SUSITNA HYDROELECTRIC PROJECT

ECONOMIC AND FINANCIAL UPDATE

DRAFT REPORT

FEBRUARY 27, 1984

ALASKA POWER AUTHORITY

ECONOMIC AND FINANCIAL UPDATE

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1.0 INTRODUCTION

1.1 BACKGROUND AND PURPOSE OF UPDATE

The Susitna Hydroelectric Project is one of the largest hydroelectric projects ever brought before the Federal Energy Regulatory Commission (FERC) for issuance of a license. Pursuant to legislative authorization, the Alaska Power Authority (Power Authority) has filed for a license to construct and operate the Susitna Project in furtherance of its statutory duty "to promote, develop, and advance the general prosperity and economic welfare of the people of Alaska by providing a means of constructing, acquiring, financing, and operating power projects," including hydroelectric projects (ALASKA STAT. § 44.83.070.). The Project is designed to play a major role in meeting the future electrical demand of the Alaskan Railbelt, where over 70 percent of the State's population currently resides.

Proceeding with Susitna has not been undertaken lightly or without careful consideration of its feasibility. Beginning in 1980, a detailed study of the economic, engineering, environmental, and financial feasibility of the Project was undertaken for the Power Authority by Acres American, Inc. (Acres). Acres completed the Feasibility Report in April, 1982. With regard to the economic feasibility of the Susitna Project, the Acres' study concluded "that there is a high probability that development of the hydroelectric potential of the Susitna basin would provide significant cost advantages when compared to alternative means of meeting projected Railbelt power demands. . ."

To ensure an independent and objective evaluation of alternatives, the 1980 State Legislature determined that an independent consultant should prepare a study of Railbelt electrical power alternatives. The Office of the Governor contracted with Battelle Pacific Northwest Laboratories, Inc. (Battelle) to analyze and prepare a series of reports on alternative means of meeting anticipated Railbelt electric power demand, including a forecast of electrical power demand in the Railbelt through the year 2010. In its December 1982 report, Battelle considered various Railbelt energy plans and concluded that the plan which included construction of the Susitna Project would provide the lowest cost of power over an extended time period and be the most resistant to inflation.

In an "Addendum to Executive Summary," issued in December, 1982, Battelle noted that there had been a decline in world oil prices during the period January through March, 1982. The report concluded that, although these lower world oil prices would make the Susitna Project less attractive economically, it still was the best means of meeting the Railbelt's long-term power requirements.

The Susitna Hydroelectric Project License Application was prepared based on data developed in the feasibility and project alternatives studies and, with Legislative authorization, was filed with the FERC on February 28, 1983. Noting the sensitivity of the Project's economic feasibility to world oil prices, the FERC directed the Power Authority to refine the relevant studies in the Application to reflect up-to-date projections of, among other things, world oil prices. The Joint Venture of Harza Engineering Company and Ebasco Services, Inc. (Harza-Ebasco), which had been retained by the Power Authority for the design phase of the Susitna Project, performed these analyses.

On July 11, 1983, the Power Authority complied with the FERC directive and supplied supplemental data and electric power demand forecasts based on several, revised world oil price forecasts, including a "Reference Case" developed by Sherman H. Clark Associates (SHCA). As with most world oil price forecasts evaluated, the electrical demand estimates derived from the SHCA world oil prices supported the economic feasibility of the Project. The License Application, as supplemented, was accepted by FERC on July 29, 1983.

Considering the 1983 drop in world oil prices and the sensitivity of Susitna's feasibility to such prices, the Power Authority Board of Directors has instructed that an "update" report be prepared on the economic and financial feasibility of the Project. The report is to take into account the most current data on the key economic variables affecting the Project's feasibility, including world oil prices and the pricing and availability of alternative fuels. It is also to provide options for financing the Susitna Project. This report is supplied in response to the Board's request.

Beyond the general purpose of providing updated economic and financial data relating to the Susitna Project, this Update has several specific functions. They are:

1. To provide a status report on Project engineering, environmental, and planning studies;

2. To provide an assessment of the economic and financial feasibility of the Project using current data for key variables, including world oil prices and the cost of alternative sources of power. A summary of current values for the key variables and of threshold values for those variables is presented in the "Checklist of Key Variables" included at the end of this chapter as Exhibit 1.1;

3. To identify environmental consequences associated with alternative generation modes; and

4. To identify options for financing the Project.

1.2 CONTENTS OF THIS UPDATE

This Update is organized into eight chapters which follow the methodology used to assess the feasibility of the Project. Chapter 2 provides a description of the electrical demand forecasts. It describes the computer models and the methodology used in linking the oil price forecasts to economic analysis, electrical demand forecast, and optimal system planning. This chapter relies largely upon the work performed in connection with the July 1983 License Application filing.

Chapter 3 provides a description of the Project as contained in the FERC License Application. As a status report, Chapter 3 then describes the various design refinements which are under consideration. It also discusses the status of environmental programs relating to the Watana Development.

Chapter 4 reviews the Non-Susitna generation alternatives. The costs and performance characteristics of these generation alternatives are updated to reflect the latest available information. The chapter also discusses the availability and cost of natural gas and coal for use in the thermal plant alternatives.

Chapter 5 describes the means by which the demands of the future electrical system can be met, with and without the Susitna Project. The sizes, types, and number of power plants and the installation schedules are developed by a computer model. The annual costs of constructing, operating, and maintaining each supply alternative are presented.

Chapter 6 presents conclusions, based upon the preceding chapters, regarding the economic feasibility of the Susitna Project. Benefit/cost ratios are developed for the Susitna Project by comparing the "present worth" of the With-Susitna expansion plan with the Non-Susitna expansion plan.

Chapter 7 discusses potential sources of financing, and reviews two potential finance plans with differing levels of State capital involvement.

Chapter 8 presents further actions which need to be taken prior to construction. These include: 1) completion of power sales agreements; 2) resolution of finance issues; 3) obtaining legislative authorization; 4) issuance of the FERC license and other permits; 5) completion of design; 6) concurrence of final design by the External Review Board; 7) execution of an acceptable labor agreement; 8) acquisition of Project lands; and 9) final approval by the Board of Directors.

1.3 SUMMARY OF OBSERVATIONS AND CONCLUSIONS

From the economic and financial studies presented in this Update, the following observations and conclusions can be made:

- Assuming world oil prices as forecast in the SHCA-NSD case, the Susitna Project is economically more attractive than thermal alternative plans. The construction of the Susitna Project would result in a net benefit of $1.06 billion (in 1983 dollars) over the first 50 years of operation.

- The 1983 construction cost estimates for the Watana and Devil Canyon projects as submitted to the FERC are \$3.8 and \$1.6 billion, respectively. Engineering design refinements could reduce Watana construction costs by approximately eight percent.

- The electric energy demand forecast for the Railbelt is sufficient to absorb the output of the Watana project as early as 1993.

- Based on either of two recommended financing options, will require about \$2 billion (1983 dollars) in State equity and rate stabilization fund contributions in order for the initial cost of energy from Susitna to be competitive with the cost of energy from the least-cost thermal alternative.

- Major changes in economics and in load projections could change the expected net benefits of the Susitna Project. Events such as substantially lower world oil prices, higher construction costs and higher interest rates than those assumed in the Update, could reduce the net benefits. On the other hand, higher world oil prices, lower interest rates or lower Susitna construction costs would increase the net benefits of the Susitna Project.

