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68-71

(FILE 7)

# ALASKA STATE LEGISLATURE

SENATE STATE AFFAIRS COMMITTEE  
SENATOR VIC FISCHER, CHAIRMAN

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February 21, 1983

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

The enclosed packet includes:

- A. SB 68-71 and a summary of them
- B. statutory references
- C. Task 11 financing options and a summary
- D. article from the Legislative Digest
- E. summary of Birch-Horton "Regulatory Impact Management Plan"
- F. historical perspective and statutory framework from Battelle "Alternatives Study"
- G. House Research memo -- Jan. 1983 -- Susitna Status Report
- H. House Research memo -- Feb. 1983 -- Tyee
- I. article from "Business Week"
- J. correspondence between Sen. Vic Fischer and the APA
- K. SRI report -- "Potential for Industrial Development..."
- L. Tussing/Erickson report -- "Alaska Energy Planning Studies"
- M. memo from Milt Barker re: funds available for capital projects

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

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

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

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

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

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

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

Sec. 3. Approves the preliminary report and project.

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

Sec. 5. Effective date -- immediately.

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

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

Sec. 2. Effective date -- immediately.

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

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

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

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

Sec. 4. Effective date -- immediately.

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

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

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

Sec. 3. Repeals the permanent fund dividend program.

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

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

Sec. 6. Effective date -- immediately.

References cited in  
SB 60 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;

(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(1)(2)(B)(i); or

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

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

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

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

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

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

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

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

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

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

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

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

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

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

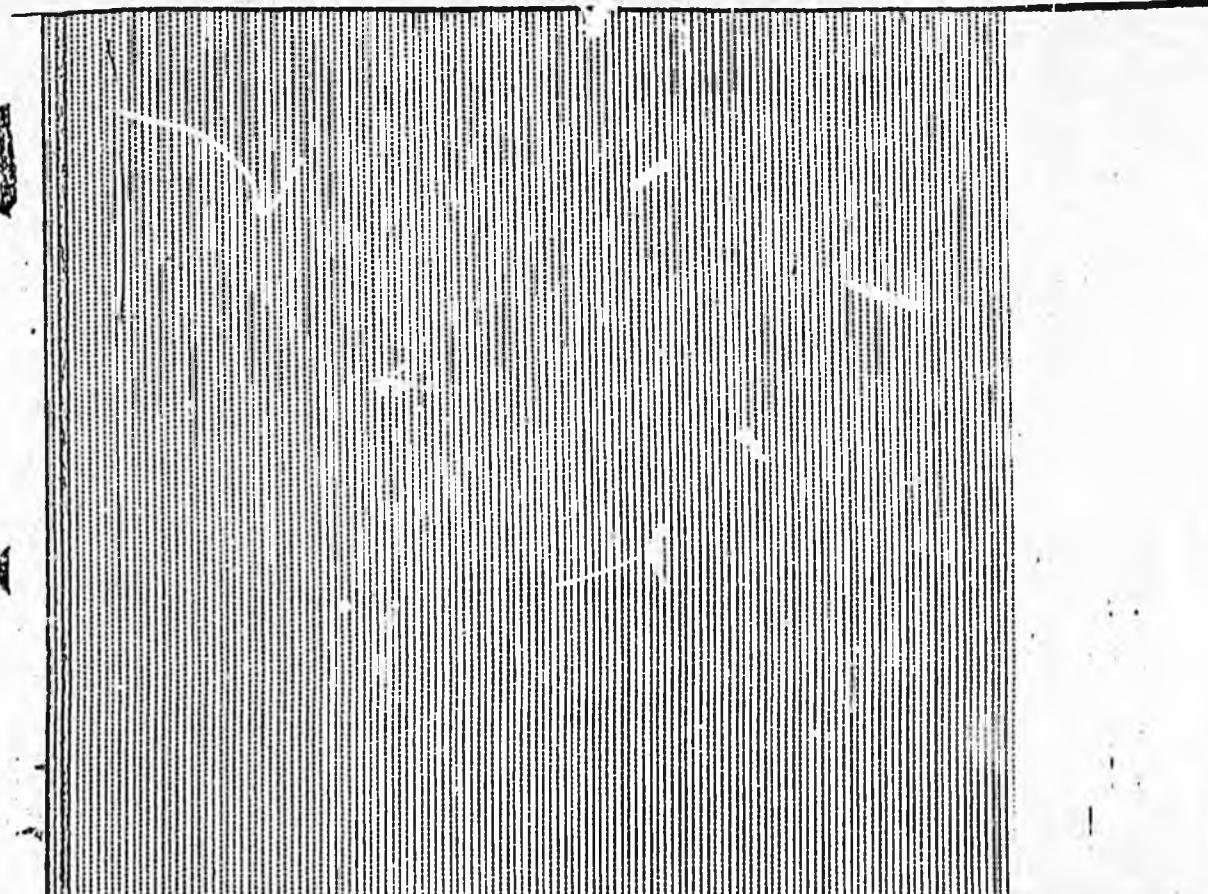
(b) The authority may not proceed with work on the engineering or design phase of a proposed new project for which legislative approval is required until the legislature approves the proposed new project. However, the authority may proceed with the engineering or design work necessary to meet the requirements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

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

Effect of amendments. — The 1982 amendment, effective June 26, 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, June 25, 1982, in accordance with AS SLA 1982, makes this section effective 01.10.070(c).



