3018 SSA SB 68-71 (FILE 5) - (FILE 6)

UNIVERSITY OF ALASKA
Institute of Social and Economic Research
707 "A" St., Suite 206
Anchorage, Alaska 99501
Phone (907) 278-4621

February 24, 1983

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

Dear Senator Fischer:

At the request of the Senate State Affairs Committee, I am sending you a brief paper which describes our work to date in developing new economic projections for determining future electricity demand in the Railbelt.

Our work is still in a preliminary stage as all components of our projection methodology and data inputs are currently under intensive review and scrutiny both from within and without the Institute. Consequently, the projections presented in the paper are subject to change before they are actually used in a revised evaluation of Susitna feasibility.

With the caveat in mind, the paper presents our best estimate at this time of a base case (most likely) projection of economic activity. High and low projections are not yet available, but it should be kept in mind that due to the inherent uncertainties surrounding oil prices and production, as well as other variables affecting the levels of future economic activity, the range of possible futures covers a broad band.

Tables 1-4 in the paper show the 1983 preliminary projections for state population, employment, petroleum revenues, and general fund expenditures (defined to include Permanent Fund Dividends and restricted general fund expenditures). It also compares these projections to those done by the Institute in 1981 for the Battelle Railbelt study.

The significantly lower population and employment projections are the result of the downward adjustment in forecasted petroleum revenues. For the mid-1990s the most recent projections are less

than one-third those of 1981. This fall in forecasted petroleum revenues dramatically reduces state spending in the current projection below the projection made in 1981. Further, as lower petroleum revenues are a reflection of lower real energy prices, lower petroleum revenue projections go hand in hand with a reduction of the economic viability of large scale energy projections such as the ANGTS line.

Table 5 of the paper describes the revised base case economic scenario and compares it with the one used in the Battelle study. One can see the postponement or elimination of several projects, but also the addition of some new projects.

The difference between the 1981 projection and the preliminary 1983 projection is symptomatic of the uncertainty inherent in energy planning in Alaska. We cannot expect that this uncertainty has now been eliminated because a revised set of projections, albeit preliminary, has been developed. Events will continue to surprise us, forcing us to continuously change our best estimates of what the future economic picture of the state will be. Energy planning must confront this uncertainty directly and direct us toward those options which minimize the risks inherent in planning in an uncertain world.

I will be unavailable to appear before the committee on March 1, but if you desire an oral briefing on our work to date, please contact Dr. Gunnar Knapp of the Institute, who is prepared to explain in more detail the current status of our research.

Sincerely,

Oliver Scott Goldsmith/D.K.

Oliver Scott Goldsmith
Associate Professor of Economics

Enclosures

cc: Ned Lesnick, Harza-Ebasco
Robert Mohn, APA

COMPARISON OF ISER MAP MODEL PROJECTIONS PREPARED IN 1981 FOR BATTELLE RAILBELT STUDY AND PRELIMINARY PROJECTIONS PREPARED IN 1983

Prepared for

The Alaska Senate State Affairs Committee

Prepared by

Scott Goldsmith and Gunnar Knapp
University of Alaska
Institute of Social and Economic Research

February 1983

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Our current work is still in a preliminary stage, and all of the components of the projection methodology and data inputs are currently under intensive review and scrutiny from both within and without ISER. Consequently, the projections presented in the attached tables are subject to change.

With this caveat in mind, the preliminary 1983 projections represent our best estimate at this time of a base case (most likely) projection of economic activity. We have not yet completed high and low projections, but it should be kept in mind that due to the inherent uncertainties surrounding oil prices and production, as well as other variables affecting the levels of future economic activity, the range of possible futures covers a broad band.

I. COMPARISON OF 1981 PROJECTIONS AND 1983 PRELIMINARY PROJECTIONS

In 1981, the Institute of Social and Economic Research (ISER) prepared projections of population and economic activity in Alaska and the Railbelt for Battelle.* Tables 1-4 compare these 1981 projections for state population, employment, petroleum revenues, and general fund expenditures with the preliminary results of projections which ISER is presently preparing for the Alaska Power Authority and the Minerals Management Service Alaska OCS Office.

The significantly lower population and employment projections are the result of the downward adjustment in forecasted petroleum revenues. For the mid-1990s the most recent petroleum revenue projections are less than one-third those made in 1981. This fall in forecasted petroleum revenues dramatically reduces state spending in the current projection below the projection made in 1981 Further, as lower petroleum revenues are a reflection of lower real energy prices, lower petroleum revenue projections go hand in hand with a reduction of the economic viability of large scale energy projects such as the ANGTS line.

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*See Scott Goldsmith and Ed Porter, "Alaska Economic Projections for Estimating Electricity Requirements for the Railbelt" (ISER report prepared for Battelle, October 1981).

TABLE 2.

COMPARISON OF MAP MODEL PROJECTIONS:

EMPLOYMENT

(THOUSANDS)

	1981 PROJECTIONS	1983 PRELIMINARY PROJECTIONS	DIFFERENCE
1980	206.214	-	-
1981	214.193	214.217	0.024
1982	223.028	228.620	5.592
1983	233.475	234.000	0.525
1984	244.809	237.027	-7.782
1985	268.663	242.787	-25.876
1986	291.040	251.519	-39.521
1987	299.174	256.739	-42.435
1988	298.113	263.751	-34.362
1989	301.154	268.122	-33.033
1990	299.004	271.005	-27.999
1991	303.003	278.883	-24.120
1992	303.739	277.461	-26.278
1993	306.920	275.488	-31.432
1994	311.561	275.260	-36.301
1995	316.167	274.677	-41.489
1996	322.484	273.882	-48.602
1997	329.803	274.101	-55.702
1998	336.114	275.637	-60.477
1999	343.883	278.370	-65.513
2000	351.656	281.385	-70.271
2001	-	284.108	-
2002	-	286.979	-
2003	-	290.281	-
2004	-	293.862	-
2005	-	297.658	-
2006	-	301.571	-
2007	-	305.768	-
2008	-	310.155	-
2009	-	314.532	-
2010	-	319.225	-

NOTE: DIFFERENCE IS 1983 PRELIMINARY PROJECTIONS MINUS 1981 PROJECTIONS
BLANKS INDICATE PROJECTIONS NOT AVAILABLE
SEE NOTES AT END OF TABLES FOR SOURCES

TABLE 1.

COMPARISON OF MAP MODEL PROJECTIONS:

POPULATION

(THOUSANDS)

	1981 PROJECTIONS	1983 PRELIMINARY PROJECTIONS	DIFFERENCE
1980	400.457	-	-
1981	412.395	415.695	3.300
1982	428.251	431.412	3.160
1983	444.492	445.441	0.948
1984	463.274	457.310	-5.964
1985	498.151	468.152	-30.000
1986	531.933	481.069	-50.864
1987	545.304	491.021	-54.283
1988	547.669	502.515	-45.154
1989	558.208	512.465	-45.743
1990	562.438	521.061	-41.377
1991	572.732	533.891	-38.841
1992	579.364	538.950	-40.413
1993	588.021	541.646	-46.375
1994	598.543	544.941	-53.603
1995	608.963	547.669	-61.293
1996	621.173	549.747	-71.426
1997	634.519	552.455	-82.064
1998	646.899	556.224	-90.675
1999	660.873	561.274	-99.600
2000	674.983	566.779	-108.204
2001	-	572.190	-
2002	-	577.875	-
2003	-	584.169	-
2004	-	590.959	-
2005	-	598.222	-
2006	-	605.880	-
2007	-	614.087	-
2008	-	622.780	-
2009	-	631.767	-
2010	-	641.297	-

NOTE: DIFFERENCE IS 1983 PRELIMINARY PROJECTIONS MINUS 1981 PROJECTIONS
BLANKS INDICATE PROJECTIONS NOT AVAILABLE
SEE NOTES AT END OF TABLES FOR SOURCES

NOTE: Population projections are for long-term trends and will not capture short-term cyclical swings.

TABLE 4.

COMPARISON OF MAP MODEL PROJECTIONS:

STATE GENERAL FUND EXPENDITURES

(MILLIONS OF CURRENT DOLLARS)

	1981 PROJECTIONS	1983 PRELIMINARY PROJECTIONS	DIFFERENCE
1980	1402.121	-	-
1981	2381.692	2783.068	401.375
1982	3238.556	4000.100	761.543
1983	3582.562	3076.350	-506.212
1984	4033.220	3510.656	-522.564
1985	4556.820	3841.445	-715.375
1986	5410.379	4191.855	-1218.523
1987	6319.211	4305.965	-2013.246
1988	6915.836	4834.742	-2081.094
1989	7354.871	5063.359	-2291.512
1990	7908.508	5711.844	-2196.664
1991	8566.227	6206.945	-2359.281
1992	9202.680	5754.664	-3448.012
1993	10045.590	5810.402	-4235.191
1994	11018.460	5987.262	-5031.195
1995	12145.130	5984.492	-6160.633
1996	13389.920	5981.754	-7408.168
1997	14818.750	6268.918	-8549.828
1998	16433.000	6537.012	-9895.980
1999	18144.310	6991.930	-11152.380
2000	20107.040	7382.637	-12724.410
2001	-	7798.238	-
2002	-	8237.258	-
2003	-	8705.035	-
2004	-	9205.180	-
2005	-	9738.430	-
2006	-	10306.680	-
2007	-	10911.940	-
2008	-	11557.960	-
2009	-	12245.140	-
2010	-	12976.270	-

NOTE: DIFFERENCE IS 1983 PRELIMINARY PROJECTIONS MINUS 1981 PROJECTIONS
BLANKS INDICATE PROJECTIONS NOT AVAILABLE
SEE NOTES AT END OF TABLES FOR SOURCES

NOTE: General Fund Expenditures are defined to include permanent fund dividends and restricted general fund expenditures.

TABLE 3.