CHECKLIST OF KEY VARIABLES
(January 1983 prices)

	Feasibility Study	FERC License Application	Update	Threshold(a)
Oil Price Forecast - $/bbl (b)				
1983	38 (c)	28.95	28.95	28.95
1993	46 (c)	30.49	30.49	25.13
2010	65 (c)	50.39	50.39	33.35
2020	65 (c)	64.48	64.48	37.62
Long Term Oil Price Growth - %/yr				
1983-1993	2.0	0.5	0.5	-1.4
1983-2010	2.0	2.0	2.0	0.5
1983-2020	1.5	2.2	2.2	0.7
Projection of Energy Generation - GWh/yr				
1983	3,402	3,027	3,088	-
1993	5,126	4,321	4,397	(e)
2010	8,414(d)	6,280	6,444	(e)
2020	---	8,039(d)	8,312(d)	(e)
Long Term Load Growth Rate - %/yr				
1983-1993	4.2	3.6	3.6	(e)
1983-2010	3.4	2.7	2.7	(e)
1983-2020	—	2.7	2.7	(e)
Cook Inlet Gas Price Forecast - $/MMBtu (b)				
1993	3.2	3.02	3.02	2.45(g)
2010	6.2	5.00	6.97(f)	2.97(g)
2020	6.2	6.39	8.92(f)	4.85(g)
2050	6.2	9.05	12.62(f)	7.58(g)
Cook Inlet Gas Price Growth - %		Linked with oil price growth		
Cook Inlet Gas Availability Forecast	Assumed unlimited	Assumed unlimited	Price dependent	(h)
North Slope Gas Price Forecast - $/MMBtu (i)				
1993	NA	4.22	4.22	4.00(g)
2010	NA	6.97	6.97	4.18(g)
2020	NA	8.92	8.92	4.85(g)
2050	NA	12.62	12.62	7.58(g)
North Slope Gas Availability Forecast	NA	Assumed unlimited	Available in 2007	(j)

CHECKLIST OF KEY VARIABLES
(January 1983 prices)

	Feasibility Study	FERC License Application	Update	Threshold(a)
Nenana Coal Price Forecast \$/MMBtu (b)				
1983	1.9	1.72	1.72	1.72
1993	2.4	2.17	2.17	1.72
2010	3.1	2.57	2.57	1.72
2020	---	2.84	2.84	1.72
Nenana Coal Price Growth - %/yr				
1983-1993	2.4	2.3	2.3	0.0
1983-2010	1.8	1.3	1.3	0.0
1983-2020	---	1.2	1.2	0.0
Nenana Coal Availability Forecast	(k)	(k)	(k)	(m)
Beluga Coal Price Forecast \$/MMBtu (b) (l)				
1983	1.5	1.86	1.86	1.86
1993	2.0	2.17	2.17	1.86
2010	2.7	2.57	2.57	1.86
2020	---	2.84	2.84	1.86
Beluga Coal Price Growth - %/yr				
1983-1993	2.9	1.6	1.6	0.0
1983-2010	2.2	1.3	1.3	0.0
1983-2020	---	1.2	1.2	0.0
Beluga Coal Availability Forecast	Unlimited	Unlimited	Unlimited	(m)
Real Discount Rate (%)	3.0	3.0	3.5	5.3
Real Interest Rate (%)	3.0	3.0	3.5	7.4
General Inflation Rate (%)	7.0	7.0	6.5	N/A
Susitna Construction Cost - $\$ \times 10^6$				
Watana	3,805 (o)	3,750 (o)	3,750	+33%
Devil Canyon	1,535 (o)	1,620 (o)	1,620	(n)
Capital Cost Escalation Rate - %	1982 to 1985 : 1.1	0.0	0.0	(n)
	1986 to 1992 : 1.0	0.0	0.0	(n)
	1993 on : 2.0	0.0	0.0	(n)

CHECKLIST OF KEY VARIABLES
(January 1983 prices)

	Feasibility Study	FERC License Application	Update	Threshold(a)
Project Timing				
Watana	1993	1993	1993	
NA Devil Canyon	2002	2002	2002	NA
Benefit/Cost Ratio	1.17	1.33	1.19	NA
State Equity Contribution (1983 $ billions)	1.9 (p)(q)	1.9 (p)(q)	1.9/2.1 (r)	NA
Wholesale Cost of Energy (cents per kWh)	14.7 (q)	13.6 (q)	11.2 (r)	NA

NA: Not Applicable

(a) The threshold point is that point for each variable at which the Susitna Project has a benefit/cost ratio close to 1:00, holding all other variables constant.
In determining the threshold points for prices of oil and natural gas, the values under the June 1983 DOR Mean scenario are used, since the benefit-cost ratio for that scenario is close to 1.00.

(b) 1982 Feasibility Study fuel costs were inflated to January 1983 price level using the U.S. GNP index of 6.0%.

(c) Based on 2.0% average annual growth rate until 2010, and 0% thereafter as reported in February 1983 Exhibit D p. D-4-22.

(d) Last year of generation expansion planning studies.

(e) A large decrease of this variable would be required to arrive at the threshold value.

(f) Economically recoverable Cook Inlet reserves are assumed to be depleted in 2007. Analysis assumes further Cook Inlet reserves will be priced equivalent to North Slope gas.

(g) Approximate. The threshold value would be lower.

(h) No threshold value, because of substitution possibilities.

(i) Forecast also represents prices of gas from some other sources such as Cook Inlet after year 2007 to reflect increased prices due to higher exploration and development costs, and associated risks.

CHECKLIST OF KEY VARIABLES

(j) Unavailability of North Slope gas, when Cook Inlet gas is depleted, could cause major supply problems to the thermal alternatives. No threshold value is available.

(k) 1982 Feasibility Study up to 200 MW of coal-fired steam plant. Revised FERC License and 1983 Update up to 400 MW of coal-fired steam plant.

(l) Assume Beluga field developed for export market, but prices sold for local needs independent of opportunity price.

(m) Unavailability of Nenana or Beluga coal could cause major supply disruption to the thermal alternatives.

(n) A large increase would be required to arrive at the threshold value.

(o) January 1982 costs escalated to January 1983 using a 4.3 percent factor.

(p) Inflated from 1982 to 1983 using U.S. GNP index of 6.0%.

(q) Nominal cost of energy in 1993 based on coal expansion plan.

(r) Nominal cost of energy in 1996 based on gas and coal expansion plan.

2.0 UPDATE OF ELECTRIC DEMAND STUDIES

2.1 INTRODUCTION

The first step in assessing the economic and financial feasibility of the Susitna Project is to forecast future electrical demand in the Railbelt. This chapter uses the same methodology used in the July 1983 FERC License filing to re-examine predictions of Railbelt electrical demand. Essentially, the methodology involves using a series of interactive models to project electrical demand based on population, employment, number of households and electricity end use data. These economic factors are, in turn, based on a series of assumptions and forecasts, the most important of which is the projected world oil price.

This Update incorporates the most current data regarding key variables in the modeling process, including world oil prices, the relative cost of alternative fuels, expected electric power prices and energy conservation data. The conclusion of the analyses is that electric energy requirements in the Railbelt will increase from 2,808 gigawatts hours (GWh) in 1983 to 3,737 GWh in 1990, 4,542 GWh in 2000, and 5,858 GWh in 2010.

There are means of predicting electrical demand other than by econometric modeling. For example, most Railbelt utilities forecast electrical demand on their systems by analyzing past trends in conjunction with anticipated commercial and industrial development and population growth. The Power Authority has also considered the recent forecasts of the Railbelt utilities in this Update for purposes of comparison.

The following sections describe the Railbelt market, the basic approach used to develop the demand forecast and the principal variables and assumptions used in the forecast. The electrical demand forecast produced by the models is given and the forecasts of the Railbelt utilities are reviewed. The forecast developed by the econometric models is used to develop the system expansion programs described in Chapter 5.

2.2 METHODOLOGY FOR ELECTRICAL DEMAND FORECASTING

The electrical demand forecast used in this Update is based upon a broad econometric, end-use approach. As in the July FERC License filing, four computer models were used in developing the updated power market forecast and the assessment of alternatives. These models are: a petroleum revenue forecasting model operated by Alaska Department of Revenue (DOR); the Man-in-the-Arctic Program (MAP) model operated by the Institute of Social and Economic Research (ISER); the Railbelt Electricity Demand (RED) model operated by Battelle, and the Optimized Generation Planning (OGP) model, owned and operated by General Electric Company. The relationship between the models and their principal input and output data are shown on Exhibit 2.1. A brief description of the interactive relationship of the models follows.

