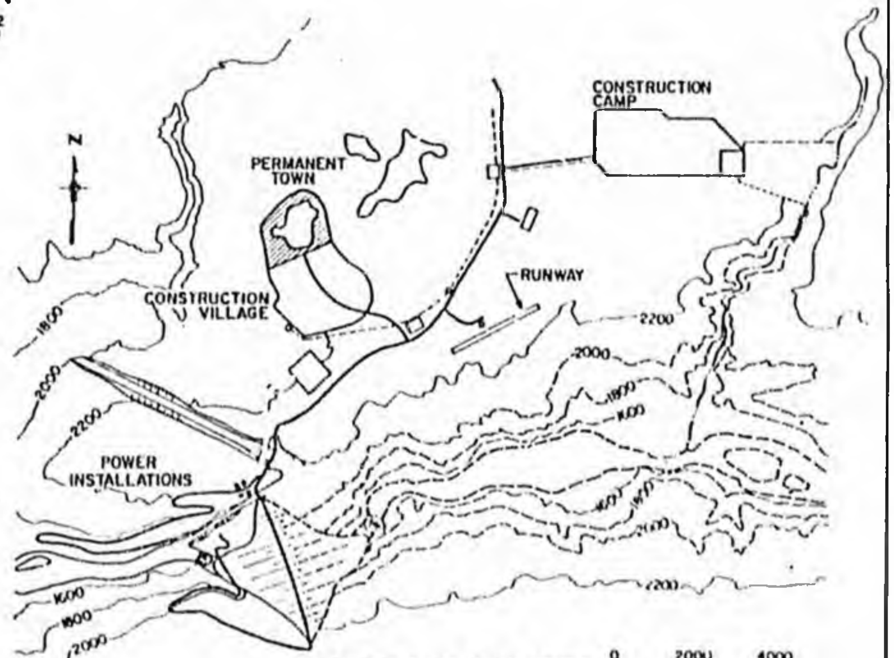
RESERVOIR PLAN

0 6 12 MILES



DEVIL CANYON SITE FACILITIES

0 2000 4000 FEET



WATANA SITE FACILITIES

0 2000 4000 FEET

PLATE 9 PREFERRED DEVELOPMENT PLAN

PROPOSED DEVELOPMENT

The proposed plan for full basin development is shown on Plate 9. In the event that the State decides to develop this plan, two major reservoirs will be formed. The larger reservoir extends 48 miles upstream of the Watana site and has an average width of about one mile and a maximum width of 5 miles. The Watana reservoir has a surface area of 38,000 acres and a maximum depth of about 680 feet at normal operating level.

The Devil Canyon reservoir is about 26 miles long and one-half mile wide at its widest point. A surface area of 7,800 acres and a maximum depth of about 550 feet represent conditions at normal operating level.

Temporary construction camps near each of the dam sites will be removed after construction is complete, but a permanent townsite will remain in the project area to accommodate the needs of the operating and maintenance staff. Appropriate recreational, educational, medical, commercial, sanitation, water supply, and religious facilities will be included in the townsite. Access and egress will follow the same route as was originally provided for construction purposes. A permanent 6,000-foot airstrip will be constructed.

Staged development is planned to provide maximum flexiblity in meeting actual growth in energy demand as it develops. An initial installation of 680-MW of capacity at Watana will be available to the system in 1993 and 340 MW will be added in 1994. If the mid-range forecast is realized, Devil Canyon will be completed by 2002 with an installed capacity of 600 MW. Even so, the commencement of construction and the completion date for this second stage can be deferred or advanced as necessary to meet future needs.

THE WATANA RESERVOIR WILL BE 48 MILES LONG AND THE DEVIL CANYON RESERVOIR 26 MILES LONG.

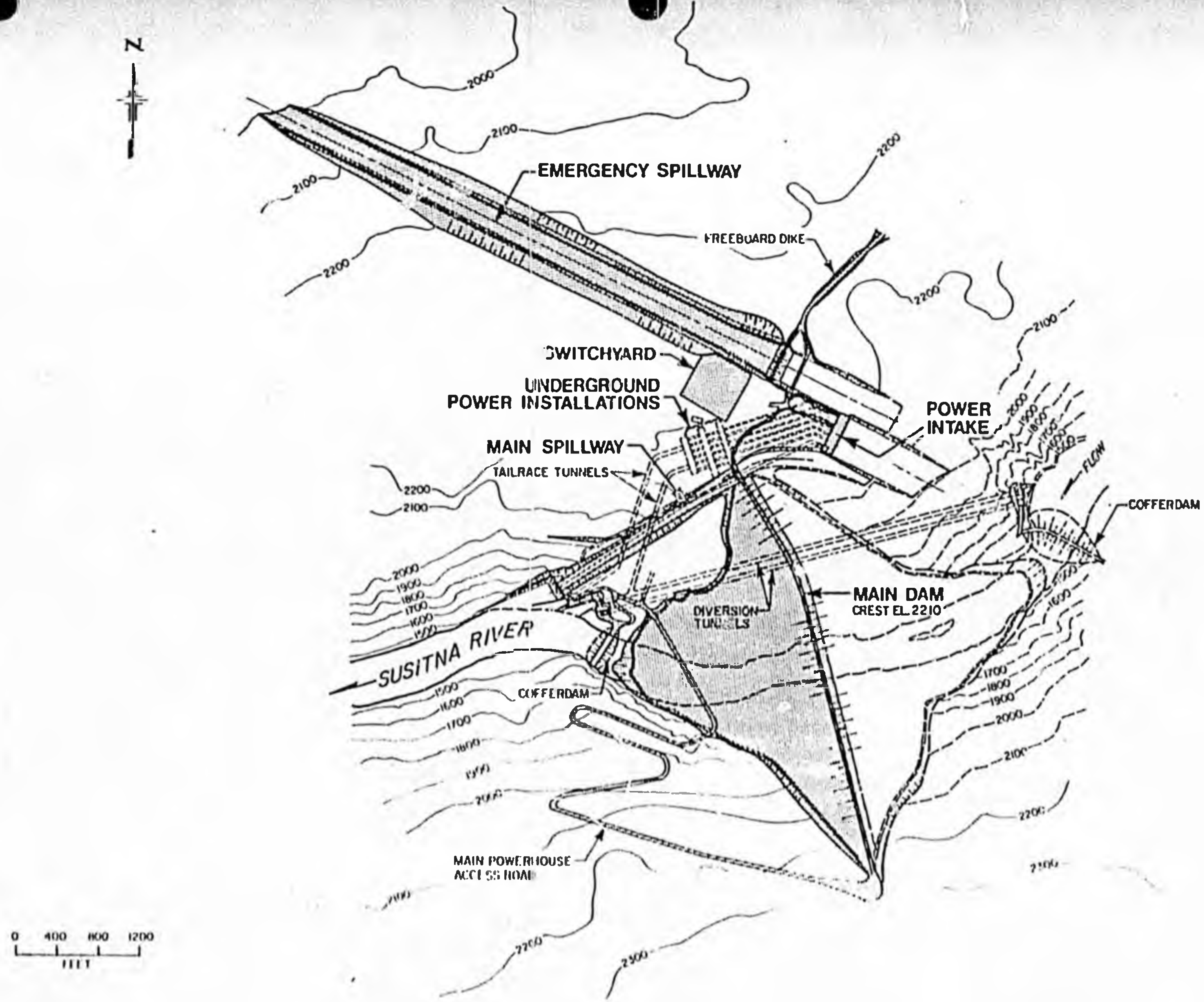


PLATE 10 WATANA GENERAL ARRANGEMENT

Watana Details

The general arrangement for development of the Watana site is illustrated on Plate 10 and a sketch appears on Plate 27. Comparisons of embankment and arch dam alternatives at Watana showed significant cost advantages in favor of the former.

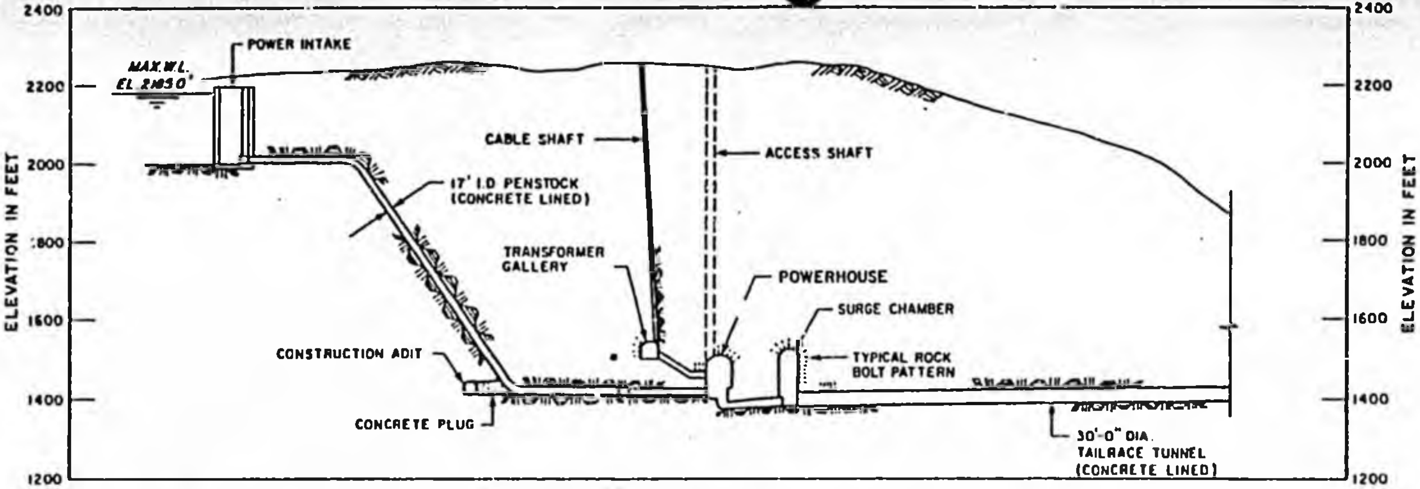
The main dam will be an earthfill structure with a maximum height of 885 feet, a crest length of 4,100 feet, and a total volume of about 62,000,000 cubic yards. During construction, the river will be diverted through two concrete-lined diversion tunnels, each 38 feet in diameter, in the right (north) bank of the river. Upstream and downstream cofferdams will protect the dam construction area from floods with return frequencies of 50 years or less.

The power intake includes an approach channel in rock on the right bank. A multi-level, reinforced concrete, gated intake structure capable of operating over a full 140-foot drawdown range will facilitate maintenance of downstream water quality (especially temperature control — an important consideration for Susitna fishery resources). Six concrete-lined penstocks, each 17 feet in diameter, lead to steel-lined sections terminating in an underground powerhouse complex where six Francis turbines, each producing 250,000 hp at rated head, can be accommodated. The initial stage includes four such units together with 180-MVA generators to be installed by 1993, followed in 1994 by the final two units. The turbines discharge into a surge chamber and thence to the river via two concrete-lined 30-foot diameter tailrace tunnels, one of which connects with one of the original diversion tunnels. A transformer gallery is provided upstream of the powerhouse cavern. Oil filled cables extend from the transformer gallery to a surface switchyard.

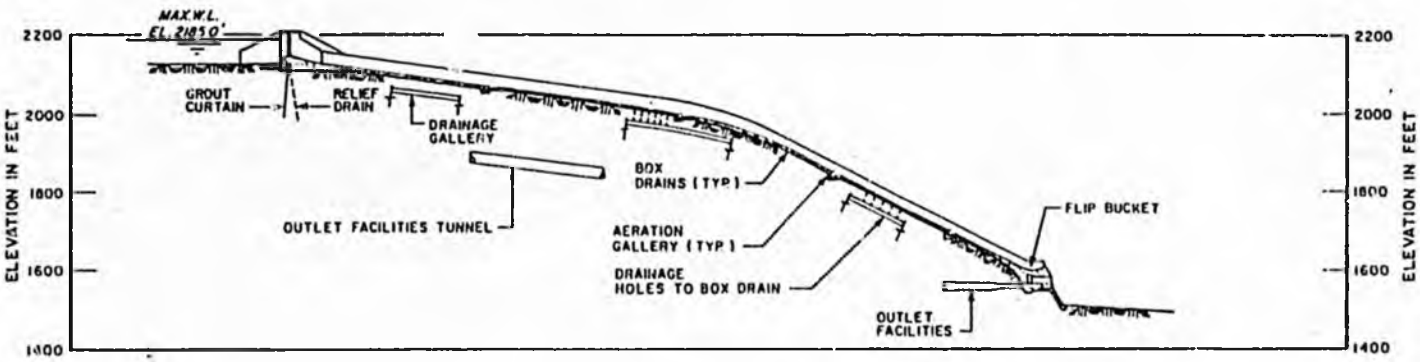
Outlet facilities incorporated into the arrangement will discharge floods with return frequencies of 50 years or less through six fixed-cone valves to minimize undesirable downstream nitrogen supersaturation — another important consideration for fishery resources.

Two spillways will also be provided. Flows with return frequencies between 50 years and 10,000 years will be handled by a main chute spillway on the right bank. An emergency spillway, also on the right bank, will permit discharge of the probable maximum flood without overtopping the dam.

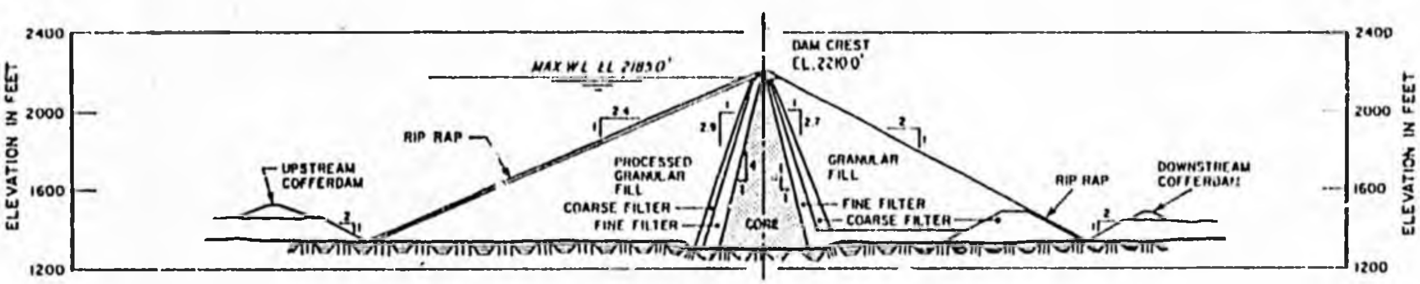
OUTLET FACILITIES WITH FIXED-CONE VALVES WILL MINIMIZE UNDESIRABLE DOWNSTREAM NITROGEN SUPERSATURATION.



POWER INSTALLATIONS PROFILE



SPILLWAY PROFILE



MAIN DAM SECTION

PLATE 11 **WATANA DETAILS**

Details of certain components at the Watana site are shown on Plate 11.

The main dam at Watana will be among the highest in the world. Its 885-foot height will exceed that of the highest completed embankment dams in North America at Mica Creek in British Columbia (794 feet) and at Oroville in California (771 feet). Two dams under construction in the USSR will exceed 1,000 feet, but only one dam higher than 800 feet has been completed there.

At least seven large (over 500-feet high) embankment dams have been built in seismically active areas. The proposed core width, upstream and downstream slopes, and other parameters of the Watana design are consistent with and generally more conservative than corresponding average values for precedent structures. Even so, special features are incorporated in the Watana section to provide additional safeguards against the effects of seismic loading.

The dam foundation will be excavated to solid rock throughout its cross-section and allowances have been made for extensive consolidation and curtain grouting. Grouting will be accomplished from underground galleries, after which the same tunnels will be used to facilitate drilling drainage pressure relief holes.

The core of the main dam is a trapezoidal section, separated from granular fill sections by coarse and fine filter zones. Rip rap protection is provided upstream and a coarse filter zone will be placed at the downstream toe.

Field investigations conducted to date have provided supporting data for selection of the proposed general Watana arrangement. Even so, extensive data collection is expected to continue into the construction phase to ensure the safety and reliability of the various structures. One area of particular concern is a buried (relict) channel which runs from a point upstream of the proposed dam site to Tsusena Creek, a distance of about 1.5 miles. This channel represents a potential source of leakage from the Watana reservoir and remedial measures may be required to guarantee the integrity of the reservoir rim through the channel area. Allowances have been made in the project estimate to account for this feature. If no major problems are identified in continuing field investigations of the relict channel, construction costs will probably be less than those indicated in Section 8 of this report.

THE MAIN DAM AT WATANA WILL BE AMONG THE HIGHEST IN THE WORLD.

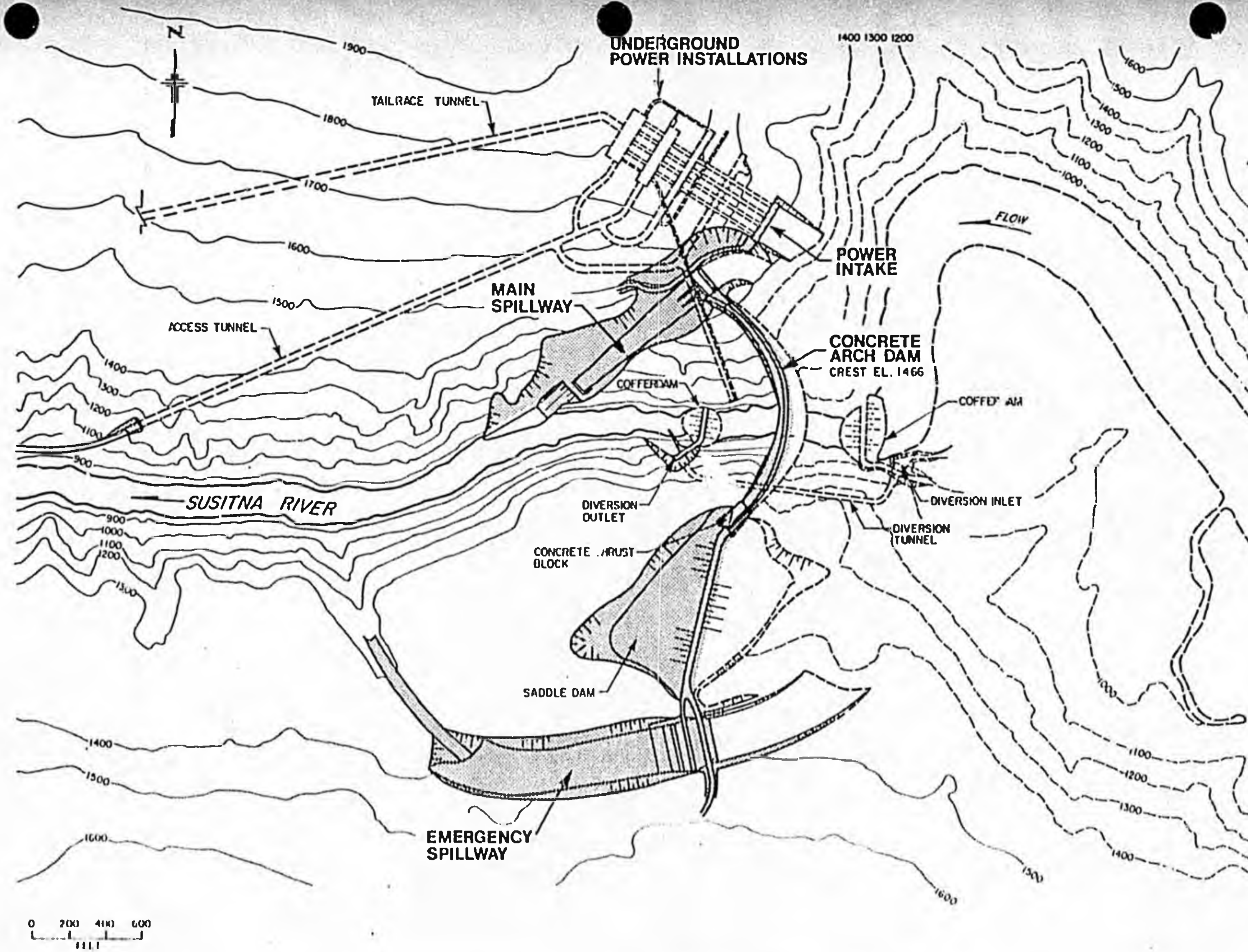


PLATE 12 **DEVIL CANYON GENERAL ARRANGEMENT**

Devil Canyon Details

Plate 12 illustrates the general arrangement for development of the Devil Canyon site and a sketch is presented on Plate 28.

The narrow "V" shaped canyon allows a number of alternative dam types to be considered. Detailed analysis indicated that a thin arch concrete dam is preferred over either a rock-fill embankment dam or a concrete gravity arch dam.

The main dam will be a double-curved arch structure with a maximum height of about 645 feet and a crest elevation of 1463 feet. The crest will be a uniform 20-foot width and the maximum base width will be 90 feet. The center section will be founded on a concrete pad, carried to bedrock beneath the river sediments, and the exteme upper portion of the dam will terminate in concrete thrust blocks located on the abutments. A two-center configuration will be adopted for the arches to counteract the slight asymmetry of the valley and to give more uniform stress distribution across the dam. A rock-fill saddle dam on the left (south) bank of the river will be constructed to a maximum height of about 245 feet above foundation level.

Flow during construction will be diverted through a single 30-foot diameter concrete-lined pressure tunnel in the left bank. Cofferdams and the diversion tunnel provide adequate protection during construction against floods with return periods of 25 years or less. The selection of a lesser return period than that used at Watana takes into account a shorter construction period, the availability of regulation at the then completed upstream Watana dam, and the fact that not only is the main concrete dam at Devil Canyon less susceptible to damage than an earthfill dam if it is overtopped during construction, but also that outlet facilities at the base of the dam will have been constructed well before the entire dam is completed.

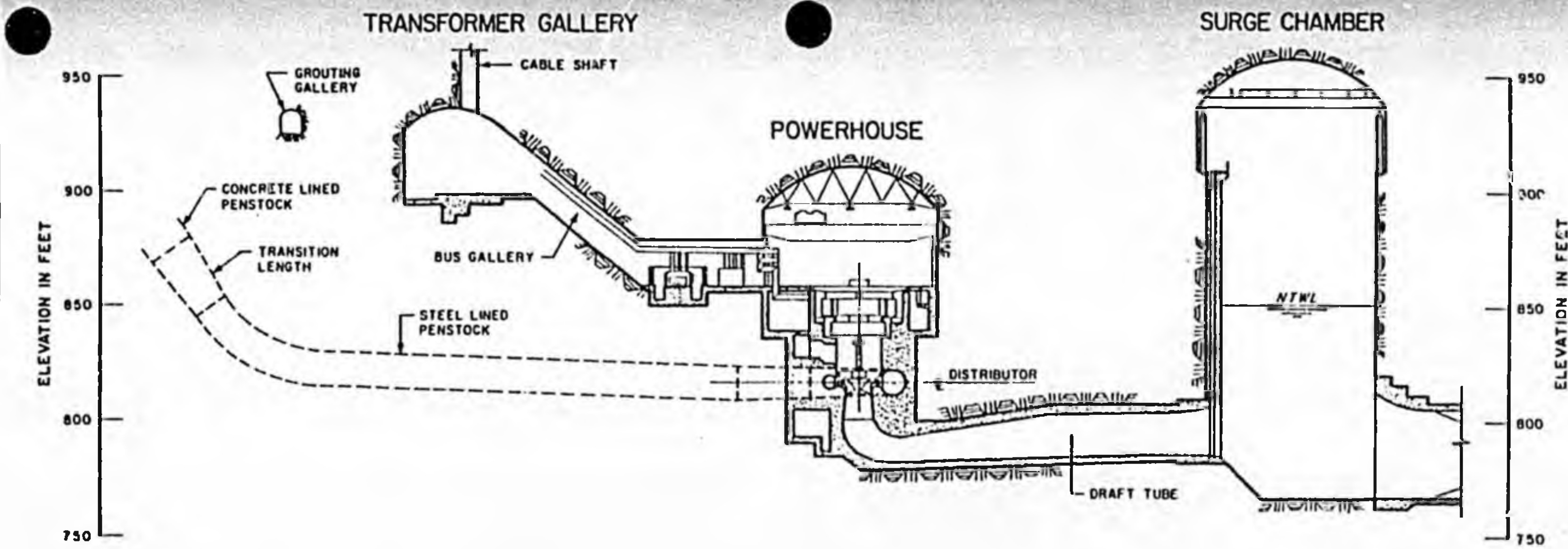
The power intake on the right bank will include an approach channel in rock leading to a reinforced concrete gate structure which will accommodate a maximum drawdown of 55 feet. Four concrete-lined penstocks, each 20 feet in diameter, will lead to an underground powerhouse, where four 225,000 hp (at rated head) Francis turbines will be housed. A single 38-foot diameter tailrace tunnel will lead from a surge chamber downstream of the powerhouse cavern.

The transformer gallery, oil-filled cable arrangement, and surface switchyard are similar in concept to those at Watana.

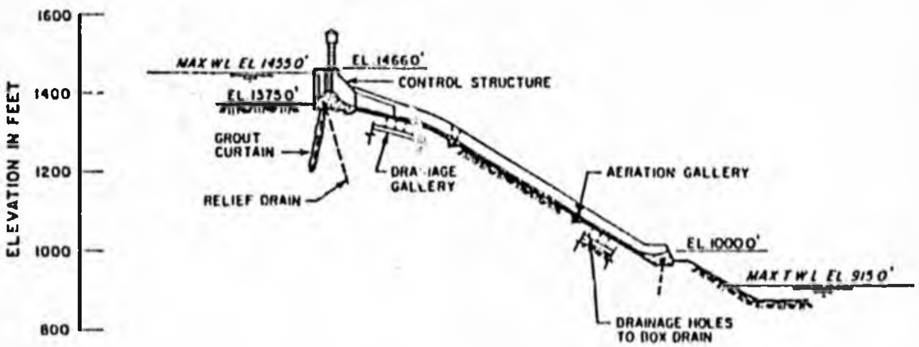
Seven individual outlets, each with a fixed-cone valve, will be located in the lower part of the main dam and will be designed to discharge all floods with return frequencies less than 50 years. Once again, this approach, though more costly than conventional surface spillways, minimizes nitrogen supersaturation problems downstream.

Floods with return periods between 50 and 10,000 years will be handled by a chute spillway on the right bank, similar in design to that for Watana. An emergency spillway on the left bank will permit discharge of the probable maximum flood without overtopping the dam.

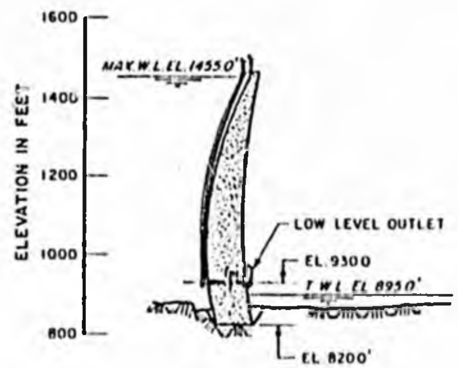
THE MAIN DAM AT DEVIL CANYON WILL BE A DOUBLE-CURVED CONCRETE ARCH STRUCTURE.



POWER INSTALLATIONS SECTION



MAIN SPILLWAY PROFILE



ARCH DAM SECTION

PLATE 13 | DEVIL CANYON DETAILS

Details of certain components at Devil Canyon are shown on Plate 13.