## Article 7. Susitna River Hydroelectric Project.

### Section

- 300. Description of project
- 310. Purpose of project
- 320. Preliminary reports
- 325. Restrictions on contracting
- 330. Construction, maintenance and operation of project

### Section

- 340. Annual report
- 350. Legislative and executive oversight
- 360. Project financing

**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;

**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)

(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;

§ 44.83.350

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

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

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

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

## Article 7. Susitna River Hydroelectric Project.

### Sec. 44.83.325. Restrictions on contracting.

Editor's note. — Section 21, ch. 133, SLA 1982, provides: "Notwithstanding the provisions of AS 44.83.325, the Alaska Power Authority may enter into contracts under AS 44.83.300 — 44.83.360 for preliminary work without the approval required by AS 44.83.325. In this section, 'preliminary work' means the preparation of plans and studies and the preparation and submission of license applications, as well as other types of work, that must be

completed before actual construction of the Susitna River hydroelectric project, described in AS 44.83.300, may begin. This section does not authorize the Alaska Power Authority to enter into contracts for the actual construction of the Susitna River hydroelectric project or for the preparation of the site of the Susitna River hydroelectric project without the approval required by AS 44.83.325."

# LOOKING AT SUSITNA ISSUES

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

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

## Some Arguments Against

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

A few years ago, oil revenue analysts projected a continual rise in Alaska's oil revenue. The curve was to increase steadily until 1989 and then begin a gradual decline to the end of the century. The decline, because of the fluctuation in world oil prices, has already begun. With our income in decline, 89 percent of which comes from sales of oil, the anticipated population and industrial boom of the 1980s may not materialize as predicted. The upshot of decreased revenues is that as oil and gas prices fall, less money will be available with which to build the

Susitna project. At the same time, again because of falling oil and gas prices, Susitna becomes a less feasible source of power because of the cheaper thermal alternative: natural gas. The price of natural gas will not rise as sharply in the 1980s and early 1990s as previously thought.

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

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

## New Gas Price

A more recent fact has produced concern about the project's near-term feasibility: the Enstar gas contract. Last December Enstar Natural Gas Company negotiated a 15-year gas contract, which would supply high 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 Battelle 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 high 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 knowledgeable person, including those who would be in direct competition with Susitna, who would disagree with the belief that at some point we will need Susitna hydro power, whether it is the high Devils Canyon dam or a combination of the Watana and Devils Canyon dams. The question critics are asking is: When and how much?

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

## Susitna Hearings

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

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

Summary  
of 3 Volume  
Report +  
2 Volumes of  
appropriate regulations

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 HOGGE & HILLS

Gerald R. Hill  
REGULATORY IMPACT MANAGEMENT INC.



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## EXECUTIVE SUMMARY

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

- ° 15 to 20 state and local government approvals
  - air and water quality permits, fish and game impact-mitigation measures, waste disposal, etc.;
- ° 10 to 15 federal permits
  - involving at a minimum these federal agencies:
    - Federal Energy Regulatory Commission (FERC);
    - Environmental Protection Agency (EPA); Corps of Engineers (COE); Coast Guard; U.S. Fish and Wildlife Service (USF&WS); Bureau of Land Management (BLM); Advisory Council on Historic Preservation (ACHP); National Marine Fishery Service (NMFS); and the Federal Aviation Administration (FAA);
- ° other factors
  - uncertain land ownership patterns, water rights disputes, and subsistence rights, plus probability of intra- and inter-agency communications breakdowns concerning the adequacy and implications of the data base.

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

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

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

This report constitutes the first step of Phase I of such a system. It identifies and documents the problems, both regulatory and non-regulatory, facing the Susitna project. The report makes specific findings and recommendations that require state officials' immediate consideration. Furthermore, 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.