COMPARISON OF MAP MODEL PROJECTIONS:

PETROLEUM REVENUES

(MILLIONS OF CURRENT DOLLARS)

	1981 PROJECTIONS	1983 PRELIMINARY PROJECTIONS	DIFFERENCE
1980	1721.020	-	-
1981	4036.738	3314.232	277.495
1982	4132.719	3964.701	-168.018
1983	5030.418	3450.448	-1579.970
1984	5598.605	3163.283	-2435.323
1985	6623.777	3388.757	-3235.021
1986	7427.689	3772.009	-3655.680
1987	8612.336	3952.286	-4660.047
1988	9549.510	4470.195	-5079.316
1989	10907.430	4713.133	-6194.301
1990	11456.360	4502.570	-6953.793
1991	12468.160	4213.605	-8254.551
1992	13032.680	4134.953	-8897.730
1993	13766.180	4049.570	-9716.610
1994	13911.120	4108.281	-9802.840
1995	13456.950	3938.794	-9518.150
1996	12864.070	3771.708	-9092.360
1997	12155.070	3927.083	-8227.984
1998	11311.730	4055.789	-7255.941
1999	10396.860	4369.531	-6027.324
2000	9559.230	4590.996	-4968.238
2001	-	4824.875	-
2002	-	5072.004	-
2003	-	5333.211	-
2004	-	5609.359	-
2005	-	5901.387	-
2006	-	6210.293	-
2007	-	6537.129	-
2008	-	6883.031	-
2009	-	7249.211	-
2010	-	7636.957	-

NOTE: DIFFERENCE IS 1983 PRELIMINARY PROJECTIONS MINUS 1981 PROJECTIONS
BLANKS INDICATE PROJECTIONS NOT AVAILABLE
SEE NOTES AT END OF TABLES FOR SOURCES

TABLE 5. COMPARISON OF ASSUMPTIONS, 1981 PROJECTIONS AND PRELIMINARY 1983 PROJECTIONS

	1981 Projections	Preliminary 1983 Projections
State Revenues and Expenditure Assumptions		
Revenues	Petroleum revenues based upon Alaska Department of Revenue projections published in June of 1981 (see Table 3 for projections).	Petroleum revenues based upon Alaska Department of Revenue projections published in December of 1982 (see Table 3 for projections). The income tax is reinstated in 1989.
Expenditures	Real per capita expenditures increase at the same rate as per capita income.	State expenditures are at the levels allowed by the recently-passed spending limit. In 1992 when revenues are no longer sufficient to allow expenditures at the level permitted by the spending limit, expenditures are cut to equal total revenues.
Exogenous Employment Assumptions*		
Trans-Alaska Pipeline	Operating employment continues; four new pumping stations constructed.	Operating employment continues; four new pumping stations constructed.
North Slope Oil	Long-run North Slope oil operating employment is 1,667.	Long-run North Slope oil operating employment is 2,400.
Upper Cook Inlet Oil and Gas	Upper Cook Inlet employment remains constant with gas development offsetting declines in oil production.	Upper Cook Inlet employment declines to 50 percent of current levels by 2010.
Tertiary Oil Recovery	No tertiary oil recovery assumed.	Tertiary employment in oil recovery project on North Slope utilizing natural gas peaks at 2,000 in early 1990s.
Gas Pipeline	Northwest gas pipeline constructed, 1983-87.	No gas pipeline assumed.

*Employment in different special projects and basic industries is totaled to arrive at the total exogenous employment assumptions shown in Table 6.

II. COMPARISON OF ASSUMPTIONS USED IN 1981 PROJECTIONS AND PRELIMINARY 1983 ASSUMPTIONS

Differences between the 1981 and 1983 projections result primarily from differences in the assumptions used. Some changes have also been made to the structure of the model; however, these are of less importance in explaining differences between projections.

Table 5 presents a brief comparison of these assumptions for the 1981 and the 1983 preliminary projections. Exogenous employment assumptions are developed by constructing a scenario of employment in different special projects and basic industries. The scenario used in the 1983 preliminary projections postponed or eliminated some projects assumed for the 1981 projections, but added others.

Table 6 compares the total exogenous employment that resulted from the exogenous employment scenarios outlined in Table 5. The significant decline in the assumptions for total exogenous employment results primarily from lower exogenous employment assumptions for the mining, construction, and transportation industries.

TABLE 6. COMPARISON OF MAP MODEL TOTAL EXOGENOUS EMPLOYMENT ASSUMPTIONS

(thousands)

	1981 Projections	1983 Preliminary Projections	Difference
1980	67.010	66.152	-.858
1981	69.105	66.696	-2.409
1982	70.184	69.150	-1.034
1983	72.627	70.688	-1.939
1984	74.391	70.733	-3.658
1985	80.888	71.160	-9.728
1986	83.928	72.238	-11.690
1987	80.182	72.525	-7.657
1988	75.257	73.319	-2.208
1989	76.170	74.565	-1.595
1990	77.657	74.964	-2.693
1991	79.648	74.944	-4.704
1992	79.451	74.683	-4.798
1993	79.250	75.026	-4.224
1994	80.295	75.486	-4.809
1995	80.749	74.964	-5.755
1996	81.388	74.944	-6.444
1997	82.344	74.683	-7.661
1998	82.190	75.026	-7.164
1999	82.672	75.486	-7.186
2000	83.308	75.947	-7.361
2001	-	75.912	-
2002	-	75.816	-
2003	-	75.902	-
2004	-	75.995	-
2005	-	76.097	-
2006	-	76.152	-
2007	-	76.284	-
2008	-	76.418	-
2009	-	76.438	-
2010	-	76.598	-

TABLE 5. COMPARISON OF ASSUMPTIONS, 1981 PROJECTIONS AND PRELIMINARY 1983 PROJECTIONS (Continued)

	1981 Projections	Preliminary 1983 Projections
National Petroleum Reserve in Alaska	Slow development of 5 oil fields.	No development assumed.
Outer Continental Shelf (OCS) Petroleum and Gas	Oil and gas resources are developed in Lower Cook Inlet, the Beaufort Sea, the Chukchi Sea, & the Navarin Basin, with total employment exceeding 4,000 by 1998.	Oil and gas resources are developed only in the Beaufort Sea, with maximum employment of 1,771 in 1995.
Hydroelectric Development	No hydroelectric development assumed.	Employment in construction of hydroelectric projects peaks at 700 in 1990.
Coal Development	Beluga Coal Field developed for export.	Beluga Coal Field developed for export.
Mining	1 percent annual growth in employment	U.S. Borax, Greens Creek, and Red Dog Mines constructed; other mining employment increases at 1 percent per year.
Petroleum Refining	100,000 barrel-per-day refinery constructed at Valdez.	No new refineries assumed.
Pacific LNG Project	LNG project assumed for Anchorage area.	No LNG project assumed.
Forestry, Lumber and Pulp	Employment expands to 6,778 in 2000.	Employment expands to 4,028 in 2000.
Agriculture	Employment expands to 1,037 in 2000.	Employment expands to 508 in 2000.
Fishing	Total fish-harvesting employment expands to 7,423 in 2000. Fish processing employment expands roughly proportionately.	Total fish-harvesting employment expands to 7,096 in 2000. Fish processing employment expands roughly proportionately.
Federal Gov't Employment	Military employment constant. Civilian employment grows at .5 percent per year.	Military employment constant. Civilian employment grows at .5 percent per year.

ALASKA POWER AUTHORITY

334 WEST 5th AVENUE - ANCHORAGE, ALASKA 99501

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

April 26, 1982

The Honorable Jay S. Hammond
Governor
State of Alaska
Pouch A
Juneau, Alaska 99811

Dear Governor Hammond:

Alaska Statute 44.83.300 mandates that the Alaska Power Authority prepare and submit a preliminary report recommending whether work should continue on the Susitna River Hydroelectric Project and on other viable alternatives. The law further directs the Authority to explain certain project aspects in detail, in the event of an affirmative recommendation. This letter and the accompanying materials constitute that preliminary report.

In formulating its recommendations, the Power Authority has reviewed the Acres American Draft Feasibility Report, has been briefed by Battelle Pacific Northwest on the results of the Railbelt Alternatives Study, has received an inuependent Susitna Project cost estimate, has received a final report from our Susitna External Review Panel, and has listened to public, agency and utility testimony about the proposed project.

The Board of Directors has concluded that the Susitna Project offers a potential of long term benefits to the residents of the State. While this potential exists, the realization of those benefits is dependent upon certain assumptions about the future that are far from certain, upon proper project development timing, and upon very skillful project management. Because of these uncertainties and the time available before any construction decision is necessary, the Authority believes it is premature to make any commitment, at this time, to actual project construction. On the other hand, since the potential exists for realizing substantial long-term benefits and since no information has come to light to suggest that environmental and social impacts, after mitigation, would be unacceptable, we recommend the following actions which were unanimously approved at the meeting of the Power Authority on April 22, 1982.

1. Pre-construction developmental efforts on the Susitna Hydroelectric Project should be continued;

2. The Alaska Legislature should authorize the Power Authority to submit a Federal Energy Regulatory Commission license application at a time deemed appropriate by the Authority. The issue of license application timing will be resolved by the Authority not later than June 30, 1982;

3. Funds in the amount of $25.6 million should be appropriated to the Authority in FY-83 for the continuation and intensification of environmental studies, for site exploration activities, and for the initiation of project design.

Ensuing Board discussions raised several additional issues. Assessment of selected alternative power generation options should be pursued in the event that Susitna development does not proceed as scheduled for one reason or another. Specifically, we suggest that an initial assessment be made of the technical viability, environmental impact and life cycle cost of a North Slope gas generation and transmission system to serve railbelt power needs, and that feasibility studies of the proposed Chakachamna Hydroelectric Project by continued. The estimated FY-83 costs of these activities are $200,000 and $3,300,000, respectively.

In as much as a substantial State monetary contribution (in the form of either a loan or a grant) will be necessary to offset the relatively high power cost in the initial years of project operation, State officials should carefully consider the alternative near term uses of these State funds that would be foregone.

The Authority wishes it be understood that the recommendation to continue development activities on the Susitna Project is not an endorsement of the consulting engineer's recommendations regarding specific project details. For instance, the engineer's plan for access to the project site is the subject of reanalysis and will be reconsidered by the Authority at an appropriate future time.

With respect to the detailed information required by AS 44.83.300, please reference the accompanying draft feasibility report and associated documents. The proposed conceptual design can be found in Chapters 11-14 of Volume 1. The phases of construction and the expected completion dates for each phase are presented in Chapter 17 of Volume 1 and on Plates 75 and 76 of Volume 3. This schedule represents an optimal program under the assumption of a mid-range load growth forecast. The actual commitment to begin construction will require continued assessment of the opportunities and constraints associated with financial markets, Railbelt load growth and State revenues. The expected cost of constructing each phase is shown in Chapter 16 of Volume 1. A second estimate, prepared at Power Authority direction independently of the consulting engineer is also provided. Finally, the anticipated costs to the State and to power consumers under a number of alternative methods of project financing are presented in Chapter 18 of Volume 1. Analysis must continue on these as well as other financing alternatives.

You will find additional very important information in the other sections of the draft feasibility report, in the independent cost estimate report, in the Susitna External Review Panel report, and in the transcript of public, agency and utility testimony.