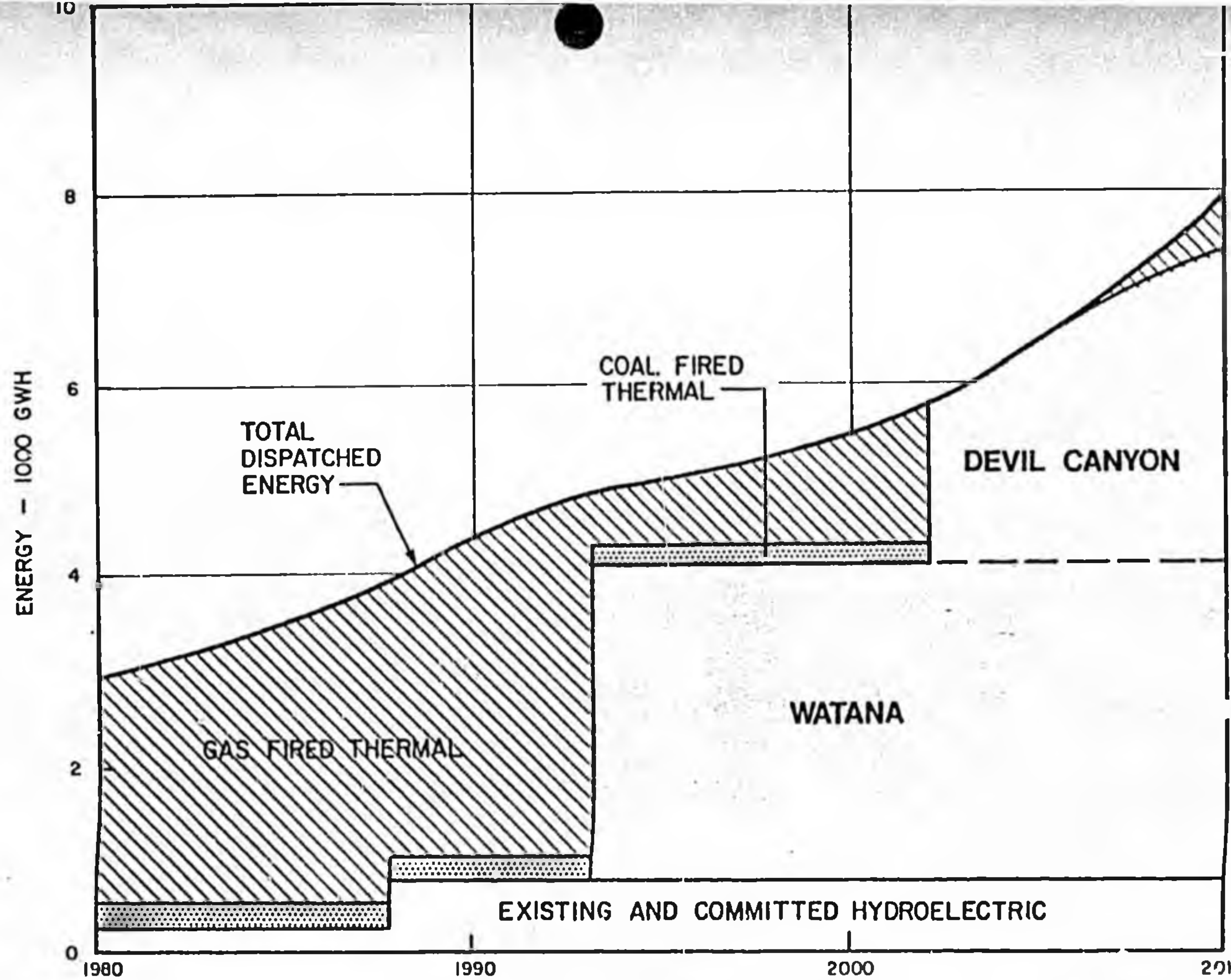
Eight major arch dams greater than 650-feet high have been constructed in the world, the highest being 858 feet at Veneto, Italy. A new arch dam is under construction at Inguiri in the USSR. Upon completion in 1985, it will be 892 feet high.

The Devil Canyon thin arch dam will be designed to withstand dynamic loadings from intense seismic shaking. High earthquake loadings at the 548-foot high Vidraru Arges dam in Rumania and at the 372-foot high Pacoima dam in California have been experienced with no loss of structural integrity.

The arch dam will be founded on sound bedrock located 20 to 40 feet below the normal bedrock surface. To minimize stress concentrations and to increase symmetry, rock surfaces will be trimmed. Consolidation grouting will be provided over the whole of the foundation area and a double grout curtain up to 300 feet deep will run the length of the dam. As at Watana, galleries will be provided both to facilitate grouting and for the purpose of collecting any seepage to be drained through holes drilled downstream of the grout curtain.

The saddle dam is similar in design to that for Watana, except that the saddle dam shells will be rock-filled.

EIGHT MAJOR ARCH DAMS GREATER THAN 650 FEET HIGH HAVE BEEN CONSTRUCTED.



VALUES OF SELECTED PARAMETERS

	1020 MW AT WATANA (FIRST STAGE)	1020 MW WATANA 600 MW DEVIL CANYON (SECOND STAGE)
FUEL PRICE (1982 $/MMBTU)	0	0
CAPITAL COSTS (1982 $/KW)	$ 3,643	$ 3,186
ANNUAL CAPITAL COST ESCALATION	1.8 %	1.8 %
INFLATION RATE	0 %	0 %
DISCOUNT RATE	3 %	3 %
ANNUAL OPERATING AND MAINTENANCE COSTS (1982 $ IN MILLIONS)	$ 10.0	$ 15.2
USEFUL LIFE FOR ECONOMIC ANALYSIS (YEARS)		50
EXPECTED USEFUL LIFE OF PROJECT (YEARS)		100

PLATE 14 SUSITNA INSTALLATION SEQUENCE

PROJECT OPERATION

6

The OGP model described in Section 3 was used to determine the optimum project staging sequence under each of the demand forecasts. As may be seen from Plate 14, in the case of the mid-range forecast, the Susitna project represents a major portion of the net energy generation when its various stages come on line, though this share would gradually decrease after 2010 if demand continued to rise.

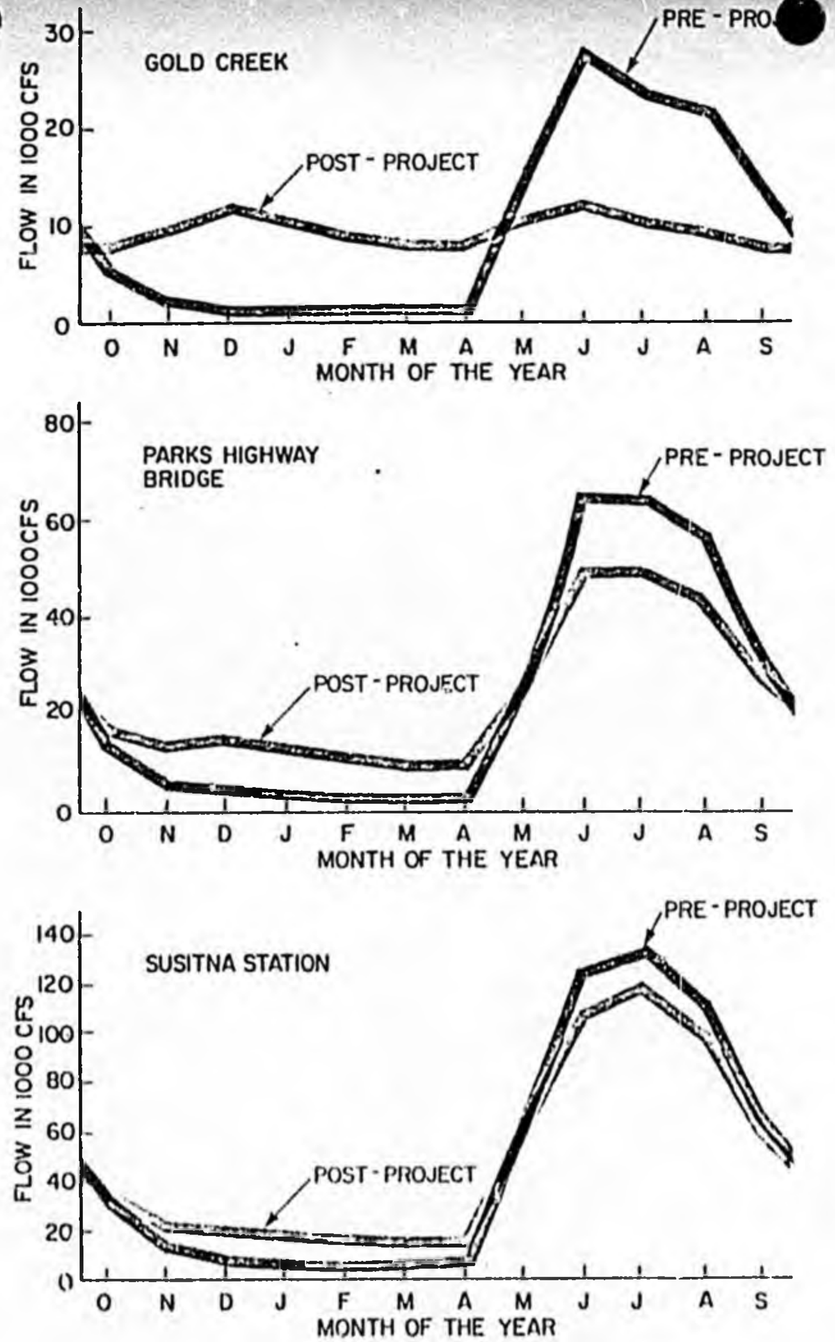
Operating Constraints

The extent of the concentration of Railbelt generation once Susitna has been built requires that special attention be paid to system reliability. To this end, four major categories of operational reliability criteria were applied in generation planning and project scoping: (1) total system loss of load probability must be less than one day in ten years, (2) a single contingency situation (e.g., loss of a single generating unit or a single transmission line) must be met without overloading remaining system components; a double contingency situation should be handled within emergency ratings of surviving system components for the probable duration of the outage, (3) provisions must be made for maintaining system stability and voltage regulation through a broad range of likely incidents, and (4) in the event of catastrophic loss (e.g. all transmission lines on a single right of way), rapid restoration of supply must be possible. A risk analysis of the proposed, transmission system confirmed that these criteria will be satisfied.

In addition to meeting technical criteria, project operation must also accommodate vagaries of nature (e.g., a year of unusually low flow conditions), a variety of important environmental constraints (e.g., downstream water quality and quantity), the performance characteristics of generating units (e.g., rough operation at less than 50 percent of maximum output for any single turbine-generator represents an equipment constraint), and geotechnical concerns (e.g., reservoir slope stability problems can be exacerbated by extreme drawdown and filling limits).

A mathematical model of the reservoir was used to evaluate the optimum method of operating the Susitna reservoirs and power plants to meet these criteria; from this it is estimated that average annual energy output of 3540 GWh at Watana alone and 6790 GWh for the total project can be achieved. Firm energy, corresponding to a low flow sequence expected to occur only once in 70 years, is about 5400 GWh per year.

AVERAGE ANNUAL ENERGY WILL BE 3450 GWh FOR WATANA ALONE AND 6790 GWh FOR THE TOTAL PROJECT.



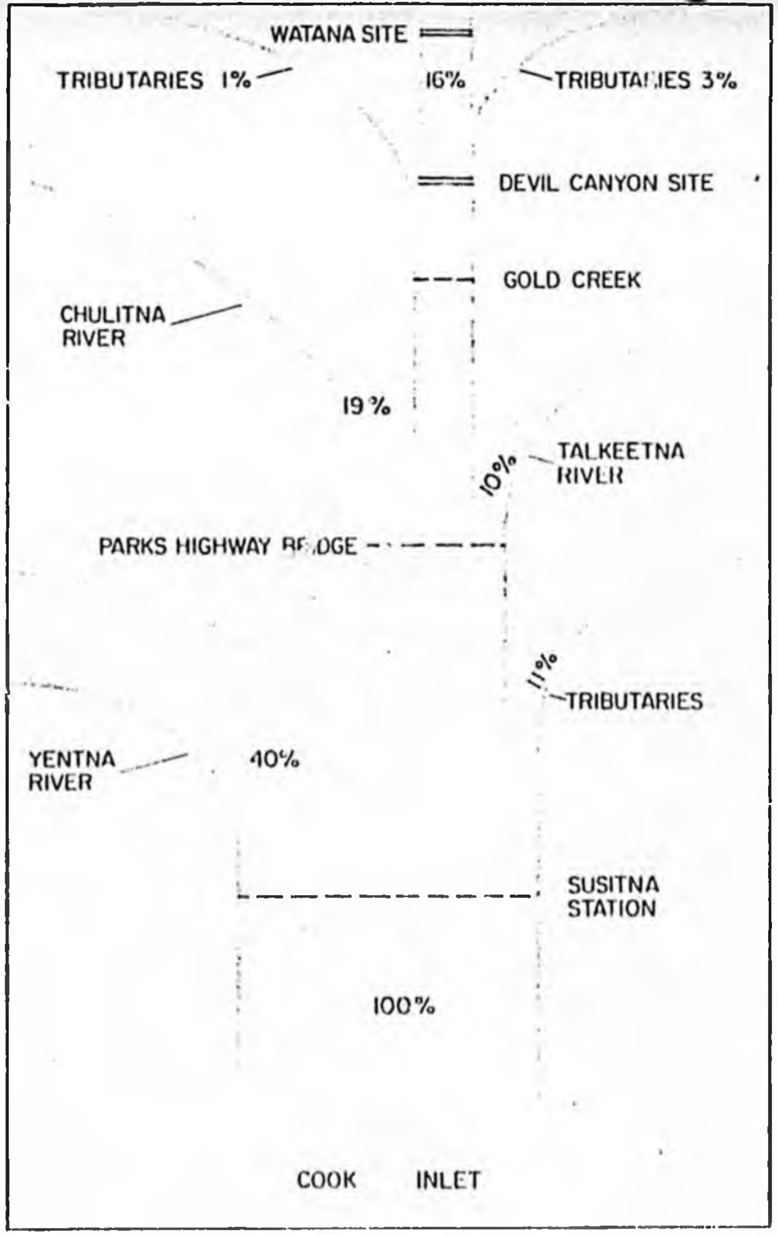


PLATE 15 SUSITNA RIVER FLOWS

Reservoir Considerations

A particularly critical period for effective project implementation occurs during impoundment of the Watana reservoir. Based upon meeting minimum post-project flow requirements in critical months for river maintenance and fisheries needs, about 2-1/2 years of average stream flow is required to fill the reservoir. Filling will commence after dam construction proceeds to a point where impoundment concurrent with continued construction can be accommodated even if a flood with a 100-year return frequency is realized during the filling operation. Once Watana reservoir is operational, later impoundment in the smaller Devil Canyon reservoir can be accomplished with relative ease.

Downstream Flows

Plate 15 provides a hydrograph which relates average flows under natural conditions with those which would normally be provided after the project is completed. Below the confluences with major tributaries of the Susitna River, differences between pre- and post-project flow conditions will be less pronounced, as the entire upper basin contributes less than 20 percent of the total discharge into Cook Inlet.

Reservoir Induced Seismicity

After the reservoirs are filled and particularly during the early years of project operation, some potential exists for reservoir induced seismicity (RIS). Earthquakes which would occur at some point in time under natural states of stress may be triggered by the increased weight of water in a new reservoir or by lubrication and hydraulic action upon highly stressed rock. Based upon mathematical models and data collected during the feasibility study, it is estimated that there is a 90-percent probability of an RIS event if both reservoirs are considered as a single hydrologic regime. The maximum magnitude of such an earthquake is estimated to be 6.0 on the Richter scale, which is within the range of extreme seismic events which the dams are designed to withstand. This maximum magnitude is no greater than that which could be produced under natural conditions if the project is never constructed.

IT WILL TAKE 2-1/2 YEARS TO FILL THE WATANA RESERVOIR.

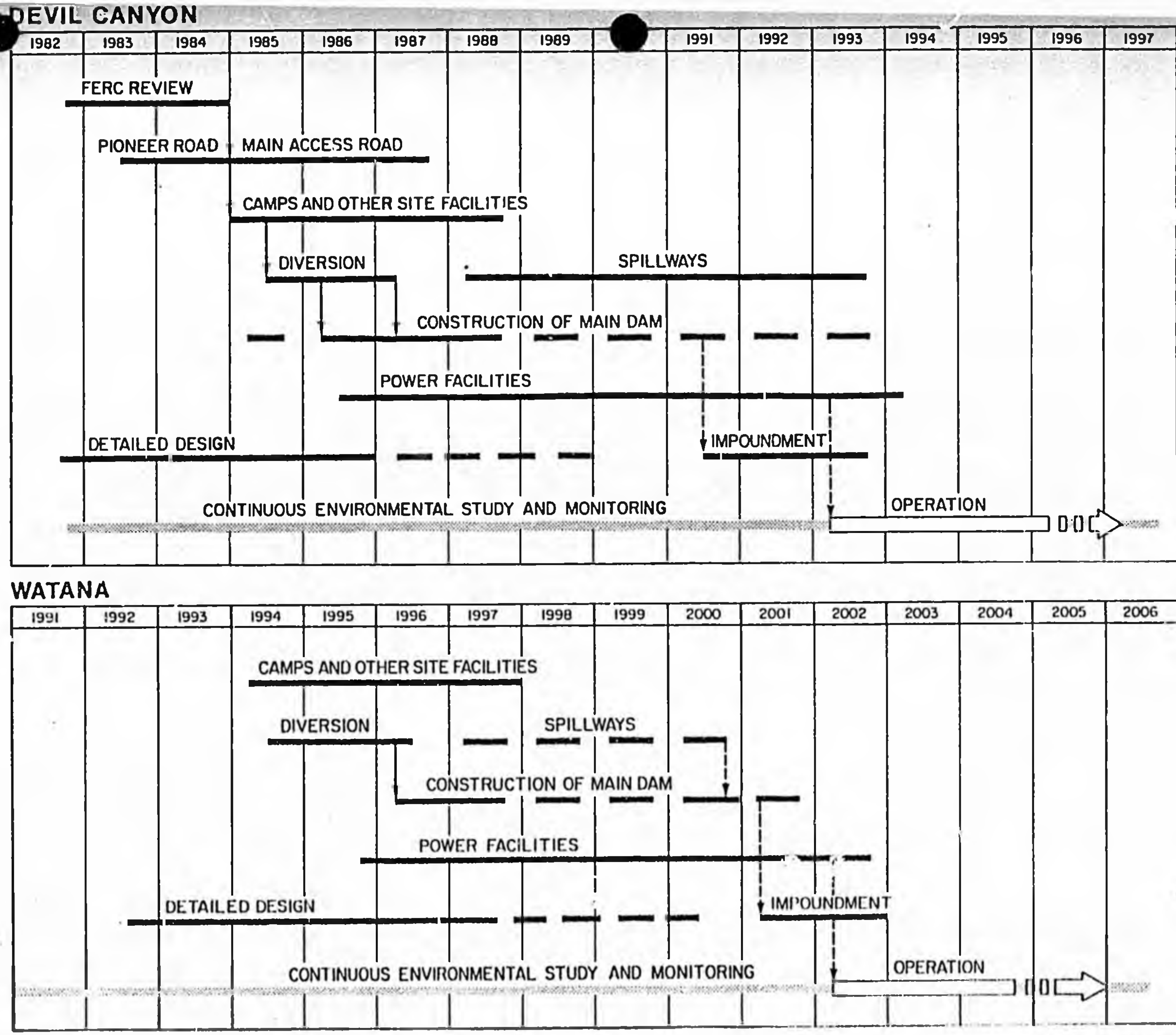


PLATE 16 | PROJECT SCHEDULE

CONSTRUCTION

7

Because generation planning studies indicated that capacity must be added to the Railbelt system in the early 1990s, construction planning for the proposed Susitna project has been based upon meeting a 1993 power-on-line date. Plate 16 provides a broad schedule of activities which must take place if the Susitna proj[illegible] is to assist in meeting perceived needs implicit in the mid-range forecasts.

The Licensing Period

Should the State of Alaska decide to proceed with the project, a license application will be submitted to the Federal Energy Regulat[illegible] Commission (FERC) on September 30, 1982. Given the large size of the project and the inevitable changes its construction would cause, it may be anticipated that concerned agencies, organizations, and individuals will avail themselves of the opportunity to be heard. Thus, a period of 27 months has been set aside to accommodate license processing. Commencing in mid-1983 and concurrent with this processing period, construction of a limited access pioneer road is planned. Necessary permits for this activity will be submitted by September 1982.

Detailed design and the preparation of initial construction bid packages will also proceed during the license processing period. Important field investigations, particularly in the environmental an[illegible] geotechnical areas, will continue.

Post-License Activities

Upon award of the FERC license, bids will be solicited for required early construction activities and for equipment with long lead times. The pioneer road will facilitate the transporta[illegible]on of equipment and camp modules to the Watana site so that camp and diversion facilities can be developed while construction of the main access [illegible]ad proceeds.

By mid-1985, work will commence on the first diversion tunnel at Watana. All diversion facilities, including cofferdams, will be operable in the spring of 1987. Thereafter, major construction activities for various project features will generally proceed in parallel. Reservoir impoundment will begin after breakup in 199[illegible] and as soon as the main dam elevation is high enough to safel[illegible] permit it.

The construction schedule for Devil Canyon is less critical, since under the mid-range forecast, power is not needed there until nearly a decade later than at Watana.

SHOULD THE STATE OF ALASKA DECIDE TO PROCEED WITH THE PROJECT, A LICENSE APPLICATION WILL BE SUBMITTED TO THE FEDERAL ENERGY REGULATORY COMMISSION ON SEPTEMBER 30, 1982.

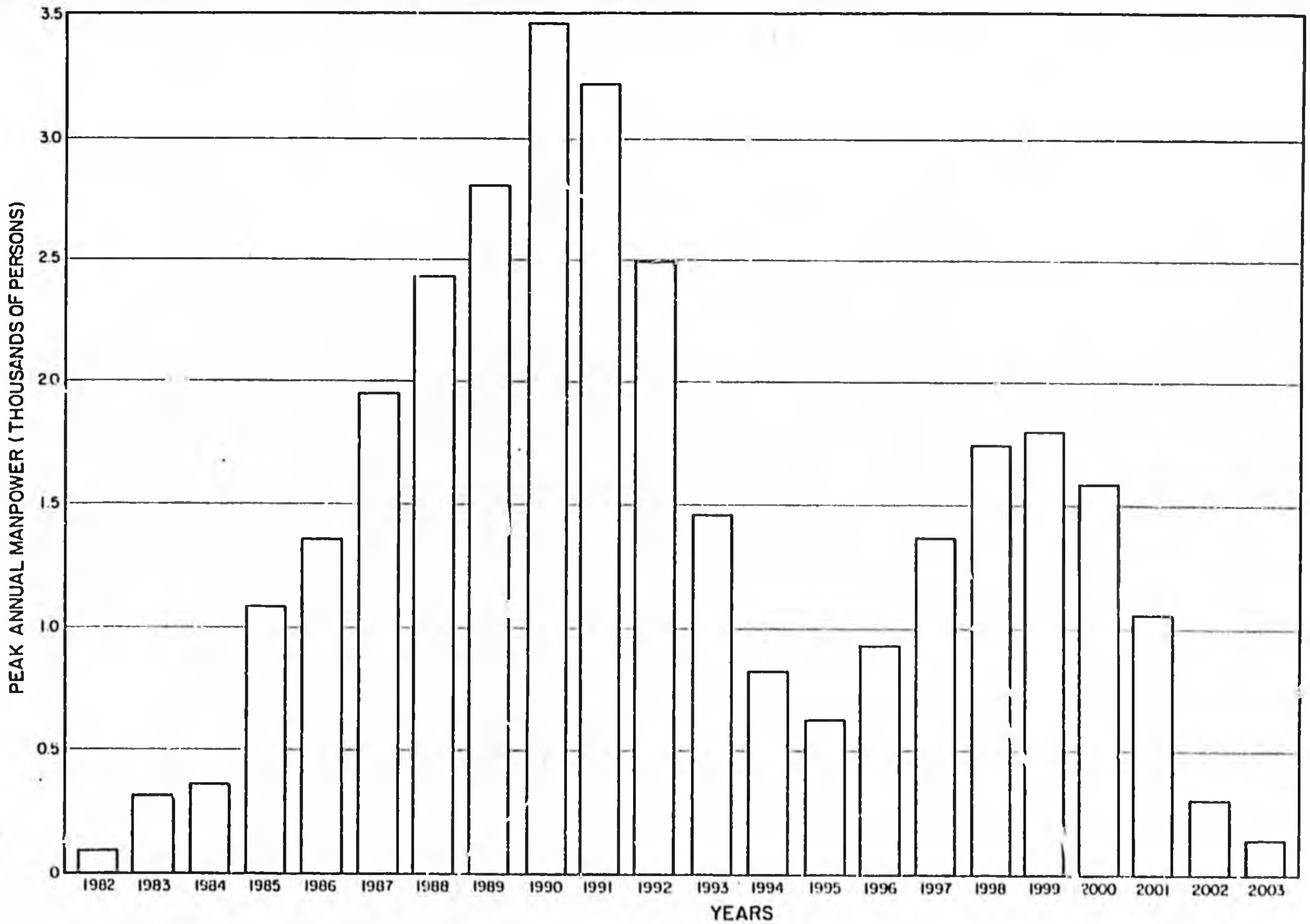


PLATE 17 WORK FORCE

Risks

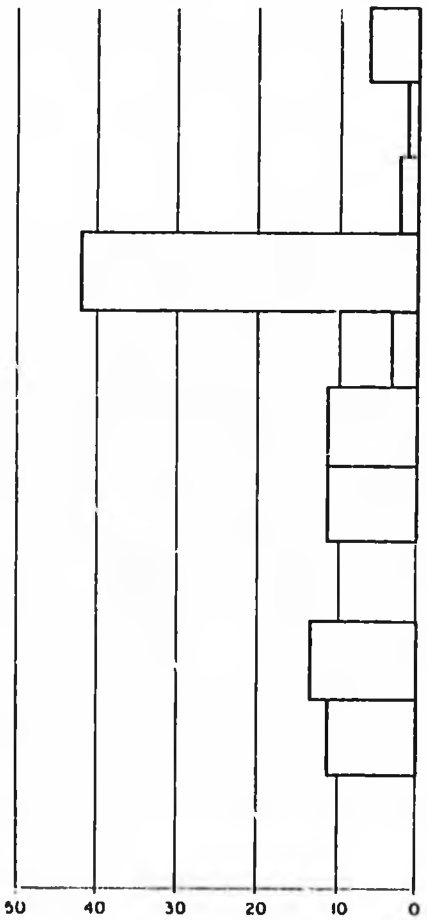
Although the project scheduling has taken into account historical data for normal efficiency and productivity in northern regions and allowances have been made for a range of possible adverse conditions, it is nonetheless true that important uncertainties remain. A schedule risk analysis was conducted to account for unusual extremes in nature, labor and material, and other variables. This indicates that while there is a 65-percent chance that the Watana project will be completed on or before the scheduled date, there is about a 10-percent chance that the power-on-line date will be delayed by two years or longer when important regulatory risks are accounted for (especially the possibility of delays in FERC licensing). Risks are further discussed in Section 8.

Manpower

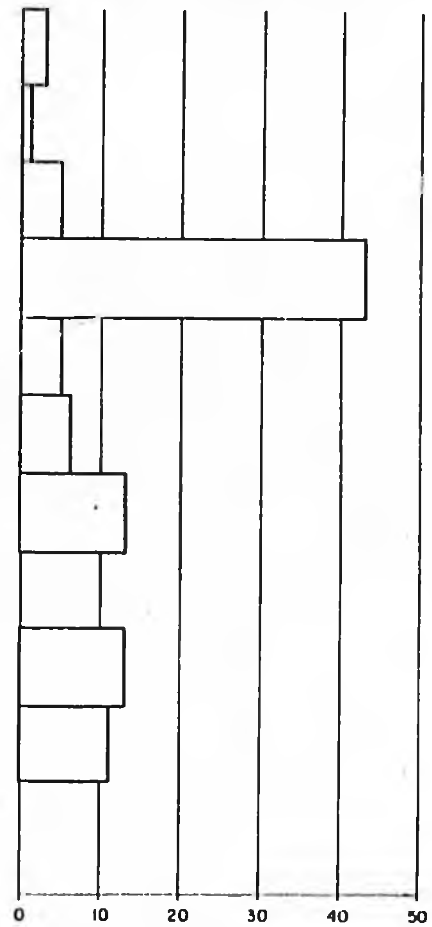
Employment opportunities will be significant during construction of the Susitna project. A gradual increase in the work force will lead to an average requirement of about 1,450 persons between 1985 and 2000, and a peak of about 3,500 in 1990. Plate 17 plots manpower needs during the construction period of both projects.

EMPLOYMENT OPPORTUNITIES WILL BE SIGNIFICANT DURING CONSTRUCTION OF THE SUSITNA PROJECT.

WATANA



DEVIL CANYON



Watana		Devil Canyon
$ 230	ROADS	$ 39
51	LAND AND LAND RIGHTS	22
78	POWERPLANT	76
1,532	DAMS AND SPILLWAYS	635
100	MECHANICAL AND ELECTRICAL EQUIPMENT	68
391	TRANSMISSION	91
378	CONSTRUCTION INDIRECT COSTS	188
2,760	SUBTOTAL	1,119
482	CONTINGENCIES	196
405	ENGINEERING AND ADMINISTRATION	165
$ 3,647	TOTALS	$ 1,480

ESTIMATED TOTAL COST OF PROJECT = $ 5,127

ALL COSTS IN MILLIONS (JANUARY 1982 DOLLARS)

PLATE 18 **ESTIMATE OF COST**

Capital Cost Estimate

In terms of January 1982 dollars, the cost estimate of the Susitna development, including a 17.5 percent contingency and all overhead costs, but exclusive of allowance for funds used during construction, is about $5.1 billion dollars. Plate 18 summarizes major accounts for the Watana and Devil Canyon projects.