The petroleum revenue model produces State revenue forecasts based upon petroleum price forecasts. MAP converts these revenue projections into projections of State-wide economic conditions, including population, housing, and employment. The RED model then uses MAP model output, along with additional data, to produce an electrical energy and peak demand forecast for the Railbelt. Results of the RED model analysis, plus generating plant cost data, are then used by OGP to produce least cost generation expansion plans. OGP is provided different sets of input to calculate the best plan with and without Susitna. A complete description of these models is presented in Exhibit B of the FERC July 1983 filing. A condensed description is presented below.

2.2.1 Petroleum Revenue Forecasting System

Petroleum royalty payments and taxes constitute approximately 85 percent of the revenue of the State of Alaska. For this reason, projections of State oil revenues are generated by a special model system. The system generates 17-year State revenue forecasts based upon world oil price projections and other factors.

The principal model in the DOR forecasting system, PETREV, is an economic accounting model that examines factors that affect State petroleum revenues in order to produce a range of possible State royalties and production taxes. The principal factors influencing the level of petroleum revenues are North Slope petroleum production rates, the world market price of petroleum, and tax and royalty rates applicable to the wellhead value of petroleum.

In preparation of the July 1983 FERC License filing, a sub-model of the PETREV model (MJSENSO) was used to project petroleum revenues based on alternative world oil prices. Similarly in this Update, the oil revenues which would be available to the State of Alaska, assuming world oil prices as forecast in the SHCA-NSD case, were derived from the MJSENSO sub-model.

2.2.2 The Man-in-the-Arctic Program (MAP) Economic Model

The forecast State revenues derived from the MJSENSO sub-model, along with other key economic financial and demographic data, are placed into the MAP model. MAP is a computer-based economic modeling system that simulates the behavior of the economy and the population of the State of Alaska in each of 26 regions of the State. The Railbelt consists of six of these regions. The MAP model projects Railbelt economic activity to the year 2010, including factors affecting population, employment and number of households.

The MAP model functions as three separate but linked sub-models: the scenario generator sub-model, the economic sub-model, and the regionalization sub-model, as illustrated on Exhibit 2.2. The scenario generator sub-model enables the user to define scenarios of development in activities that are basic to the economy rather than supportive. Examples of such activities are petroleum production and other mining, Federal government operations, and tourism. The scenario generator sub-model also enables the user to enter into the model assumptions concerning State petroleum revenues, as developed by the MJSENSO model.

The economic sub-model produces Statewide projections of economic and demographic data, based on relationships between such factors as employment in industries, State revenues and spending, wages and salaries, gross product, the Alaskan consumer price index, and population. The regionalization sub-model enables the user to break-down the Statewide projections to specific regions of the State, including the six that make up the Railbelt.

2.2.3 The Railbelt Electricity Demand (RED) Model

The projections of population, employment and households generated by the MAP model are entered into the Railbelt Electricity Demand (RED) model to project Railbelt electrical demand. RED is a partial end-use, econometric model that projects both annual electric energy and peak load demand in Railbelt load centers over the period 1983 through 2010. The RED model forecasts annual consumption of electricity for the residential, commercial, small industrial, government, large industrial, and miscellaneous end-use sectors of the two load centers of the Railbelt (Anchorage-Cook Inlet and Fairbanks-Tanana Valley). The model is made up of seven separate but interrelated modules: the uncertainty, housing, residential consumption, business consumption, program-induced conservation, miscellaneous consumption, and peak demand modules. Exhibit 2.3 shows the basic relationship among the seven modules.

The model may be operated in a probability mode to produce a distribution of projections, each based on a different, randomly selected set of input parameters. The model may also be operated in a deterministic mode in which only one forecast is developed based on one set of input values. The latter mode is used in the Susitna analysis to accommodate input derived from the other models and to accept certain assumptions.

The RED model produces projections of electricity consumption by load centers and sectors at five-year intervals. Yearly data are obtained by linear interpolation between the five-year points.

2.2.4 The Optimized Generation Planning (OGP) Model

The Optimized Generation Planning (OGP) model uses the output from the RED model, plus data regarding the existing electrical generating system and planned new power plants, to determine the most cost-effective electrical generation system over future time periods.

In conjunction with inputting electric demand data into OGP, an important step in determining the generating capacity that should be installed in a future year is to provide the model with the required reliability of the system expressed in terms of the loss-of-load probability (LOLP). LOLP is the maximum acceptable unplanned outage rate on a system. The OGP model then determines how much capacity is required and when increments should be installed. Production cost is simulated to compute the operating costs of the generating system with the given unit additions. Finally, the annual investment cost is analyzed considering service lives of equipment and a real interest rate of 3.5 percent. The operating and investment cost analyses enable OGP to project the kind of generation which should be added to the system.

2.3 FUTURE OIL PRICES

An important premise of the economic analyses presented in the FERC License Application and this Update is that the State's economy and electrical power demand in the Railbelt are linked to the world price of oil. In addition to driving the general economy, oil prices directly affect the State's ability to finance the Project. Accordingly, the necessary starting point for the Update analysis is selection of the world oil price projections.

In analyzing the feasibility of the Susitna Project, the Power Authority reviewed several world oil price forecasts. The Power Authority has based its analysis in this Update upon the SHCA-NSD case (the Reference Case in the July 11, 1983 License Application filing). The December 1983 forecast of DOR, which is very similar to the SHCA-NSD case, is also analyzed. For purposes of this review, the Summer 1983 Data Resources Incorporated (DRI) forecast, the U.S. Department of Energy (DOE) forecast contained in the 1983 National Energy Policy Plan (NEPP), and oil price forecasts by several other nationally known organizations are also reviewed. These forecasts are summarized on Exhibit 2.4 and graphically displayed on Exhibit 2.6.

2.3.1 Sherman H. Clark Associates - No Supply Disruption (May 1983)

SHCA specializes in energy and resources economics. Clients include major oil companies, independent oil producers, independent refineries and tanker companies, state, federal and foreign governments, coal companies, and electric utilities. SHCA's experience in evaluating and projecting world economics and energy developments has resulted in the development of an extensive and detailed energy data base which is continuously updated.

SHCA annually prepares a detailed 25 to 30 year forecast of the world supply and demand for all types of energy and estimated pricing, titled Evaluation of World Energy Developments and Their Economic Significance. In June 1983, SHCA also prepared an analysis for the Power Authority titled Long Term Outlook for Crude Oil and Fuel Oil Prices, which extended the oil pricing projections in the annual report from year 2010 to year 2040.

The most recent SHCA forecast of world oil prices to 2010 contains three pricing cases based on three different political-economic scenarios: Supply Disruption Case, Zero Economic Growth Case and No Supply Disruption Case.

SHCA's "Supply Disruption Case" assumes a severe supply disruption in the world oil market in the late 1980's, followed by production-limiting decisions by several key producing countries. These factors result in forecast world oil prices of $40.00 in 1990, $53.76 in 2000 and $87.80 in 2040. The "Zero Economic Growth" scenario assumes no severe supply disruption, combined with zero economic growth in the United States and 0.4 percent growth per year in the free world through 1990. Economic growth after 1990 rises at a rate no greater than 4 percent per year. The forecast oil prices under this scenario are $17.00 in 1990 and

$45.11 in 2010. Falling between these two scenarios is the "No Supply Disruption" (NSD) case.

SHCA's NSD case is similar to the Supply Disruption case but it assumes that there is no supply disruption in the late 1980s. Economic growth after 1988 is assumed to be at an annual rate of 3 percent in the United States, slowing gradually to an annual rate of 2.5 percent. Economic growth in the free world is assumed to be 3.6 percent annually.

For the years 1983-1988, forecast oil prices are the same for both the NSD and Supply Disruption case scenarios. From 1988 to 2010, prices increase under the NSD Case at a 3.0 percent annual rate because of the relatively high rate of world economic growth. The rate of price escalation is then assumed to taper off as the oil price approaches the price that will bring forth supplies of alternative fuels. This market condition occurs between the years 2035 and 2040.