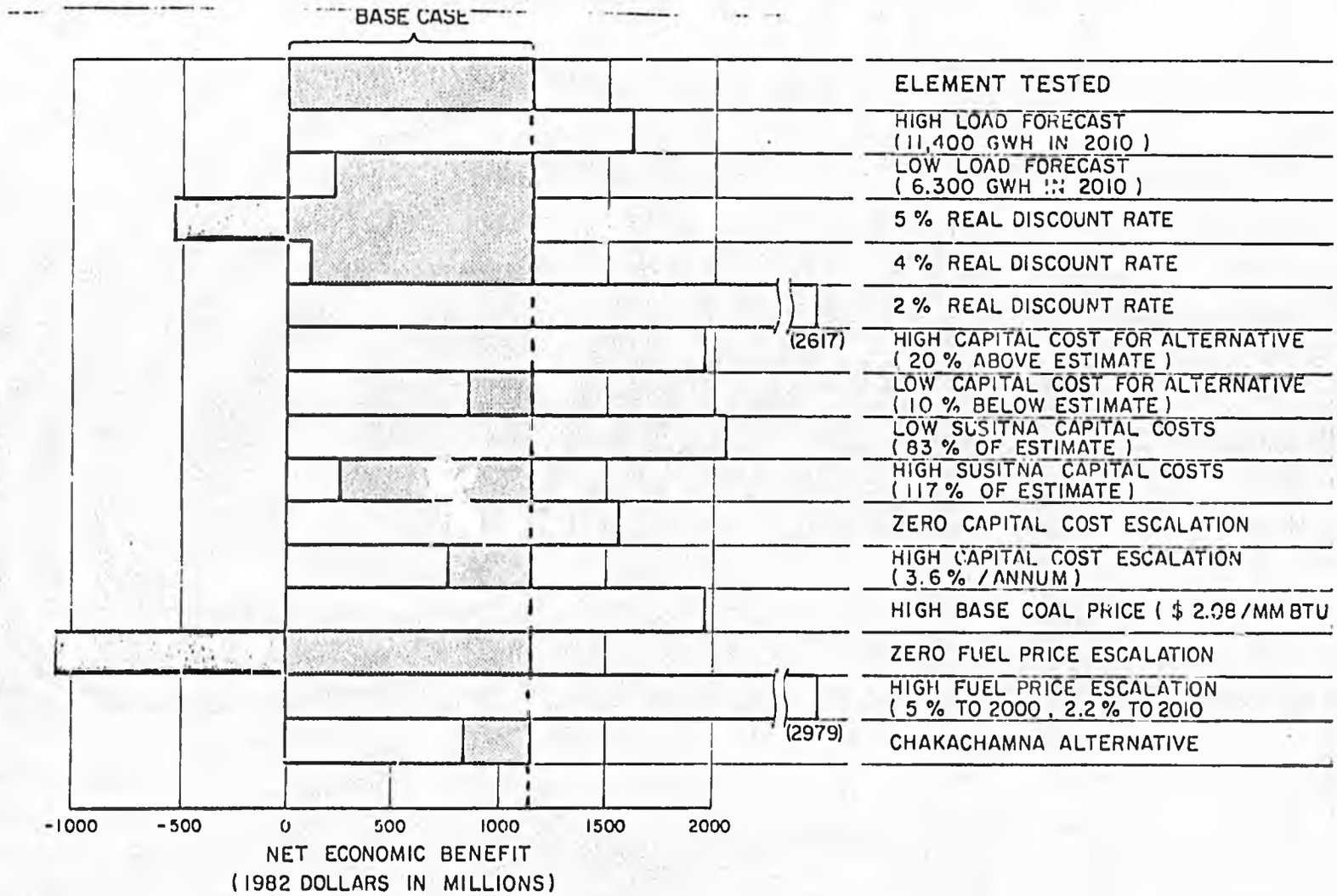
The Power Authority appreciates the opportunity to provide this preliminary report and make these recommendations on the Susitna Hydroelectric Project.

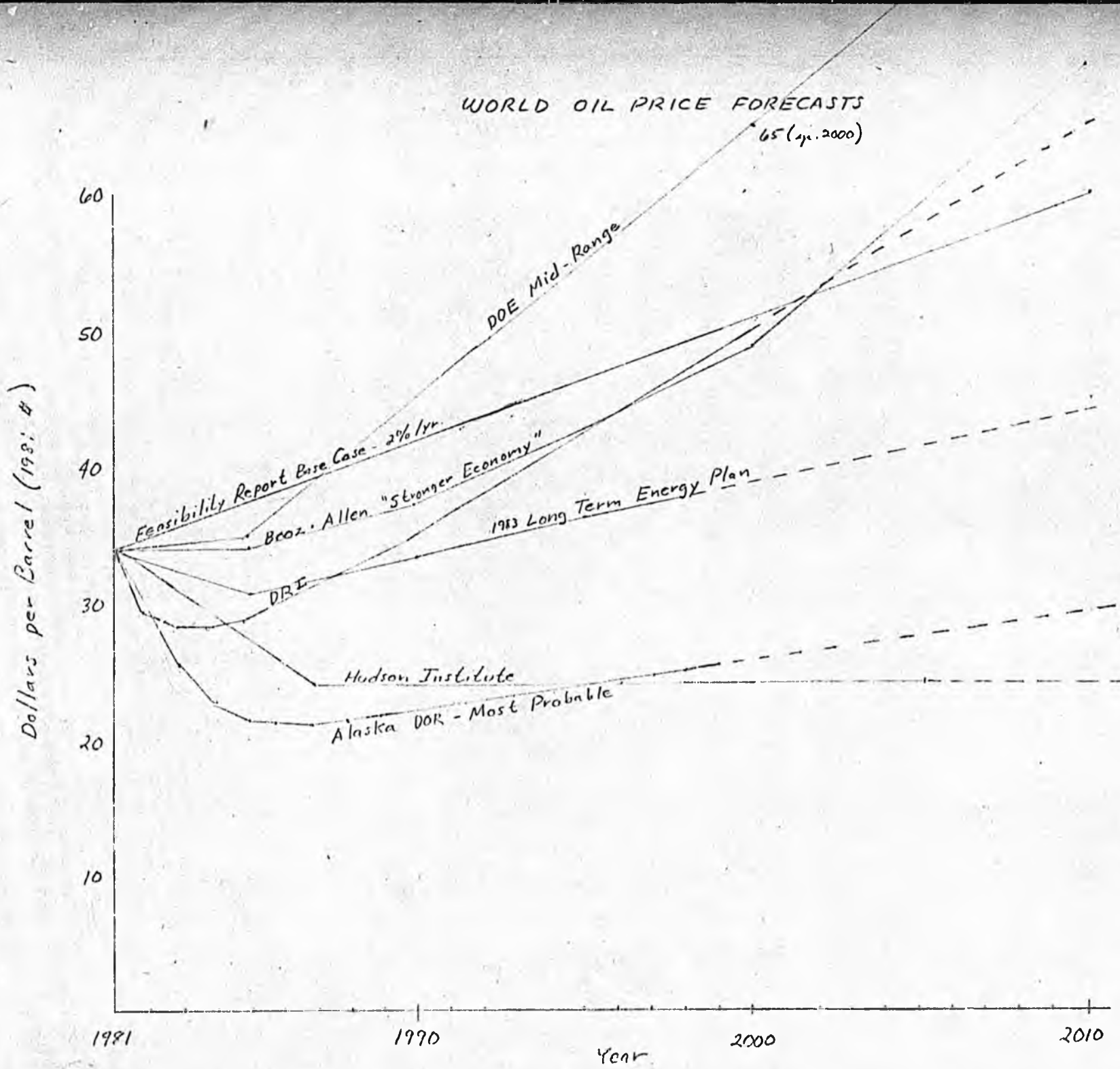
Respectfully Submitted,

Charles Conway
Chairman

Attachments: As noted.

SENSITIVITY ANALYSIS




WORLD OIL PRICE FORECASTS
65 (yr. 2000)
DOE Mid-Range
Feasibility Report Base Case - 2%/yr.
Broz. Allen "Stronger Economy"
1983 Long Term Energy Plan
DRI
Hudson Institute
Alaska DOR - Most Probable
60
50
40
30
20
10
Dollars per Barrel (1981 $)
1981
1990
2000
2010
Year

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

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

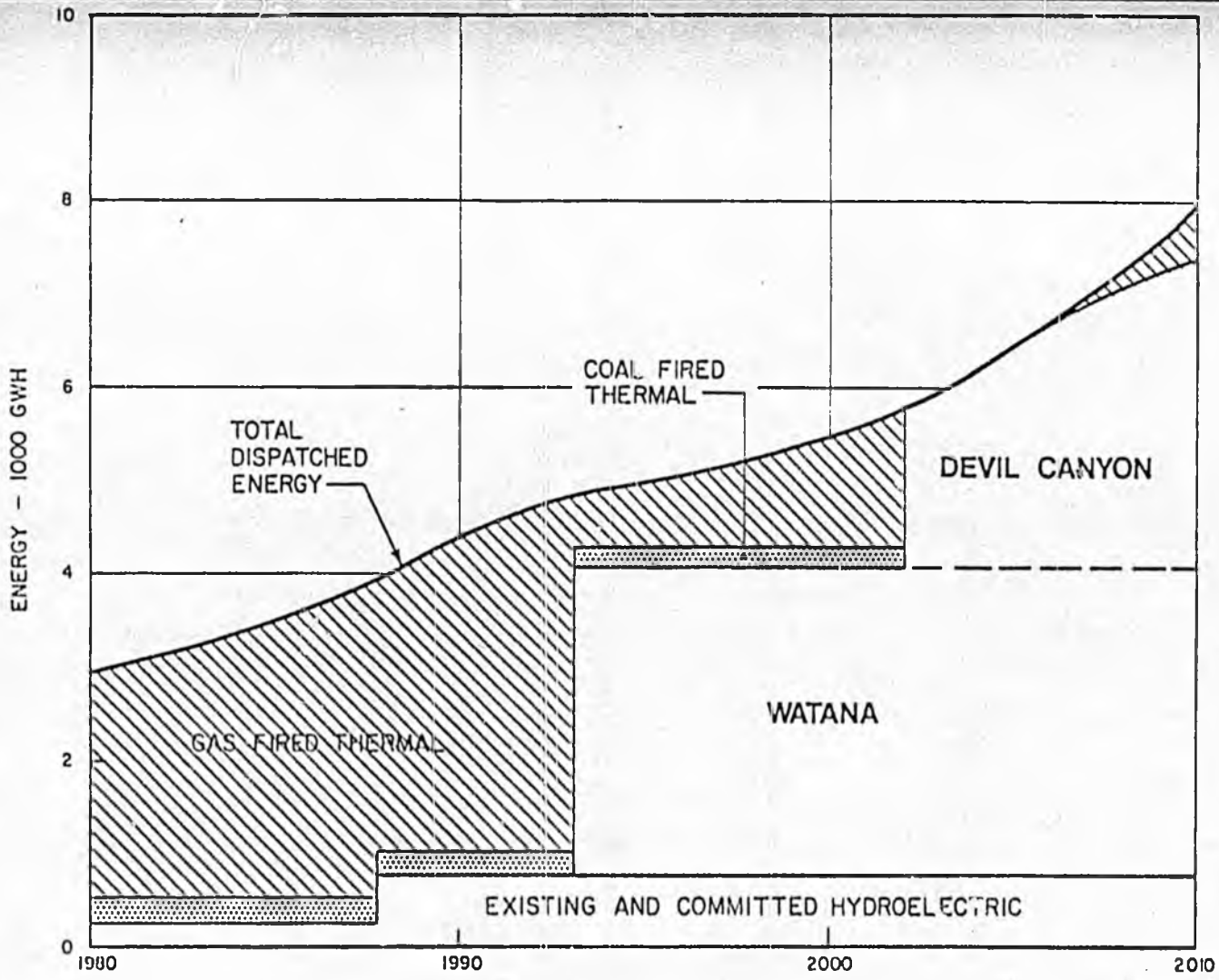
THE SUSITNA PROJECT

	WATANA	DEVIL CANYON
DAM TYPE	ZONED EARTHFILL	CONCRETE ARCH
DAM HEIGHT	885 FEET	645 FEET
RESERVOIR LENGTH	48 MILES	26 MILES
INSTALLED CAPACITY	1,020 MW	600 MW
AVERAGE ANNUAL ENERGY	3,460 GWH	3,340 GWH
TRANSMISSION SYSTEM	345 KV	345 KV
COST ($ 1982)	3.58 BILLION	1.57 BILLION
COST (@ 6% INFLATION)	5.74 BILLION	---
COMMISSIONING DATE	1993	2002