Preparation of the project estimate took into account detailed Alaska-specific data and historical experience, vendor quotations, construction methodology and feasibility, seasonal influences on productivity, and a variety of other factors. Allowances of about $150 million are included for important mitigation features integral to design (e.g., multi-level intake structure, outlet facility valves) or appropriate for aesthetic and socioeconomic considerations (e.g., restoration of disturbed areas, self-contained camp facilities).

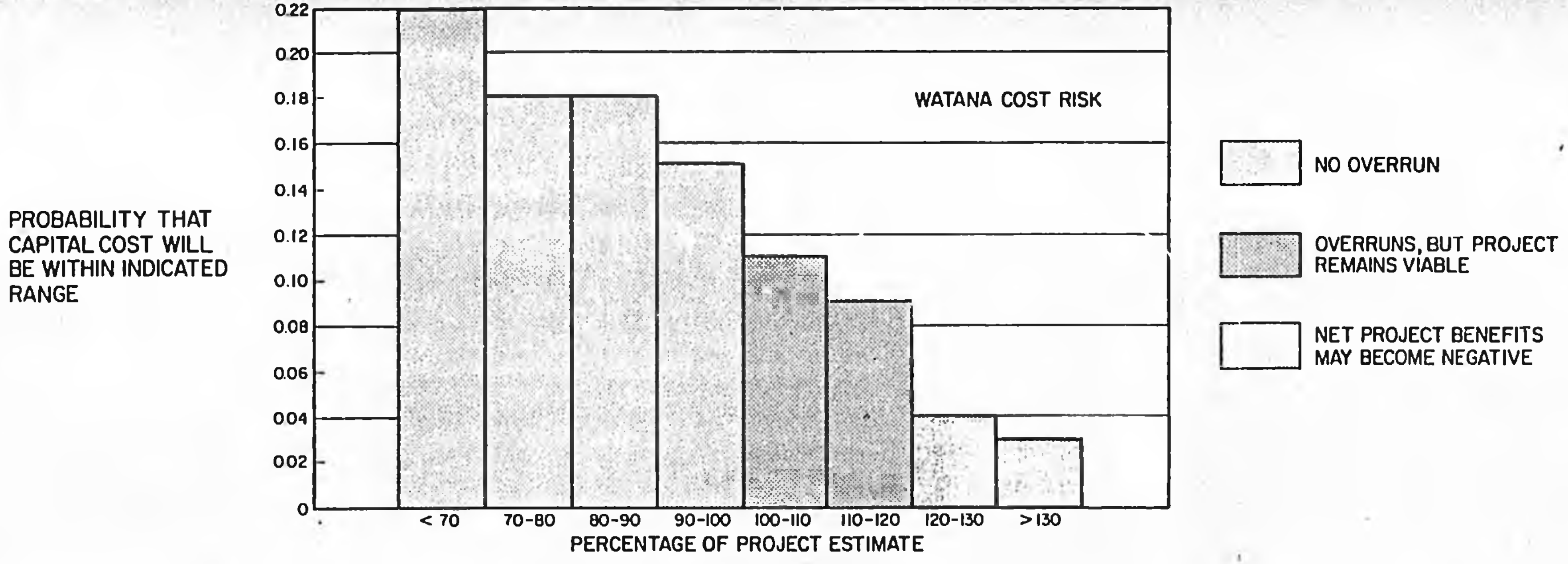
Assumptions were generally conservative and the total project cost estimate is on the order of 50 percent higher than the January 1982 dollar value of the most recent estimate by the U.S. Army Corps of Engineers for a similar development of the upper Susitna basin.

Cost and Schedule Risks

Extreme floods or major earthquakes can lead to serious cost consequences if they occur during construction, although the project is designed to safely withstand such events after it is completed. Geotechnical investigations to date have included an unusually extensive drilling program for feasibility determination, but excavation during construction may yet reveal unfavorable and unanticipated conditions for which expensive remedial measures must be applied.

A risk analysis was conducted to determine the confidence level of the estimate as well as to define the probability of exposure to serious overruns. Up to 10 possible magnitudes for each of 21 different risks were considered, and probabilities were associated with each. Estimates were made of the conditional probabilities of various damage levels if any single risk magnitude were to be realized; and minimum, modal, and maximum values were assigned to the cost and schedule implications of appropriate responses. In addition to considering unusual and unexpected possibilities, the risk analysis also took into account historical variance between initial estimates and actual costs on various completed water resources projects.

PREPARATION OF THE PROJECT ESTIMATE TOOK INTO ACCOUNT DETAILED ALASKA-SPECIFIC DATA...



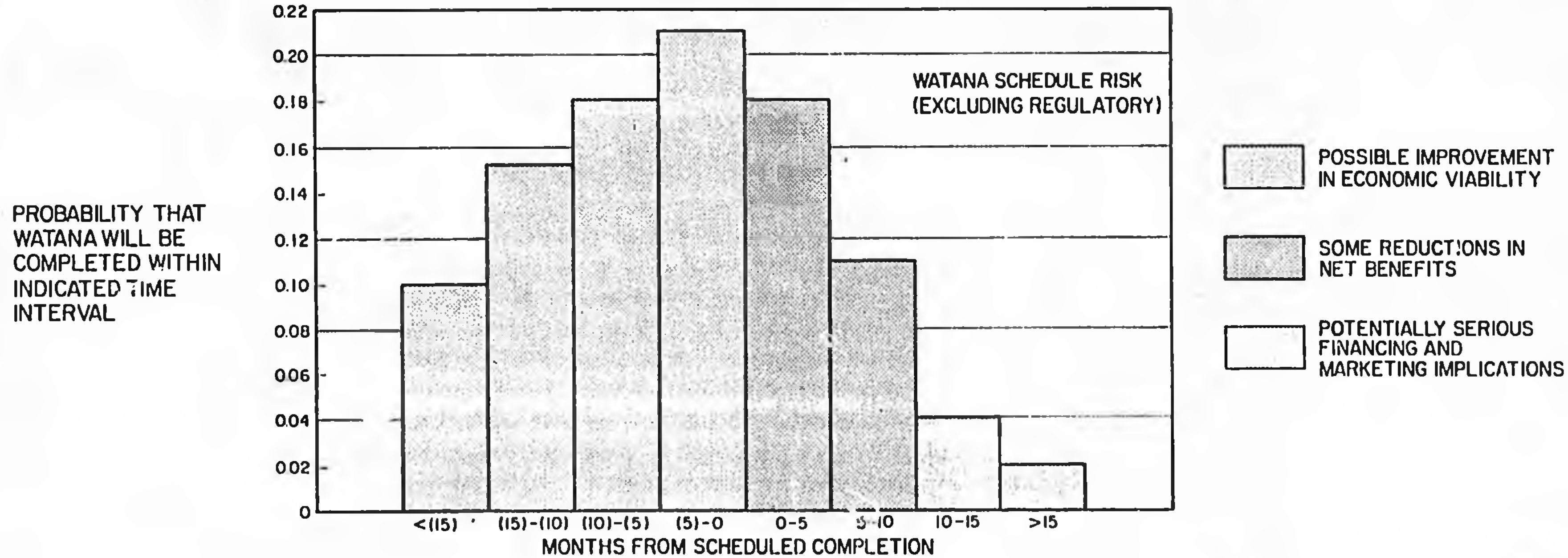


PLATE 19 **RISK DATA**

Probability distributions for selected intervals of possible cost and schedule variations are presented on Plate 19. As may be seen from the cost risk histogram, the probability that the project will be completed at a total cost between 90 percent and 100 percent of the estimate is about 0.15. A probability of 0.73 (73 percent confidence level) that the actual cost (in January 1982 dollars) will not exceed the project estimate can be determined by adding individual probabilities for each interval.

There is a 7-percent chance that the proposed Susitna development will experience overruns so great that the base case thermal alternative would be favorable.

The second histogram on Plate 19 indicates that there is about a 6-percent chance that delays other than those caused by regulatory matters will be long enough to cause serious financing and marketing implications.

In short, the estimated cost and schedule are likely to be achieved, although a not insignificant exposure remains.

Operation and Maintenance

As is characteristic of most new hydroelectric developments, the capital cost of the Susitna project per unit of installed capacity is much greater than that for conventional thermal plants. To the extent that net benefits are demonstrated for Susitna, they are largely derived from avoiding escalating fuel costs which form a large portion of the annual operating costs in the thermal case.

When the Susitna project is fully operational, a central maintenance staff and an operating staff, together with appropriate support personnel, will be located at the permanent townsite. Power plants at both dams will be controlled from the Susitna Area Control Center at Watana. In January 1982 dollars, the annual operating and maintenance costs will be $10 million for the first stage Watana project and $15.2 million for the complete development. For operation of the project within the Railbelt system, a Central Dispatch Control Center is planned near Willow.

POWER PLANTS AT BOTH DAMS WILL BE CONTROLLED FROM THE SUSITNA AREA CONTROL CENTER AT WATANA.

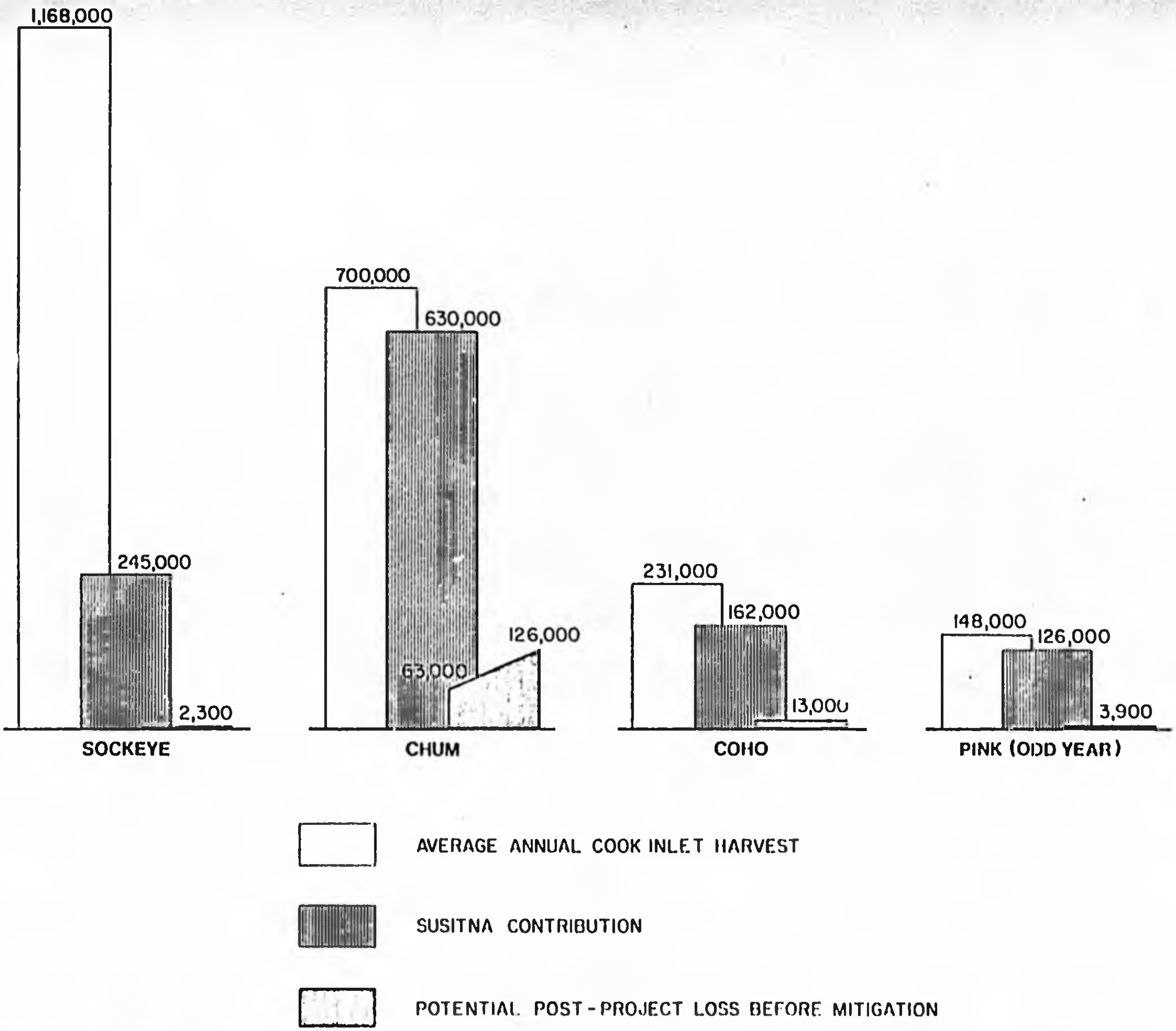


PLATE 20 SALMON DISTRIBUTION IN THE SUSITNA

ENVIRONMENTAL ISSUES

Environmental issues are addressed initially in this section in the context of the proposed Susitna development. Potential impacts associated with the non-Susitna plan are summarized in the final portion.

Fisheries

The Susitna River is a major contributor to Cook Inlet fisheries. More than half of the combined Cook Inlet total of chum, sockeye, coho and pink salmon return to the Susitna to spawn. Resident fish species abound as well in the basin. The mainstem provides a migratory corridor and most of the spawning habitat is located within tributaries, side channels and sloughs. Plate 20 illustrates estimated migratory distributions for important anadromous fish.

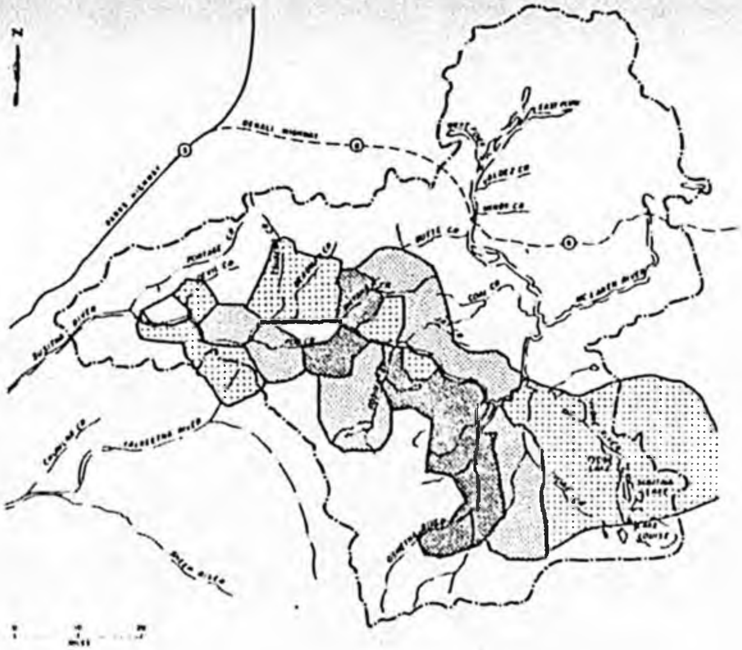
If the Susitna project is constructed, the principal fishery impacts will be measured upstream of the confluence of the Talkeetna River and the Susitna mainstem. In the absence of any mitigation efforts, the greatly altered post-project flow regime and warmer water temperatures in winter could result in a reduction of 63,000 to 126,000 chum from the current long-term average annual Cook Inlet harvest of 700,000. There would also be a decrease of 2,300 sockeye from an annual harvest of 1,168,000, and other losses as shown on Plate 20. In any single year, relatively large differences from these estimated long-term averages can occur. In 1981, for example, chum losses would have been 68,000 and sockeye 14,000.

Mitigation measures incorporated into project design include the effective removal of nitrogen supersaturation as a contributor to fish mortality and provisions for some water temperature control, as earlier described in Section 5. Other mitigation plans under consideration include modification of operating procedures to increase downstream flows during critical times, streambed modification to compensate for lost spawning habitat (though the effectiveness of such a measure is by no means certain — homing problems could ensue), and construction of a hatchery to replace losses.

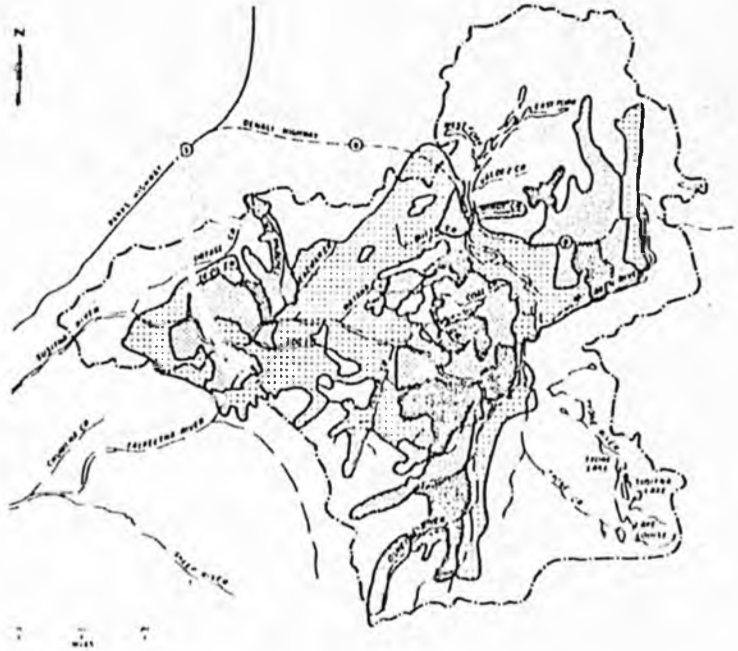
Because of the natural barrier to migration near Devil Canyon, the principal direct impacts of reservoir impoundment will be felt only by resident fish populations. Some loss of spawning areas will be compensated by an increase in overwintering habitat and the reservoirs may provide the habitat necessary for the existing population of resident fisheries.

The ultimate objective of all the various mitigation measures is to achieve no net loss. Potential losses need not occur if proposed artificial measures to maintain the fishery resource are taken.

MITIGATION MEASURES HAVE BEEN INCORPORATED INTO PROJECT DESIGN...



MARCH 1980



NOVEMBER 1980

LOW DENSITY

MEDIUM DENSITY

HIGH DENSITY

PLATE 21 **MOOSE DISTRIBUTION**

Wildlife Resources

The principal species of big game in the proposed project area are moose, caribou, wolf, wolverine, bear and dall sheep.

Plate 21 provides relative distributions of moose observed during the field investigation program. In addition to direct loss of inundated moose habitat and displacement of home ranges within the reservoir area, some reduction in downstream browse may occur as altered flow regimes affect vegetative succession. Habitat management is the principal mitigation measure being explored to maintain the moose population. Controlled burning to stimulate browse growth and reclamation of areas of disturbance are typical examples of habitat management being considered.

Although not recently used, an important historical migration route for caribou will be intersected by reservoir impoundment. Mud flats and shore line ice conditions could impede caribou migration despite their excellent swimming capability. Monitoring spring migration to locate calving areas and protection of calving grounds from human intrusion during the calving period are proposed. Clearing and removal of trees from the reservoirs is also proposed, to prevent mortalities which may be caused by floating debris.

Black bear prefer the forest habitat which lies within the impoundment zone. Nine known dens in the Watana reservoir and one in Devil Canyon will be flooded. Reductions in black bear population are likely if the project proceeds. Lesser losses will be suffered by brown bear as a result of reductions in seasonal foraging areas, though no known dens will be flooded. Restrictions will be imposed to reduce human-caused disturbances, and maintenance of a healthy moose population will aid in providing a food source for bears.

The Watana dall sheep herd uses a mineral lick along Jay Creek. Partial inundation of this lick will occur, and in the event that use by the herd is discontinued, an artificial lick with similar chemical composition will be established.

Furbearers will suffer some habitat loss and increased trapping and hunting pressure can be expected. Measures have been included in project planning to limit human access and to create common corridors for transmission and ground transportation. Hunting and trapping regulations will be enforced.

Active and inactive nest sites for golden eagle, bald eagle, and raven lie within the proposed reservoir area. Even so, creation of two large impoundments may result in an increased eagle population in the upper basin. Measures will be taken to preserve clumps of tall spruce trees to encourage nesting and the possibility of and need for constructing artificial nests will be explored.

No endangered species (the bald eagle is not endangered in Alaska) have been identified in the project area.

Historic and Archeological Resources

Archeological sites representing human occupation during the last 10,000 years and historic cabins built in the 1920s were located during the field investigation program. Mitigation will be accomplished through avoidance, preservation, and where appropriate, excavation and removal of artifacts to museums.

NO ENDANGERED SPECIES . . . HAVE BEEN IDENTIFIED IN THE PROJECT AREA.

USE		INTENSITY
1	RECREATION	MEDIUM
2	MINING	MEDIUM
3	RECREATION	MEDIUM
4	MINING/RESID.	HIGH
5	MINING	HIGH
6	REC./RESID.	HIGH
7	RECREATION	HIGH
8	RECREATION	LOW
9	RECREATION	MEDIUM
10	RECREATION	MEDIUM
11	RECREATION	LOW

PLATE 22 | LAND USE

Socioeconomics

The population of Alaska has increased steadily since the 1940s, with accelerated growth occuring in the 1970s. About 50 percent of the total is located in the greater Anchorage area, and the Railbelt as a whole contains 70 percent. Historical spurts have been occasioned by major project activities, generally followed by short-term decline or a leveling off. The Trans Alaska Pipeline System provides the most recent example of this phenomenon. Increases in population during the past decade have been particularly pronounced in the Matanuska-Susitna Borough, within which the proposed dam sites are contained. The borough is more dependent on seasonal employment than large urban centers and has consistently had high unemployment rates.

As was indicated in section 8 of this report, significant employment opportunities will be generated over a period of 15 years if Susitna proceeds.

Demands for services (e.g. water supply, education) will increase in general by less than 5 percent above baseline conditions, particularly if much of the required work force is drawn, as planned, from within the state.

The greatest relative impacts are likely to be felt in Talkeetna and Trapper Creek, where housing shortages may occur and where proportionally greater numbers of visitors and would-be residents, particularly during the construction period, can be expected.

To mitigate adverse impacts on local communities, the proposed site facilities include construction camps and a permanent town site fully equipped with all amenities, thereby reducing the need for travel to and service from these areas. As the project proceeds, coordination will be maintained with local communities in order to maintain a proper balance between preservation of desired life style and local economic needs which project management may be able to satisfy.

Land Ownership and Use

Most land in the project area and directly south has been selected by Native corporations under provisions of the Alaska Native Claims Settlement Act. The U.S. Bureau of Land Management generally manages lands to the north.

Existing land use in the upper basin is typical for that of interior undeveloped Alaska (see Plate 22). Broad expanses of wilderness areas are present, access is severely restricted, and only a few man-made developments or structures are currently found. Early in the feasibility study period, a camp near the Watana dam site was erected on Native land to support field investigation activities. In the event that the Susitna project does not proceed, this camp facility may revert to Native ownership. If so, some further developments on Native land would probably occur.

If the project does proceed, only low-level recreational development is currently proposed. Camp grounds, picnic areas, boat launches, and hiking trails are planned, as are scenic overlooks.

While the creation of major dams and reservoirs will necessarily change the aesthetics, efforts were made in project planning to minimize visual impacts. Powerhouses will be underground, flow will be maintained in the short stretch between Devil Canyon dam and the tailrace portal downstream, borrow areas will be within the impoundment area where possible and will otherwise be restored or converted to ponds, and other similar measures will be taken.

MOST LAND IN THE PROJECT AREA AND DIRECTLY SOUTH HAS BEEN SELECTED BY NATIVE CORPORATIONS...

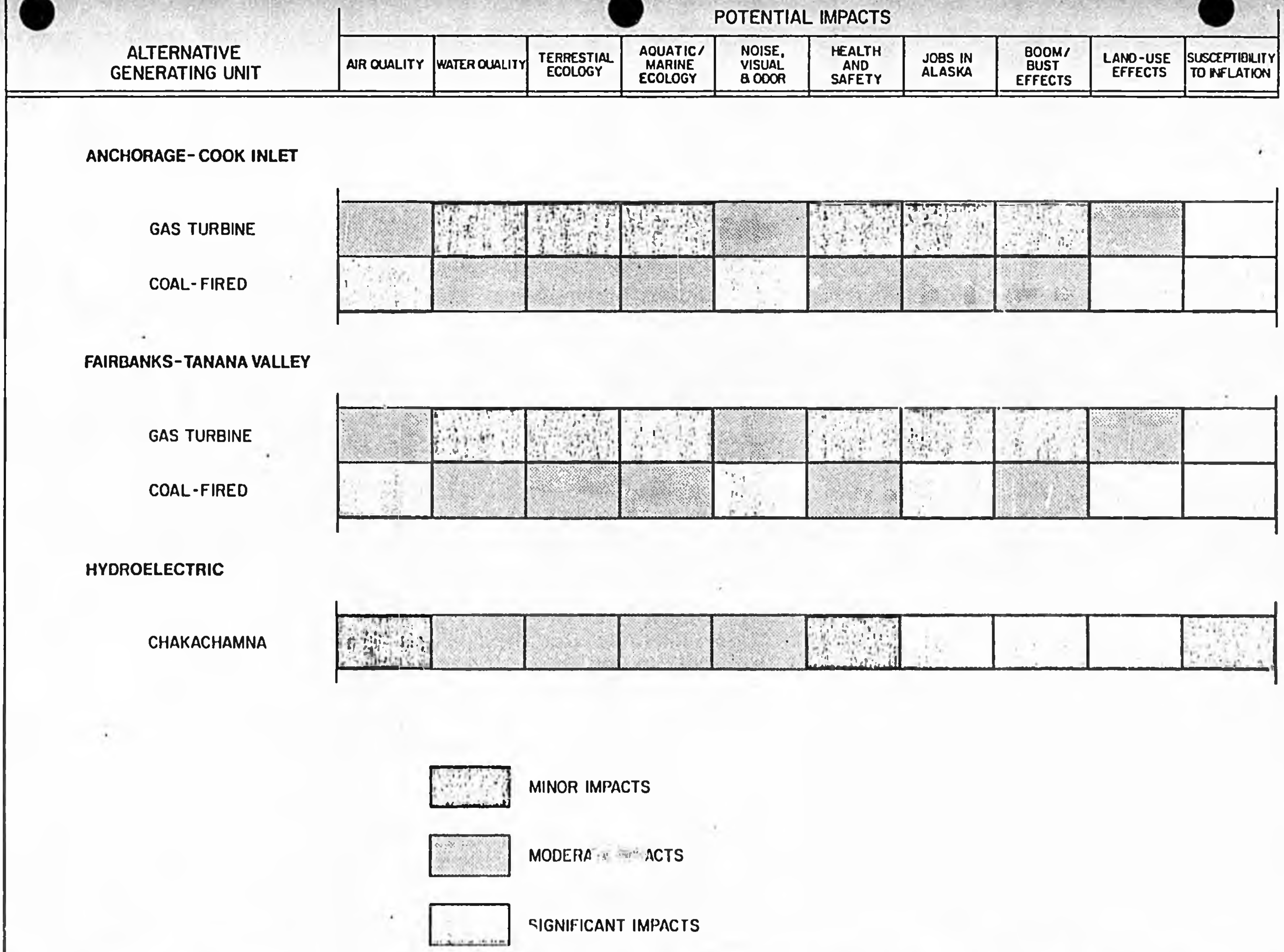


PLATE 23 BASE CASE IMPACTS

Water Quality

In its natural state, the Susitna River is turbid after breakup. The estimated annual transport of suspended materials at the Gold Creek gaging station is 7.7 million tons. Winter flows are relatively free of sediment.

Sediment capture efficiencies for proposed reservoirs are estimated at 70 to 100 percent. In 100 years, the estimated sediment deposition will represent about 5 percent of the gross reservoir volume at Watana and about 14.2 percent at Devil Canyon. No reduction in energy production as a result of sedimentation is anticipated during the project life. As a result of sedimentation entrapment, flows downstream of Devil Canyon will be considerably less turbid in late spring, summer, and early fall. Winter flows will be more turbid than under natural conditions. Other water quality changes will occur, but no significantly adverse impacts are anticipated.