The SHCA-NSD case was selected as the Reference Case in the July 11, 1983 FERC License filing because its assumptions were consistent with observable events. The NSD case assumes that OPEC will continue operating as a viable entity and will successfully support its benchmark pricing system. It also assumes that economic growth in the United States and the free world will continue at reasonable rates. In addition, the NSD case falls in the middle range of forecasts examined by the Power Authority and, therefore, was determined to be an appropriately conservative forecast for the economic feasibility analysis presented to the FERC. Similar reasoning, and the fact that the NSD scenario now corresponds closely to DOR's world oil price figures, supports the appropriateness of using the SHCA-NSD case in this Update.

Under the SHCA-NSD scenario presented on Exhibit 2.4, the real price of oil is expected to remain at $26.30 until 1988. From 1988 to 2010, prices increase 3.0 percent annually. Although price projections for the period 2010 through 2040 are not utilized directly in the modeling process, other than to provide escalation rates, they are presented in Table 2.1. As can be seen, the rate of price escalation is projected to taper off after 2010.

Table 2.1
SHCA-NSD WORLD OIL PRICE PROJECTIONS
2010-2040

Year	(1983 $/bbl)	Annual Growth Rate
2010	$ 50.39	2.5%
2020	64.48	1.5%
2030	74.84	1.0%
2040	82.66	

2.3.2 Alaska Department of Revenue (DOR) Forecast (December, 1983)

DOR forecasts future petroleum revenues over a 17-year period to assist in the preparation of State budgets. These forecasts are updated on a quarterly basis. To develop the revenue forecast, a number of employees of the State's Office of Management and Budget (OMB), Alaska Department of Natural Resources (DNR), and the Department of Revenue (DOR) each develop one to ten scenarios of future world oil prices, and assign a subjective probability to each scenario. DOR then aggregates these individuals' forecasts and develops a composite probability distribution of future world oil prices.

DOR's forecasts of oil prices are on a monthly basis for the first two years and quarterly for the next three years. Beyond the first five years, DOR forecasts a fixed escalation rate in oil prices for each probability point. The mean oil price for each period is determined from the composite frequency distribution.

Among the oil prices analyzed in the July 1983 FERC filing were those projected in March 1983 by the DOR. DOR's estimates of future revenues are made on a quarterly basis and are used by the OMB in developing and managing the State's budget. A review of the oil prices used in DOR's most recent (December 1983 Quarterly Report) petroleum revenue forecast indicates that the recent mean DOR forecast and the SHCA-NSD case are almost identical.

The 17-year projections developed by DOR are presented in Exhibit 2.4. Under the mean scenario, the crude oil real price is expected to decrease until 1986 to $25.43 per barrel; then, the real price would increase to $36.57/per barrel in year 2000. A graphic comparison of the SHCA-NSD and DOR mean world oil prices is presented in Exhibit 2.5.

To simplify the process and to maintain continuity with the analyses in the FERC License Application, the world oil prices utilized throughout this Update are those developed by SHCA as the NSD case. This approach seems reasonable in light of the similarity of the SHCA-NSD and the most recent DOR forecasts.

2.3.3 Data Resources Incorporated (DRI) Forecast (Summer 1983)

The projections of crude oil price developed by DRI for 1983 through 2005 are also presented on Exhibit 2.4. Crude oil prices are expected to begin escalating rapidly in the latter half of the 1980's. DRI projects averages of real price increase of about 3.0 percent in the 1990's, and 1.6 percent for the period 2000 through 2005. The 2005 real price is expected to be $49.47 per barrel.

2.3.4 U.S. Department of Energy (DOE) Forecast (First Quarter 1983)

The policy group of the U.S. Department of Energy has developed projections of crude oil price for inclusion in the 1983 National Energy Policy Plan. These projections are presented in Exhibit 2.4. Real prices are expected to decrease until the mid 1980's, and increase rapidly after 1990. The 2010 real price would vary between $54.60 and $111.46 per barrel.

2.3.5 Other Oil Price Forecasts

In addition to the oil price forecasts discussed above, the Power Authority solicited forecasts from 17 other sources. These sources included research organizations, universities and oil companies. Ten of the 17 sources contacted had no forecast available or did not supply oil price data. The forecasts obtained from the remaining seven sources are presented on Exhibit 2.6, along with the SHCA-NSD, DOR and DOE forecasts.

Inspection of Exhibit 2.6, which portrays the various forecasts graphically, shows that in the early years (1983-1990) of the projections, the SHCA-NSD forecast is in the low range. In the later years (1995-2010) the SHCA-NSD forecast is in the middle of the range of forecasts illustrated.

2.4 ELECTRICAL DEMAND

Exhibit 2.7 summarizes the input and output data generated by the MJSENSO, MAP and RED models using the SHCA-NSD world oil price forecast for the period 1983 through 2010, the forecast period for the MAP and RED models.

To establish a starting point for analysis, historical data and projections of general fund expenditures, population, household, energy demand, and peak demand are displayed in graphic form in Exhibits 2.8 through 2.12.

In summary, the exhibits show that Railbelt population is expected to increase from about 320,000 in 1983 to approximately 530,000 by the year 2010. The corresponding number of households would increase from approximately 110,000 in 1983 to 196,000 in 2010. The electric energy consumption predicted is approximately 5,900 GWh in 2010. The corresponding average annual growth rate over the period 1983 through 2010 is 2.8 percent. The peak demand is expected to increase from about 580 MW in 1983 to approximately 1,200 MW in the year 2010.

2.4.1 Projections Underlying Electric Demand

Detailed projections of State revenues, economic conditions, and electric energy demand are presented on Exhibits 2.13 through 2.21.

2.4.1.1 Petroleum Revenues

Exhibit 2.13 presents projections of State petroleum revenues from each of the primary revenue sources through the year 2010. The first two columns of this Exhibit contain projected royalties and severance taxes, respectively. These projections are in nominal dollars, reflecting an annual change in the consumer price index of 6.5 percent. The projections of royalties and severance taxes through the year 1999 were produced by the DOR's PETREV forecasting model system, adjusted for minor differences in the assumed future rate of inflation. These projections are similar to the DOR mean projections presented in the DOR December 1983 report. Exhibit 2.13 also presents projections of State petroleum revenues derived from corporate income taxes, property taxes, lease bonuses, and Federal shared royalties. Future revenues from these sources, estimated by ISER, were used along with the projections of royalties and severance taxes as input to MAP.

2.4.1.2 Population and Employment

Exhibit 2.15 presents population projections for the State, Railbelt, Anchorage-Cook Inlet area, and Fairbanks-Tanana Valley area. Railbelt population is projected to grow by approximately 67 percent between 1983 and 2010 from 320,000 to 533,000. Within the Railbelt, the Anchorage area is projected to grow by 69 percent, compared to projected growth in the Fairbanks area of 57 percent.

The growth of employment, shown on Exhibit 2.16, is uniformly lower than that of population. While Statewide non-agricultural wage and salary employment is projected to grow by 61 percent during the next 27 years, total State employment is forecast to increase by only 51 percent. The Railbelt is projected to experience a higher employment increase, rising by 61 percent, with the Anchorage area growing by 63 percent, compared to 52 percent growth in the Fairbanks area.

2.4.1.3 Domestic Use of Electricity

Exhibit 2.17 presents projections of households by the following categories: State total, the Railbelt, the Anchorage area, Fairbanks area, and Statewide by age of head of household. In contrast to projected employment, households are projected to increase faster than population. Statewide, households are projected to increase by 72 percent by the year 2010, compared to a 75 percent increase in the Railbelt, a 78 percent rise in the Anchorage area, and a 67 percent increase in the Fairbanks area.

The effects of demand elasticity are shown on Exhibit 2.18 by adjusting the average consumption per household for conservation and fuel substitution. In the Anchorage area, the average consumption per household is expected to decrease from about 13,700 kWh in 1980 to 12,560 kWh in

1990, due mainly to the real increase in the price of electricity which will continue to cause some conversion from electric space heating to substitute fuels. After 1990, consumption is expected to slowly increase to about 13,200 kWh in 2010, at an average annual growth rate of 0.25 percent. In the Fairbanks area, the average household consumption is expected to increase from 11,500 kWh in 1980 to 15,200 kWh in 2010, an average annual growth rate of about 0.9 percent. This increase is due to the stabilization of electricity prices, combined with increasing prices of substitute fuels. The projected consumption in year 2000 is similar to the 1975 average consumption.