PROJECT PURPOSE

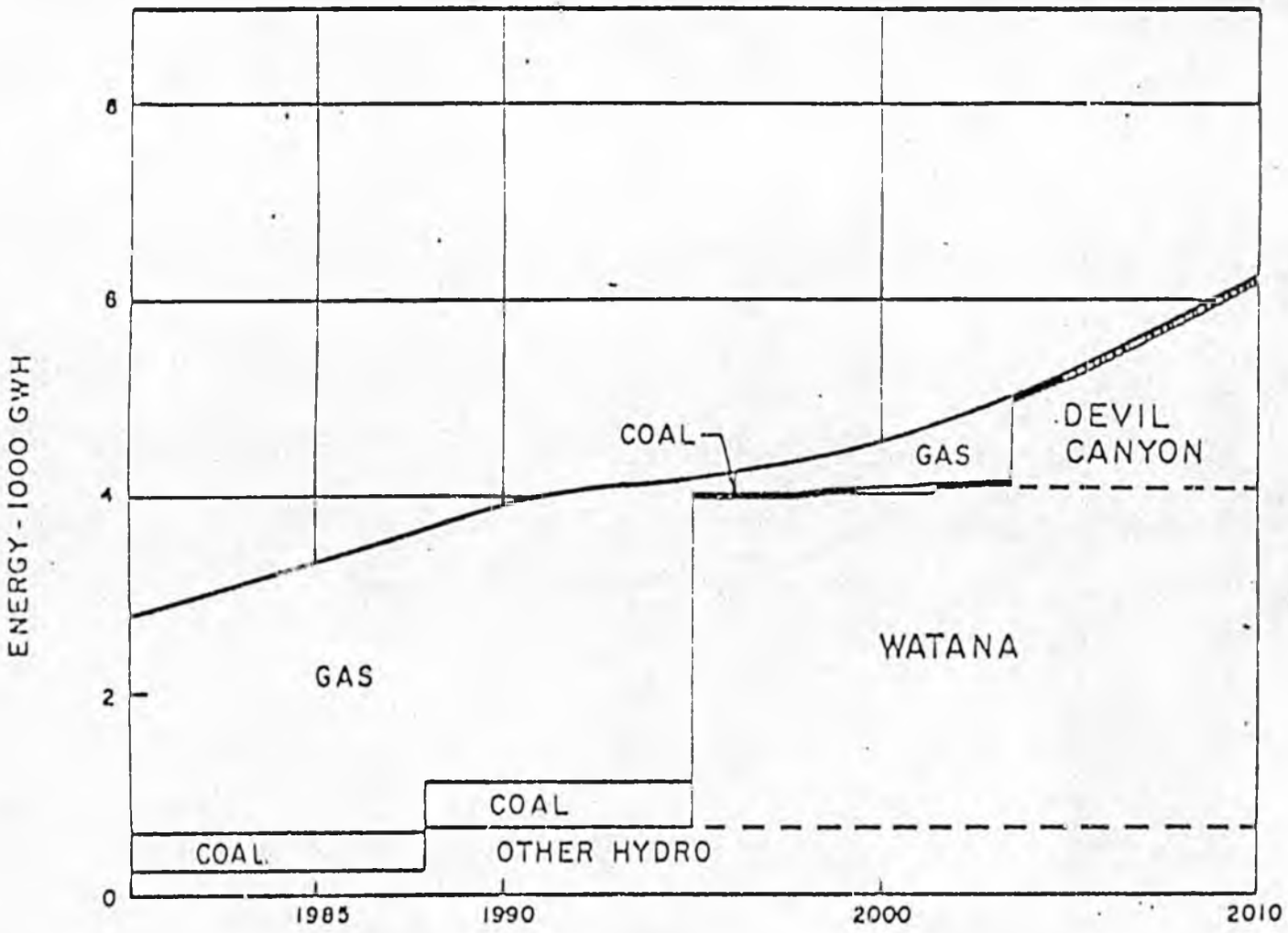
- MEET RESERVE MARGINAL AND ENERGY REQUIREMENTS
- REDUCE OVERALL COST OF THE GENERATING SYSTEM