Non-Susitna Expansion

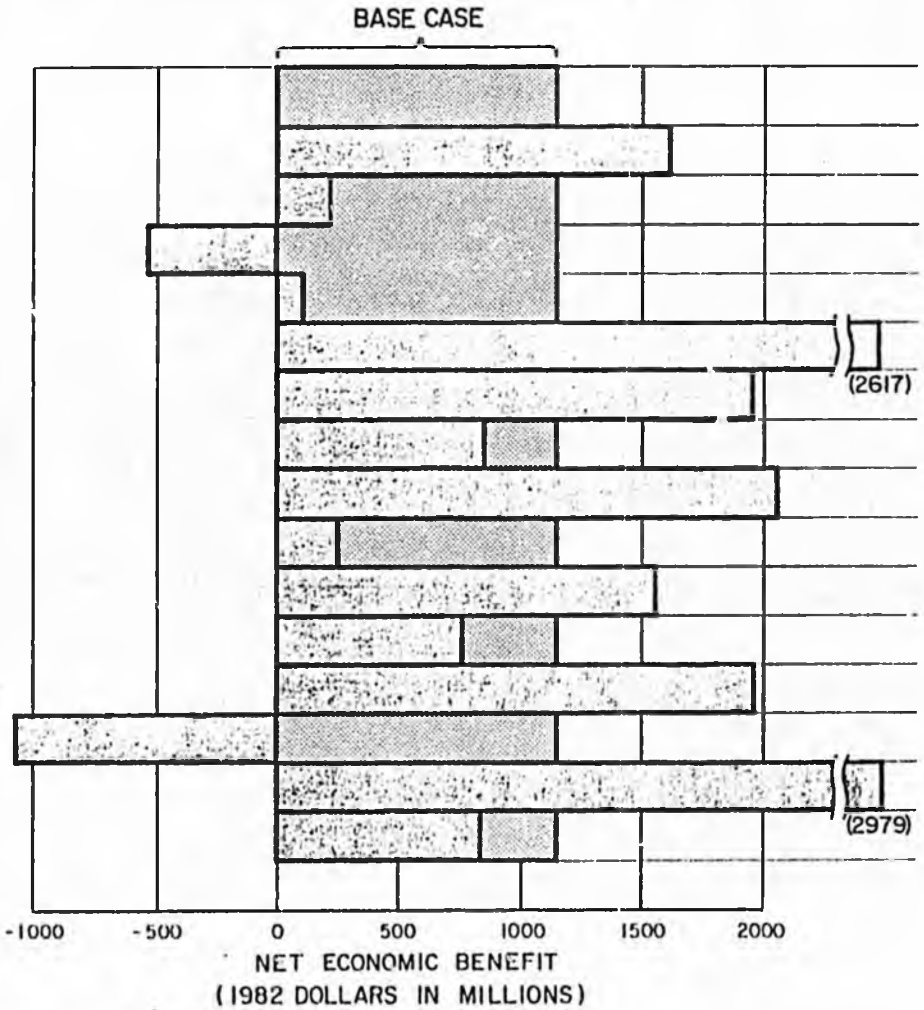
It was earlier noted that significant generating capacity must be added to the Railbelt system during the study period if the mid-range forecast is realized. If, instead of proceeding with Susitna, the base case representative thermal plan is followed, different types of environmental impacts can be expected. Plate 23 summarizes impacts as presented in the Battelle report for system additions common to both Battelle's Plan 1A and the representative thermal plan. Chakachamna appears on the summary because the economic effect of its inclusion was tested in the sensitivity analysis.

Coal-fired steam generating plants, the principal component of the representative non-Susitna plan, will be developed in open, well-ventilated sites as near as possible to available coal fields. Visual impacts will be significant since plumes from cooling towers and smokestacks will be seen for miles, particularly in winter months. Local air quality degradation will be inevitable. Relatively large land areas will be required to accommodate major plant components, stockpiles, and mining operations. Lesser, but nonetheless important impacts in other categories as shown on Plate 23 will occur.

Gas turbines would be environmentally superior to coal-fired plants, but new units of this type will serve primarily to satisfy peaking needs and to maintain system reliability criteria. Neither gas supply estimates nor cost expectations support long-term reliance on gas as the principal fuel for generation of electricity.

Construction of a hydroelectric plant at Chakachamna would introduce impacts generally of the types described in preceding paragraphs for the Susitna project. Studies to date by others on Chakachamna have not advanced sufficiently to make definitive estimates of potential fish losses, but initial indications are that they will be greater on a relative basis that those associated with the Susitna project.

IN 100 YEARS, THE ESTIMATED SEDIMENT DEPOSITION WILL REPRESENT ABOUT 5 PERCENT OF THE GROSS RESERVOIR VOLUME AT WATANA AND ABOUT 14.2 PERCENT AT DEVIL CANYON.



ELEMENT TESTED	BASE CASE VALUE
HIGH LOAD FORECAST (11,400 GWH IN 2010)	7,800 GWH IN 2010
LOW LOAD FORECAST (6,300 GWH IN 2010)	7,800 GWH IN 2010
5 % REAL DISCOUNT RATE	3 %
4 % REAL DISCOUNT RATE	3 %
2 % REAL DISCOUNT RATE	3 %
HIGH CAPITAL COST FOR ALTERNATIVE (20 % ABOVE ESTIMATE)	BATTELLE ESTIMATE
LOW CAPITAL COST FOR ALTERNATIVE (10 % BELOW ESTIMATE)	BATTELLE ESTIMATE
LOW SUSITNA CAPITAL COSTS (83 % OF ESTIMATE)	PROJECT ESTIMATE
HIGH SUSITNA CAPITAL COSTS (117 % OF ESTIMATE)	PROJECT ESTIMATE
ZERO CAPITAL COST ESCALATION	1.8 % / ANNUM
HIGH CAPITAL COST ESCALATION (3.6 % / ANNUM)	1.8 % / ANNUM
HIGH BASE COAL PRICE ($ 2.08 / MM BTU)	$ 1.43 / MM BTU
ZERO FUEL PRICE ESCALATION	2.6 % TO 2000 1.2 % TO 2010
HIGH FUEL PRICE ESCALATION (5 % TO 2000, 2.2 % TO 2010)	2.6 % TO 2000 1.2 % TO 2010
CHAKACHAMNA ALTERNATIVE	ALL THERMAL PLAN

PLATE 24 **SENSITIVITY ANALYSIS**

In spite of the fact that some legislative support has been demonstrated for subsidies and grants for hydroelectric development, all economic analyses to identify plans and to determine net benefits were conducted on a common, non-subsidized basis. Thus, competing plans were tested on equal terms.

Net economic benefits were calculated by comparing the system-wide production costs of electricity with and without the Susitna project. The OGP model was employed for this purpose, and for the set of economic parameters considered most likely in the base case, the Susitna project was shown to have an advantage over the representative thermal plan of $1176 million (expressed as present worth in 1982 dollars of the difference in total costs of the two plans over an assumed 50-year operating period). A great deal of uncertainty was associated with the various parameters whose values contributed to this result, however. It was noted in Section 8, for example, that a range of possible Susitna capital costs must be contemplated, and earlier in Section 2 that demand can vary across a broad spectrum. Other parameters are far from firm.

Sensitivity Analysis

A sensitivity analysis was conducted to determine the extent to which a reasonably conceivable change in any single parameter would affect the outcome of the analysis. Results are presented on Plate 24.

The most sensitive parameter is clearly the assumed future escalation of fuel prices, particularly coal, over and above the underlying inflation rate. Simply stated, it would be an unwise economic decision to develop Susitna if long-term fuel price stability could be assured. High fuel price escalation in the future, on the other hand, would make Susitna increasingly attractive.

Varying the real (inflation adjusted) discount rate also demonstrates strong effects. The apparent "break even" discount rate is about 4.1 percent.

The Chakachamna project had not been included in the base case for reasons earlier noted in Section 3. If environmental issues can be resolved there and if the initial cost estimate is adhered to, a combination of the Chakachamna hydroelectric project and thermal generation additions would present a lower cost alternative than the all-thermal plan, but Susitna would continue to be favored.

Tests were also made to evaluate the economic effects of delays. A one year delay for the Watana project alone would reduce net benefits by $43 million. Delaying both Watana and Devil Canyon one year causes a reduction of $103 million. A two year delay for both yields a decrease of $168 million.

Not shown on Plate 24, but also worthy of consideration is the extent to which a decision not to proceed with the currently planned Bradley Lake Project would change net benefits. Such a scenario would make the non-Susitna plan more costly and would raise the net benefits of the Susitna plan from $1176 million to $1453 million.

. . . ALL ECONOMIC ANALYSES TO IDENTIFY OPTIMAL PLANS AND TO DETERMINE NET BENEFITS WERE CONDUCTED ON A COMMON, NON-SUBSIDIZED BASIS.

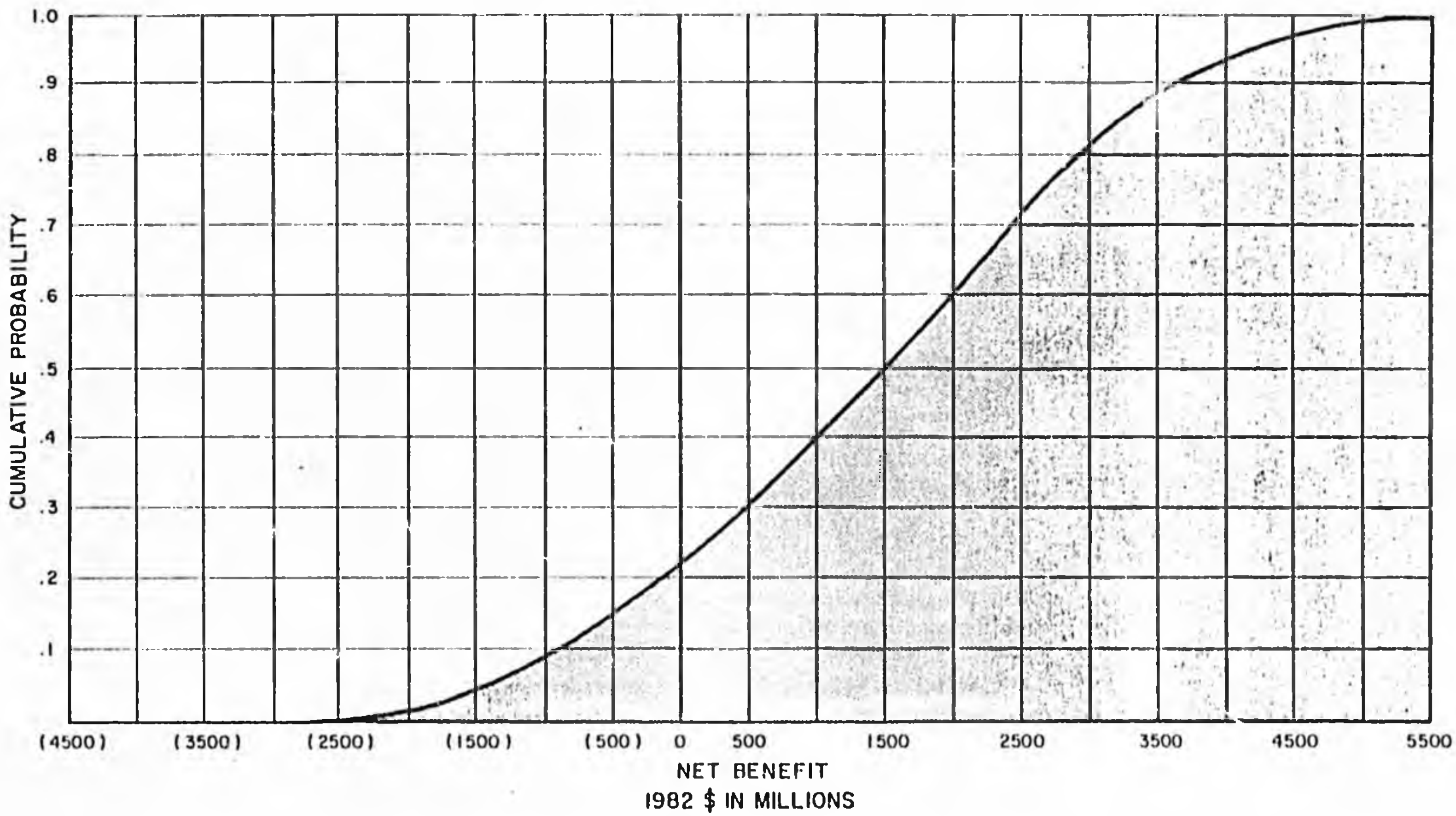


PLATE 25 **MULTI-VARIATE SENSITIVITY**

"Multi-Variate" Analysis

Given the uncertainties involved in each of the parameters subjected to sensitivity tests, there is no reason to believe that only one will ultimately vary from the assumed center-point values. To test the effect of multiple variations, a "decision tree" was constructed and the probability of occurrence was assigned to each of three possible values for the four most sensitive parameters. OGP runs were made to determine long-term present worth costs of each possible combination of load forecast, Susitna capital cost, alternative capital cost, and fuel cost escalation. Discount rates were not included in this analysis because their determination is largely a matter of policy.

Based on this analysis, the cumulative probability that a particular net benefit will not be exceeded is plotted on Plate 25. As may be seen from that depiction, there is about a 23 percent chance that a decision to proceed with Susitna will result in negative or zero net benefits, and the maximum negative exposure is about $2.5 billion. Correspondingly, the chance that Susitna will produce positive benefits over a 50-year operating period is about 77 percent, with cost advantages as high as $5.5 billion.

Conservative Treatment

Certain features of the economic analysis probably introduced a measure of conservatism into the calculation of net benefits. The first and most significant such feature is the fact that constant production costs were assumed after 2010 in all cases tested. This assumption has the effect of excluding both real escalation in fuel prices after 2010 and the replacement costs of thermal plants which have a shorter operating life than hydroelectric facilities.

A second consideration has to do with load forecasts. For purposes of the economic analysis, no further growth was assumed after 2010. Thus, no benefit to Susitna accrues for available energy output of about 340 GWh which is not forecast to be required by the system by 2010. In addition, no cost penalties were assigned to thermal plants to account for possible future environmental legislation; finally, indications by the OGP model that a new thermal plant would be needed in 2011 if only a minor increase in load occurred thereafter were ignored.

It was earlier noted in Section 3 that important uncertainties exist with respect to economic development of the Beluga coal fields and the long term availability of Cook Inlet gas. Nonetheless, the economic analysis was conducted as if no such constraints were present.

CERTAIN FEATURES OF THE ECONOMIC ANALYSIS PROBABLY INTRODUCED A MEASURE OF CONSERVATISM INTO THE CALCULATION OF NET BENEFITS.

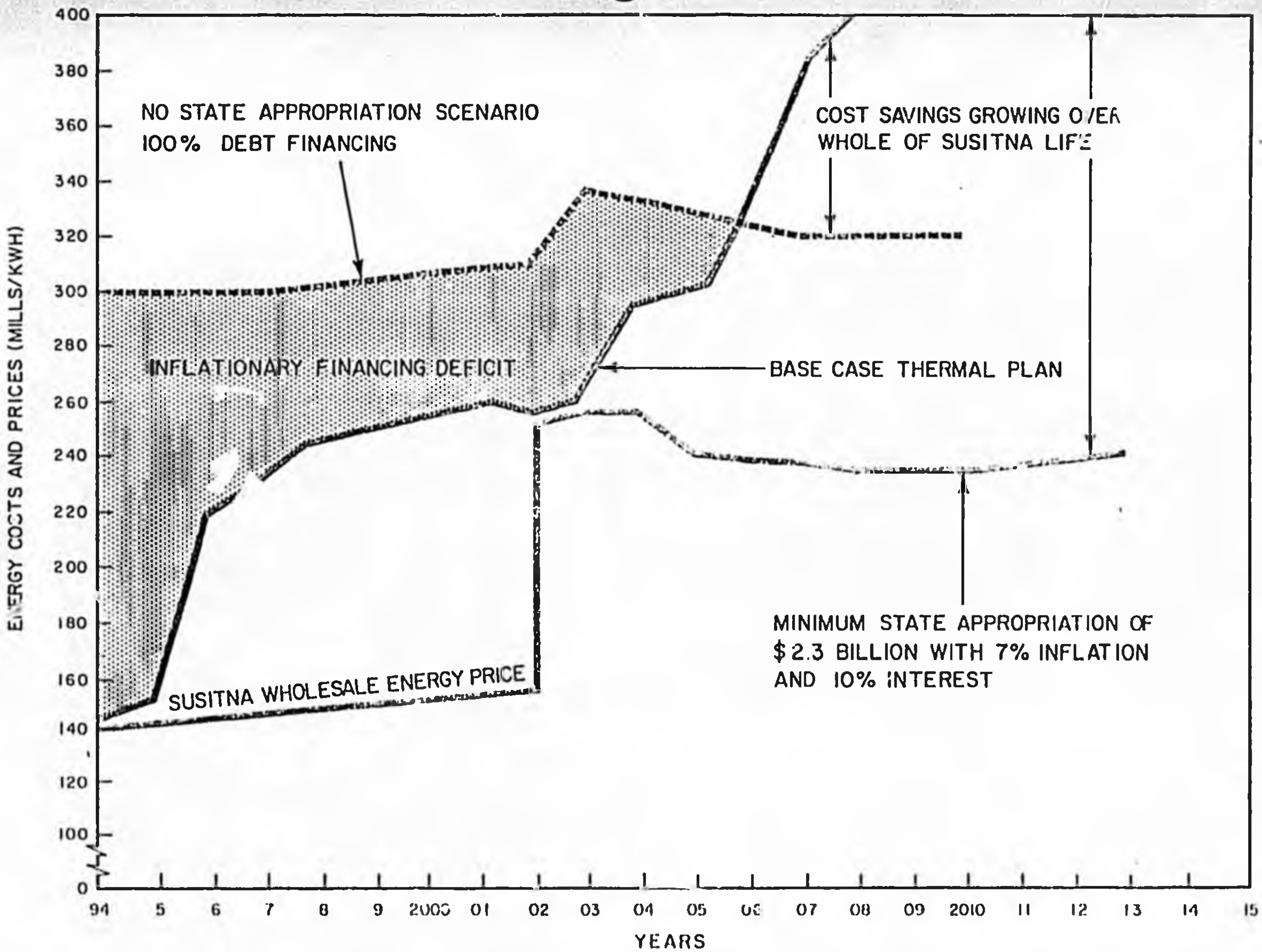


PLATE 26 | ANNUAL COST COMPARISION

FINANCING AND MARKETING

Having demonstrated, by the economic analysis described in the previous secton, that there is a high probability that development of the hydroelectric potential of the Susitna basin would provide significant cost advantages when compared to alternative means of meeting projected Railbelt power demands, further analyses were made of the financial aspects of the development program. These further analyses were aimed at determining whether the project could be financed in an inflationary economy and what impact various scenarios for state participation in funding would have on the ultimate cost to the consumer. The results of one such analysis are plotted in Plate 26.

The sharply rising red line on Plate 26 traces the unit energy costs associated with the representative all-thermal plan. The same curve had been presented earlier on Plate 5. The dashed curve lying above thermal plan costs in the early years of project operation is associated with a Susitna case with no state participation. It exhibits a characteristic which is common to many major capital-intensive projects. Simply stated, the Susitna Hydroelectric Project would be more costly to the consumer in its early years of operation, if no state participation is involved, than the thermal plan. After about a dozen years, rising thermal plan costs intersect those for Susitna. Thereafter, the Susitna plan looks increasingly more attractive and, over a 50-year economic life, it can be shown that Susitna would generate important cost savings — even without state funding participation. The project is expected to remain operational long after the 50-year life upon which economic and financial analyses were based. Once project debts are amortized, Susitna costs will drop dramatically.

The third curve, shown as the solid blue line on Plate 26, illustrates the case for which state participation is just enough to make the entry costs for Susitna comparable to those for the thermal plan, increasingly great savings being realized thereafter. Other financing variations were explored in the detailed feasibility report. It is anticipated that conventional financing will be used to provide required funding over and above whatever state participation is involved. State participation at the level indicated by the solid blue curve would provide an 11 percent return on investment.

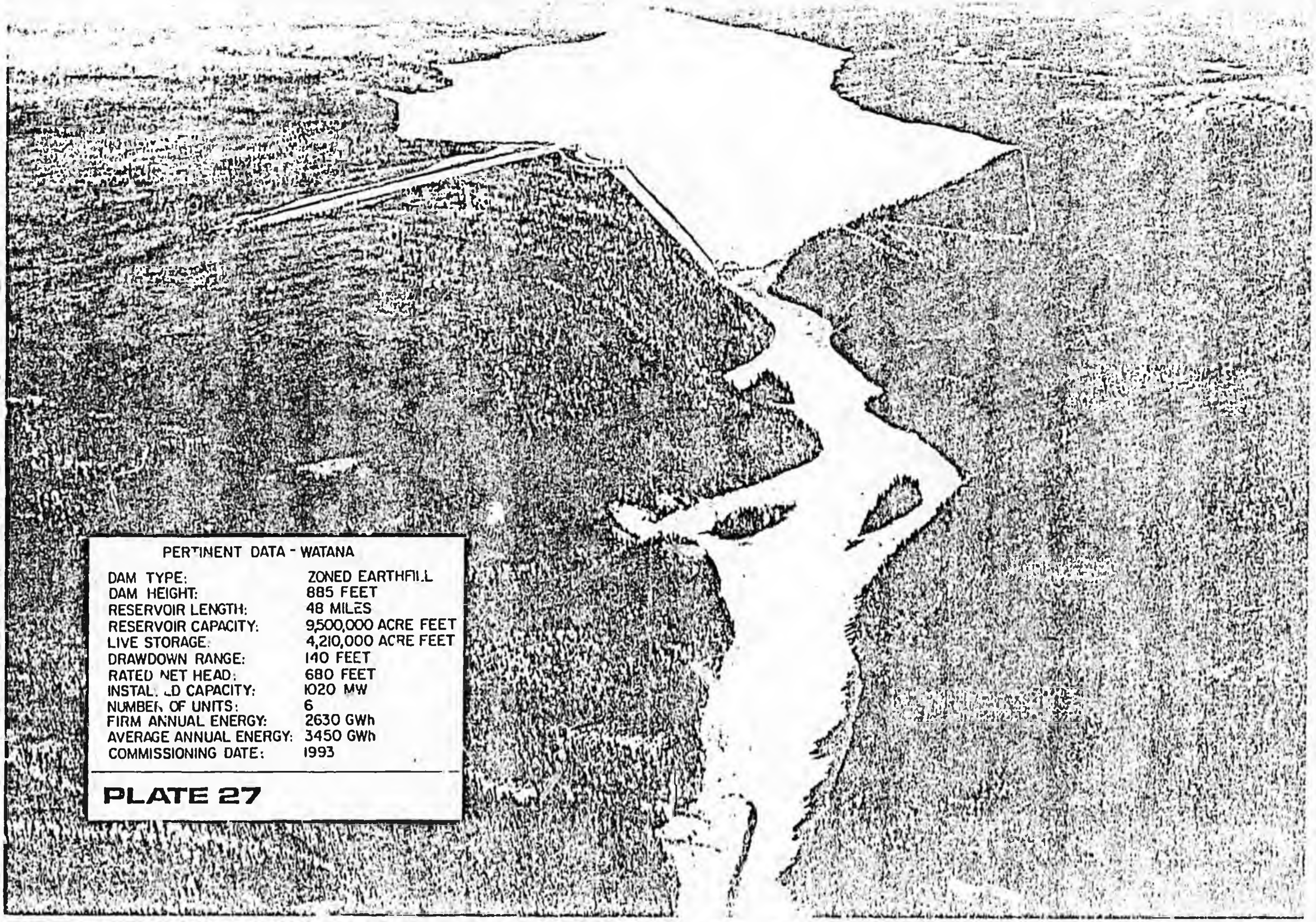
Financing Risks

Financial risks to the state and to consumers were analyzed, taking into account such factors as the risks of bond requirement overrun, inadequate debt service cover and others. The analysis suggests that there is a probability of 0.73 (73 percent confidence level) that savings to the Alaska consumer will be equal to or greater than those calculated.

Marketing Considerations

The Railbelt market area was earlier described in Section 2. In the absence of any plans to merge existing utilities into a central power authority, it was assumed that various utilities will enter into contracts for Susitna energy if it is seen as the lowest cost alternative available for meeting demand. Under the minimum state appropriation scenario, purchase of Susitna energy would be found preferable to installing and operating new thermal plants either to meet demand or to replace retiring units.

The relatively large capacity associated with each successive stage of the Susitna project will inevitably lead to periods during which more capacity is available to the system than prudent reserve criteria would otherwise require. As a result, it may be anticipated that those thermal units which are most costly to operate will be shut down temporarily until demand rises once again to the point that additional capacity is needed. During wet years, hydroelectric energy production in excess of estimated firm energy output will be available at virtually no incremental cost, and it will be used to displace higher cost energy from some thermal plants which may be operated only during years of low flow. In short, under the minimum state appropriation scenario, total system generation costs (and, therefore, costs to the consumer) will be less after various Susitna stages come on line even though a temporary surfeit of capacity may exist.



PERTINENT DATA - WATANA

DAM TYPE:	ZONED EARTHFILL
DAM HEIGHT:	885 FEET
RESERVOIR LENGTH:	48 MILES
RESERVOIR CAPACITY:	9,500,000 ACRE FEET
LIVE STORAGE:	4,210,000 ACRE FEET
DRAWDOWN RANGE:	140 FEET
RATED NET HEAD:	680 FEET
INSTALLED CAPACITY:	1020 MW
NUMBER OF UNITS:	6
FIRM ANNUAL ENERGY:	2630 GWh
AVERAGE ANNUAL ENERGY:	3450 GWh
COMMISSIONING DATE:	1993

PLATE 27

IMPLEMENTATION

The essential conclusions of the detailed feasibility study are that the project is technically feasible and economically viable. The safety of the population in the vicinity of the project will not be impaired and the unavoidable impacts which this large project will cause on the environment will not be unduly severe and can be adequately mitigated. Financing of the project is also feasible with state assistance at acceptable risk to consumers in the Railbelt region.

In the event that the state decides to proceed with the project, a license application will be prepared and it will be filed with the Federal Energy Regulatory Commission by September 30, 1982.

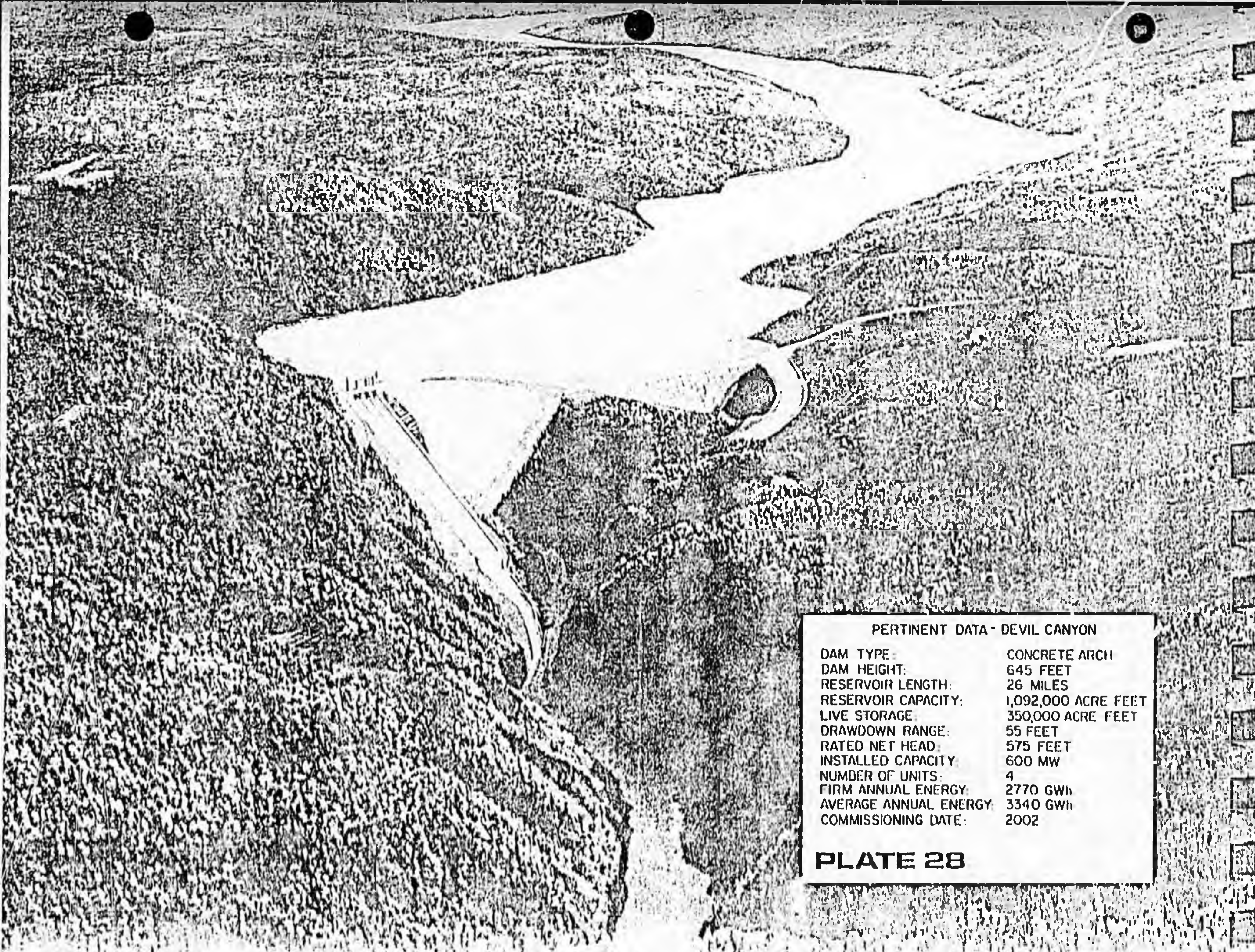
The high level of activity associated with environmental studies will continue unabated throughout the licensing period, which is assumed to extend until December 1984, and into the construction period should this proceed. Technical field investigations will continue as well. Future environmental and engineering findings will influence detailed design.