2.4.1.4 Commercial, Government and Small Business Use of Electricity

The employment forecasts obtained from MAP are used in the RED Business Consumption module to derive the electric demand in the commercial-government-small industrial sector. Exhibit 2.19 summarizes the "business use per employee" projections. The consumption projections were obtained from a forecast of floor space per employee and electricity consumption per square foot, which was then adjusted for price impacts. Floor space per employee is expected to increase by 10 percent in Anchorage and 15 percent in Fairbanks by the year 2010 to approach the current national average. As a result, in the Anchorage area the average consumption per employee is expected to increase from about 8,400 kWh in 1980 to 11,500 kWh in 2010, an average annual increase of 1.0 percent. In the Fairbanks area consumption per employee is expected to increase from 7,500 kWh in 1980 to 9,900 kWh in 2010, at an average annual growth rate of 0.9 percent.

A breakdown of electric energy demand projections by customer categories, based on the underlying projections of average consumption per household and per employee set forth in the previous paragraphs, is presented on Exhibit 2.20. Exhibit 2.20 also shows miscellaneous sector usage which includes street lighting, second (recreation) homes, and vacant houses. That sector's usage corresponds to about one percent of the total energy demand. The estimates of industrial loads, including the large industrial customers which are located in the Homer Electric Association, Inc. service area, and the estimate of the amount of electricity that could be provided by utilities to the military installations, are provided as inputs to the RED model. These loads are projected to increase from about 108 GWh in 1983 to 315 GWh in 2010 for the Anchorage-Cook Inlet area, and from 0 to 50 GWh in the Fairbanks-Tanana Valley area.

As most of the large industrial customers are located in the Homer Electric Association service area, the projections of growth in large industrial customers is based on a 1983 power requirements study by Burns & McDonnell for that utility. Those projections indicate that electrical demand is expected to increase from 100 GWh in 1982 to 142 GWh in 1990 and 158 GWh in 1995. An annual growth rate of 3.5 percent was assumed after 1995.

Discussions with representatives of the two military installations (Fort Richardson and Elmendorf Air Force Base) in the Anchorage-Cook Inlet Region, and the three military installations (Fort Wainwright, Fort Greely, and Eielson Air Force Base) in the Fairbanks-Tanana Valley

Region, provided information on their historical and projected electricity consumption. Continuation of the annual military electricity demand of 150 GWh is expected in each area. Existing power contracts and exchanges with the utilities were reviewed and estimates of the amount of electrical capacity and energy that could be provided by the utilities were discussed. For load forecasting, it was assumed that one-third of the total military electrical demand in each of the two regions, or 50 GWh annually per region, would be provided by the utilities. The military demand is, therefore, assumed to increase in a linear fashion from 0 GWh in 1985 to 50 GWh in 1990 in each region, and remain at 50 GWh thereafter.

2.4.2 Total Electrical Demand Projections

Exhibit 2.21 summarizes the annual peak and energy sales projections for each load center and for the total system. This single load forecast was used for all system expansion alternatives described in Chapter 5. A single load forecast for different expansion plans is appropriate because the RED model evaluates consumer conservation of electricity based on price and assumed that the sales price of electricity from the Susitna plan would not be higher than the price of the thermal alternative. In effect, this assumption may understate the load forecast for the Susitna expansion plan, since electricity prices would not be as high over the long run for Susitna generated power and conservation would accordingly be less.

2.5 COMPARISON WITH UTILITY FORECASTS

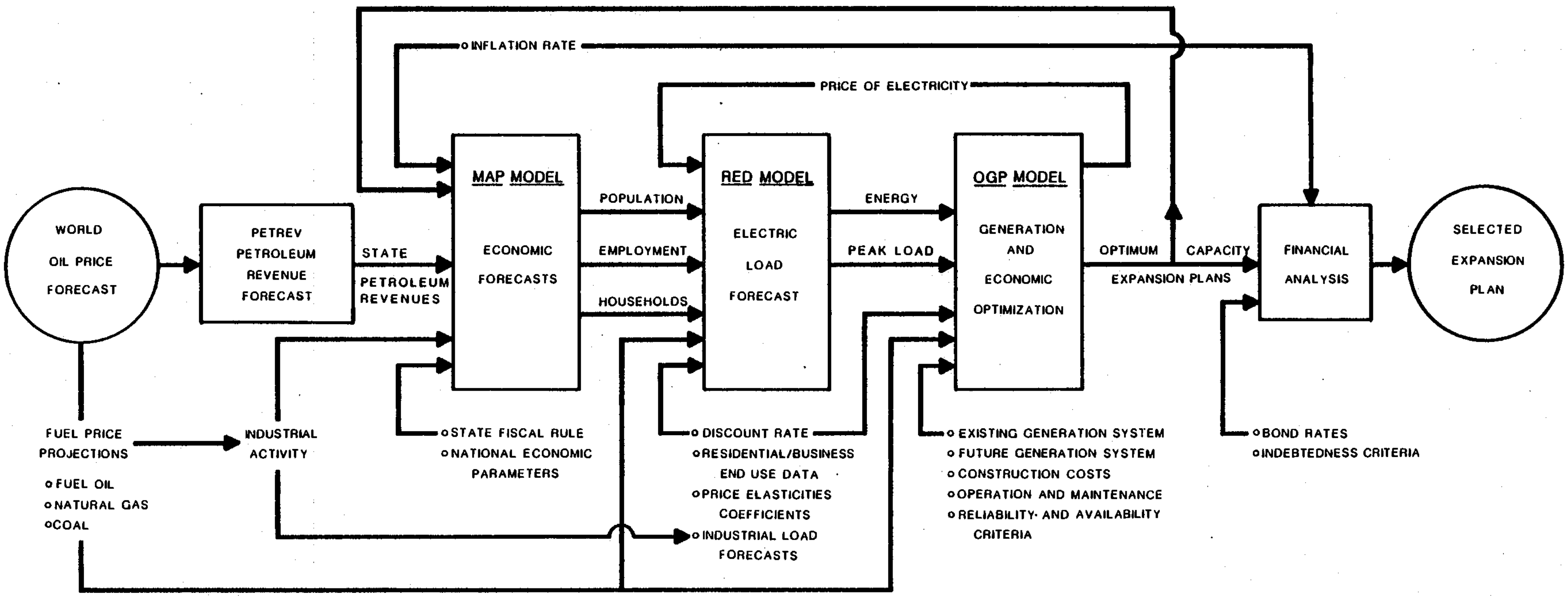
The Railbelt utilities annually produce forecasts of electrical demand for their own respective markets. Exhibit 2.22 summarizes projections made for the period 1983 through 2001 by the utilities in early 1983, in response to a request from the Alaska Power Administration (APAd). As that Exhibit indicates, the utilities expect the average annual growth rate to be about 6.0 percent for the period 1983 through 1990, decreasing to 4.5 percent for the period 1991 through 2001. The total energy generation is expected to be 7,662 GWh in the year 2001, which is about 50 percent greater than the model-derived projections.

A recent power requirements study done by Burns & McDonnell for Chugach Electric Association, Inc. (CEA) confirms the growth predicted in the APAd survey. The results are summarized in Exhibit 2.23. Three forecasts of economic activity -- low, moderate, and high -- were developed for the period 1983 through 1997. Under the Burns & McDonnell moderate forecast, CEA's energy generation projection for the year 1997 is 3,467 GWh, while the utility itself projected 3,428 GWh. The average annual growth rate of electric energy demand projections made by Burns & McDonnell is expected to vary between 3.9 and 6.2 percent for the period 1983 through 1997.