I. INTRODUCTION  
▼  
II. FINDINGS AND RECOMMENDATIONS  
▼  
III. LICENSING  
▼  
IV. REGULATORY NEEDS  
▼  
V. NON-REGULATOR FACTORS

(F) 2

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

## 9.2 A HISTORICAL PERSPECTIVE OF POWER PLANNING IN ALASKA

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

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

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

#### Legislative Finding and Policy

- (a) The legislature finds, determines and declares that
  - (1) there exist numerous potential hydroelectric and fossil fuel generating sites in the state;
  - (2) the establishment of power projects at these sites is necessary to supply lower cost power to the state's municipal electric, rural electric, cooperative electric, and private electric utilities, and regional electric authorities, and thereby to the consumers of the state, as well as to supply existing or future industrial needs;
  - (3) the achievement of the goals of lower consumer power costs and long-term economic growth and of establishing, operating and development power projects in the state will be accelerated and facilitated by the creation of an instrumentality of the state with powers to incur for constructing, and with powers to operate, power projects.
- (b) It is declared to be the policy of the state, in the interests of promoting the general welfare of all the people of the state, and public purposes, to reduce consumer power costs and otherwise to encourage the long-term economic growth of the state, including the development of its natural resources, through the establishment of power projects by creating the public corporation with powers, duties and functions as provided in this chapter.

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

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

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

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

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

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

The 1980 session of the legislature passed substantial legislation relating to the Power Authority. Approximately \$50 million was appropriated for some 35 projects. The major appropriations were \$15 million for the Tye 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 distribution systems by local utilities. The revenues used included the following:

- \$70 million toward construction of the Tye 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 choose 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 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 a 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, reconnaissance, 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 the 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.

Implementing the conservation option appears to require new authorizing legislation.

Although the requirements of A.S. 44.83.384 et seq. 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 statutes 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 approach 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 influenced 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 preferring 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  
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January 5, 1983

MEMORANDUM

TO: Representative Brian Rogers

FROM: Jack Kreinheder  
Research Staff *JK*

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.

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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 from 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."<sup>1</sup>

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.<sup>2</sup> 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.

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<sup>1</sup> Battelle, Railbelt Electric Power Alternatives Study, Newsletter #4, December 1982, p. 13

<sup>2</sup> 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.

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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."<sup>3</sup> 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."

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<sup>3</sup> Tussing and Erickson, Alaska Energy Planning Studies, November 1982, p. 15.

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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 of 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 not 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

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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

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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 1980'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

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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.

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#### 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

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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

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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.



ALASKA STATE LEGISLATURE  
HOUSE OF REPRESENTATIVES  
RESEARCH AGENCY

Pouch Y, State Capitol  
Juneau, Alaska 99811  
(507) 465-3991

February 11, 1983

MEMORANDUM

TO: Representative Don Clocksin

FROM: Jack Kreinheder  
Research Staff *JK*

RE: Lake Tye 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 Tye 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 Tye power costs to marketable levels..

The attached letter from the Alaska Power Authority outlines the sequence of construction cost estimates for the Tye 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 Tye 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 Tye 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 Tye 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 Tye 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 AFA 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 Tye power rate will probably increase by about two percent per year.\*

#### PROJECT FINANCING

82M/112M

The completed cost of the Tye 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 Tye 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 Tye is 25 percent of the total cost of all projects in the system, Tye 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 Tye 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

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\* 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 Tye 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 Tye 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 Tye 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 Tye 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 Tye 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

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\* 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 Tye power or the cost of Tye 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 Tye 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 Tye 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 Tye 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 Tye situation.

#### IMPLICATIONS FOR OTHER POWER PROJECTS

A number of legislators and other observers have expressed concern about the possibility of the Tye 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 Tye 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 Tye 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 Tye is also accentuated by the fact that Tye 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 Tye 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 Tye 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) 278-0001

February 9, 1983

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

Subject: Tye 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 Tye 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 Tye Hydroelectric Project in the vicinity of Wrangell and Petersburg, Alaska. Our engineers, R.H. Ratherford 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 representative 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 Tye 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 Tye 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 Tye Project. TBPC and Representative E.J. Haugen request the APA take over Tye. The Board directed staff to bring information back at next Board meeting for Project take-over.

September 27, 1979 Tye 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 Tye 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 Tyes 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 Tye 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 Tye Project based on present knowledge of the costs. Commissioners Ward and Mueller and Dr. Heeden 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.

Mr. Jack Kreinheder

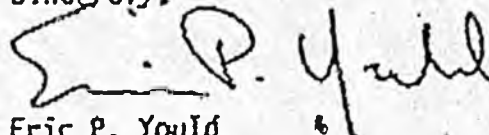
Page #4

February 9, 1983

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  
Executive Director

CC:

C. Conway

~~Cox~~ 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 alle-

gations 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. "Every-

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.