Prior to submission of the license application, the Alaska Power Authority will accept competitive proposals for detailed engineering services from qualified firms and will select one or more organizations to continue the work after September 1982 when the contractual obligations of Acres American Incorporated will have been fulfilled.

Aside from the construction of a limited access pioneer road commencing in mid-1983, activities within the proposed project area will not cause irreversible change before award of a license and prior to a further decision by the state to construct the first stage Watana dam and associated facilities.

No major commitment of funds is necessary to support preparation of a license application since its content will largely be based upon studies completed to date. Continuation beyond that point will require an investment in excess of $50 million, including land costs, before the end of 1983 to support continuing investigations and the commencement of detailed design and pioneer road construction. Immediate action is necessary to ensure that required lands are available for this early construction activity. Options open to the Power Authority include purchase, lease, and land transfer options.

THE ESSENTIAL CONCLUSIONS ARE THAT THE PROJECT IS TECHNICALLY FEASIBLE AND ECONOMICALLY VIABLE. UNAVOIDABLE IMPACTS WILL NOT BE UNDULY SEVERE AND CAN BE ADEQUATELY MITIGATED.



PERTINENT DATA - DEVIL CANYON

DAM TYPE:	CONCRETE ARCH
DAM HEIGHT:	645 FEET
RESERVOIR LENGTH:	26 MILES
RESERVOIR CAPACITY:	1,092,000 ACRE FEET
LIVE STORAGE:	350,000 ACRE FEET
DRAWDOWN RANGE:	55 FEET
RATED NET HEAD:	575 FEET
INSTALLED CAPACITY:	600 MW
NUMBER OF UNITS:	4
FIRM ANNUAL ENERGY:	2770 GWh
AVERAGE ANNUAL ENERGY:	3340 GWh
COMMISSIONING DATE:	2002

PLATE 28

REFERENCES AND ACKNOWLEDGEMENTS 13

References

Information presented in this summary report is drawn from two principal sources, both of which have been distributed to libraries throughout the Railbelt:

(1) **Draft Susitna Hydroelectric Project Feasibility Report**, Acres American Incorporated, March 1982:

Volume 1 — Engineering and Economic Aspects
- Section 1: Introduction
- Section 2: Summary
- Section 3: Scope of Work
- Section 4: Previous Studies
- Section 5: Railbelt Load Forecasts
- Section 6: Railbelt System and Future Power Generation Options
- Section 7: Susitna Basin
- Section 8: Susitna Basin Development Selection
- Section 9: Selection of Watana General Arrangement
- Section 10: Selection of Devil Canyon General Arrangement
- Section 11: Selection of Main Access Plans
- Section 12: Watana Development
- Section 13: Devil Canyon Development
- Section 14: Transmission Facilities
- Section 15: Project Operation
- Section 16: Estimates of Cost
- Section 17: Development Schedule
- Section 18: Economic and Financial Evaluation

Volume 2 — Environmental Aspects
- Section 1: General Description of the Locale
- Section 2: Water Use and Quality
- Section 3: Report on Fish, Wildlife, and Botanical Resources
- Section 4: Report on Historic and Archeological Resources
- Section 5: Report on Socioeconomic Impacts
- Section 6: Geology and Soils
- Section 7: Report on Recreational Resources
- Section 8: Report on Aesthetic Resources
- Section 9: Report on Land Use
- Section 10: Alternatives to the Susitna Project
- Section 11: List of Literature

Volume 3 — Plates

Volumes 4 through 8 — Appendices

(2) **Comment Draft Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans**, Battelle Pacific Northwest Laboratories, February 1982.

Acknowledgements

Major subcontractors to Acres American Incorporated who made significant contributions during the course of the study include:

- R&M Consultants, Incorporated
- Cook Inlet Region, Incorporated/Holmes and Narver, Incorporated
- Woodward-Clyde Consultants
- Frank Moolin & Associates, Incorporated
- Terrestrial Environmental Specialists, Incorporated, together with subcontractors and members of the faculty of the University of Alaska.

Numerous other participants in Alaska provided responsive logistical support and related activities.

State agencies working under the terms of reimbursable services agreements with the Alaska Power Authority conducted studies and investigations, without which this report would not have been possible:

- Institute for Social and Economic Research, University of Alaska
- Alaska Department of Fish and Game

Cooperation and assistance from resource agency representatives who served on the Steering Committee is gratefully acknowledged, as is the extraordinary effort of the Public Participation staff of the Alaska Power Authority.

Rigorous professional review of all major aspects of the proposed Susitna development was accomplished by the External Review Panel which reported to the Alaska Power Authority, and by a second Review Panel and numerous consultants who assisted the Acres' team throughout the course of the work. The diligence and skill of these eminent experts has been important to the successful identification and resolution of problems and to the development of optimal plans.

Space limitations preclude the mention by name of the many others whose interest, support, and healthy criticism have been invaluable, but their selfless efforts are sincerely appreciated.

Finally, the expert management and guidance provided by the Executive Director and the staff of the Alaska Power Authority and the unusual professionalism they have displayed throughout the study period are particularly worthy of note.

SUSITNA HYDROELECTRIC PROJECT

TASK 11: FINANCING OPTIONS

Prepared by:
Acres American Incorporated

January 1983

ACRES

ALASKA POWER AUTHORITY

TABLE OF CONTENTS

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC DEVELOPMENT
FINANCING OPTIONS

1 - OBJECTIVES

The objective of this report is to set out the currently most viable financing options for the Watana phase (1985-1993) of the Susitna Hydroelectric Development together with the comment of the Power Authority's investment advisors (The First Boston Corporation, John Nuveen & Company, and First Southwest Company) on the impact of these options on the credit rating of the State of Alaska and on other related issues.

2 - ECONOMIC CONTEXT OF THE FINANCING PROPOSALS

The economics, marketing and financing of Susitna will be the subject of a final review by Acres American in March of 1983. The data utilized in this analysis however is, with minor modification, based on the Susitna Task 11 Reference Report. Some amendment of the data used here will then arise in the light of the March 1983 review. Our preliminary indications are however that the probable revisions will not materially impact the conclusions which may be based on the results presented in this memorandum.

3 - BASIC POLICY ISSUES: RISK AND TIMING

The Watana phase alone of Susitna will take 10 years (from the present stage of FERC licence application) to complete. It is also clearly apparent that it will not be possible to produce wholly certain forecasts of the underlying energy economics of the project nor of the availability of State revenues or of the competing demands for State resources which may arise over this extended period. The requirement that such forecasts be produced as an initial pre-condition for authorization of development would therefore effectively preclude Susitna or indeed, any long term development of Alaska's natural resources.

It must also be frankly recognized that risks from erroneous forecasts will arise from proceeding with Watana at its estimated capital cost of $3.6 billion (1982 dollars). These are primarily risks associated with load forecasts, interest rates, inflation, etc. But it must be recognized also that risks will arise through <u>not</u> proceeding with Susitna since this will force Alaska electric power consumers to face the alternative risks arising from the estimated $1.7 billion (1982 dollars) of capital cost for fossil fuel plants and the risk that these plants will also require meeting the ever increasing operating costs reflected in Exhibit A. Moreover, these other options also involve risks from forecasting errors in the load forecasts, interest rates, inflation, etc.

In the Watana investment decision, therefore, the issue is not between risk and no risk, or investment and no investment, but only between one set of risks and another and one set of capital expenditures and another. The financing options as developed below therefore endeavor to reflect these risks in a realistic manner and provide for development/financing options which effectively minimize these risks.

It is an inherent characteristic in the very magnitude of their financial requirements and the complex political and economic issues which they pose, that "mega-projects" such as Susitna, have a "window of opportunity" during which they can proceed. If this "window" is missed the opportunity to proceed may not recur for many years.

Ultimate development of the hydroelectric potential of Susitna must be considered as highly probable given the authoritive estimates (see Exhibit C) and forecasts of Alaska's own Department of Revenue of continued significant long term real increase in alternative energy prices. Hence the essential issue is whether we proceed in the immediate future with this window of opportunity or whether the project is postponed-- possibly for a long period. Here, the following considerations must be taken into account:

(a) On present forecasts, postponement of Susitna wholly delaying its net benefits, would cost $43 million p.a. in 1982 present value terms.

(b) The possibility, referred to above, that the "window of opportunity" for Susitna may not recur for a very long period. This could result in the cost of postponement being a multiple of that given in (a).

Finally, we would stress that the Susitna Project would also be re-assessed by the Power Authority in 1984 before any major outlays were undertaken in 1985. By this date we will have two more years of economic and financial data with which to re-evaluate the situation and the uncertainties regarding the scale of the world economic recovery. The existing uncertainty of near-term future petroleum prices and revenues should be substantially reduced.

4 - THE FINANCING OPTIONS

The Essential Pre-conditions

The essential pre-conditions for any financing scheme is taken as the requirement that they meet:

(a) An acceptable cost of energy in the early years of operation. This is taken as effectively meaning that the cost of power must be close to or below the cost of energy that would result from pursuing the best Thermal Option as shown in Exhibit A.

(b) Meeting its debt coverage. All the residual financing requirements are assumed to be met (long-term) by borrowing in the form of tax-exempt bond financing at 10% with a coverage requirement of 1.1. This requirement must be met or the borrowing could not be regarded as meeting the basic requirements of acceptability to investors.

(c) Acceptable and viable levels of borrowing. The level of borrowing which the project requires to be met by G.O. bonds will depend upon the capacity of the State of Alaska to raise G.O. Bonds either without effect on its bond rating or with an effect that is regarded as an acceptable price for proceeding with the project. The other source of borrowing will be Revenue Bonds which, as discussed below, depend upon the power contracts which are in place.

(d) An acceptable level of demands on the funds available to the State of Alaska. The funds here are taken as the estimate of the uncommitted funds for capital appropriation as estimated by John Nuveen & Company and shown in Tables 1 and 2. (These take into account the estimated maximum G.O. Bonds as a source of funds.)

The Financing Options

A very large number of financing options have been considered. The four options: A, B, C, and D summarized in Tables 3 and 4 appear those most likely to fulfill the essential criteria stated above. These options are:

Option A

This option calls for $1.4 billion 1982 dollars in State appropriations phased over the period 1984 to 1989. This option may also indirectly involve drawing upon G.O. Bonds since these (see Tables 1 and 2) are built into the final total "available for Susitna". (The phasing of the appropriations year-to-year is, of course, arbitrary in that it can be adapted to the flow of funds represented by the "available for Susitna", providing the total remains the same.)

Option B

This option is precisely identical to that of Option A except that it involves a State appropriation of $1.8 billion in 1982 dollars phased over the period 1984-1989.

Options C and D

These options involve the concept of dedicated funds of the same magnitude as Option A and B being made available through a constitutional amendment. Since these options are of a markedly different character, they are discussed separately below.

Phases and Forms of Borrowing

Before reviewing the characteristics of the schemes proposed, it is necessary first to deal briefly with the phases and forms which the borrowing may involve.

In the Preliminary Phase between 1985 and 1987, the dam itself will not be under actual construction and only preliminary work will be in progress. Under these circumstances, it must be accepted that no Revenue Bond financing could be obtained and that the project at this stage would have to rely wholly upon State appropriations from the resources shown in Tables 1 and 2.

In the final and major phase of construction between 1989 and 1993 the objective of any financing or scheme must be to ensure that the financing at this stage is based upon Revenue Bonds which, although they will require moral obligation of the State of Alaska, are based on sufficiently rigorous power contracts that they wholly meet their debt coverage requirements when Watana comes into operation and do not to any significant extent rely upon the credit of the State of Alaska.

Whether this objective can be attained will depend first on the levels of State appropriations. This might be seen as the "equity" investment in the project which provides security to the investors and reduces the total amount of borrowing which the project requires.

The second factor is the precise magnitude and terms of the power contracts with the utilities. Since this depends upon detailed negotiations and organizational considerations it is not possible to comment definitively on whether or not the objective of 100% Revenue Bond financing would be possible for the final stage of the Watana development. In what follows, therefore, the Revenue Bond requirement is simply stated as a total sum which follows from the level of State appropriations A, B, C and D.

Hence any financing scheme must be seen at this stage as simply conditional with a key condition being that power contracts providing for such Revenue Bond financing are obtained and are in place before any major capital expenditure is undertaken. Since any significant capital expenditure could not, in any case, take place before the end of 1984 when the FERC license is expected to be granted, there are at least two years during which to secure such power contracts and meet this condition.

Assessment of the Financing Options

Details of the financing options are given in the computer printouts (attached) and the basic details are summarized in Tables 3 and 4 and Attachment E. In order to make the data conform as far as possible with the data on State revenues and the sums described in Tables 1 and 2 as "uncommited capital funds", the inflation assumptions in the Acres Task 11 March 1982 report, were revised to conform to those of the State revenue projections. Other minor revisions were also made.

Subject to maintaining the State's present double A rating, the assessment of the options given in Table 3 must be seen as a trade-off between the criteria of cost of power and State appropriations, (the higher the State appropriations, the lower the cost of power). Where these objectives are in conflict, it is left to the political decision-makers to resolve this conflict by modification of the criteria.

Considering Option A first, it is seen from Table 3 to involve State appropriations of $1.4 billion over the six year to 1989 and to require Revenue Bond financing of $2.7 billion (all in 1982 dollars).

Turning first then to the criterion of acceptability in terms of the percentage of uncommitted capital funds in Tables 1 and 2, this is shown in Table 4 as an average over the appropriation period 1984 to 1989. It varies from 57% for the 30th percentile projections to 38% in the 50th percentile case. It is left, of course, for the political assessment whether the percentages shown are acceptable in the light of other priorities.

No year-by-year figures of this percentage is given since in Acres' assessment the year-by-year engineering estimates of costs are, in the early years, subject to very considerable choice and could be changed significantly with rescheduling if this was thought desirable to reduce the claims on the funds available.

Turning then to the criterion of the cost of power, it is found that this option, because of the high level of borrowing (assuming a 10% rate of interest), would involve significant deficits during operation in early years unless the cost of power were increased above the level set by the Best Thermal Option.

In these early years the essential problem facing Watana in marketing its power is that, in the first year or two of its life, it is in competiton with power sources with the advantage of being based on the cost of facilities purchased years earlier at much lower cost than will be involved either in their replacement or in the additional coal-fired units which would be required in 1995 and 1996 if Watana power were not available.

As shown in Tables 3 and 4 and in Exhibit E, the only means of meeting the deficits without further State appropriations would be to allow the cost of power to rise above the best Thermal Option in these three transitional years. Whether this would be regarded as an acceptable option is again an issue of political judgment. It might reasonably be supposed given that the only alternative option would be to face the dramatically escalating cost of the best Thermal Option only a few years later, the increase in the cost of power above the Best Thermal Option might be acceptable in turn for the very considerable long-term advantages afforded by a source of power which would be virtually fixed in cost even in nominal dollars.

It is also possible that appropriate levelizing provisions could be devised in the rate base to bring about a phased increase in price closer to the price set by the Best Thermal Option ceiling.

Option B might be seen as defining an alternative to any increase in the cost of power by increasing the level of State appropriation to $1.8 billion over the period 1984 to 1989. This is seen from Table 2 and the attached Exhibit E, to produce a cost of power below the Thermal Option even in the earliest years. It also has the advantage of reducing the Revenue Bond requirement in the Final Phase of Watana by $0.52 billion (in 1982 dollars). It would, however, mean committing between 50% and 75% of the uncommitted capital funds to the project over the period 1984-1989 and thus heavily competing with other priorities in the 30th percentile revenue forecast case.

The Dedicated Fund Options C & D

A significant difficulty in the development of any long-term financing scheme such as would be required for any long term development of Alaskan resources is the uncertainty of the year-by-year political appropriation process. This applies generally throughout North America, but is of particular relevance in the context of Alaska given the constitutional considerations and the relative importance of appropriations for capital spending in the State.

It is of understandable concern to investors in State of Alaska securities related to long-term developments, that through the political process these projects could be subject to deferral, limitations of State contribution, or even cancellation in the course of their development phase. This may be considered a serious handicap to the long-term development of Alaska's natural resources.

In the light of this, we have been asked to consider the dedication of 50% of the Permanent Fund income to a Power Development Fund which would be designed to provide a relatively more secure and certain source of appropriations for the major long-term development potential for Alaska represented by hydroelectric power and which could offer most Alaskans permanent low-cost power as a basic domestic and industrial resource. This proposal is regarded as representing an important contribution to securing long-term appropriations for such major developments in a manner which would be regarded by investors as offering much greater assurance of on-going systematic development and hence greater security for borrowing in the course of construction.

The scheme, as provisionally formulated, involves the principle of $4,500 to $6,000 per capita being the normal contribution from the fund for a hydro development serving a particular area. In the context of Susitna this would involve a total State appropriation from the fund of approximately $1.4 to $1.8 billion. Its results are shown as Options C and D in Tables 3 and 4 and in Exhibit E. Its impact on cost of power and the level of Revenue Bond financing required is seen to be very close to that of Options A and B.

A further important characteristic of this particular proposal, however, is that such funding would provide the Power Authority with a substantial financial base that would make it capable of raising finance or providing guarantees where these were important to secure financing under changing market conditions or secure funding for developments lacking an adequate independent credit base.

It is recognized that this proposal would involve a constitutional amendment, but it is precisely the constitutional nature of such a dedicated fund that would be most effective in terms of development of Alaska's resources.

5 -STATEMENT BY THE FIRST BOSTON CORPORATION, JOHN NUVEEN & COMPANY, AND FIRST SOUTHWEST COMPANY

The First Boston Corporation and John Nuveen & Company (the Alaska Power Authority's co-senior managing underwriters) and First Southwest Company (the Power Authority's financial advisor) have reviewed the financing options described in this memorandum and have made the following observations regarding the financing of the Susitna Project. Together these investment firms are referred to as the Power Authority's Investment Advisors. Their opinions stated herein are based primarily upon the State's projected revenues using the "30th Percentile". First Boston Corporation, John Nuveen & Company and First Southwest Company have concurred in the following statement:

"It is our opinion that prior to major State expenditures, of State appropriations definitive contractual commitments by participating Railbelt Utilities be in place and that such appropriations should be funded by the State during the period 1983-1989, a period within the estimated life of Alaska's oil and gas reserves, so that appropriations provided during this period will provide the crucial "equity" to assure the most economical bond financing of the remainder of the project.

In view of the magnitude of Susitna and the relatively long construction period, the Power Authority should not commence significant borrowing for Susitna before the late 1980's at which time major risks have been defined and completion and start-up dates are known with a high degree of reliability.

In our opinion, in order to maintain the financial integrity for the State of Alaska, prerequisites for issuance of bonds of any type for the project are:

(a) Definitive contractual commitments by participating Railbelt utilities;

(b) Up-dated economic and financial analysis of the project; and

(c) Resolution of the question of tax exemption of such bonds.

With regard to the utilization of State G.O. Bonds, it is our opinion that the issuance of such bonds will be of limited importance to financing Susitna because of the substantial borrowing required for this project. If a major portion of such borrowing were met from State G.O. Bonds, Alaska's present double A ratings would be endangered. The following are some major limitations of State G.O. Bonds:

(1) A crucial feature of Alaska's double A rating is the Rating Agencies' concurrence with the State's present debt policy of amortizing G.O. Bonds rapidly (i.e., within 10 to 15 years (a period within current estimates of oil/gas revenues (the principal source of State revenues) and we believe this policy should be continued.

(2) Using the State's December, 1982 Department of Revenue forecasts, we estimate that the State can issue a relatively small volume of G.O. Bonds while maintaining it's double A rating (see Tables 1 and 2). Based on the "30th percentile" of the Department of Revenue projections, the State could "safely" issue $565 million (nominal dollars, assuming 8% inflation) G.O. Bonds during the period fiscal 1983-1990. This amount would rise to $945 million if the "50th percentile" revenue projections were achieved during this period.

A reduction in the State's rating from double A to single A could correspondingly lower the rating of Alaska Power Authority's own revenue bonds backed by a Capital Reserve Fund with a moral obligation to a rating as low as Baa by Moody's and BBB by Standard & Poors. Such a rating would substantially raise the

Authority's borrowing cost and could impair the viability of the project. The volume of debt contemplated under all scenarios would be extremely difficult to market if rated less than "A".

The Power Authority, rather than utilizing State G.O. Bonds, should utilize, to the fullest extent possible, revenue bonds secured by the income derived from participating Railbelt Utilities pursuant to long-term power sales contracts. Additional security for the bonds would be provided by the Capital Reserve Fund provided in the Alaska Power Authority Act whereby to the extent that revenues from Susitna were insufficient to service the bonds, the Legislature may, but is not legally obligated to, appropriate monies to make up such deficiency in the Capital Reserve Fund. Alaska Power Authority's credit perception will be enhanced by a simple and straightforward debt structure comprised solely of revenue bonds backed by the State's "moral obligation" pledge.

Any dedicated stream of State appropriations covering the entire construction and start-up period will enhance confidence of investors, participating utilities, and the rating agencies in the completion of the project. Such an appropriation would, however, require a constitutional amendment.
In conclusion, as Investment Advisors to the Authority, we strongly prefer the financing plan developed as Option B and D which requires greater appropriations prior to issuance of Revenue Bonds because the credit status of the State is least affected and the credit quality of the Authority's bonds is enhanced, maintaining project feasibility. Should oil revenue and projections, however, dramatically improve we would be in a position to more favorably consider alternate financial options."

6 - CONCLUSIONS

Our conclusions relate primarily to Options A and B since the dedicated fund proposals C and D can be seen in the present context as primarily a legislative route to these options.

It may be appropriate in conclusion first to state our own assessment of the decision issues involved at this stage. First, the decision issue is not an irrevocable commitment to proceed with Watana. As already noted, the FERC license will not be available for another two years and no major expenditures could be undertaken until 1985.

It would therefore appear that the essential issue is that of maintaining and planning for the Watana option. The only grounds for not maintaining this option with its very substantial long-term economic advantages, would be that we had concluded that no viable and politically acceptable financing scenario was possible.

Given the very wide range of uncertainties for future State revenues, and hence the levels of State appropriations which might be available at the first point of major commitment in late 1985, such an adverse conclusion certainly cannot be substantiated at this time on the basis of the preceding analysis. If, for example, State revenues were as high or higher than the 50th percentile, the State capital fund available for Watana would be substantially increased and the $1.4 billion appropriation (Option A) would represent 38% of the uncommitted capital funds over the period 1984-1989. Moreover, the circumstances which would bring about such an increase in State funds--mainly a recovery in world oil prices--would confirm the economic desirability of advancing with Watana and obviating dependence on fuels with prices related to that of oil.

We must also note again that the levels of spending in individual years used in the analysis was constructed on normal engineering criteria without reference to phasing the engineering expenditures to conform (without significant additional cost) to year-to-year budget constraints.

Subject to political decisions and priorities, therefore, our assessment is that all the financing options proposed in this memorandum are viable. In consequence, we recommend that over the two-year decision period to 1984, the remaining preconditions of financing viability, both political and contractual (in terms of power contracts and tax exempt bond financing) are resolved. A reconsideration of the financing options might then be undertaken in 1984 when, as aleady noted, some of the major economic uncertainties affecting the economics of generation options and the revenues of the State of Alaska are also likely to be resolved. It should also be possible within this time frame to review the time profile of potential cash demands for construction and bring them more closely into conformity with available appropriations.

If this conclusion were adopted, it might also be considered appropriate, in order to avoid undue "bunching" of demands for Susitna financing, to establish a level of funding for the project of the order of perhaps $100 million in FY 1984. This, in our view, would be seen as a positive step which should appreciably assist in the negotiations of power contracts since it would indicate the State's conditional intent to proceed with the project. This would give such negotiations the credibility essential to a successful outcome.

TABLES

ALASKA POWER AUTHORITY
CAPITAL FUNDS AVAILABLE FOR SUSITNA
30th PERCENTILE PROJECTION

Fiscal Year	General Fund Unrestricted Revenues (1)	Total Capital Spending Limits	Estimated Maximum G.O. Bond Issues (2)	Total Available Capital	Committed Capital Grants and Loans (8%)	Remaining Capital	APA Capital Budget Excluding Susitna	Uncommitted Capital Funds	Planned Susitna Expenditures (nom. $) (3)
1984	2908.2	969	0	969	475	494	174.2	320	0
1985	2939.9	980	0	980	513	467	244.5	222	183
1986	3472.9	1158	300	1458	554	904	282.3	622	405
1987	3870.4	1290	90	1380	598	782	125.8	656	437
1988	3917.0	1306	125	1431	646	785	0	785	442
1989	4293.8	1431	0	1431	698	733	0	733	639
1990	3679.9	1227	50	1277	754	523	0	523	1121
1991	3295.9	1099	140	1239	814	425	0	425	1270
1992	3186.4	1062	0	1062	879	183	0	183	862
1993	2919.4	973	110	1083	950	133	0	133	584
1994	2779.0	926	0	926	1025	0	0	0	0

(1) 30th percentile projection of Department of Revenue net of Debt Service on the State G.O. Debt.

(2) Maximum General Obligation Debt that can be issued (10 year, equal annual principal amortization at 7.5%) and keep total G.O. Bond Debt Service below 5% of General Fund Unrestricted Revenues.

(3) Source: Acres American Incorporated (Converted to June 30 Fiscal Year).

TABLE 1

ACRES

ALASKA POWER AUTHORITY
CAPITAL FUNDS AVAILABLE FOR SUSITNA
50th PERCENTILE PROJECTION

Fiscal Year	General Fund Unrestricted Revenues (1)	Total Capital Spending Limits	Estimated Maximum G.O. Bond Issues (2)	Total Available Capital	Committed Capital Grants and Loans (8%)	Remaining Capital	APA Capital Budget Excluding Susitna	Uncommitted Capital Funds	Planned Susitna Expenditures (nom. $) (3)
1984	3369	1123	0	1123	475	648	174.2	474	0
1985	3492	1164	350	1514	513	1001	244.5	757	183
1986	4116	1372	190	1562	554	1008	282.3	726	405
1987	4553	1518	95	1613	598	1015	125.8	889	437
1988	4645	1548	235	1783	646	1137	0	1137	442
1989	5103	1701	50	1751	698	1053	0	1053	639
1990	4848	1616	25	1641	754	887	0	887	1121
1991	4345	1448	160	1608	814	794	0	794	1270
1992	4221	1407	35	1442	879	563	0	563	862
1993	4017	1339	170	1509	950	559	0	559	584
1994	3957	1319	0	1319	1025	294	0	294	0

(1) 50th percentile projection of Department of Revenue net of Debt Service on the State G.O. Debt.

(2) Maximum General Obligation Debt that can be issued (10 year, equal annual principal amortization at 7.5%) and keep total G.O. Bond Debt Service below 5% of General Fund Unrestricted Revenues.

(3) Source: Acres American Incorporated (Converted to June 30 Fiscal Year).