Exhibit 2.24 compares the model-derived electrical demand forecast with the current forecasts of the Railbelt utilities. The Exhibit shows that the Power Authority's forecasts are substantially lower. For example, the Railbelt utilities' 1990 energy demand is 4,678 GWh; the Authority's is 4,111 GWh, approximately 12% less.

2.6 SUMMARY

Exhibit 2.7 provides the basic data upon which the economic and financial feasibility of the Susitna Project and alternatives are analyzed. Utilizing the world oil price forecast by the SHCA-NSD case (line 1 of Exhibit 2.7), the PETREV/MJSENSO model calculates the petroleum revenues available to the State (lines 5-7). The MAP model utilizes this data as its primary input and calculates State economic conditions over the forecast period (lines 8-13). Using these economic data and other inputs, the RED model predicts electric demand in the Railbelt for the period 1984-2010. The result of the models' analysis is a forecast of total Railbelt electric energy sales of 3,737 GWh in 1990 and 5,858 GWh in 2010.



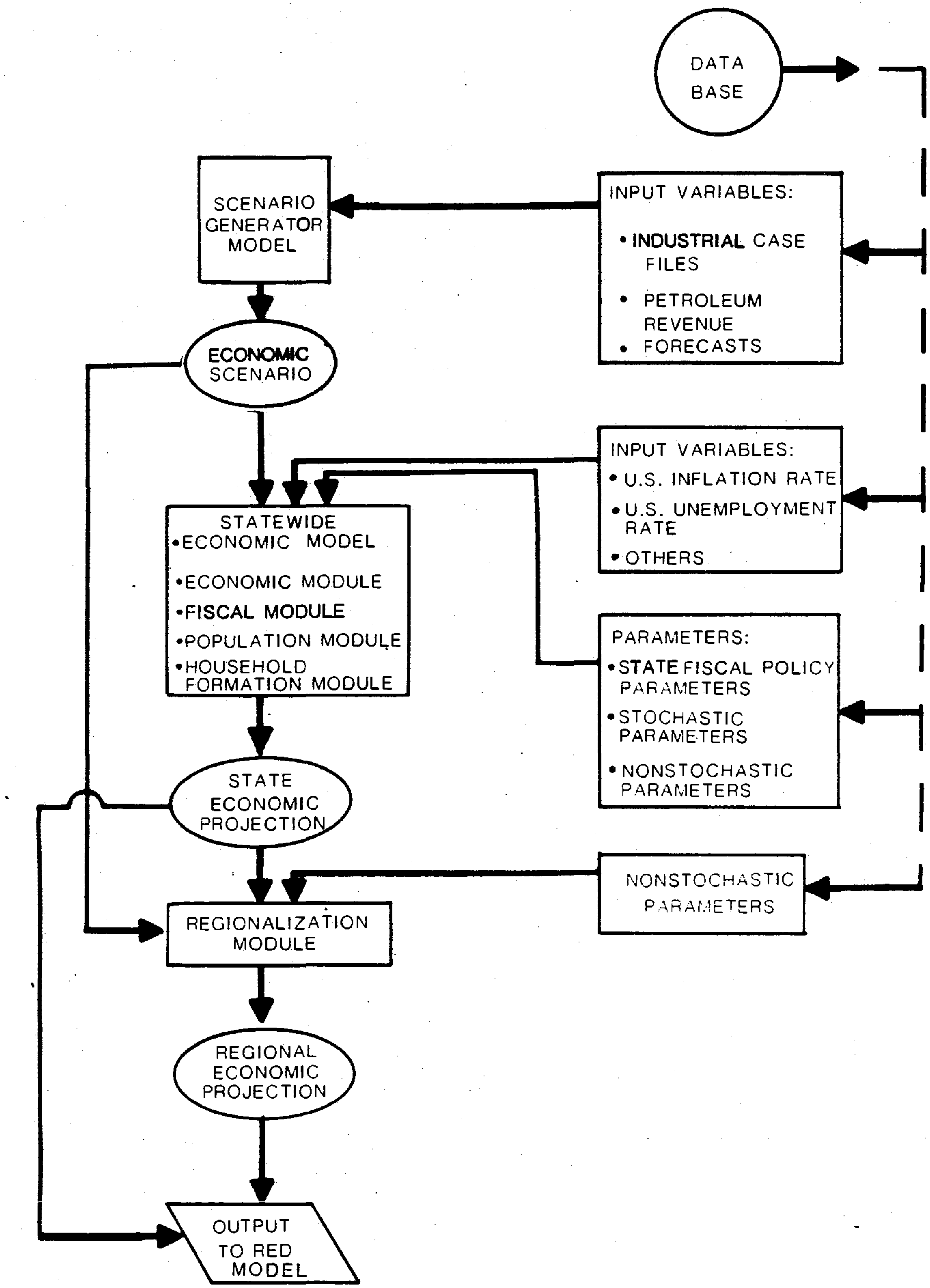