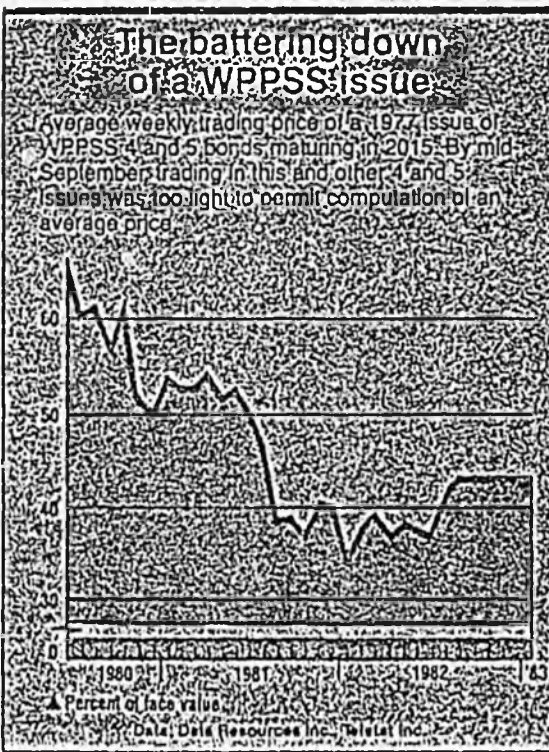
WPPSS needs the funds to make monthly payments to Chemical Bank, the bond fund trustee, which in turn makes semi-annual distributions to investors. Unless WPPSS begins collecting by March, it will not have enough money to cover the \$93.9 million payment due bondholders on July 1. Chemical holds \$102 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, 48% 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.

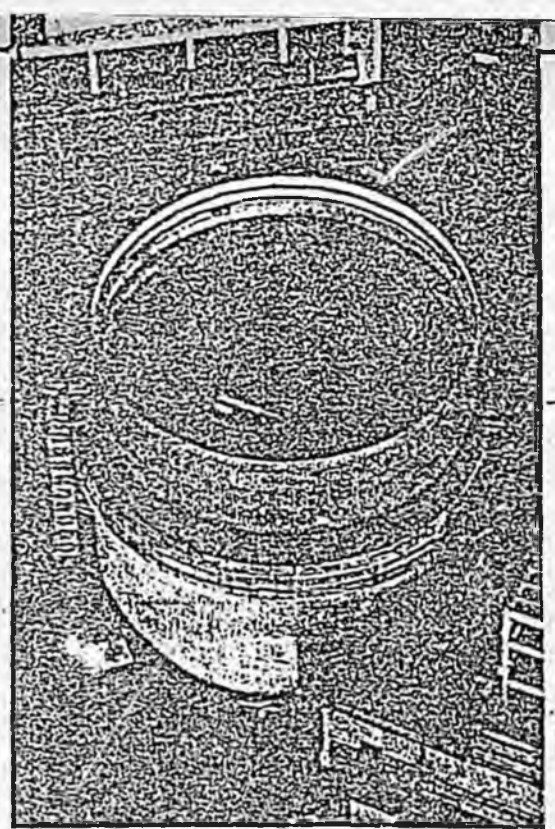
No sympathy. Northwestern political and business leaders have tried in vain to jawbone recalcitrant utilities into paying. Attempts to seek a solution outside the region have proved similarly ineffective. California utilities have demonstrated little interest in buying WPPSS plants or any future output,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



body sold Whoops bonds," says one analyst. To the dismay of investors, a long series of setbacks has depressed many WPPSS bond issues (chart).

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,



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." ■



# Alaska State Legislature

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

January 20, 1983

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

RECEIVED  
JAN 27 1982  
ALASKA POWER AUTHORITY

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

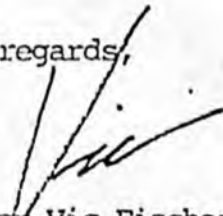
may be some value in providing such a comparison, it seems to me obvious that we have at work some local market conditions that must be considered when deciding on the relative costs and merits of competing sources of energy. In fact, the market value of Cook Inlet gas is not the price it might bring 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 AJA, 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,



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, then 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

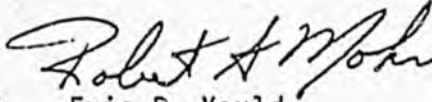
include the sensitivity testing methodology of the Feasibility Report and the full range of sensitivity test results. As the license processing proceeds, the Power Authority will be transmitting periodically updated load forecasts, fuel price assumptions and revenue projections. The FERC staff can be 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,

  
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

NOTE REGARDING THE FOLLOWING FRAME(S) ON MICROFILM:  
COMPLETE DOCUMENT IS AVAILABLE IN ORIGINAL FILES,  
TITLE PAGE ONLY HAS BEEN FILMED.

(K)

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



**STATE OF ALASKA**  
**OFFICE OF THE GOVERNOR**

**Division of Policy Development and Planning**

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