TABLE 2

SUSITNA-SUMMARY OF FINANCING REQUIREMENTS

REAL 1982 DOLLARS

	STATE APPROPIATION TAKEN AS NEEDED				DEDICATED STATE APPROPIATION			
	$1.4 BN (REAL)		$1.8 BN (REAL)		$1.4 BN (REAL)		$1.8 BN (REAL)	
	DEBT	STATE APPROP.	DEBT	STATE APPROP.	DEBT	STATE APPROP.	DEBT	STATE APPROP.
	$M	$M	$M	$M	$M	$M	$M	$M
1983	-	-	-	-	-	160	-	160
1984	-	81	-	81	-	222	-	222
1985	-	225	-	225	-	276	-	276
1986	-	336	-	336	-	318	-	318
1987	-	317	-	317	-	345	-	345
1988	-	306	-	306	-	79	-	378
1989	409	94	9	535	337	-		101
1990	884	-	847	-	878	-	770	-
1991	757	-	718	-	750	-	710	-
1992	505	-	466	-	498	-	457	-
1993	146	-	146	-	146	-	146	-
TOTAL	2701	1400	2186	1800	2609	1400	2083	1800

COST OF ENERGY TO MEET 1.1 DEBT SERVICE COVER AND PERCENT IN EXCESS OF BEST THERMAL OPTION

	MILLS		MILLS		MILLS		MILLS	
1993	74	46 %	61	17 %	72	41 %	58	14 %
1994	77	25 %	64	5 %	75	22 %	62	-
1995	73	21 %	61	1 %	70	17 %	58	-
1996	72	-	57	-	69	-	55	-
1998	68	-	54	-	65	-	51	-
1999	63	-	51	-	61	-	48	-
2000	60	-	48	-	57	-	46	-

TABLE 3 -- SUSITNA: SUMMARY OF FINANCING REQUIREMENTS IN REAL TERMS

ACRES

SUSITNA-SUMMARY OF FINANCING REQUIREMENTS

-------------<u>NOMINAL</u> DOLLARS-------------

	STATE APPROPIATION TAKEN AS NEEDED				DEDICATED STATE APPROPIATION			
	----$1.4 BN----- (REAL)		----$1.8 BN----- (REAL)		----$1.4 BN----- (REAL)		----$1.8 BN----- (REAL)	
	DEBT	STATE APPROP.	DEBT	STATE APPROP.	DEBT	STATE APPROP.	DEBT	STATE APPROP.
	$M	$M	$M	$M	$M	$M	$M	$M
1983	-	-	-	-	-	175	-	175
1984	-	100	-	100	-	257	-	257
1985	-	276	-	276	-	338	-	338
1986	-	436	-	436	-	413	-	413
1987	-	437	-	437	-	475	-	475
1988	-	447	-	447	-	115	-	552
1989	633	208	13	828	522	-		157
1990	1465	-	1403	-	1454	-	1275	-
1991	1341	-	1274	-	1329	-	1259	-
1992	958	-	883	-	945	-	868	-
1993	296	-	296	-	296	-	296	-
	----	----	----	----	----	----	----	----
TOTAL	4693	1904	3869	2524	4546	1773	3698	2367
	====	====	====	====	====	====	====	====
PERCENTAGE OF UNCOMMITTED STATE CAPITAL FUNDS	30 to 57 %		50 to 75 %					

COST OF ENERGY TO MEET 1.1 DEBT SERVICE COVER AND PERCENT IN EXCESS OF BEST THERMAL OPTION

	MILLS		MILLS		MILLS		MILLS	
	-----		-----		-----		-----	
1993	150	46 %	123	17 %	145	41 %	110	14 %
1994	168	25 %	140	5 %	163	22 %	134	-
1995	169	21 %	141	1 %	164	17 %	135	-
1996	179	-	143	-	172	-	137	-
1998	180	-	144	-	173	-	137	-
1999	181	-	145	-	175	-	139	-
2000	182	-	147	-	176	-	140	-

<u>NOTE</u>: PERCENTAGE OF UNCOMMITTED FUNDS CALCULATED FROM 30 AND 50 PERCENTILE PROJECTIONS

TABLE 4 -- SUSITNA: SUMMARY OF FINANCING REQUIREMENTS IN NOMINAL TERMS

ACRES

EXHIBITS

ACRES

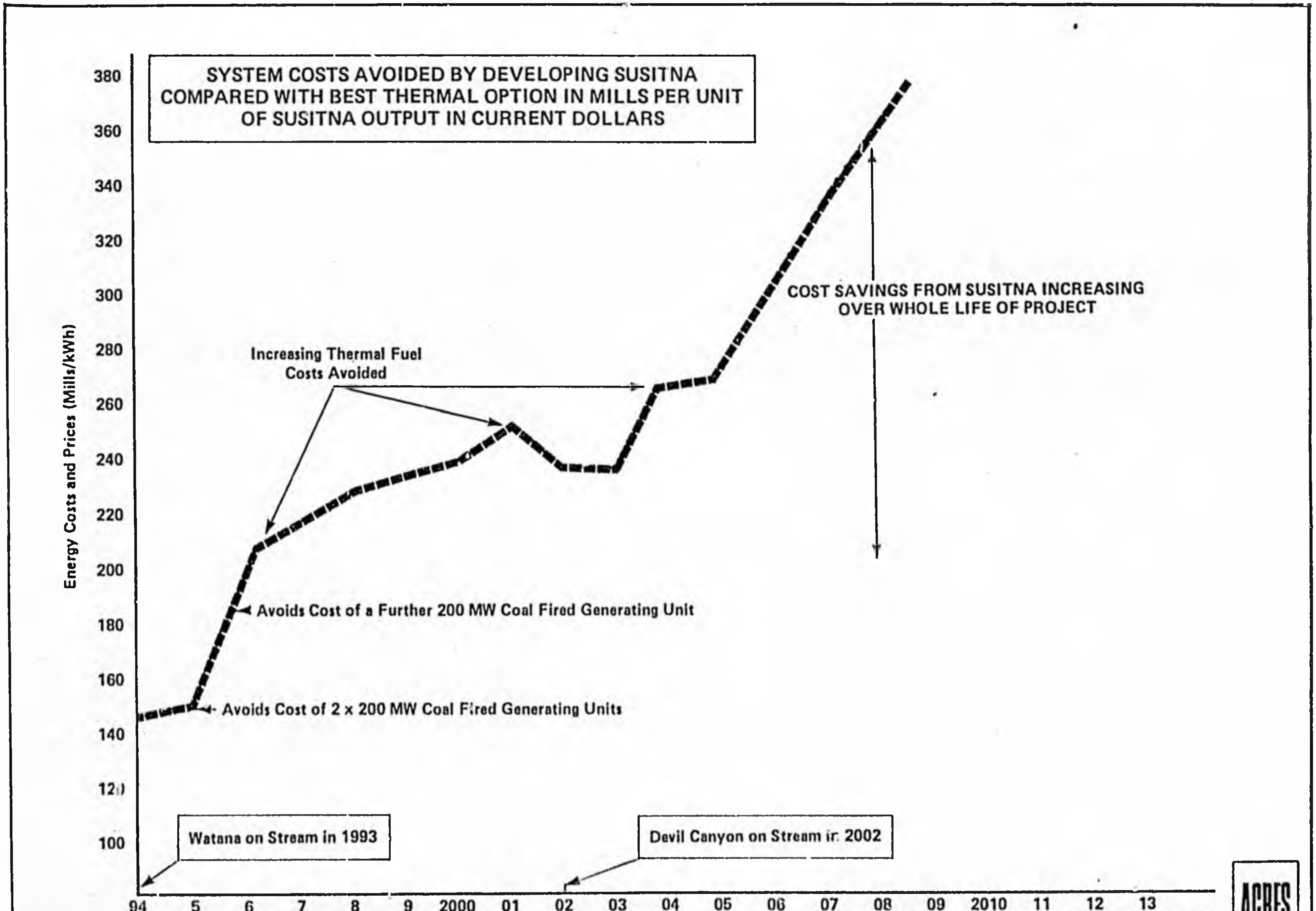


Exhibit A – SYSTEM COSTS AVOIDED BY DEVELOPING SUSITNA

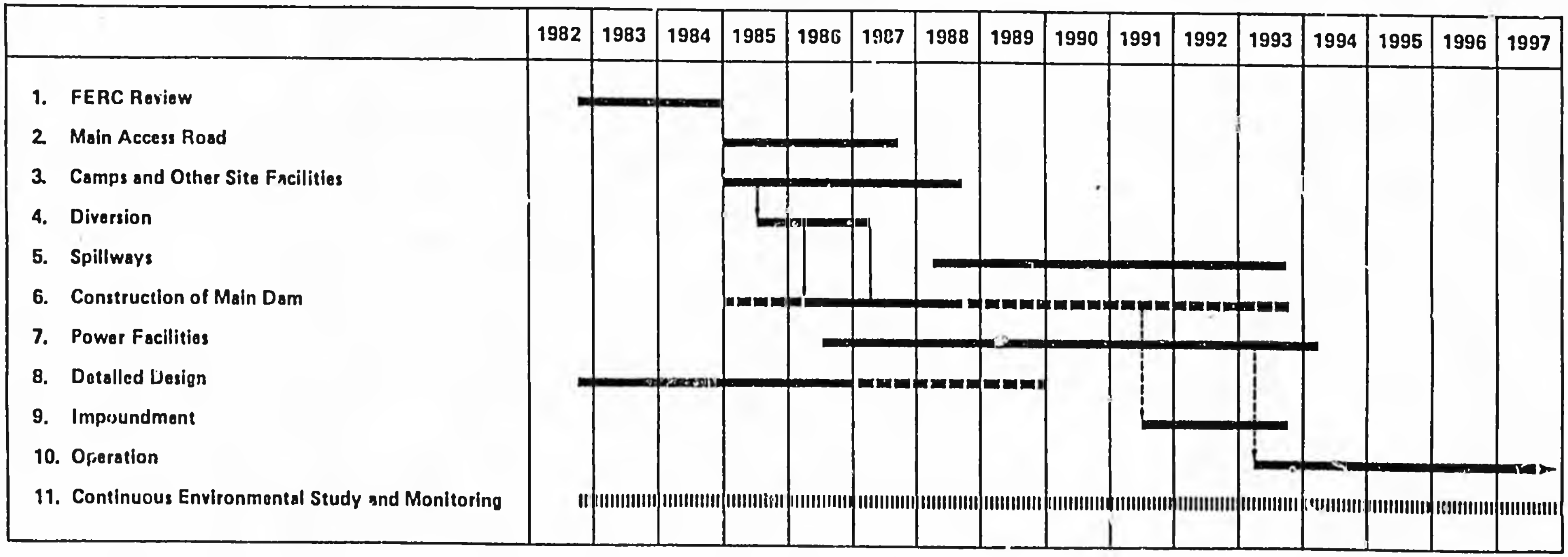


EXHIBIT B -- WATANA CONSTRUCTION SCHEDULE

ACRES

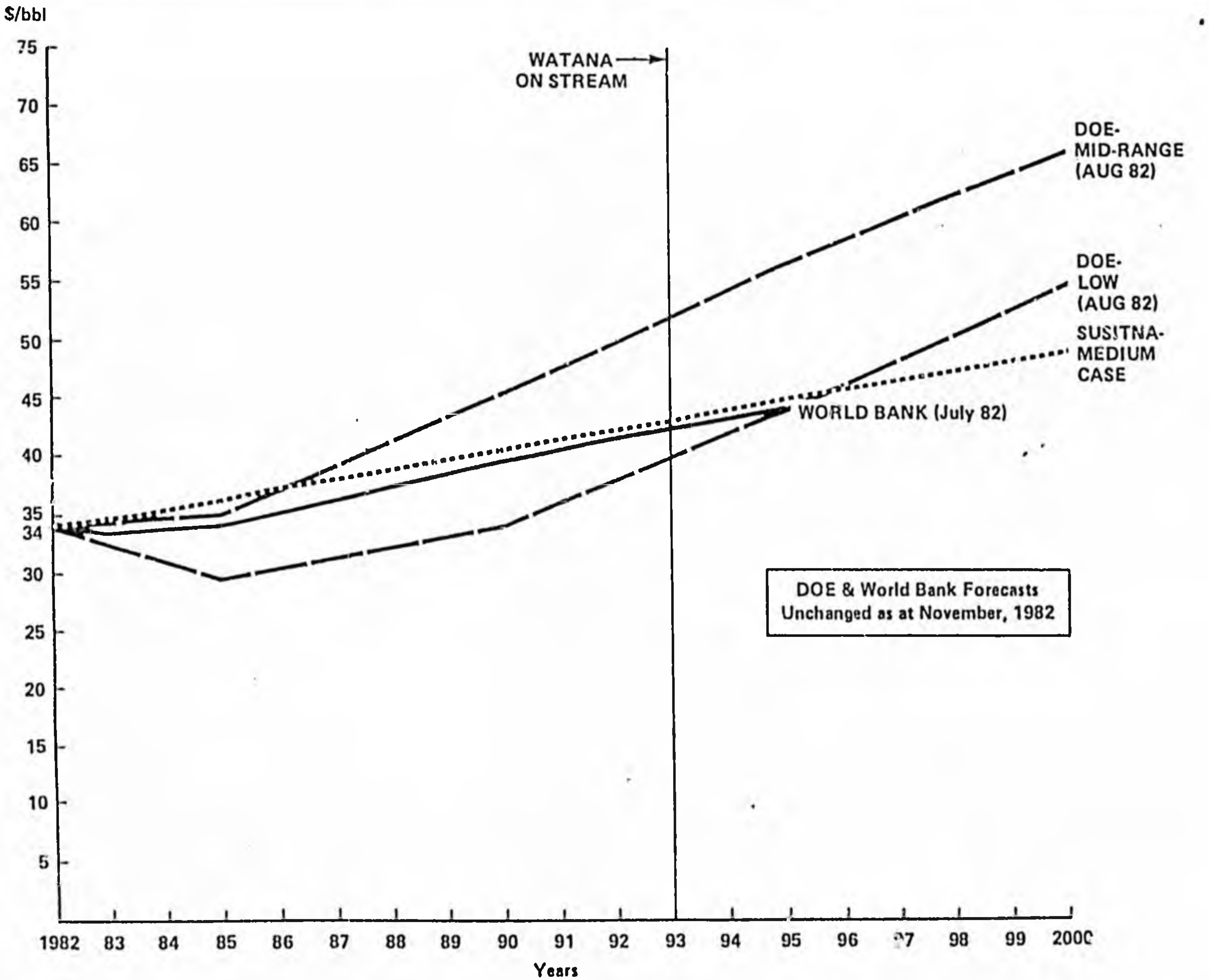
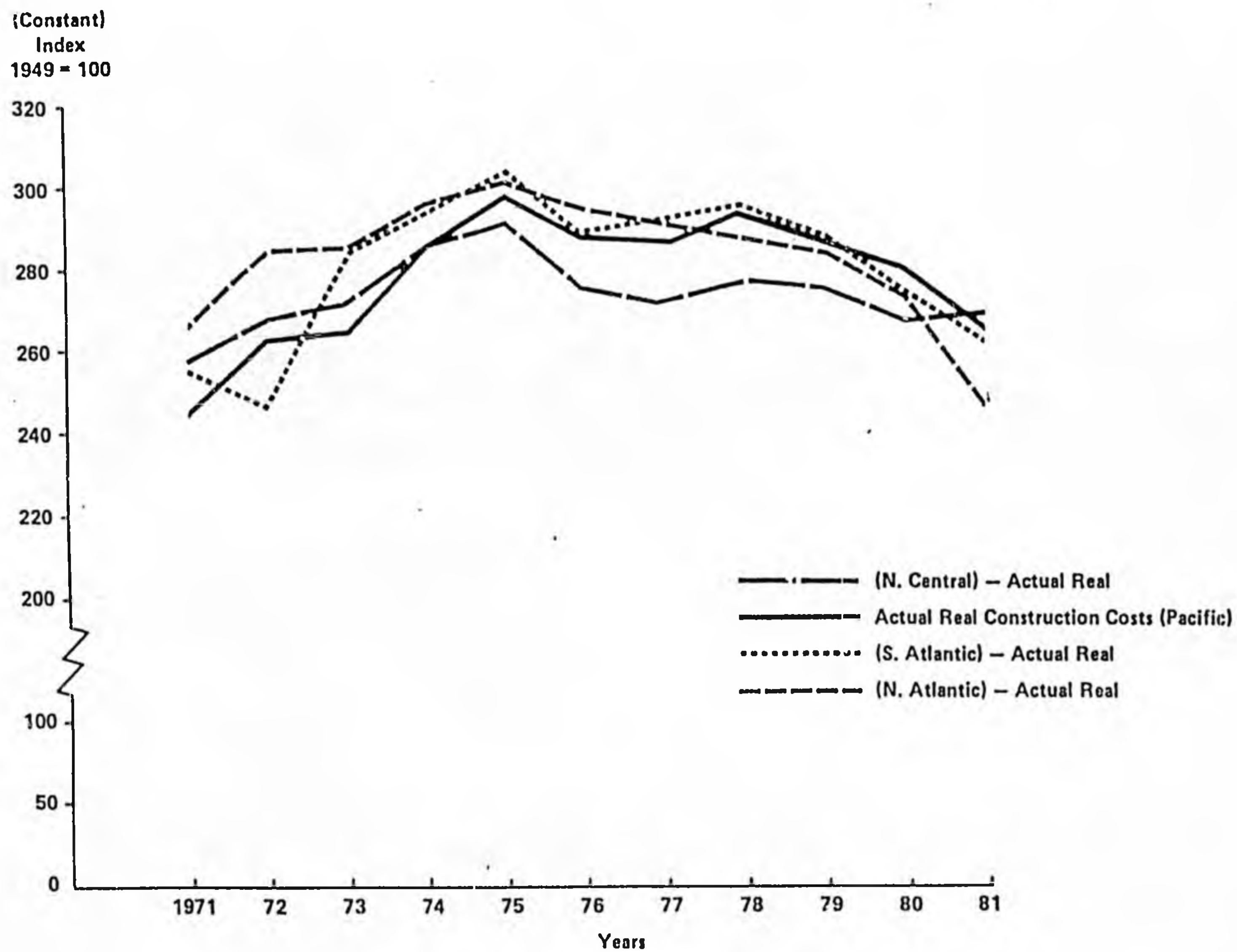


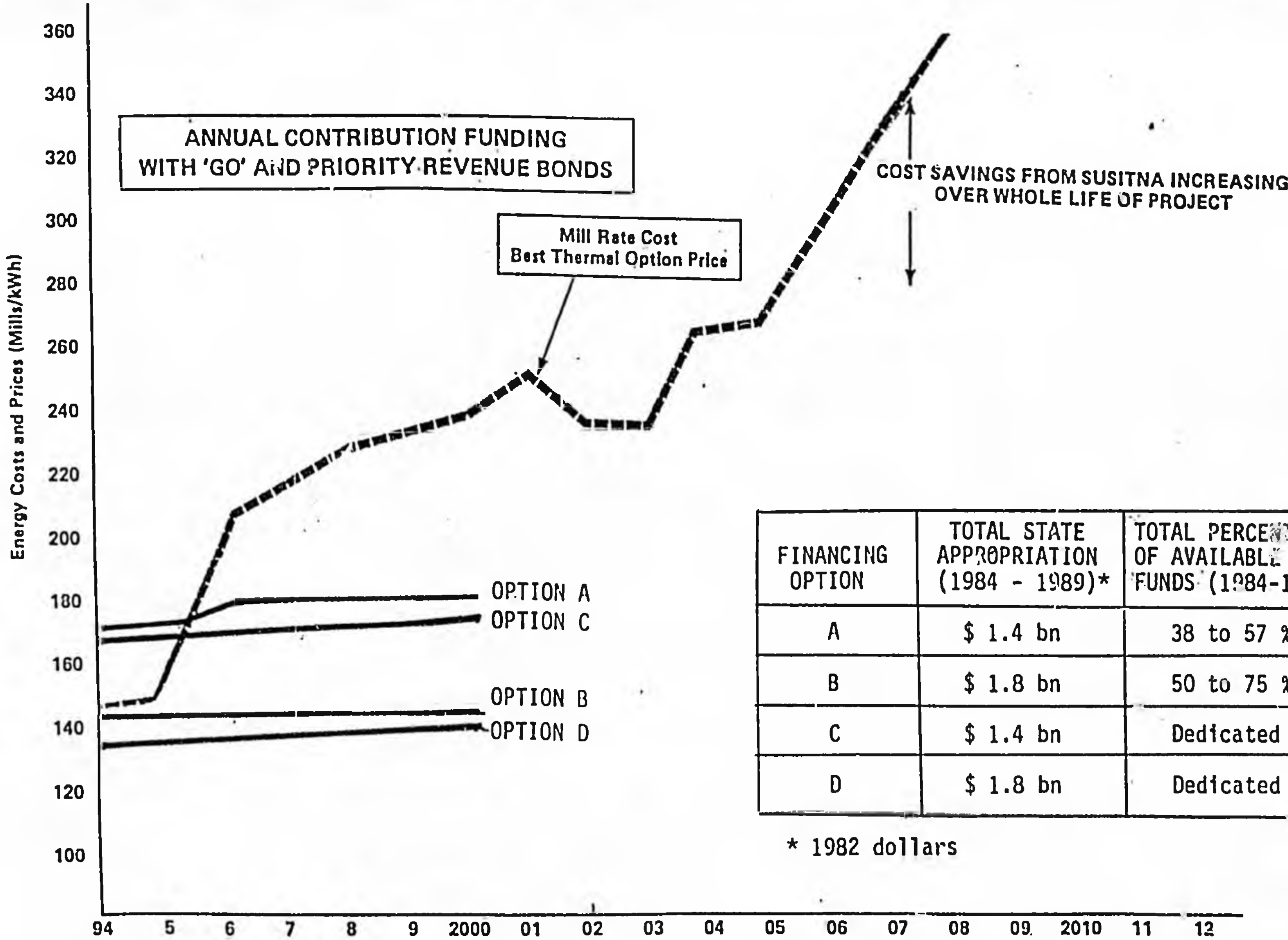
Exhibit C
WORLD OIL PRICE FORECASTS
(Constant 1982 Dollars)



Source: ENR Utilities, December 17, 1981 for nominal costs;
Monthly Labor Review, US Dept. of Labor November, 1982 for Consumer Price Index

EXHIBIT D -- US HYDROELECTRIC PLANT CONSTRUCTION COST INDEXES

ACRES



FINANCING OPTION	TOTAL STATE APPROPRIATION (1984 - 1989)*	TOTAL PERCENTAGE OF AVAILABLE STATE FUNDS (1984-1989)*
A	$ 1.4 bn	38 to 57 %
B	$ 1.8 bn	50 to 75 %
C	$ 1.4 bn	Dedicated
D	$ 1.8 bn	Dedicated

* 1982 dollars

EXHIBIT E
ENERGY COST COMPARISON
WITH VARIOUS FINANCING OPTIONS

ACRES

FINANCIAL ANALYSES

ACRES

DATA10M5.D11 WATANA (ON LINE 1993)- STATE FUNDS TO 1989 ($1.4 BN)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 BN 8-JAN-93

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.05	154.81	165.65	177.24	189.65	202.92	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	[illegible]	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6
[illegible] LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	439.7	469.3
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-114.7	-59.0
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-114.7	-59.0
446 STATE CONTRIBUTION	375.7	436.1	437.2	447.4	208.2	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	632.6	1464.8	1341.6	957.8	411.1	102.0
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	375.7	436.1	437.2	447.4	840.8	1464.8	1341.6	957.8	387.8	58.5
320 LESS CAPITAL EXPENDITURE	375.7	436.1	437.2	447.4	840.8	1464.8	1341.6	957.8	296.4	25.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.3
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	49.4
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	375.7	811.8	1248.9	1696.3	2537.1	4002.0	5343.5	6301.3	6597.7	6623.4
465 CAPITAL EMPLOYED	375.7	811.8	1248.9	1696.3	2537.1	4002.0	5343.5	6301.3	6689.1	6730.3
461 STATE CONTRIBUTION	375.7	811.8	1248.9	1696.3	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-114.7	-173.8
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.8
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	632.6	2097.4	3439.0	4396.8	4807.9	4892.7
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	408.6	884.3	756.9	505.0	202.6	47.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	408.6	1292.9	2049.8	2554.9	2757.5	2804.5
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.74	0.84

Option A -- $1.4 Billion Drawn From Uncommitted State
Funds Available For Capital Construction

ACRES

DATA1OM5.DI? WATANA (ON LINE 1993)- STATE FUNDS TO 1989 ($1.4 BN)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 BN 8-JAN-83

CASH FLOW SUMMARY
===($MILLION)=====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	60.24	71.94	67.56	63.34	59.44	55.81	52.45	49.36	46.51	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.53	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	139.96	178.84	179.71	180.28	181.02	181.87	182.87	184.15	185.64	0.00
-----INCOME-----------------										
516 REVENUE	474.0	605.7	608.6	610.6	613.1	615.9	619.3	623.7	628.7	6202.6
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	444.2	573.1	573.1	571.8	570.7	569.7	568.9	568.6	568.7	5759.3
214 ADD INTEREST EARNED ON FUNDS	5.7	6.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	32.4	42.8	43.2	42.4	41.9	41.5	41.3	41.7	42.4	390.1
391 LESS INTEREST ON LONG TERM DEBT	467.6	465.7	463.6	461.3	458.7	456.0	452.9	449.5	445.8	5030.1
548 NET EARNINGS FROM OPERS	-50.1	70.9	73.1	75.6	78.2	81.2	84.5	88.0	92.0	419.7
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	-50.1	70.9	73.1	75.6	78.2	81.2	84.5	88.0	92.0	419.7
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1904.5
143 LONG TERM DEBT DRAWDOWNS	96.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5006.6
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
549 TOTAL SOURCES OF FUNDS	54.3	95.5	83.6	86.8	88.4	91.1	98.0	102.4	107.3	7555.0
320 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6953.0
448 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	19.0	22.1	24.3	26.8	29.4	32.4	35.6	39.2	43.1	289.2
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	19.3	17.3	15.1	12.8	10.2	7.6	4.7	1.6	88.6
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.8	75.0	79.4	82.2	83.9	88.6	93.3	98.0	98.0
454 CASH SURPLUS RETAINED	0.0	19.3	36.6	51.7	64.5	74.7	82.3	87.0	88.6	88.6
370 CUM. CAPITAL EXPENDITURE	6651.0	6680.4	6711.9	6745.6	6781.7	6820.3	6861.6	6905.7	6953.0	6953.0
465 CAPITAL EMPLOYED	6765.5	6838.9	6898.2	6958.2	7017.2	7076.0	7138.3	7201.6	7265.8	7265.8
461 STATE CONTRIBUTION	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5	1904.5
462 RETAINED EARNINGS	-223.8	-152.9	-79.8	-4.2	74.0	155.2	239.7	327.7	419.7	419.7
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	4970.2	4940.1	4923.8	4897.0	4867.6	4835.2	4799.6	4760.5	4717.4	4717.4
542 ANNUAL DEBT DRAWDOWN $1982	41.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2846.0
543 CUM. DEBT DRAWDOWN $1982	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0	2846.0
519 DEBT SERVICE COVER	0.86	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

DATA10M5.D11 WATANA (ON LINE 1993)- STATE FUNDS TO 1989 ($1.8 BN)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 BN 8-JAN-83

CASH FLOW SUMMARY ($MILLION)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.[illegible]	154.81	165.65	177.24	189.65	202.92	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.0	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.4
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	357.3	386.9
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-32.3	31.6
-----CASH SOURCE AND USE-----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-32.3	31.6
446 STATE CONTRIBUTION	375.7	436.1	437.2	447.4	827.4	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	13.3	1402.9	1273.5	882.9	328.7	8.3
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	375.7	436.1	437.2	447.4	840.8	1402.9	1273.5	882.9	387.8	55.4
320 LESS CAPITAL EXPENDITURE	375.7	436.1	437.2	447.4	840.8	1402.9	1273.5	882.9	296.4	25.7
548 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.3
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET-----										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	49.4
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	375.7	811.8	1248.9	1696.3	2537.1	3940.0	5213.5	6096.4	6392.8	6418.5
465 CAPITAL EMPLOYED	375.7	811.9	1248.9	1696.3	2537.1	3940.0	5213.5	6096.4	6484.1	6525.3
461 STATE CONTRIBUTION	375.7	811.8	1248.9	1696.3	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-32.3	-0.7
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.8
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	13.3	1416.3	2689.7	3572.6	3901.3	3895.4
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	8.6	846.9	718.5	465.5	162.0	3.8
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	8.6	855.5	1574.0	2039.5	2201.5	2205.4
517 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	1.04

Option B -- $1.8 Billion Drawn From Uncommitted State Funds Available For Capital Construction

ACRES

DATA1OM5. [illegible] LINE 1993)- STATE FUNDS TO 1989 ($1.8 BN)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 BN   8-JAN-83