SUSITNA HYDROELECTRIC PROJECT UPDATE
ALASKA POWER AUTHORITY

RELATIONSHIP OF PLANNING MODELS AND INPUT DATA

FEBRUARY 1984

EXHIBIT 2.1

EXHIBIT 2.2

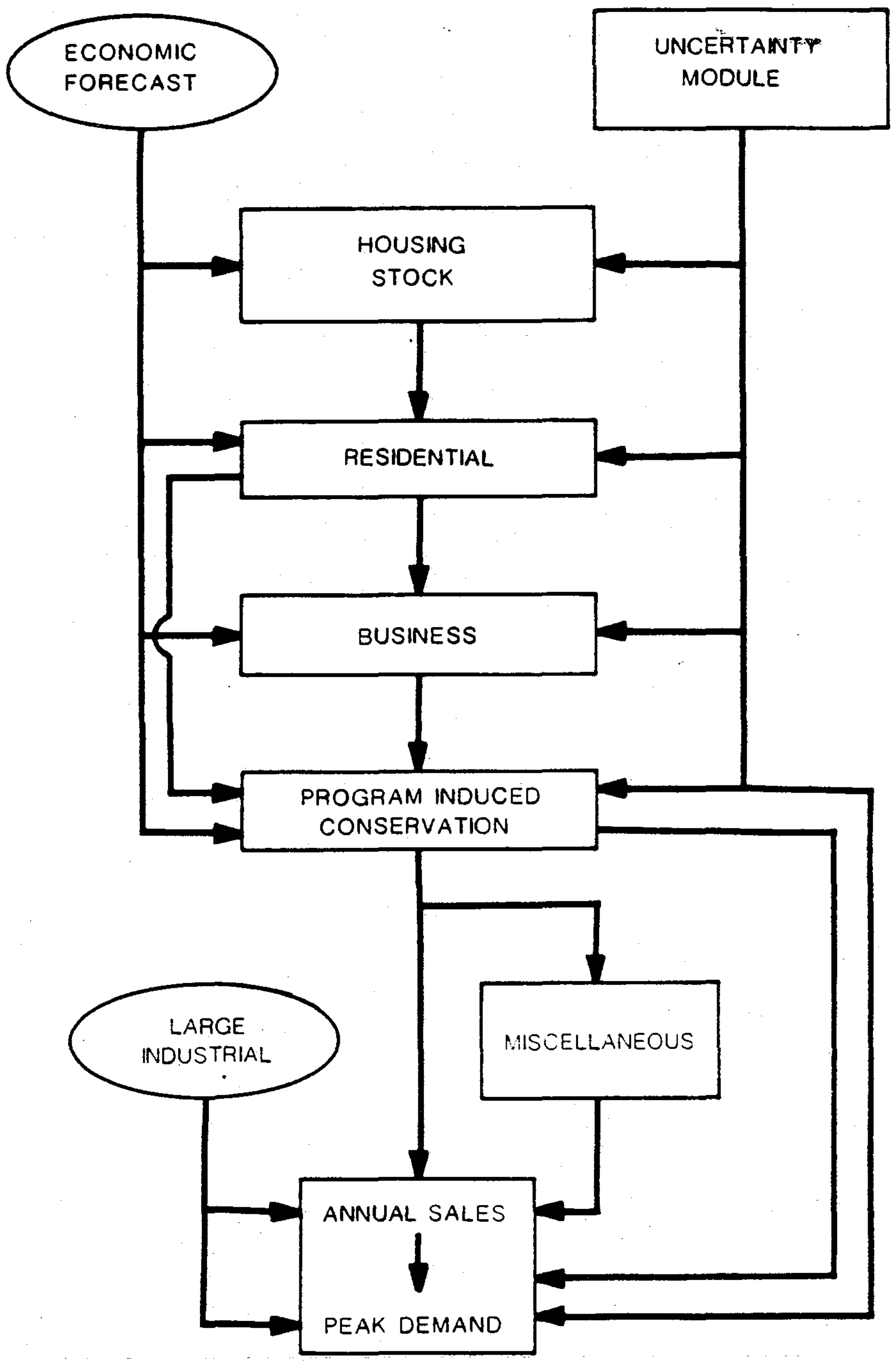


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

MAP MODEL SYSTEM

FEBRUARY 1984

EXHIBIT 2.3



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

RED INFORMATION FLOWS

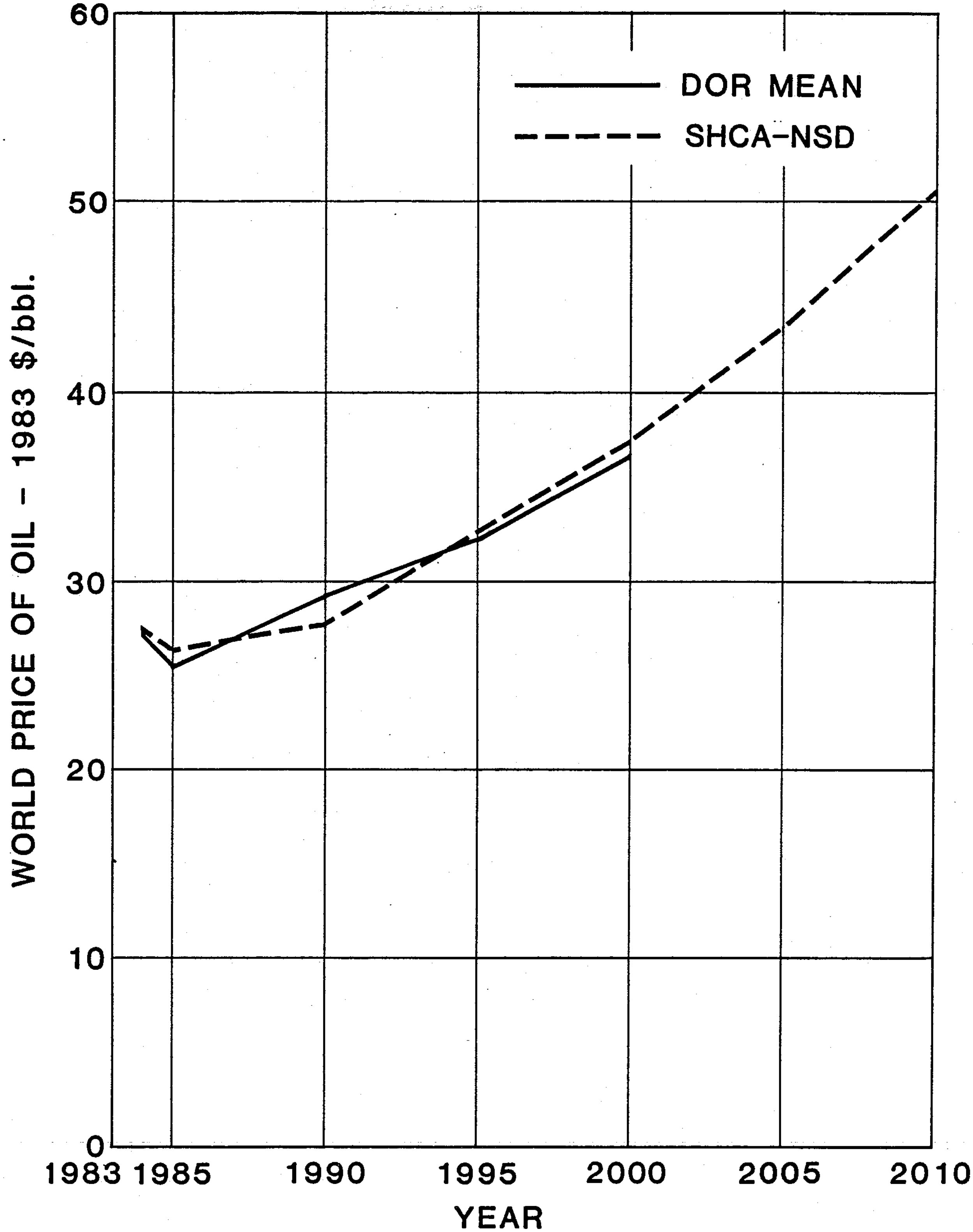
FEBRUARY 1984

OIL PRICE FORECASTS
(1983 $/bbl except as noted)

	Year 1985	Average Rate of Change Per Year (%)	Year 1990	Average Rate of Change Per Year (%)	Year 1995	Average Rate of Change Per Year (%)	Year 2000	Average Rate of Change Per Year (%)	Year 2005	Average Rate of Change Per Year (%)	Year 2010
DOR Mean	25.78	2.6	29.30	1.8	32.09	2.6	36.57	-	-	-	-
SHCA-NSD	26.30	1.2	27.90	3.0	32.34	3.0	37.50	3.0	43.47	3.0	50.39
DRI*	27.77	4.0	33.85	3.2	39.58	2.9	45.71	1.6	49.47	NA	NA
DOE Low*	21.00	4.0	25.60	3.4	30.30	3.5	36.00	5.2	46.50	3.2	54.60
DOE Mid-Range*	25.90	4.3	31.90	7.8	46.50	4.3	57.40	6.4	72.20	1.3	83.60
DOE High*	30.50	5.7	40.30	8.1	59.50	6.2	80.30	5.3	104.00	1.4	111.40