USE OF SUSITNA GENERATION



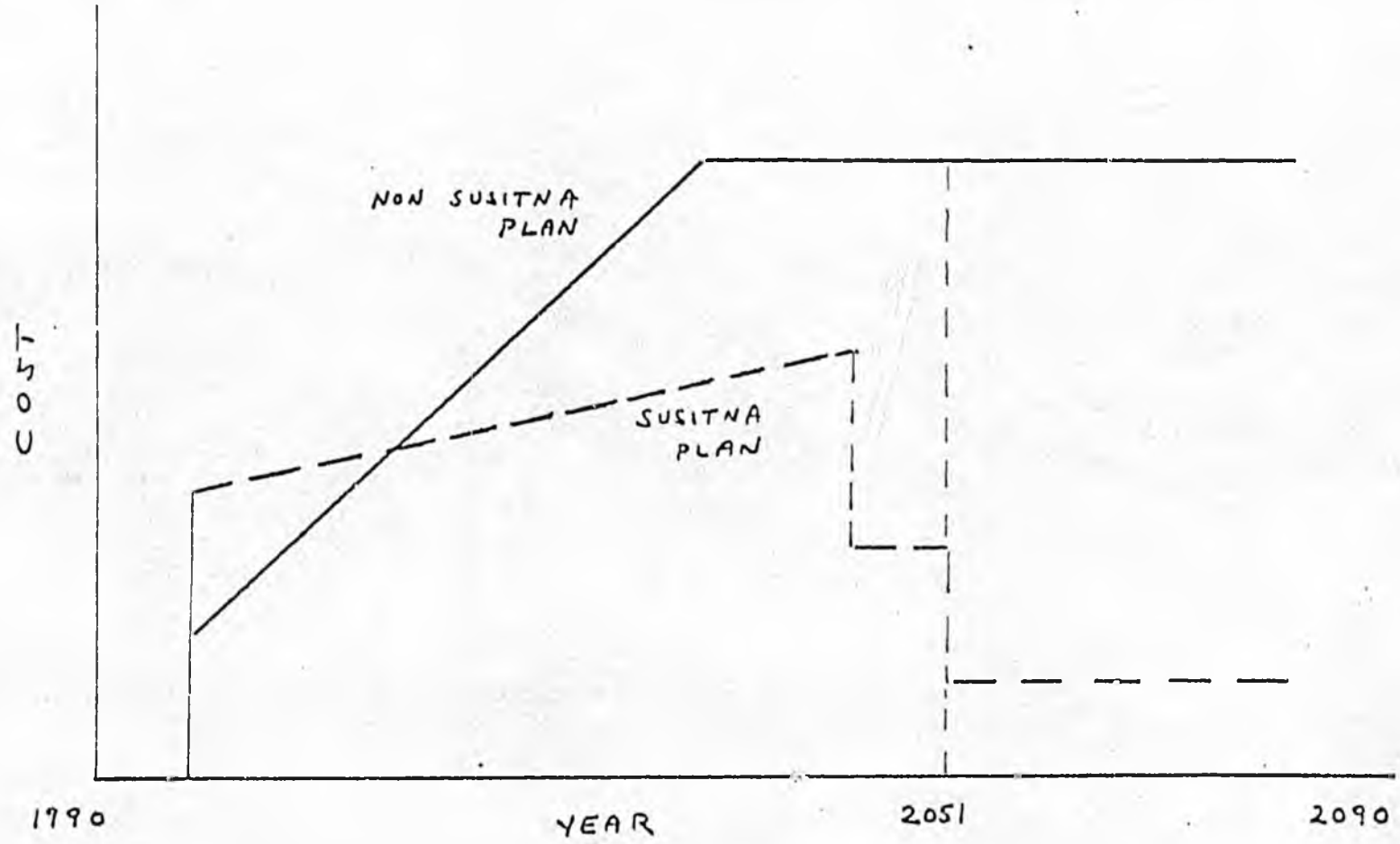
Medium Load Forecast

USE OF SUSITNA GENERATION

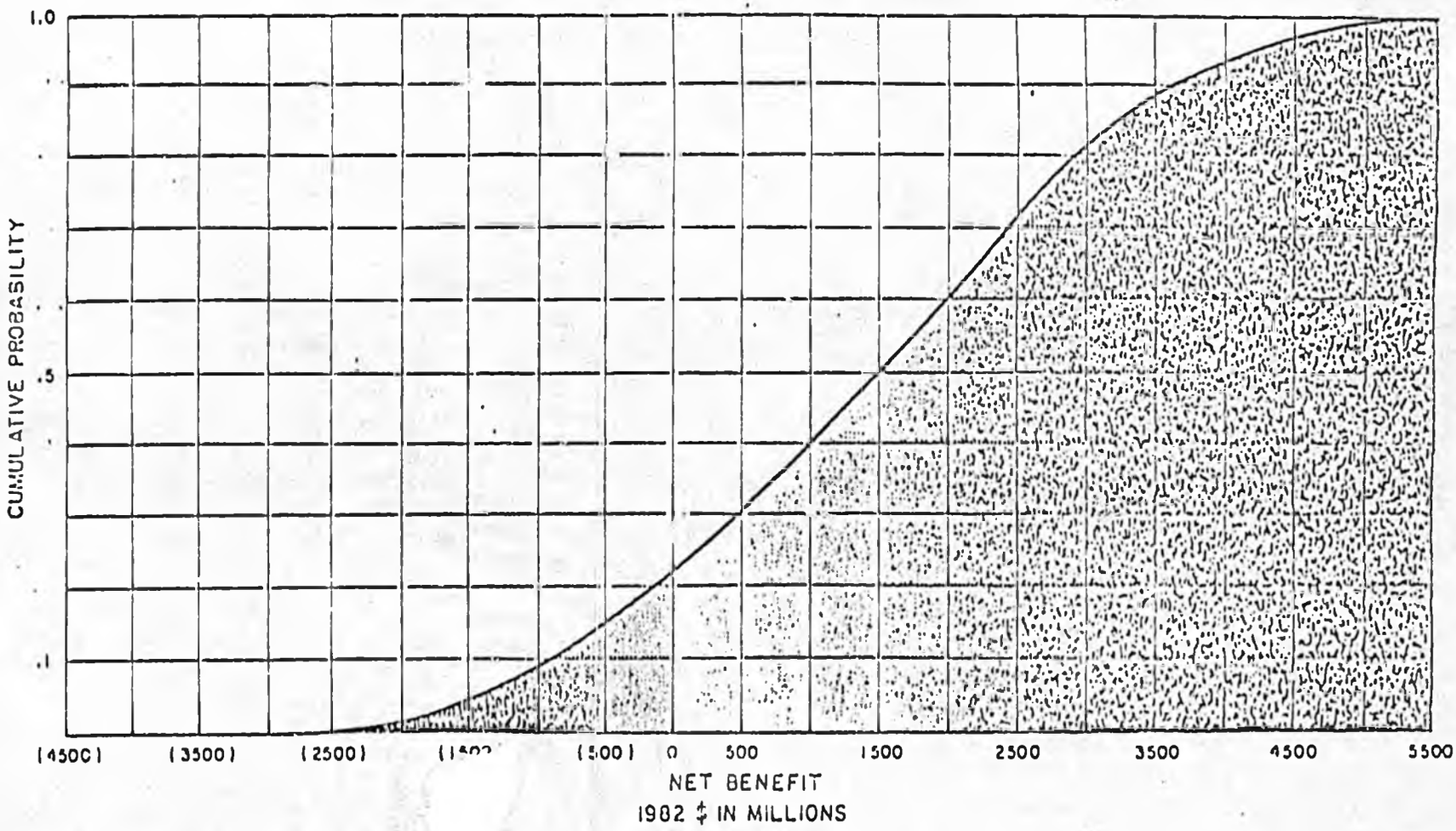


LOW LOAD FORECAST

ECONOMIC FEASIBILITY TEST



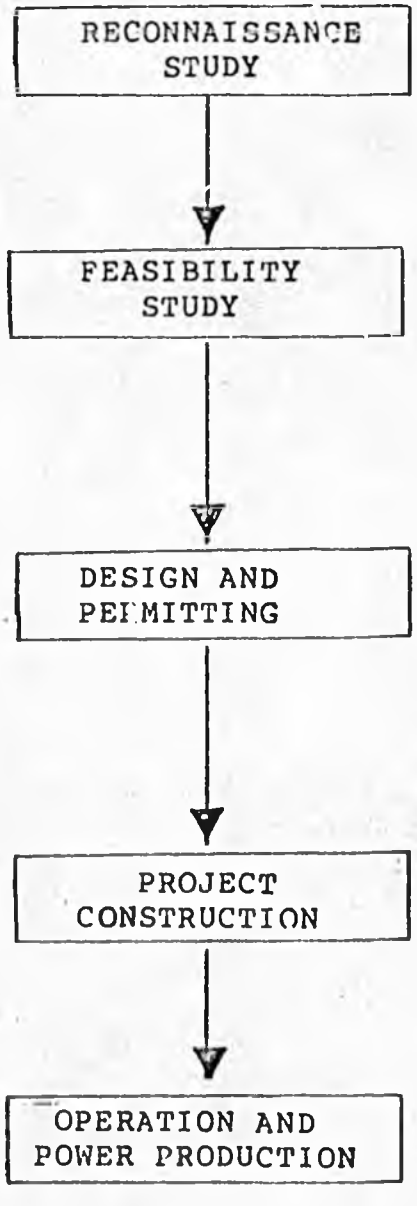
SYSTEM COSTS WITHOUT SUSITNA (A)
COMPARED TO
SYSTEM COSTS WITH SUSITNA (B)
(A-B) = NET BENEFITS OF SUSITNA PLAN



MULTIVARIATE ANALYSIS

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

FIVE STAGES OF PROJECT DEVELOPMENT



PRELIMINARY ANALYSIS.
NARROW RANGE OF OPTIONS

DETAILED ALTERNATIVES COMPARISON.
FEASIBILITY LEVEL COST ESTIMATE.
INDEPENDENT COST ESTIMATE.
FINANCE OPTIONS.

FINAL COST ESTIMATE.
CONSTRUCTION DECISION.
FINAL FINANCE PLAN.
POWER SALES AGREEMENTS.

OPERATION AND MAINTENANCE AGREEMENTS.