CASH FLOW SUMMARY
(\$MILLION)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	60.24	57.33	54.00	50.76	47.76	44.98	42.39	40.03	37.85	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.53	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	139.96	142.51	143.63	144.46	145.45	146.59	147.81	149.34	151.08	0.00
-----INCOME-----------------										
516 REVENUE	474.0	482.6	486.4	489.3	492.6	496.3	500.6	505.8	511.7	5242.3
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	444.2	450.1	450.9	450.5	450.2	450.1	450.1	450.7	451.6	4799.0
214 ADD INTEREST EARNED ON FUNDS	5.7	6.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	14.7	14.9	16.3	16.4	16.9	17.5	18.3	19.7	21.5	179.6
391 LESS INTEREST ON LONG TERM DEBT	383.5	383.9	382.2	380.3	378.2	375.9	373.4	370.6	367.5	4141.5
548 NET EARNINGS FROM OPERS	49.7	57.6	59.3	61.2	63.3	65.6	68.2	71.0	74.1	569.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	49.7	57.6	59.3	61.2	63.3	65.6	68.2	71.0	74.1	569.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2523.8
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3909.7
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
549 TOTAL SOURCES OF FUNDS	57.4	82.2	69.8	72.4	73.5	75.6	81.7	85.4	89.4	7227.0
329 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6748.0
448 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	15.7	17.4	19.2	21.1	23.2	25.5	28.1	30.9	34.0	229.2
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	6.5	10.7	8.6	6.4	4.1	1.5	-1.1	-4.0	-7.1	25.5
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.8	75.0	79.4	82.2	83.9	88.6	93.3	98.0	98.0
454 CASH SURPLUS RETAINED	6.5	17.2	25.8	32.2	36.3	37.8	36.7	32.6	25.5	25.5
370 CUM. CAPITAL EXPENDITURE	6446.0	6475.4	6506.9	6540.6	6576.7	6615.3	6656.6	6700.8	6748.0	6748.0
465 CAPITAL EMPLOYED	6567.0	6631.8	6682.4	6733.8	6784.1	6834.1	6887.8	6942.3	6997.8	6997.8
461 STATE CONTRIBUTION	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8	2523.8
462 RETAINED EARNINGS	49.0	106.6	165.9	227.1	290.4	356.1	424.3	495.3	569.4	569.4
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	3879.7	3862.2	3843.1	3822.0	3798.8	3773.3	3745.2	3714.4	3680.4	3680.4
542 ANNUAL DEBT DRAWDOWN \$1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2205.4
543 CUM. DEBT DRAWDOWN \$1982	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4	2205.4
519 DEBT SERVICE COVER	1.08	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

DATA10M5.D11 WATANA (ON LINE 1993)-$1.4 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 8-JAN-83

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.05	154.81	165.65	177.24	189.65	202.92	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.0	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.1
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	424.9	454.6
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-100.0	-42.8
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-100.0	-42.8
446 STATE CONTRIBUTION	806.8	413.3	475.3	115.4	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	521.8	1453.8	1329.4	944.4	396.4	85.3
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	806.8	413.3	475.3	115.4	521.8	1453.8	1329.4	944.4	387.8	57.9
320 LESS CAPITAL EXPENDITURE	373.3	390.5	389.2	390.9	811.8	1453.8	1329.4	944.4	296.4	25.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.8
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	433.5	22.8	86.1	-275.5	-290.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET-----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	49.4
454 CASH SURPLUS RETAINED	456.6	479.4	565.5	290.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	373.3	763.8	1153.0	1543.9	2355.7	3809.4	5138.8	6083.2	6379.6	6405.3
465 CAPITAL EMPLOYED	829.9	1243.2	1718.5	1833.9	2355.7	3809.4	5138.8	6083.2	6471.0	6512.1
461 STATE CONTRIBUTION	806.8	1220.1	1695.4	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8
462 RETAINED EARNINGS	23.1	23.1	23.1	23.1	23.1	23.1	23.[illegible]	23.1	-76.9	-119.7
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.6
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	521.8	1975.5	3304.9	4249.3	4645.7	4714.2
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	337.0	877.6	750.0	498.0	195.7	39.3
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	337.0	1214.6	1964.7	2462.6	2658.0	2697.2
519 DEBT SERVICE COVER	.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76	0.87

Option C -- $1.4 Billion Dedicated From
Permanent Fund Income

ACRES

****

DATA10M5.D11 WATANA (ON LINE 1993)-$1.4 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.6@7 8-JAN-83

****

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	60.24	69.32	65.13	61.09	57.35	53.87	50.65	47.69	44.96	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.53	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	139.96	172.33	173.25	173.87	174.65	175.55	176.60	177.92	179.46	0.00
-----INCOME-----------------										
516 REVENUE	474.0	583.7	586.7	588.9	591.5	594.5	598.1	602.6	607.8	6030.7
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	444.2	551.1	551.2	550.1	549.2	548.3	547.6	547.5	547.7	5587.4
214 ADD INTEREST EARNED ON FUNDS	5.7	6.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	29.2	37.8	38.4	37.8	37.4	37.2	37.2	37.7	38.7	350.5
391 LESS INTEREST ON LONG TERM DEBT	452.9	451.0	449.0	446.8	444.3	441.6	438.7	435.4	431.8	4871.0
548 NET EARNINGS FROM OPERS	-32.2	68.5	70.6	73.0	75.6	78.4	81.5	85.0	88.8	446.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	-32.2	68.5	70.6	73.0	75.6	78.4	81.5	85.0	88.8	446.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1810.8
143 LONG TERM DEBT DRAWDOWNS	78.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4809.1
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
549 TOTAL SOURCES OF FUNDS	53.7	93.1	81.1	84.2	85.7	88.3	95.0	99.4	104.1	7290.5
320 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6734.9
448 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	18.4	21.3	23.4	25.7	28.3	31.1	34.3	37.7	41.4	278.4
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	17.8	15.7	13.5	11.2	8.7	6.0	3.1	0.0	53.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.8	75.0	79.4	82.2	83.7	88.6	93.3	98.0	98.0
454 CASH SURPLUS RETAINED	0.0	17.8	33.5	47.1	58.3	67.0	73.0	76.1	76.1	76.1
370 CUM. CAPITAL EXPENDITURE	6432.8	6462.3	6493.8	6527.5	6563.5	6602.1	6643.4	6687.6	6734.9	6734.9
465 CAPITAL EMPLOYED	6547.4	6619.2	6677.0	6735.5	6792.9	6850.1	6910.9	6973.6	7035.2	7035.2
461 STATE CONTRIBUTION	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8	1810.8
462 RETAINED EARNINGS	-151.9	-83.4	-12.7	60.2	135.8	214.2	295.0	380.7	437.5	469.5
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	4773.9	4732.6	4729.3	4703.5	4675.2	4644.1	4609.0	4572.1	4530.7	4530.7
542 ANNUAL DEBT DRAWDOWN $1982	33.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2730.9
543 CUM. DEBT DRAWDOWN $1982	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9	2730.9
519 DEBT SERVICE COVER	0.89	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

DATA10M5.D11 WATANA (ON LINE 1993)-$1.8 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 8-JAN-83

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.93	61.60
466 INFLATION INDEX	122.62	129.98	137.78	146.05	154.81	165.65	177.24	189.65	202.92	217.13
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.34	133.76
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.0	453.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	27.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.9	425.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.7
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.2	369.8
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-15.2	50.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-15.2	50.4
446 STATE CONTRIBUTION	806.8	413.3	475.3	552.1	156.4	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	1275.1	1259.3	867.3	311.6	0.0
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
549 TOTAL SOURCES OF FUNDS	806.8	413.3	475.3	552.1	156.4	1275.1	1259.3	867.3	387.8	65.9
320 LESS CAPITAL EXPENDITURE	373.3	390.5	389.2	390.9	768.1	1390.1	1259.3	867.3	296.4	25.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	15.5
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	433.5	22.8	86.1	161.2	-611.7	-115.0	0.0	0.0	0.0	11.1
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.6	57.4
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.8	49.4
454 CASH SURPLUS RETAINED	456.6	479.4	565.5	726.7	115.0	0.0	0.0	0.0	0.0	11.1
370 CUM. CAPITAL EXPENDITURE	373.3	763.8	1153.0	1543.9	2312.0	3702.1	4961.4	5828.8	6125.2	6150.9
465 CAPITAL EMPLOYED	829.9	1243.2	1718.5	2270.6	2427.0	3702.1	4961.4	5828.8	6216.5	6268.8
461 STATE CONTRIBUTION	806.8	1220.1	1695.4	2247.5	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9
462 RETAINED EARNINGS	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	7.9	58.3
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	91.4	106.8
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	1275.1	2534.4	3401.8	3713.4	3699.7
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	769.7	710.5	457.3	153.6	0.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	769.7	1480.3	1937.6	2091.2	2091.2
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.96	1.10

Option D -- $1.8 Billion Dedicated From Permanent Fund Income

ACRES

****
DATA10M5.D11 WATANA (ON LINE 1993)-$1.8 BN STATE FUNDS (PER 30% SCHED)- INFLATION 6%,7%-INTEREST 10%-CAPCOST $3.647 8-JAN-83
****

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	3387	3387	37257
521 REAL PRICE-MILLS	58.08	54.51	51.39	48.34	45.52	42.89	40.46	38.24	36.19	0.00
466 INFLATION INDEX	232.33	248.59	265.99	284.61	304.53	325.85	348.66	373.07	399.18	0.00
520 PRICE-MILLS	134.94	135.52	136.69	137.57	138.61	139.77	141.08	142.66	144.46	0.00
-----INCOME-----------------										
516 REVENUE	457.0	459.0	462.9	465.9	469.5	473.4	477.8	483.2	489.2	5040.9
170 LESS OPERATING COSTS	29.8	32.6	35.6	38.8	42.3	46.2	50.4	55.1	60.1	443.3
517 OPERATING INCOME	427.2	426.4	427.4	427.1	427.1	427.1	427.4	428.1	429.2	4597.5
214 ADD INTEREST EARNED ON FUNDS	5.7	4.3	6.8	7.5	8.1	8.9	9.7	10.6	11.6	80.5
550 LESS INTEREST ON SHORT TERM DEBT	11.1	10.3	12.4	12.7	13.4	14.1	15.2	16.8	18.8	135.9
391 LESS INTEREST ON LONG TERM DEBT	368.5	367.0	365.3	363.5	361.5	359.3	356.9	354.2	351.3	3957.3
548 NET EARNINGS FROM OPERS	53.4	54.9	56.6	58.4	60.4	62.6	65.0	67.7	70.6	584.9
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	53.4	54.9	56.6	58.4	60.4	62.6	65.0	67.7	70.6	584.9
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2403.9
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3713.4
248 WORCAP DEBT DRAWDOWNS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
549 TOTAL SOURCES OF FUNDS	61.1	79.6	67.1	69.6	70.6	72.5	78.5	82.1	86.0	6926.3
320 LESS CAPITAL EXPENDITURE	27.5	29.4	31.5	33.7	36.1	38.6	41.3	44.2	47.3	6480.4
440 LESS WORCAP AND FUNDS	7.7	24.6	10.5	11.2	10.2	9.9	13.5	14.4	15.3	224.2
260 LESS DEBT REPAYMENTS	15.0	16.6	18.2	20.0	22.1	24.3	26.7	29.3	32.3	218.1
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	10.8	8.9	6.9	4.6	2.3	-0.2	-2.9	-5.8	-8.9	3.6
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	62.7	68.4	74.7	81.5	88.9	97.1	105.9	115.6	126.2	126.2
371 OTHER WORKING CAPITAL	51.9	70.8	75.0	79.4	82.2	83.9	88.6	93.3	98.0	98.0
454 CASH SURPLUS RETAINED	21.9	30.8	37.7	42.3	44.6	44.4	41.4	35.6	26.7	26.7
370 CUM. CAPITAL EXPENDITURE	6178.4	6207.8	6239.3	6273.0	6309.1	6347.7	6389.0	6433.2	6480.4	6480.4
4[illegible] CAPITAL EMPLOYED	6314.9	6377.8	6426.7	6476.3	6524.8	6573.1	6624.9	6677.6	6731.3	6731.3
461 STATE CONTRIBUTION	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9	2403.9
462 RETAINED EARNINGS	111.7	166.6	223.2	281.6	342.0	404.6	469.6	537.3	608.0	608.0
555 DEBT OUTSTANDING-SHORT TERM	114.6	139.2	149.7	160.9	171.1	181.0	194.5	208.9	224.2	224.2
554 DEBT OUTSTANDING-LONG TERM	3684.7	3668.2	3649.9	3629.9	3607.8	3583.6	3556.9	3527.6	3495.3	3495.3
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2091.2
543 CUM. DEBT DRAWDOWN $1982	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2	2091.2
519 DEBT SERVICE COVER	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	0.00

ACRES

initiative drive for dam project

12/5

By ANN CONY
Daily News business reporter

The Anchorage Chamber of Commerce is launching a ballot initiative drive and a $250,000 advertising campaign aimed at winning statewide voter approval for construction of the proposed $5.1 billion Susitna hydroelectric project.

The ballot initiative would have voters approve or reject a financing scheme for the controversial two-dam Susitna River project that is designed to provide electrical power to the Railbelt.

"What the chamber will accomplish is to act as a catalyst to see that construction is actually started in 1984," said Bob Penney, chairman of the chamber's energy committee. "No more studies: Let's pour some concrete."

The chamber will conduct a petition drive if the legislature fails to adopt a bill that would automatically put Susitna on the statewide general election ballot in November, he said.

Dave Rose and Eric Wohlforth are drafting a Susitna bill that Sen. President Jalmar Kerttula has agreed to sponsor in the legislative session that begins next month, according to Penney. Rose is a member of the chamber energy committee and executive director of the state Permanent Fund. Wohlforth is a private attorney and state bond counsel.

"The problem with Susitna is that because of the cost, it's hard to get the legislature to bite into spending such a massive amount of money," Penney said. "So we decided to bring the issue of constructing Susitna — including the financing — to a vote of the people."

The chamber's financing plan would allow the state to digest the cost of Susitna over 12 to 20 years, he said.

Voters would be asked to approve or reject a plan calling for direct state appropriations of $200 million per year for the next 12 years, with additional funds needed for construction of the first-phase Watana dam to be raised from state bond sales. The initiative would propose that the second-phase Devil Canyon dam be funded in 10 years, or whenever the added power is needed, solely through bond financing.

Consultants have estimated that construction of the 1020-megawatt Watana dam will cost $3.6 billion and that construction of the 600-megawatt Devil Canyon dam will cost $1.5 billion, in January 1982 dollars.

Penney said the chamber intends to raise money for its Susitna advertising campaign from business and industry sources.

"We estimate it'll take $250,000 or more to put on a public education effort beginning next year — probably in February — so the public can understand both sides of the issue," he said.

A kick-off for the campaign actually will begin earlier, with television spots and double-page newspaper advertisements scheduled for Jan. 2-15.

The chamber already has raised $25,000 for the pilot program with equal donations from the International Brotherhood of Electrical Workers and the Associated General Contractors of Alaska, Penney said.

Cartoonist Jerry Flu has created a beaver dubbed Susitna Sam to serve as the lead mascot in a cast of animated cartoon characters.

Acres American, the consulting firm that has analyzed the proposed project most recently, has said the state needs to make a direct investment of at least $2.3 billion, in January 1982 dollars, to assure that electricity generated by the dams will not cost consumers more than alternative power sources prior to the year 2006.

Appropriations of $200 million for 12 years would amount to $2.4 billion.

While Susitna supporters claim the project is the best investment the state could make, Susitna critics have maintained that it's a potential boondoggle.

The critics point to Acres' conclusion that Watana dam by itself would not be the most economical source of power and, in light of falling state revenue predictions, question the validity of Acres' projections for power demand that would justify construction of the Devil Canyon dam.

Penney expressed confidence Friday that a majority of voters favor Susitna.

Chamber's Susitna plan may focus future debate

By ANN CONY
Daily News business reporter

The Anchorage Chamber of Commerce may unveil as soon as next week the draft of a legislative bill aimed at setting aside state funds for construction of the Susitna hydroelectric project.

Meanwhile, critics this week threw out arguments likely to shape debate on the issue in the coming months.

The chamber energy committee announced last Friday that it would pursue a statewide ballot initiative that would ask voters to authorize construction of the controversial dam project backers say would carry the Railbelt into the 21st century with "cheap" electricity.

According to Bob Penney, chairman of the energy committee, the chamber wants to see the legislature appropriate $200 million annually for 12 years for Susitna construction. That $2.4 billion would be supplemented liberally by bond sales to build the first dam, and construction of the second dam would be financed solely by bond

See Page D-4, SUSITNA

Susitna

Continued from Page D-1

sales.

The advance dedication of state revenues would require an amendment to the state constitution.

The dams are estimated to cost $5.1 billion in January 1982 dollars; assuming an inflation rate of 10 percent, the project would cost $14.5 billion when finished.

Criticisms raised this week by Eric Myers of the Northern Alaska Environmental Center and economists Arlon Tussing and Gregg Erickson were that:

- Such a commitment of funds could potentially bankrupt the state;
- The bond market probably would reject such an offering as too risky;
- If the bonds could be sold, they might absorb virtually all of the state's bonding capacity for the next 12 years or longer;
- The legislature shouldn't tamper with the state constitution just to build Susitna, and
- Susitna power would seem "cheap" to some only because the money for it would come from the state rather than directly from the ratepayer's pocket.

"It represents an enormous incumbence on the state's economy and the future fiscal policy of the state," said Tussing. "It's hard to believe that the investment community isn't going to perceive that."

The bond market would perceive the issue as too risky because of the state economy's reliance on oil prices and state spending, he said.

According to Erickson, 41 percent of Alaskans' personal income is the result of state spending.

Penney countered that the economists have been wrong before, and "if everything goes according to our preliminary plans, we'll be able to show Mr. Tussing he's incorrect."

Myers and Tussing argued that even if bond financing were possible, the state could not afford it.

"It's putting all the eggs in one basket," Tussing said, warning that bonding Susitna could preclude bonding for other projects that might prove more beneficial to the state economy.

Myers questioned, as Tussing and Erickson have, whether the Railbelt will need the full capacity of power that would be generated by the Watana and Devil Canyon dams, saying the state risks ultimate bankruptcy for a project that could turn out to be a white elephant.

"The dialogue has been dominated by proponents of the project who have dismissed any consideration about less costly, more moderately scaled alternatives," Myers said. "Let's evaluate the project on its merits and not confuse the desire for a massive construction project with a rational plan for future energy development and the Railbelt."

Tussing claimed that much of the impetus for Susitna comes from groups such as contractors and unions who see the proposed project as a "big Christmas tree" and are more enamored with it the more it costs.

Penney claims the project enjoys broad based support because it will ensure present and future Railbelt residents of cheap, reliable power.

"It would be a gift to all of us," he said.

Power generated from the dams will be "one of the best electric buys in the nation," Penney argued, saying that once the project is built the cost of electricity in the Railbelt will be inflation-proof.

"Anything's cheap if somebody else pays for it," Tussing countered. "It would probably be some of the most expensive power generated anywhere in North America when you consider the capital costs."

Penney expressed confi-

2/4

February 4, 1983

Susitna hydro a good investment?

By ANN CONY
Daily News business reporter

The proposed Susitna River hydroelectric project could be the best investment the state will ever make, or the worst, depending on who you believe.

The pros and cons of the $5.1 billion two-dam project were argued Thursday by Wayne Beckwith and Eric Myers, respectively, at a luncheon meeting of the Anchorage Woman's Club.

Beckwith, co-chairman of the Anchorage Chamber of Commerce energy committee, justified the need for the 1,620-megawatt project on grounds that the cost of natural gas — which fuels more than 90 percent of electricity generation in Southcentral Alaska — is rising while the supply is falling. Though Susitna would require a large capital investment, operating costs would be minimal and the cost of hydro power would be constant after the capital investment is made, while "constantly increasing fuel costs must be passed on to the consumer."


Eric Myers


Wayne Beckwith

Susitna hydro power would be cheaper than fossil-fuel power shortly after the turn of the century, Beckwith said.

Quoting Susitna feasibility study projections that the project would create an average of 1,450 jobs a year for 16 years, he urged the audience to think about the "ripple effects" that would have on local businesses.

Myers, consultant . the Northern Alaska Environmental Center, argued that Susitna could put the state in . fiscal straitjacket and urged a careful reexamination of the project in light of outdated economic feasibility assumptions.

Rational planning to meet future state energy needs in recent years has become confused with desires for creation of new jobs and distribution of oil wealth, according to Myers.

Once a commitment to construction is made, "We've totally lost all our flexibility in dealing with energy planning for the future," he said. "If we made a commit-

See Page B-6, SUSITNA

Susitna hydro proposal's merits debated

Continued from Page B-5

ment to Susitna now, it could involve more than 50 percent of the state's capital spending revenues until the end of the century."

Myers quoted state Division of Budget and Management calculations that while Susitna is estimated to cost $5.1 billion in 1982 dollars, it will end up costing $10 billion to $15 billion, depending on inflation rates. He urged consideration of smaller-scale hydro projects as alternatives.

The recent decline in oil prices and state revenue projections lowers the outlook for the state economy, and population growth, thus lowering anticipated increases in power demand, Myers said.

Beckwith argued that forecasts for power demand used in the Susitna feasibility study were reasonable, and that even under a 2.8 percent annual "low growth" scenario, Susitna will prove economical as a replacement for fossil-fuel power generation.

Saying Susitna is "one of the finest investments this state will ever make" and "more important than any project ever developed in the history of the Railbelt," he predicted revenues from Susitna power sales would pay off revenue bonds and provide the state a return on its investment.

Myers, on the other hand, warned that if power demand does not increase as previously forecast, Susitna would strap the state economically and tax consumers.

"I'm not saying the Susitna project is a horrible idea and we ought to walk away from it . . . Susitna may be the best thing that ever happened to the Railbelt, but probably not until the year 2050," he said. The state has at least until the end of the century to make a commitment to construction, Myers argued, and "I don't think we should be stampeded into making that kind of decision now."

Environmental group asks delay of Susitna lice

by Steve Hansen
Times Writer

A statewide environment group is asking the Alaska Power Authority to delay its license request for the Susitna hydroelectric project until an alternate site at Lake Chakachamna is "adequately evaluated."

Eric Myers, an energy consultant and spokesman for the Northern Alaska Environmental Center, sent a letter to APA executive director Eric Yould on Dec. 13 saying a recent engineering study indicated the Lake Chakachamna site would be "even more economically attractive than previously thought."

He urged the APA executive to "commit the financial resources presently at its disposal toward the development of a comprehensive feasibility studye of a quality and detail equal to the Susitna studies."

Myers said the issue "is not whether you are for or against the Susitna project, but how to provide responsibly for Railbelt power needs. Many people have forgotten that."

Myers said the Chakachamna project "is the most significant and likely hydro alternative to Susitna and a comprehensive evaluation of this potential hydro option is central to the ongoing Railbelt power studies."

The letter asked Yould to defer filing of the Susitna license application with the Federal Energy Regulatory Commission until further studies have been completed.

"Chakachamna is especially attractive economically because a project the size of Chakachamna would not be vulnerable to the uncertainty of furter of electrical demand growth."

If constructed, the Chakachamna project would provide 330 megawatts while Susitna would provide 1,600 megawats.

"We can reasonably assume the need for the 330 megawatts Chakachamna could provide but we can't safely assume the need for all 1,600 megawatts from Susitna," Myers said.

Myers said a recent Railbelt electricity demand forecast for the year 2010 are 44 percent lower than previous projections which led to the Susitna proposal. Susitna would cost an estim in 1982 dollars w kachamna project estimated $1.2 billion

The most vocal nents have "confuse nomic power plann sire for a massive project . . . they s pour concrete. The a $15 billion white e nancial ruin for the said.

Dam builder praises state hydro plans

by Carl Gidlund
Times Writer

The president of a firm selected to design Watana Dam, first phase of the proposed giant Susitna power network, said today the project is the most attractive hydroelectric project in North America.

"Down south, there just isn't the potential that you have in Alaska," said Harza Engineering Co.'s Richard D. Harza. "Either the water's been used for hydro already or it can't be used because of national parks or similar barriers."

Speaking before the Anchorage Chamber of Commerce today, Harza compared the proposed Watana dam, which at 885 feet is to be the largest earth-filled structure in North America, to another project in which his firm is engaged, the Guri project in Venezuela.

Both, he said, are large projects with small, economical beginnings. Also, he said, both Susitna and Guri — which may become the world's largest power project, generating 20,000 megawatts — are conceived for eventual full-scale use of the hydro resource but are designed and built to meet smaller needs during construction.

Finally, Garza said, Guri is an example of "how to 'upgrade' revenue from a depleting resource, oil, into a non-depleting, clean, almost permanent hydro energy resource."

Although the design contract with the state has not been formally signed, the Alaska Power Authority voted unanimously in October to award it to Harza's Chicago-based company and a joint venture firm, Ebasco Services Inc. of Bellview, Wash., and New York.

The legislature has approved $25.6 million for preliminary design work on the million-kilowatt Watana dam and will be asked to appropriate more during the upcoming session. Total costs will exceed $3 billion in 1982 dollars, according to most estimates.

"It doesn't appear the project would have grave environmental impacts," Harza said. "We don't have to displace people, roads or railroads and other physical impacts are relatively minimal when looking at a project of this scale."

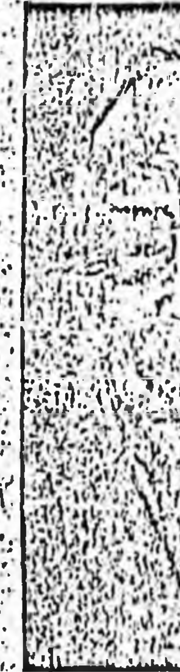
Harza described hydroelectric power as the most economical, least polluting source of energy, and he said industrial countries with hydro potential — the U.S., Soviet Union, Japan and European nations — have almost fully developed their potential.

He said high initial investment costs "are more than offset by the absence of fuel costs, and of fuel cost escalation" during the life of such projects, which may be as long as a century.

Hydro power's only drawback, he said, is its transportability. Natural gas can be shipped economically via pipeline or tanker 2,000 to 5,000 miles, and oil can be sent 10,000 miles or more, but the economic limit for sending electricity over power lines is about 800 miles, Harza said.

In addition to its Venezuela project, Harza's firm is designing hydroelectric projects in Central America, Iceland, Jordan, Egypt, Senegal and Pakistan. It also is engaged in two other Alaska projects, one near Bethel and on at Black Bear Lake, which would serve the Southeast communities of Craig, Klawok and Hydaburg.

Harza said his firm will establish a small Watana project office in Anchorage with Ebasco. Ten to 20 personnel from the two companies will be engaged in field investigation work, he said, but the principal design office, employing 50-60 people, will be in Bellview.



RICHAR
Involved in 3

Susitna engineer touts hydropower

y ANN CONY
aily News business reporter

Alaska may not have any moneys and Venezuela may not have ny moose, but the two places do ave at least one thing in common: xtensive oil and gas resources ombined with plenty of hydroelectric power potential.

That was the message delivered y Richard Harza, president of ne of two firms selected by the laska Power Authority to design ne Watana Dam of the proposed usitna River hydroelectric roject.

In touting the advantages of ydropower before the Anchorage hamber of Commerce Monday, e president of Harza Engineerng Co. of Chicago traced his rm's work on the Guri hydroelectric project on the Rio Caroni in stern Venezuela.

The first stage of that project as completed in 1968, with an tension of the initial power ant giving it an installed capacity of 2,000 megawatts in 1978. A second expansion is under way now, and — when completed in 1987 — will make Guri the second largest hydro project in the world, after the Parana River project in Brazil.

In addition, Guri has been designed for the possible ultimate expansion to a total capacity of 20,000 megawatts, Harza said.

The current expansion will bring the dam height to 475 feet, compared to a height of 885 feet envisioned for the 1,020-megawatt Susitna Watana Dam.

The Guri and the proposed Susitna projects differ in that Susitna is not intended to provide power to heavy industry, Harza said.

In Venezuela and other countries "double blessed" with fossil fuels and hydro potential, the pattern has been one of simultaneous, coordinated development of both resources, he said.

"When possible, the fossil energy has been exported while the hydro energy has served the developing domestic or local market."

According to Harza, countries such as Venezuela have chosen to invest part of their fossil fuel export revenues in long-term hydro power to meet future energy needs.

"In general, wherever it is available, hydro power is the most economical, least polluting power source," he said.