7

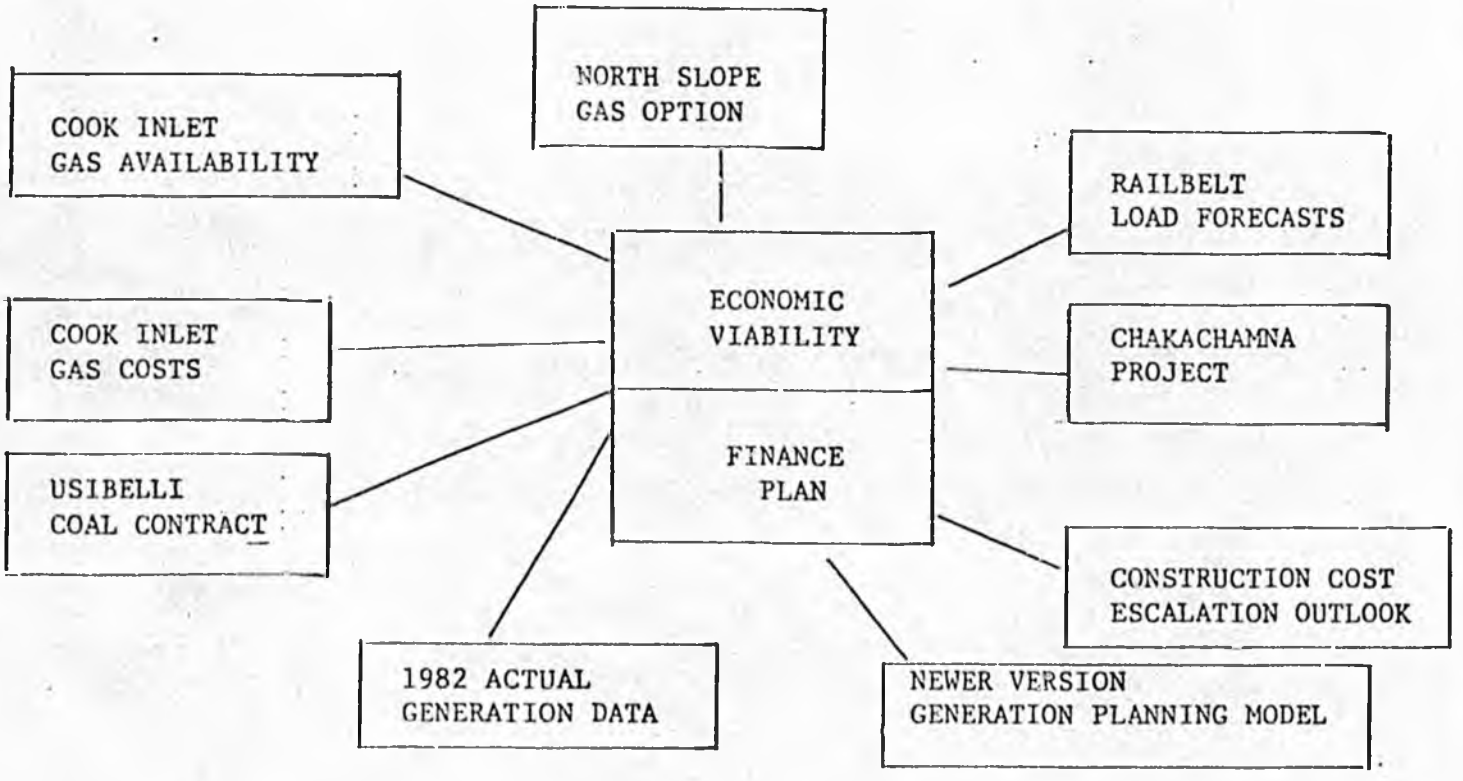
PREREQUISITES TO CONSTRUCTION

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

LAND ACQUISITION SCHEDULE

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

SPRING 1983 UPDATE



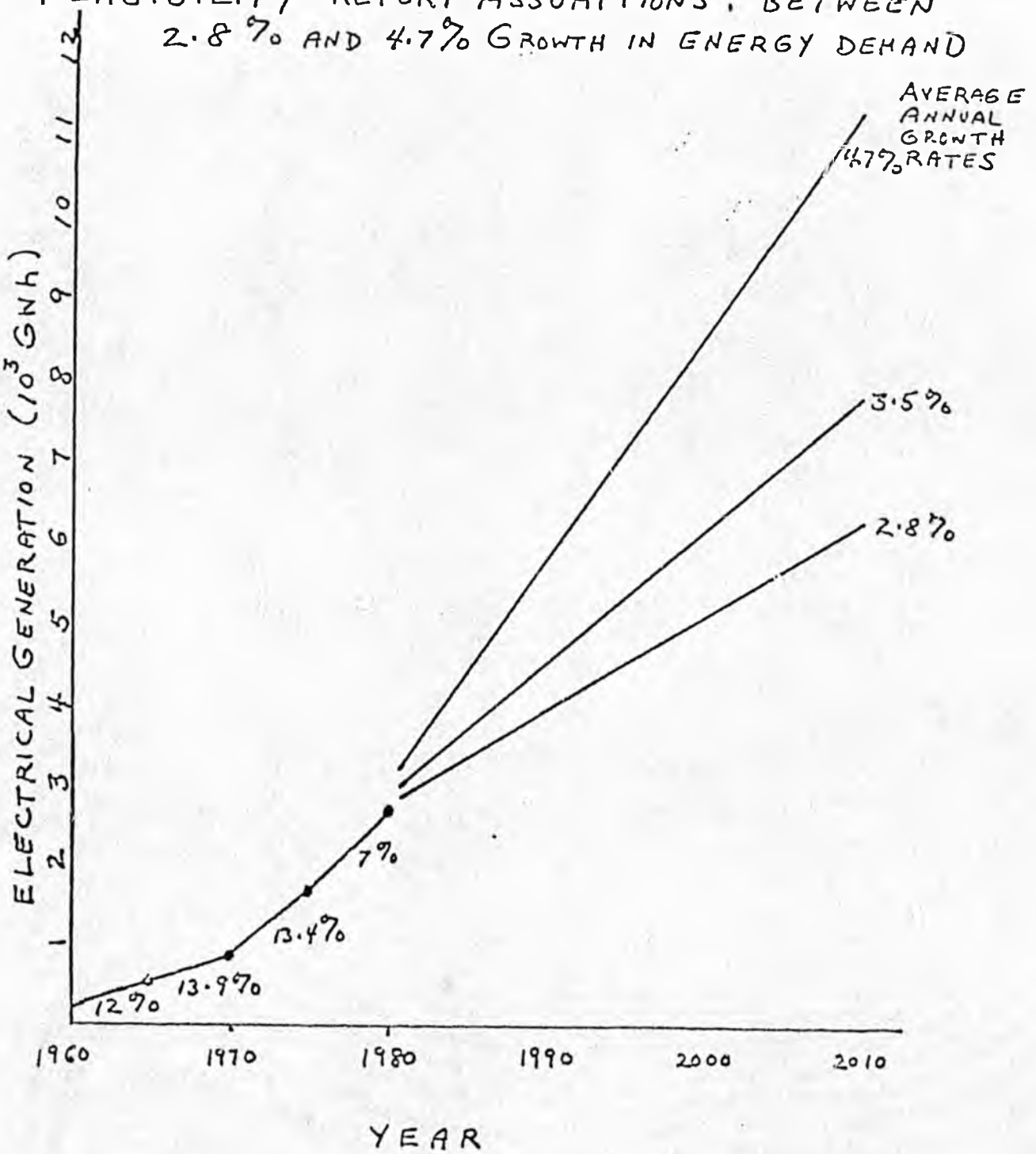
I M P O R T A N T P A R A M E T E R S

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

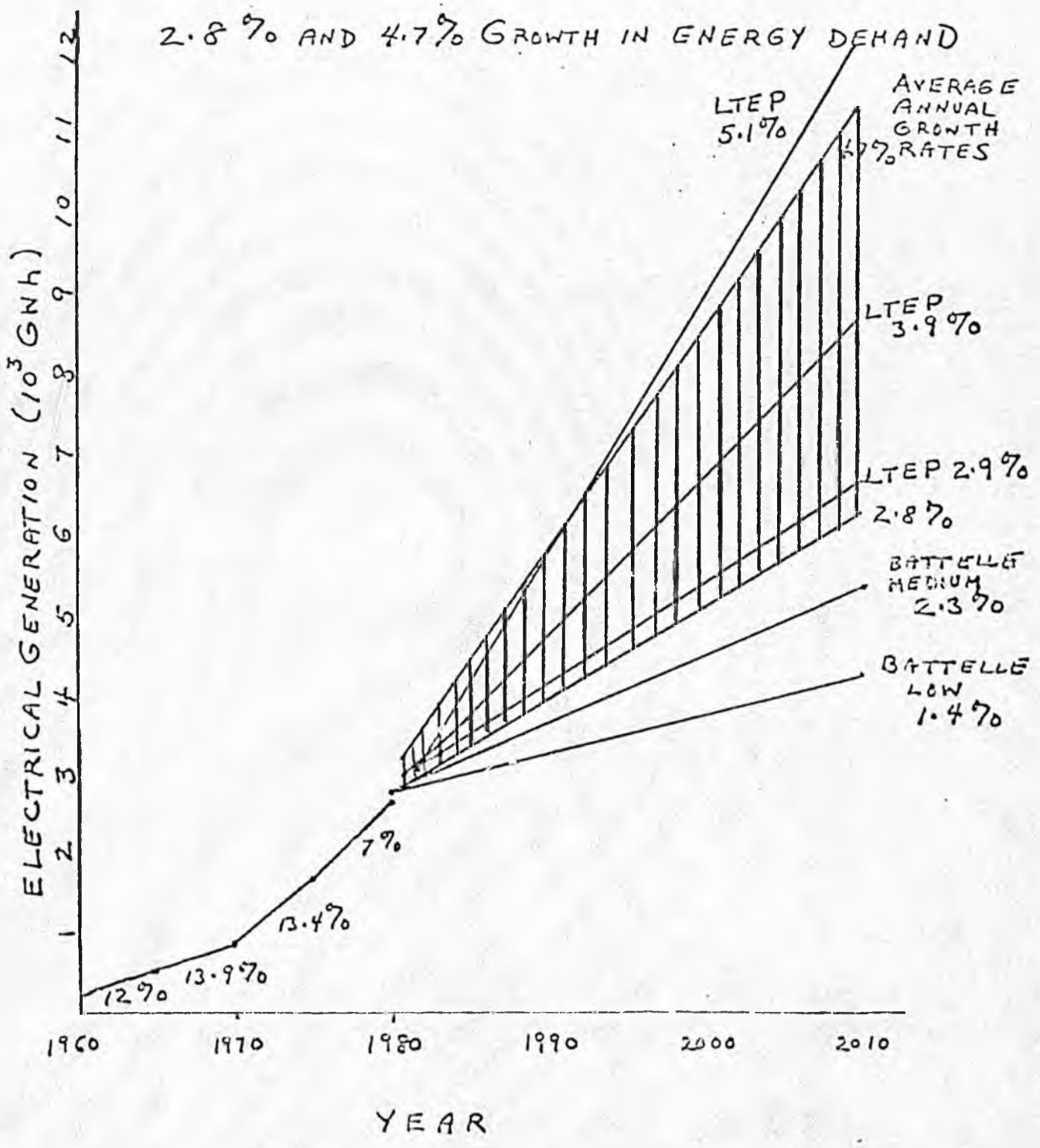
* (1982-2000)/2001-2010)
** 1982 Price Estimate

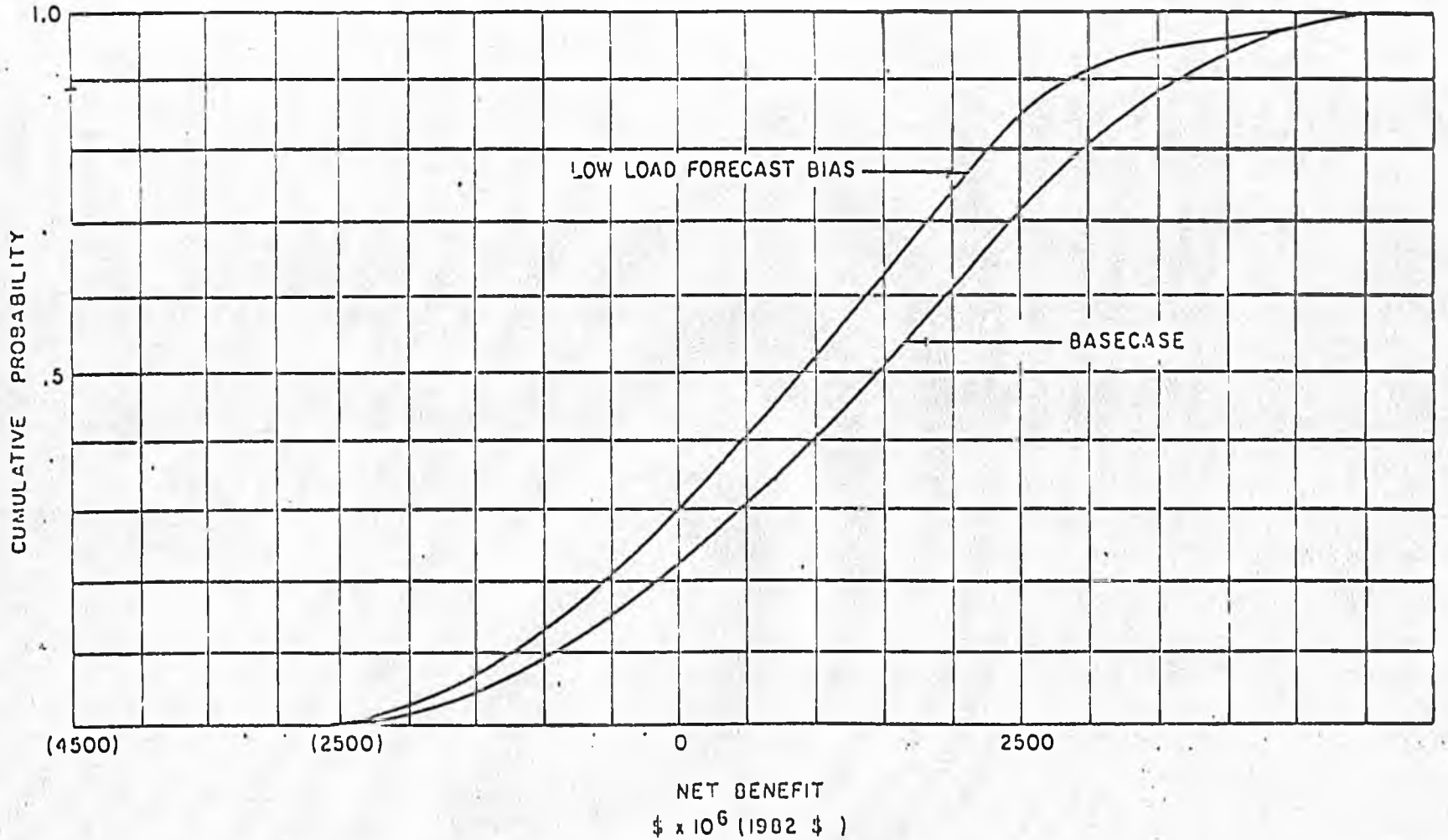
LOAD FORECAST

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



LOAD FORECAST UPDATE

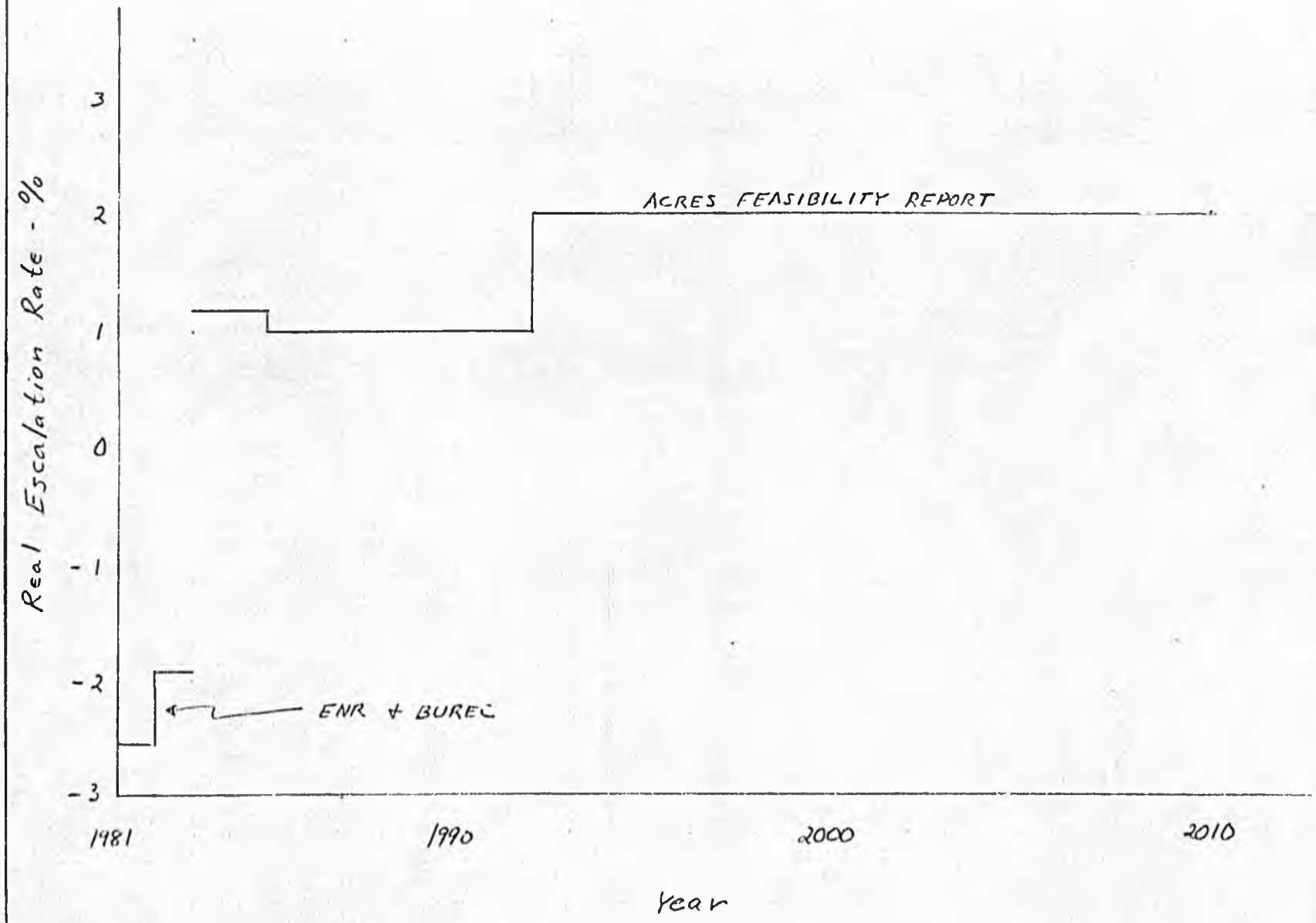


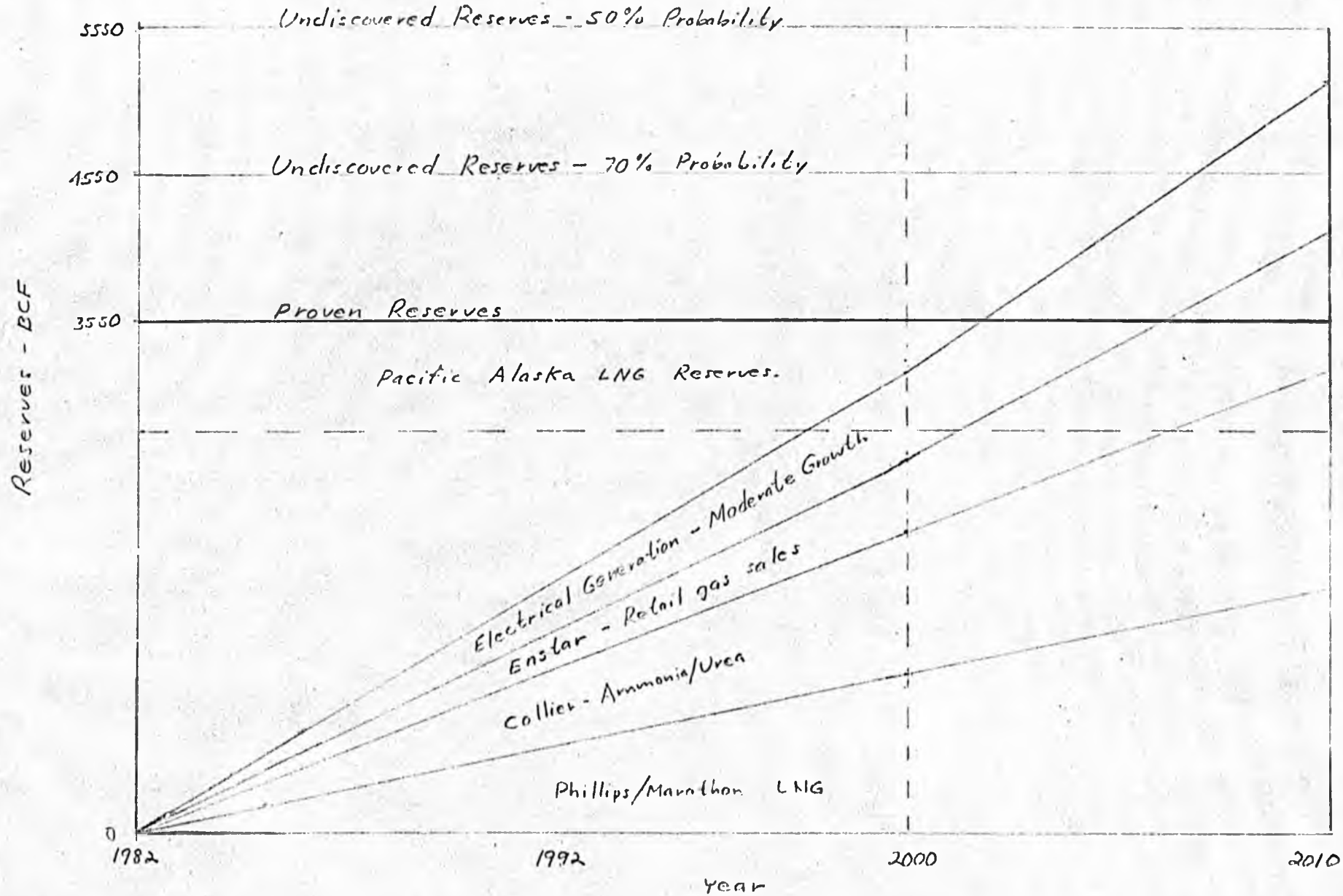


ASSIGNMENT OF PROBABILITIES

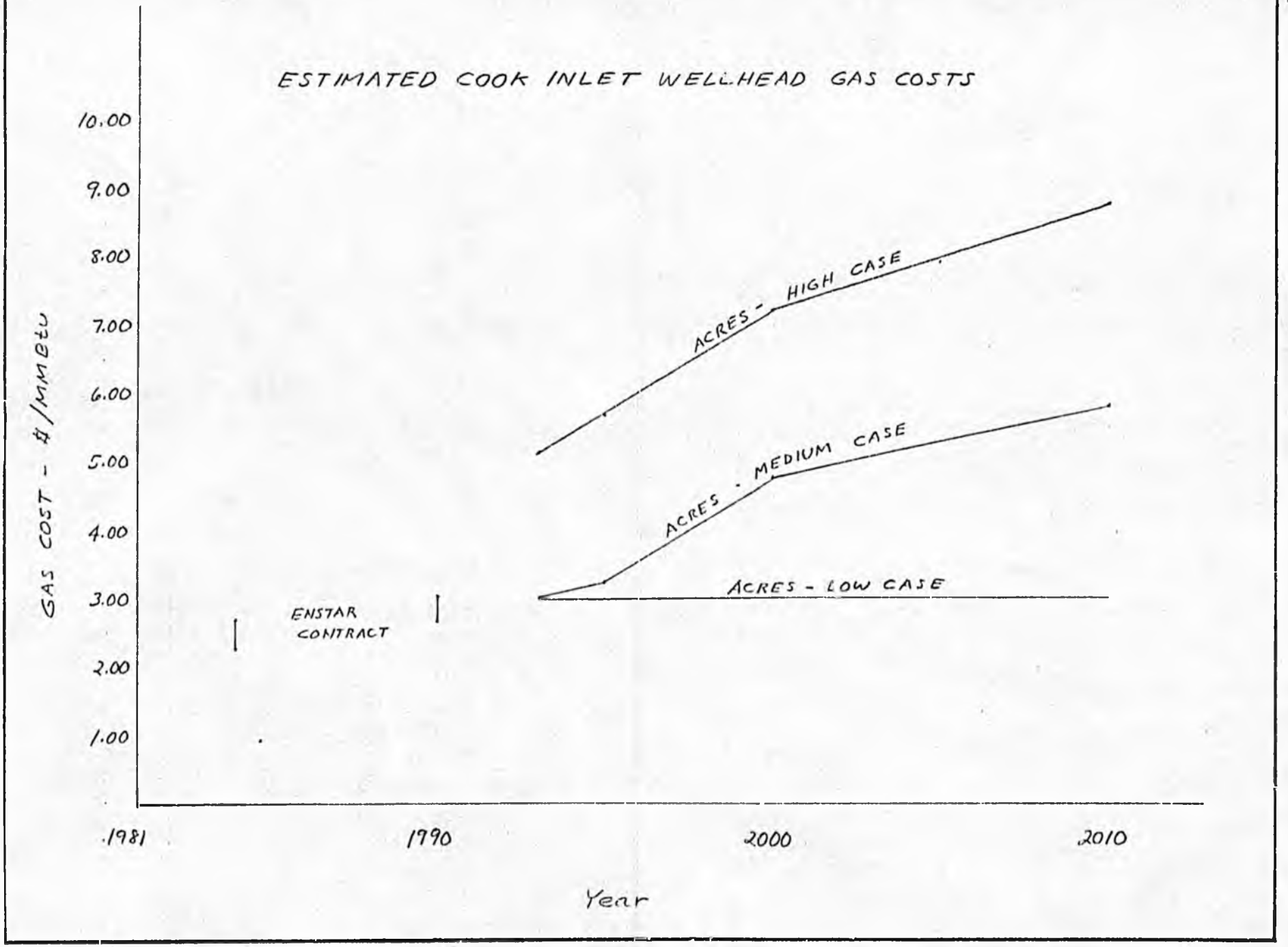
	Low	Medium	High
Feasibility Study	0.2	0.6	0.2
Alternative Outlook	0.6	0.3	6.1

CONSTRUCTION COST ESCALATION

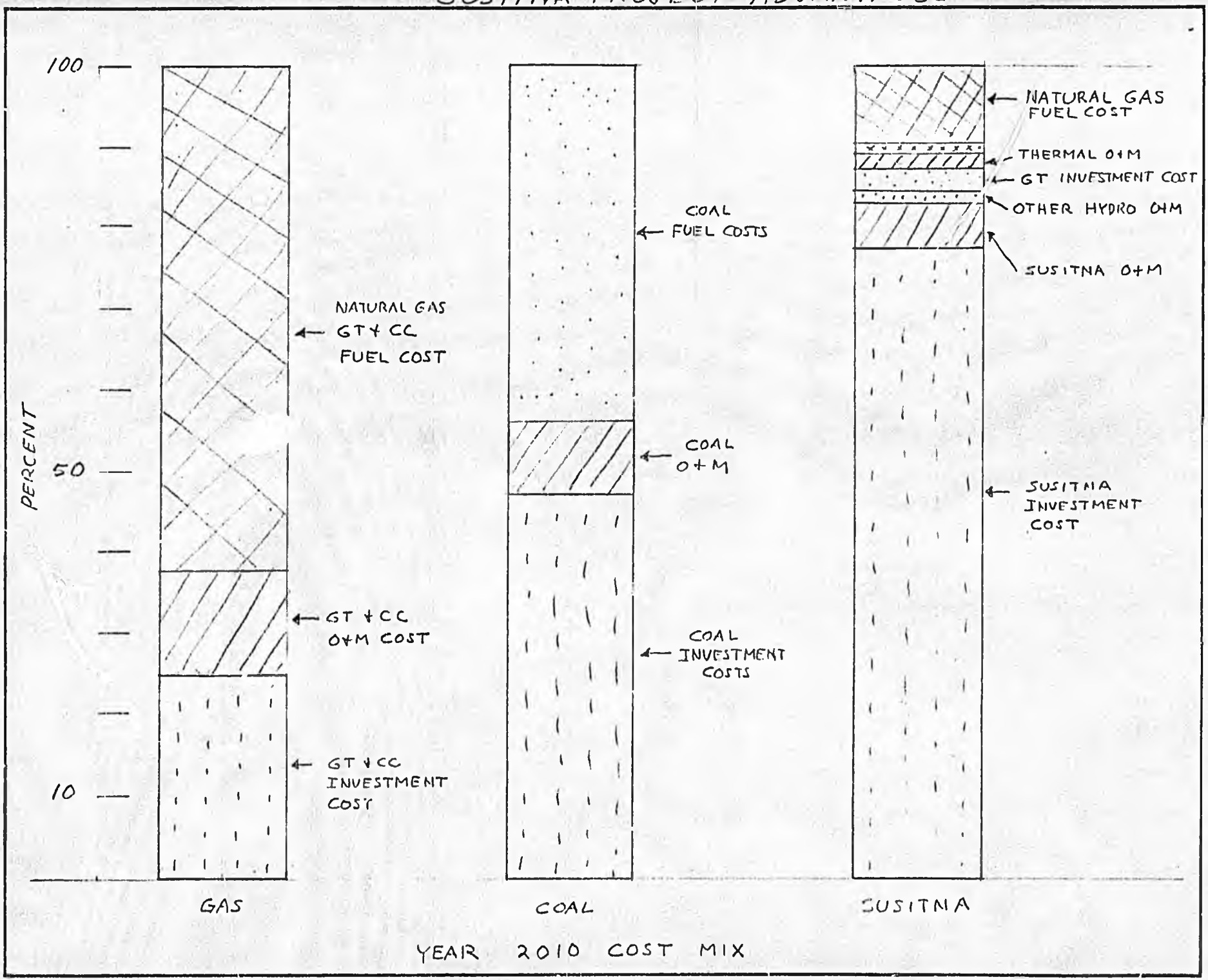




COOK INLET NATURAL GAS SUPPLIES
AND ESTIMATED CONSUMPTION


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

SUSITNA PROJECT ADVANTAGES



YEAR 2010 COST MIX

NORTH SLOPE GAS OPTION

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

CHAKACHAMNA PROJECT

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

* Includes 15 MILLS PER KWh FOR O+M

WATANA DAM HEIGHT REDUCTION
CURRENTLY UNDER STUDY

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

TECHNIQUES FOR SUSITNA COST CONTROL

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

POWER AUTHORITY RECOMMENDATIONS

APRIL 1982

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

SB

68-71

(FILE 6)