Harza acknowledged that capital costs for constructing the dams are high. But, he maintained, the high initial costs are "more than offset" by the long life expectancy of the dams and the absence of escalating fuel costs.

A useful life of 100 years has been assumed for the proposed Susitna hydroelectric project in economic analyses.

In an interview after his speech, Harza said that Susitna would last longer than 100 years, though he

See Page D-6, SUSITNA

Susitna

Continued from Page D-1

could not say how much longer.

Harza said his company along with Ebasco Services Inc. of New York and Bellevue, Wash., are just beginning to design the Watana dam. About 100 employees of both firms will work on the project, primarily in Bellevue with a secondary office in Anchorage, Harza said.

The legislature has appropriated $25.6 million to begin Watana design, and the power authority will seek additional design funds in the coming legislative session.

The total cost of designing Watana has been projected to be about $70 million. Adding construction costs, Watana dam has been estimated to cost $3.6 billion, while the second-phase, Devil Canyon dam would cost an estimated $1.5 billion, both in January 1982 dollars.

Susitna engineer touts hydropower

y ANN CONY
aily News business reporter

Alaska may not have any mon-eys and Venezuela may not have ny moose, but the two places do ave at least one thing in common: xtensive oil and gas resources ombined with plenty of hydroe-:ctric power potential.

That was the message delivered y Richard Harza, president of ne of two firms selected by the laska Power Authority to design ie Watana Dam of the proposed usitna River hydroelectric oject.

In touting the advantages of ydropower before the Anchorage hamber of Commerce Monday, e president of Harza Engineer-g Co. of Chicago traced his m's work on the Guri hydroelec-ic project on the Rio Caroni in stern Venezuela.

The first stage of that project is completed in 1968, with an tension of the initial power int giving it an installed capacity of 2,000 megawatts in 1978. A second expansion is under way now, and — when completed in 1987 — will make Guri the second largest hydro project in the world, after the Parana River project in Brazil.

In addition, Guri has been designed for the possible ultimate expansion to a total capacity of 20,000 megawatts, Harza said.

The current expansion will bring the dam height to 475 feet, compared to a height of 885 feet envisioned for the 1,020-megawatt Susitna Watana Dam.

The Guri and the proposed Susitna projects differ in that Susitna is not intended to provide power to heavy industry, Harza said.

In Venezuela and other countries "double blessed" with fossil fuels and hydro potential, the pattern has been one of simultaneous, coordinated development of both resources, he said.

"When possible, the fossil energy has been exported while the hydro energy has served the developing domestic or local market."

According to Harza, countries such as Venezuela have chosen to invest part of their fossil fuel export revenues in long-term hydro power to meet future energy needs.

"In general, wherever it is available, hydro power is the most economical, least polluting power source," he said.

Harza acknowledged that capital costs for constructing the dams are high. But, he maintained, the high initial costs are "more than offset" by the long life expectancy of the dams and the absence of escalating fuel costs.

A useful life of 100 years has been assumed for the proposed Susitna hydroelectric project in economic analyses.

In an interview after his speech, Harza said that Susitna would last longer than 100 years, though he

See Page D-6, SUSITNA

Susitna

Continued from Page D-1

could not say how much longer.

Harza said his company along with Ebasco Services Inc. of New York and Bellevue, Wash., are just beginning to design the Watana dam. About 100 employees of both firms will work on the project, primarily in Bellevue with a secondary office in Anchorage, Harza said.

The Legislature has appropriated $25.6 million to begin Watana design, and the power authority will seek additional design funds in the coming legislative session.

The total cost of designing Watana has been projected to be about $70 million. Adding construction costs, Watana dam has been estimated to cost $3.6 billion, while Devil Canyon second-phase dam would cost an estimated $1.5 billion, both in January 1982 dollars.

.awmakers hear plea for Susitna dam

ANN CONY
ly News business reporter

Calling 1983 the most critical islative year for the proposed sitna hydroelectric project since 79, a spokesman for Susitna wer Now urged Wednesday that wmakers authorize construction the $5.2 billion project in the ming legislative session.

In a speech before the Anchor-e Chamber of Commerce's an-al breakfast with local legisla-rs, Dave Hutchens urged that e legislature authorize construc-on either of the entire project or least the first dam of the assive two-dam Susitna River oject designed to carry the Rail-lt into the 21st century with heap" electricity.

In addition, Hutchens said, the legislature should devise a plan for financing Susitna and should approve the Alaska Power Authority's request for a $47 million appropriation for continued engineering work.

Distributed at the chamber's breakfast meeting attended by 15 legislators here was a Nov. 30 letter to Gov.-elect Bill Sheffield from Hutchens in the latter's capacity as executive director of the Alaska Rural Electric Cooperative Association Inc., a trade group representing 16 electric authorities in the state.

In the letter, Hutchens lambasted a report by economists Arlon Tussing and Gregg Erickson, who have argued that projections for Railbelt power demand — as presented in the Susitna feasibility study — should be lowered in light of falling world oil prices and the impact that will have on local population and economic growth.

Referring to the study by Tussing and Erickson as a "doomsday report," Hutchens told Sheffield: "If you believe that, maybe you shouldn't build Susitna. But if you do believe that, you ought to sell your hotels."

Hutchens sited Acres American's Susitna feasibility study, which predicts a 3.5 percent annual growth rate for power demand. He presented statistics showing that electricity supplied by five of six Railbelt utility companies grew by double-digit figures between the first nine mon s of 1981 and the first nine months of 1982.

By the end of this year, growth in power demand will be nearly three years ahead of Acres' projections, according to Hutchens.

"It is ludicrous for the opponents to contend that those projections are significantly too high," he wrote to Sheffield.

Asked to respond Wednesday afternoon, Tussing defended his and Erickson's position.

"This year there has been a big jump (in electric demand), but the problem is that it's atypical," Tussing said.

See Page D-3, SUSITNA

Susitna dam proponents call 1983 critica

Continued from Page D-1

Hutchens conceded that much in his letter to Sheffield. But while he maintained that the 3.5 percent projection for increased electric demand was well within reason, Tussing argued that "there's no ground for confidence in it" because the projection was based on a state spending outlook that has dimmed considerably since Acres concluded its Susitna feasibility study.

Tussing maintained that the Railbelt has plenty of natural gas and coal for future electric generation and that Susitna could prove to be a painfully expensive mistake if the 3.5 percent growth projection does not materialize.

Hutchens said that due to high capital construction costs, the cost of electricity from Susitna in its first few years of operation would be about twice as high as power from other sources.

But that problem could be solved, he maintained, if the state subsidizes construction by making an "equity investment in Susitna large enough so the rates to the consumers will not jump when it comes on line."

Acres American has pegged that figure at $2.3 billion, in January 1982 dollars.

Susitna hydroelectric power will be much cheaper in the long run than other power sources, Hutchens told legislators Wednesday.

In a packet of position papers distributed at the breakfast meeting, the chamber argued that the cost of natural gas now used to gen electricity for 90 percen Southcentral Alaska wil crease by as much as six times when current low- gas contracts expire and renegotiated, beginnin 1984.

"Energy costs, and quently the cost of doin ness and living in An ho will escalate dramatic Hydroelectric power is best alternate energy so to relieve our dependenc fossil fuel," the position per on hydroelectric p said.

In addition to financin Susitna, the chamber is ing continued state fun for hydroelectric pro statewide.

Economist ups Susitna estimates

by Bill Wh...
Times Juneau Bureau

Juneau — The two massive Susitna River dams proposed to bring cheaper power to the Railbelt region of Alaska may cost between $10 billion and $25 billion, according to a state economist.

The $5.2 billion estimate commonly used for the project is computed in 1982 dollars, not the inflated money the state will actually pay, said Ron Ripple, an economist with state budget office.

That estimate is found in a $35 million state-funded study of the Susitna dams released last March by a Buffalo, N.Y., firm, Acres American Inc.

Ripple recently took Acres' projections of how much construction money would be needed each year to build the dams, and added inflation rates to compute his estimates.

Two dams are being studied for the Susitna River northeast of Talkeetna. They are expected to provide for the power needs of the state's population center into the next century, if the dams are built.

Ron Lehr, Ripple's boss and a director of the Alaska Power Authority, which would build the dams, said many people are comparing the $5.2 billion Susitna figure with the estimated cost of moving the state capital to Willow from Juneau, $2.8 billion.

But the capital move figure is in inflated dollars. The Susitna number isn't.

If the dams are to be built, the state had better start saving, Lehr said. "If you really don't want Susitna the easiest thing to do is sit back and wait."

Ripple estimated 1991 would be the year the largest amount of cash would be needed. Depending on the inflation rate, the legislature might need to find between $1.1 billion and $2.1 billion for Susitna alone. The state budget for this year comes to $3 billion.

Ripples' lowest cost estimate — $10.5 billion — would come if inflation were 7 percent per year, the rate Acres projected.

But many economists believe that inflation rate is too low. A project the size of Susitna in a state whose economy is as small as Alaska's could whip up its own inflation, they say.

So Ripple computed Acres' figures at four higher inflation rates:

- $12.2 billion if inflation hits 8.4 percent a year, the rate used by the Capital Site Planning Committee in estimating capital move costs.
- $14.5 billion if prices rise 10 percent annually, the figure used by the state transportation department in estimating construction costs.
- $18.1 billion with a 12 percent inflation rate.
- $25.4 billion with 50 percent inflation.

Ripple assumes the state would pay cash to build the dams.

But Acres said the state could sell bonds to finance up to half the project, pay off the bonds with income from selling electricity produced by the dams and still have reasonable power rates.

Bonding would cut the amount of cash the state needs. However, it would jack up electrical rates and the cost of building the dams because the state would pay interest on the bonds.

Anchoring one of the seven volumes of Acres' Susitna report are two cost projections using bonds and cash.

In both cases inflation is estimated at 7 percent and the interest rate on the bonds is 10 percent.

If the state paid $3 billion in cash (1982 dollars) and bonded the rest, total construction costs would come to $16.1 billion by the year 2013, Acres said. The state would pay $4.8 billion cash, sell $9.1 billion in bonds and use $4.1 billion from the sale of electricity.

If the state paid $2.3 billion in cash (1982 dollars), the construction tab would hit $16.2 billion. Of that, the state would pay $3.5 billion (inflated dollars), sell $10.1 billion in bonds and use $5 billion from selling electricity.

Outside firms win contrac
for Susitna dam design w

Alaska Power Authority directors on Friday awarded a Susitna hydroelctric engineering design contract worth at least $70 million to Harza Engineering Co. of Chicago and Ebasco Services Inc. of New York.

Those firms will be responsible for designing the proposed 885-foot-high Watana dam, the first phase of the $5.1 billion two-dam project northeast of Talkeetna that has been proposed for the Susitna River to carry the Railbelt into the 21st century with "massive amounts of "cheap" electricity.

The legislature last appropriated $25.6 milli designing Watana, would be one of the l earthfill dams in the But that appropriation cover the bill, and the authority plans to ask f million in additional funds during the coming lative session.

In other action at Fr board meeting, power a ity directors voted u mously in favor of t over the $500 million Br Lake hydroelectric p

See Back Page,

10/23

Firms win contracts for design work on Susitna dam

Continued from Page A-1

from the Army Corps of Engineers after hearing endorsement of that plan from Anchorage Mayor Tony Knowles, representatives of utility companies, environmental groups and others.

The 135-megawatt Bradley Lake dam project near Homer is primarily intended to serve the Kenai Peninsula, but it would generate excess power that could supply Anchorage area utilities as well.

Many Bradley Lake backers say they support the project not as an alternative to the Susitna project but as an interim power source to meet growing electricity demand before Susitna can be built.

Yet to be answered, however, is the question of how the Susitna project will be financed.

The Anchorage Chamber of Commerce's energy committee is conside ing a ballot-initiative dri e aimed at allowing state residents to vote next year on a proposal that would require the legislature to dedicate funds for the project.

Power Authority Director Ron Lehr, who also is Gov. Jay Hammond's budget director, cited projections by his staff that while the Susitna project is estimated to cost $5.1 billion in 1982 dollars, the final cost of the project would likely be $15.5 billion by 2002, assuming an annual inflation rate of more than 10 percent but less than 12 percent.

Lehr was part of a two-director revolt that sought unsuccessfully Friday to buck the power authority staff and a majority of the board to overturn last month's choice of an access route.

On a motion by Commissioner Robert Weeden of the University of Alaska to dump the route that would provide access from Denali Highway in favor of a more environmentally acceptable route from the Parks Highway, Lehr and Weeden were overruled.

The power authority plans to apply in January for a Federal Energy Regulatory Commission license to build Susitna.

Outside firms win contract for Susitna dam design wo

Alaska Power Authority directors on Friday awarded a Susitna hydroelectric engineering design contract worth at least $70 million to Harza Engineering Co. of Chicago and Ebasco Services Inc. of New York.

Those firms will be responsible for designing the proposed 885-foot-high Watana dam, the first phase of the $5.1 billion two-dam project northeast of Talkeetna that has been proposed for the Susitna River to carry the Railbelt into the 21st century with "massive amounts of "cheap" electricity.

The legislature last appropriated $25.6 million designing Watana, wh would be one of the lar earthfill dams in the wo But that appropriation w cover the bill, and the po authority plans to ask for million in additional de funds during the coming le lative session.

In other action at Frid board meeting, power auth ity directors voted una mously in favor of tak over the $500 million Brad Lake hydroelectric proj

See Back Page, FIR

10/23

Firms win contracts for design work on Susitna dam

Continued from Page A-1

from the Army Corps of Engineers after hearing endorsement of that plan from Anchorage Mayor Tony Knowles, representatives of utility companies, environmental groups and others.

The 135-megawatt Bradley Lake dam project near Homer is primarily intended to serve the Kenai Peninsula, but it would generate excess power that could supply Anchorage area utilities as well.

Many Bradley Lake backers say they support the project not as an alternative to the Susitna project but as an interim power source to meet growing electricity demand before Susitna can be built.

Yet to be answered, however, is the question of how the Susitna project will be financed.

The Anchorage Chamber of Commerce's energy committee is considering a ballot-initiative drive aimed at allowing state residents to vote next year on a proposal that would require the legislature to dedicate funds for the project.

Power Authority Director Ron Lehr, who also is Gov. Jay Hammond's budget director, cited projections by his staff that while the Susitna project is estimated to cost $5.1 billion in 1982 dollars, the final cost of the project would likely be $15.5 billion by 2002, assuming an annual inflation rate of more than 10 percent but less than 12 percent.

Lehr was part of a two-director revolt that sought unsuccessfully Friday to buck the power authority staff and a majority of the board to overturn last month's choice of an access route.

On a motion by Commissioner Robert Weeden of the University of Alaska to dump the route that would provide access from Denali Highway in favor of a more environmentally acceptable route from the Parks Highway, Lehr and Weeden were overruled.

The power authority plans to apply in January for a Federal Energy Regulatory Commission license to build Susitna.

City / State

- The Blotter
- Tell It to Bud
- Obituaries

Official calls Susitna cost data 'obsolete'

by Bill White
Times Juneau Bureau

Juneau — Part of a two-and-a-half-year, $35 million study that endorsed building the multibillion-dollar Susitna River dams may be invalid, a high-ranking state cabinet officer has declared.

Revenue Commissioner Tom Williams said oil prices and state revenue estimates have crashed since that study was released last winter.

New, lower estimates undermine parts of the Susitna feasibility study that rely on revenue and oil price projections, Williams said in a letter to Eric Yould, executive director of the Alaska Power Authority. It is the state agency that plans to build two Susitna dams for about $5.2 billion.

"To the extent that the conclusions of the Susitna feasibility analysis are dependent on oil price levels over the long term, a radical revision in the long-range outlook for those prices may have invalidated those conclusions," Williams said.

"Certainly they have become obsolete, and the analysis supporting them should be redone using more current expectations of oil prices over the long term."

Williams referred Yould to a study done last month by Jamie Love, special assistant to the revenue commissioner. Love found that state spending helps determine population growth and electricity demands, and new revenue projections forecast much less state spending than the feasibility study had predicted.

Love also said the Susitna project will require large cash subsidies from the state up front, and that cash may not be available if the new revenue projections are true.

Yould today agreed some of the feasibility study was made using estimates that since have been lowered.

But the power agency all along planned to continue to update — while waiting to get the go-ahead to build from the Federal Energy Regulatory Commission — its assumptions on whether the dams are a good idea economically. Federal permission likely is two to three years off, Yould said.

In his letter, Williams was answering Yould's questions about the accuracy of a draft study done for the governor's office by economists Arlon Tussing and Gregg Erickson.

That study, being [...] form this week, re[...] sitna feasibility stu[...] cludes many of its [...] been canceled by a [...] for longterm oil price[...]

State revenues ar[...] mostly by the price o[...]

The Tussing-Erick[...] one of three studies [...] nor's Division of Po[...] ment and Planning [...] parts of the early fea[...] because of new inform[...]

Report says 2 dams may be 1 too many

9/30

By Bill White
Times Juneau Bureau

Juneau — Demand for electricity in Alaska's Railbelt region might be too low to justify construction of the second of two massive dams on the Susitna River, according to a study by the governor's office.

Growth in demand should be tied to growth in population, which in turn is linked to growth in state spending, concluded the report by the governor's division of policy development and planning.

But state spending may not materialize to the extent anticipated by backers of the Susitna dams, the report said. Recent long-term revenue forecasts look with pessimism at expected state income through the rest of the century.

The $5.2 billion Susitna hydroelectric project involves building two dams on the Susitna River northeast of Talkeetna to serve the power needs from Fairbanks to the Kenai Peninsula, including Anchorage. First to be built — by 1993 — would be an 885-foot rockfill dam and powerhouse at an area called Watana. Then, by 2010, a 650-foot concrete arch dam and powerhouse would be erected downstream at Devil Canyon.

"There is little question that electricity demand will be sufficient by 1990 to absorb the output of the first half of the project — the Watana dam," the report said.

"However, it is uncertain whether demand will continue to grow between 1990 and 2010 such that the second half of the project — the Devil Canyon dam — can be justified."

A two-and-a-half-year, $35 million study for the state released in March concluded demand for electricity in the Railbelt should justify building the two dams.

But the new report from the governor's office said that justification depends on the state having extensive savings in the next decade that would allow continued growth in state spending through the year 2010.

"However, it no longer seems credible that the state will actually accumulate such savings, especially in view of the substantially lower petroleum revenue forecasts that have been issued in March and June 1982 by the Department of Revenue."

The report added that revenue estimates are just estimates, and actual income could be higher than the forecasts. Oil prices could escalate, another rich oil field like Prudhoe Bay could be found and tapped in the 1990s, or private development could offset a fall in state spending.

Also, demand should be higher if the state pays for dam construction instead of consumers. "As a result, it appears likely that the full output of both dams would still be absorbed despite today's state revenue projections."

Another recent study on Susitna for the division concluded that outdated assumptions were made in previous studies that concluded there was a need for the hydroelectric project.

Written by Arlon R. Tussing and Gregg K. Erickson, the report criticized recent studies on Susitna as "already largely obsolete."

In a related development, Standard Research Institute is expected to complete within a couple weeks what kind of inducement low-cost energy from Susitna would have in luring industry to the railbelt.

New Susitna report claims old inaccuraci

by A.J. McClanahan 9/23
Times Writer

Recent studies showing a need for the two-dam $5.1 billion Susitna hydroelectric project are based on incorrect information, according to a draft report done for the governor's office.

Arlon R. Tussing and Gregg K. Erickson say in their report that outdated assumptions were made in previous studies that concluded there was a need for Susitna.

Questioning Tussing and Erickson's report, however, is the energy committee of the Anchorage Chamber of Commerce.

And the Alaska Power Authority, charged with coordinating studies on the project, has no comment yet on the Tussing-Erickson report because officials there are still studying it.

The Tussing-Erickson draft is called "Alaska Energy Planning Studies: Substantive Issues and the Effects of Recent Events," and was done for the governor's Division of Policy Development and Planning.

Tussing and Erickson criticized recent studies on the Susitna project as "already largely obsolete."

The studies' "critical assumptions — regarding the future prices of various fossil fuels, the growth of population and economic activity in Alaska and the resulting growth of energy demand in the state — are based upon a 'conventional wisdom' about future energy prices that should have been suspect even in 1980 and 1981 when the study contracts were signed, and which subsequent experience has made nearly untenable," Tussing and Erickson said in the draft.

Erickson declined to be interviewed about the report, stressing that comments are still being sought on it before it is put into final form.

The main findings of the draft report are:

• Dramatic changes in oil price expectations since 1980 demand reconsideration of the level of Alaska economic activity and energy demand.

• Assumptions in previous reports concerning prices and availability of Alaska coal and natural gas for local electric power generation are not well supported.

• Recent studies did not deal with high interest rates and capital-market conditions, and so their conclusions about risks, costs and financing arrangements of the Susitna project are suspect.

• Now is not the time for major initiatives in publicly financed power development in Alaska unless those ventures are able to satisfy stricter tests of economic feasibility.

Former chamber president Bob Penney and other representatives of the chamber energy committee said an earlier report by Tussing has proven to be "very conservative" in terms of population growth estimates for railbelt communities.

And as for the current draft repor[t] there have been dramatic changes in oil [...] tations, Penney said demand for all natur[al ...] including oil, is down now. But, he sa[id ...] economy improves, "we'll all use more."

Countering other findings, Penney sai[d:]

• Coal is economically feasible if th[e com]mercial development for coal already a[...] there are no projects to commercially [...] Beluga field, and without them Beluga'[s ...] be too high to be an alternative to Susitna[.]

• Interest rates already have fallen [...]ment in the Susitna project by the state [...]ture Alaskans a return on some of today'[s ...]

• Now is the time for the state to buil[d ...] cause gas burned today to generate elect[ricity ...] saved for future generations for heating [...]

Access route for Susitna project OK'd

by A.J. McClanahan 9/15
Times Writer

An access route for the proposed $5.1 billion Susitna hydroelectric project that would go south from the Denali Highway to the Watana Dam site was narrowly approved by the Alaska Power Authority board Tuesday.

The 4-3 vote followed a public hearing which drew little comment except from a spokesman for an environmental organization that questioned the need for the massive hydroelectric project.

Selection of the access route does not mean bulldozers will be carving up the near 100 miles of roadway soon. In fact, any road construction is likely to be at least three years away. The recommended access route will be included in the licensing application to be submitted by March to the Federal Energy Regulation Commission. Processing of the application could take up to three years.

Although the Department of Natural Resources prefers an all-rail, limited-access route, department spokesman Al Carson said his agency will cooperate as much as possible with the power authority and won't fight the access route chosen.

One of the two routes not chosen went from the Parks Highway at Hurricane, through the Chulitna Pass, then north of the Susitna River and through the Upper Portage Creek drainage, including a a spur road to the Devil Canyon dam site. The second route not chosen went from the Parks Highway at Hurricane, through the Chulitna Pass, proceeding on the south side of the river to just before the Watana Dam site, including a road from Gold Creek running to the Devil Canyon site.

The route approved by the board Tuesday was a variation on one suggested by the consulting firm Acres American. That plan called for the route to have a railroad spur built on the south side of the river to the Devil Canyon dam site.

Native corporations had listed

See Susitna, page A-4

Susitna

(Continued from page A-1)

the Acres suggestion as their second choice, saying they wanted as much access as possible to their lands.

Although the route approved has the greatest ease of construction, it also has the most environmental impact, power authority staff said. But they added that their suggestion — because it goes on the north side of the Susitna — reduces the the environmental impact because the north side is less sensitive.

Dr. Ernst Mueller disagrees. The commissioner of the state Department of Environmental Conservation said today he voted against the access route "because it's a more expensive route and the most environmentally harmful route."

Mueller said the road, if constructed, would eventually become a public road and the onslaught of more people coming into this area would affect caribou migration patterns.

Power authority Executive Director Eric Yould told board members that even though the board approved the route Tuesday as the one to be submitted to FERC, "It's not set in concrete." The commission may require that it be changed, or the power authority could change its mind and re-submit a route to the commission.

Raising questions about the project in general was Eric Myers of the Nothern Alaska Environmental Center. He said recent changes in world oil prices invali-

for the Susitna project is based.

In a prepared statement submitted to the board, Myers said revised expectations about world oil prices and associated state spending trends should be taken into account in planning for the project.

The power authority board and staff told Myers that forecasts of Alaska power needs are being re-evaluated to account for such things as changes in oil revenues and trends in state spending.

Voting for the route suggested by power authority staff were board members Dr. Ron Lehr, budget and management director in the governor's office; Charles Webber, commissioner of the state Department of Commerce and Economic Development; board Chairman Charles Conway, partner in a public relations firm; and Robert Ward, commissioner of the state Department of Transportation.

Joining Mueller in voting against the access route were John Schaeffer, president of NANA, a native corporation and Dr. Robert Weeden, University of Alaska wildlife sciences professor.

Also at the day-long power authority meeting, an Anchorage man who said he represented Talkeetna area residents said people in that area want construction of

cal transmission intertie to be by helicopter only in their area.

Jim Sykes of Anchorage, who owns land near Talkeetna, also told the power authority that Talkeetna residents don't want the agency to use pesticides.

They want the agency to adopt an official policy against the use of insecticides, herbicides and other pesticides, he said.

Power authority spokesman George Gleason said the agency will not use any pesticides in the construction of the intertie, which would allow for power exchanges between Anchorage and Fairbanks even if the Susitna project is not built. But he added that it's too early to consider what the maintenance policy for the intertie would be.

In other action the board:

— Narrowed a list of consult-

design the Watana dam to Bechtel Civil and Minerals Inc. of San Francisco, the joint venture of Harza Engineering Co. and Ebasco Services Inc. of Bellevue, Wash, and Raymond Kaiser Engineers of Oakland, Calif. The state legislature appropriated $25.6 million to begin the design of the Watana phase of the project, and the power authority will seek additional funds during the next session to complete the project design.

— Decided to begin contract negotiations with Ebasco Services Inc. on a study of using North Slope natural gas for electrical generation in the Railbelt area.

— Decided to begin negotiations with Land Field Services Inc. of Anchorage to provide land acquisition, permitting and regulatory management services for the Susitna project.

Susitna project access road approved

9/15

The directors of the Alaska Power Authority approved by a narrow margin a 100-mile access route from the Denali Highway to the proposed $5.1 billion Susitna River hydroelectric project.

The directors voted 4-3 for a staff-recommended variation of an access route favored by consultants, with the vote reflecting, in part, disagreement over environmental impacts.

The chosen route would provide road access from the Denali Highway to the proposed Watana and Devil Canyon dam sites in two phases. It also would include construction of a rail spur from the Devil Canyon site south and west to hook up to the Alaska Railroad at Gold Creek.

Power authority spokesman George Gleason said the staff recommended the revised route — and a majority of directors approved it — partly because it was deemed more cost effective.

The initial costs would be less and construction would be far easier than under the consultant's proposed access route he said.

"We can shorten the construction of the whole project by a year to a year and a half."

The power authority staff maintained that the favored route from the Denali Highway north of the Susitna River also would pose fewer environmental problems because it would cross relatively flat, dry tundra, while the consultant's suggested route from the south would run across wetlands.

But some of the board directors and representatives of state agencies felt otherwise.

Ernst Mueller, a power authority director and commissioner of the Department of Environmental Conservation, voted against the staff recommendation, saying later that the access road eventually would be public and that the road development could disrupt caribou migration.

Mueller said he opposed the chosen route also because the final cost would be higher.

The route chosen by most of the directors is not the best alternative for wildlife, according to Karl Schneider, a Department of Fish and Game biologist who supervised big game studies for the access alternatives.

"The route that they chose ... was a segment we felt would be most detrimental to wildlife, particularly caribou," Schneider said.

The chosen route will not necessarily be devastating to caribou, he said, but "it would make an important part of their range less usable."

Eric Myers of the Northern Alaska Environmental Center said Wednesday that the chosen route was "the least environmentally acceptable."

Myers also raised broader objections to the massive hydroelectric project, saying that recent state revenue forecasts could put a significant damper on the outlook for electricity demand in the Railbelt.

The board acknowledged the need to reassess future demand and said that a reevaluation is in the works.

Directors voting with Mueller against the recommended access route were Robert Weeden, a wildlife sciences professor from the University of Alaska, Fairbanks, and John Schaeffer, president of NANA, the Kotzebue-based Native regional corportion.

The access route preferred by the majority of directors will be included in the state's Federal Energy Regulatory Commission licensing application for the project.

Though the application is expected to be submitted by March, its processing could take as long as three years.

Eric Yould, the power authority's executive director, said after the vote that the access route is "not set in concrete."