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

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

February 23, 1983

M E M O R A N D U M

TO: Honorable Vic Fischer, Chairman
Senate State Affairs Committee

FROM: Milt Barker MB
Fiscal Analyst

SUBJECT: SB 70

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

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

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

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

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

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

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

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

SB 70 - Section 2

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

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

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

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

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

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

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

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

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

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

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

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

---

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

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

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

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

attachments

cc: Senator Halford

MB:ro

TABLE I
ALASKA ENERGY DIVIDEND FUND (SB 70)

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

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

PREPARED BY:
LEGISLATIVE FINANCE
2-22-83

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

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

PREPARED BY:
LEGISLATIVE FINANCE
2-22-83

TABLE II

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

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

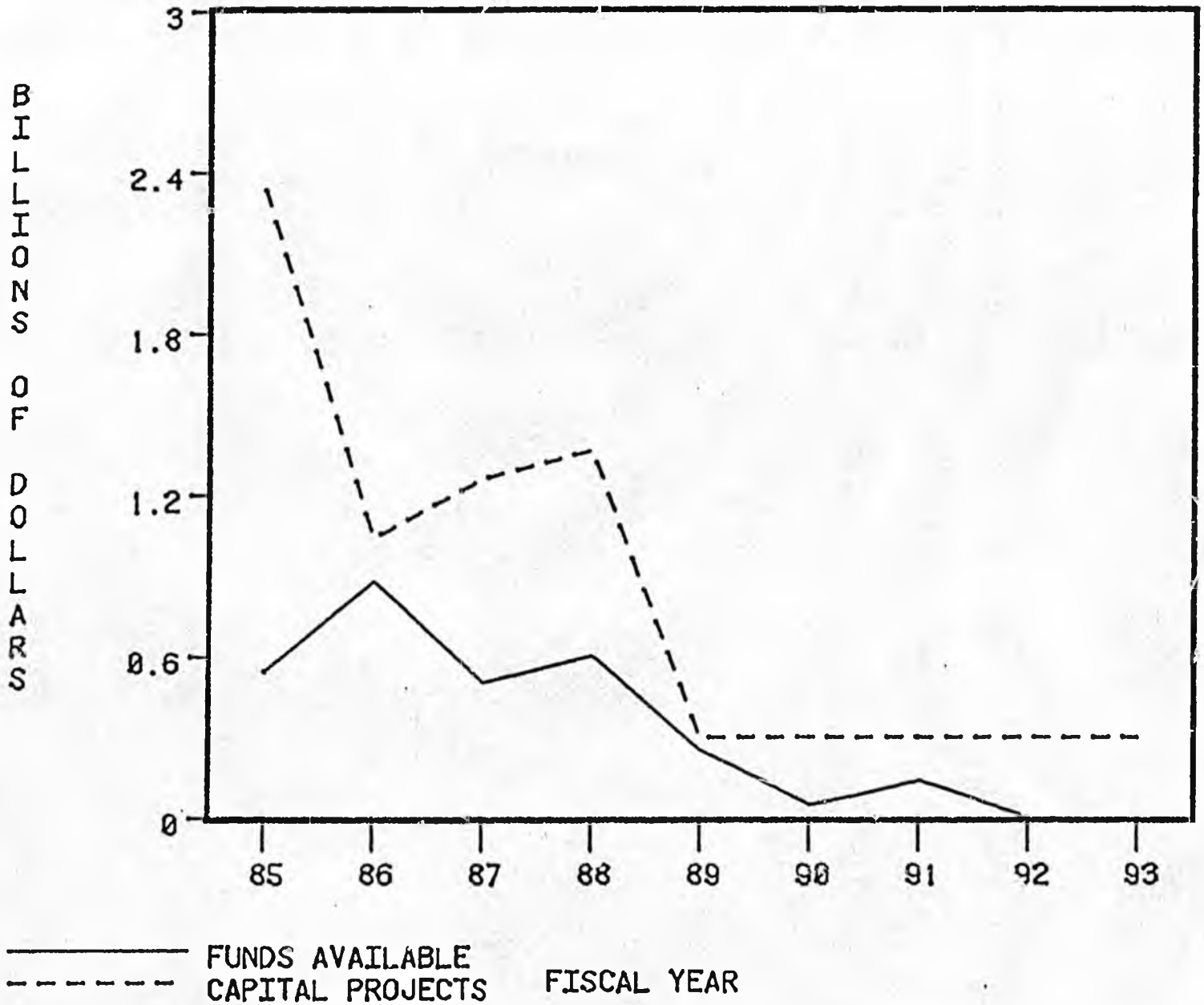
4. Assumes loan appropriations at roughly the Governor's FY 84 budget level. $294.5 million;

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

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

PREPARED BY:
LEGISLATIVE FINANCE
2-22-83

FUNDS AVAILABLE FOR CAPITAL PROJECTS
UNDER SB 70



STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

*** ACTUAL DOLLARS IN MILLIONS ***

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

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

STATE OF ALASKA
LEGISLATIVE FINANCE WORKING DOCUMENT
BUDGET FORECASTING MODEL

*** FY 1984 DOLLARS IN MILLIONS***

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

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

ERICKSON & ASSOCIATES

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

MEMORANDUM

February 24, 1983

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

The Tyee Loan

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

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

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

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

ENDNOTES

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

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

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

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

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

Attorney General will undoubtably investigate in due course.

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

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

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

Implications for the Susitna Project

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

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

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

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

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

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

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

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

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

TO: Senate State Affairs Committee Members

FROM: Committee Staff

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

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

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

Dear Senator Fischer and members of the Committee:

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

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

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

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

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

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

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

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

Sincerely,

John Strasenburgh

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

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

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

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

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

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

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

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

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

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

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

COMMENT BY CHUCK SMITH, 38 YEAR ALASKA RESIDENT.

COMMENT ON RELATED MATTER FROM MR. SMITH

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

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

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

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

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

March 3, 1982

MEMORANDUM

TO: Representative Hugh Malone

FROM: Jack Kreinheder
Research Staff

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

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

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

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

SUMMARY OF FINDINGS

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

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

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

TABLE 1

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

(Cents Per KWH - nominal dollars)

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

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

(Nominal Cents Per KWH)

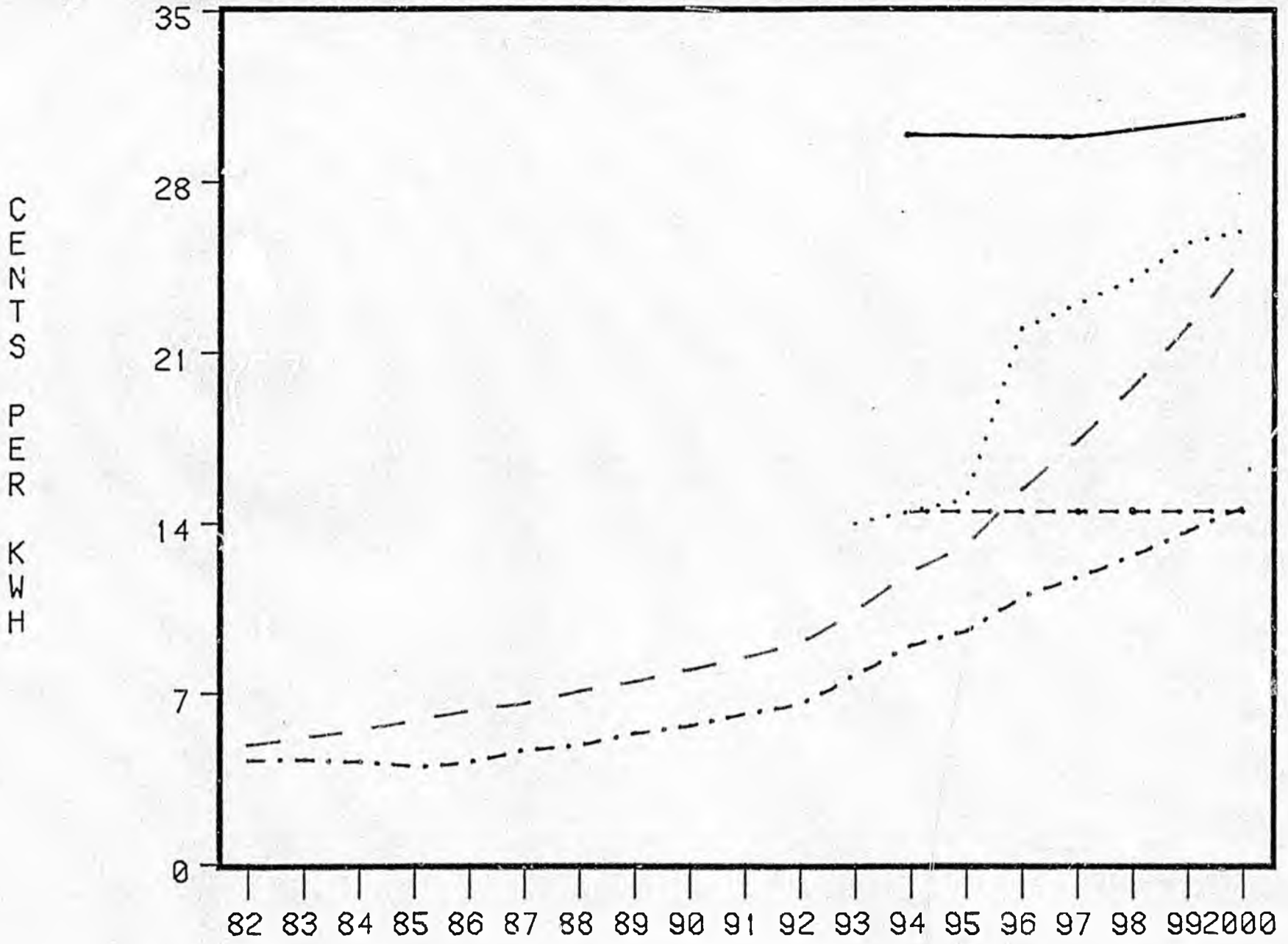


FIGURE 1

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

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

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

ENSTAR CONTRACT TERMS

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

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

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

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

THE ACRES THERMAL COST ANALYSIS

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

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

TABLE 2

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

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

ASSUMPTIONS:

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

TABLE 2 ASSUMPTIONS (Continued)

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

DIVISION OF PETROLEUM REVENUE OIL PRICE FORECAST
(Nominal Dollars)

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

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

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

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

GAS-FIRED GENERATION COSTS

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

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

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

TABLE 3

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

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

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

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

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

FOOTNOTES TO TABLE 3 (Continued)

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

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

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

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

[5] Column 1 plus column 4.

EFFECT OF OTHER GAS CONTRACTS

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

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

* * * *

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

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

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

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

SOURCE: BATTELLE VOLUME VII

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

March 2, 1983

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

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

1. WPPSS

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

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

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

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

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

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

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

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

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

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

2. GAS PRICING

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3. RECAP

The above notes are offered as personal views.

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

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

Sincerely,

R. J. Cross

Robert J. Cross
Administrator

Testimony of

Ernst W. Mueller

on

Alaska Power Authority Operations

before

Senate State Affairs Committee
Alaska State Legislature
24 February 1983

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

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

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

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

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

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

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