*1982 $/bbl

EXHIBIT 2.4

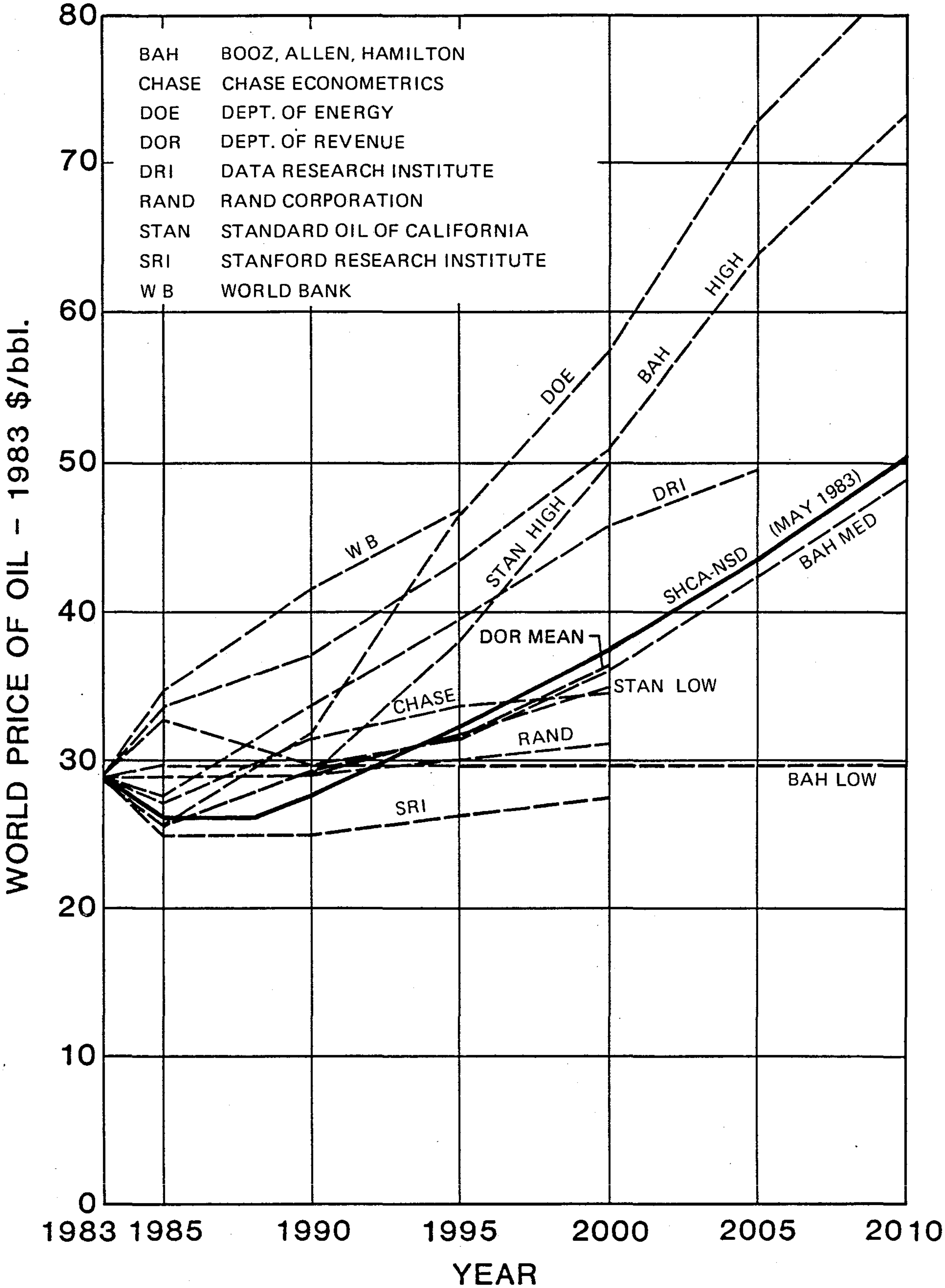


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

SHCA-NSD AND DOR MEAN
OIL PRICE PROJECTIONS

FEBRUARY 1984

EXHIBIT 2.6



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ALTERNATIVE OIL PRICE PROJECTIONS

FEBRUARY 1984

SUMMARY OF INPUT AND OUTPUT DATA FROM THE COMPUTER MODELS

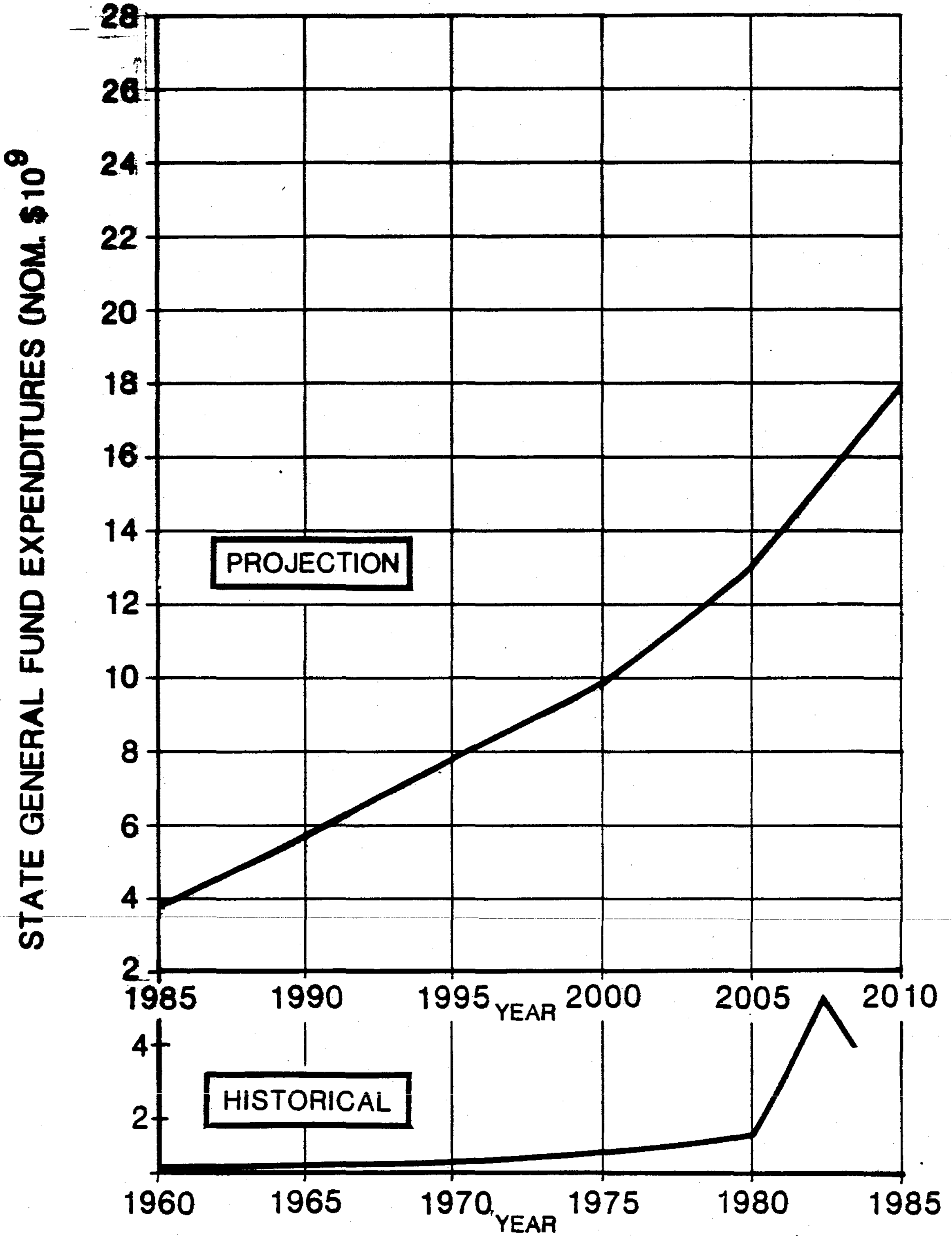
Line	Item Description	1983	1985	1990	1995	2000	2005	2010
1	World Oil Price (1983$/bbl)	28.95	26.30	27.90	32.34	37.50	43.47	50.39
2	Energy Price Used by RED (1980$)							
3	Heating Fuel Oil - Anchorage ($/MMBtu)	7.75	6.45	6.84	7.93	9.19	10.65	12.35
4	Natural Gas - Anchorage ($/MMBtu)	1.73	1.95	2.88	4.05	4.29	4.96	5.38
5	State Petroleum Revenues 1/ (Nom. $\$x10^6$)							
6	Production Taxes	1,474	1,561	2,032	1,868	1,910	2,150	2,421
7	Royalty Fees	1,457	1,555	2,480	2,651	3,078	3,799	4,689
8	State General Fund Expenditures (Nom. $\$x10^6$)	3,288	3,700	5,577	7,729	9,714	13,035	17,975
9	State Population	457,836	490,146	554,634	608,810	644,111	686,663	744,418
10	State Employment	243,067	258,396	293,689	313,954	325,186	345,701	376,169
11	Railbelt Population	319,767	341,613	389,026	423,460	451,561	486,851	533,218
12	Railbelt Employment	159,147	169,197	190,883	204,668	214,542	231,584	255,974
13	Railbelt Total Number of Households	111,549	120,140	138,640	152,463	163,913	177,849	195,652
14	Railbelt Electricity Consumption 2/ (GWh)							
15	Anchorage	2,326	2,561	3,045	3,371	3,662	4,107	4,735
16	Fairbanks	482	535	691	800	880	986	1,123
17	Total	2,808	3,096	3,737	4,171	4,542	5,093	5,858
18	Railbelt Peak Demand (MW)	579	639	777	868	945	1,059	1,217
19	Railbelt System Generation (GWh)	3,089	3,406	4,111	4,588	4,996	5,602	6,444

1/ Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, and federal shared royalties.

2/ Add 10 percent to obtain total generation.

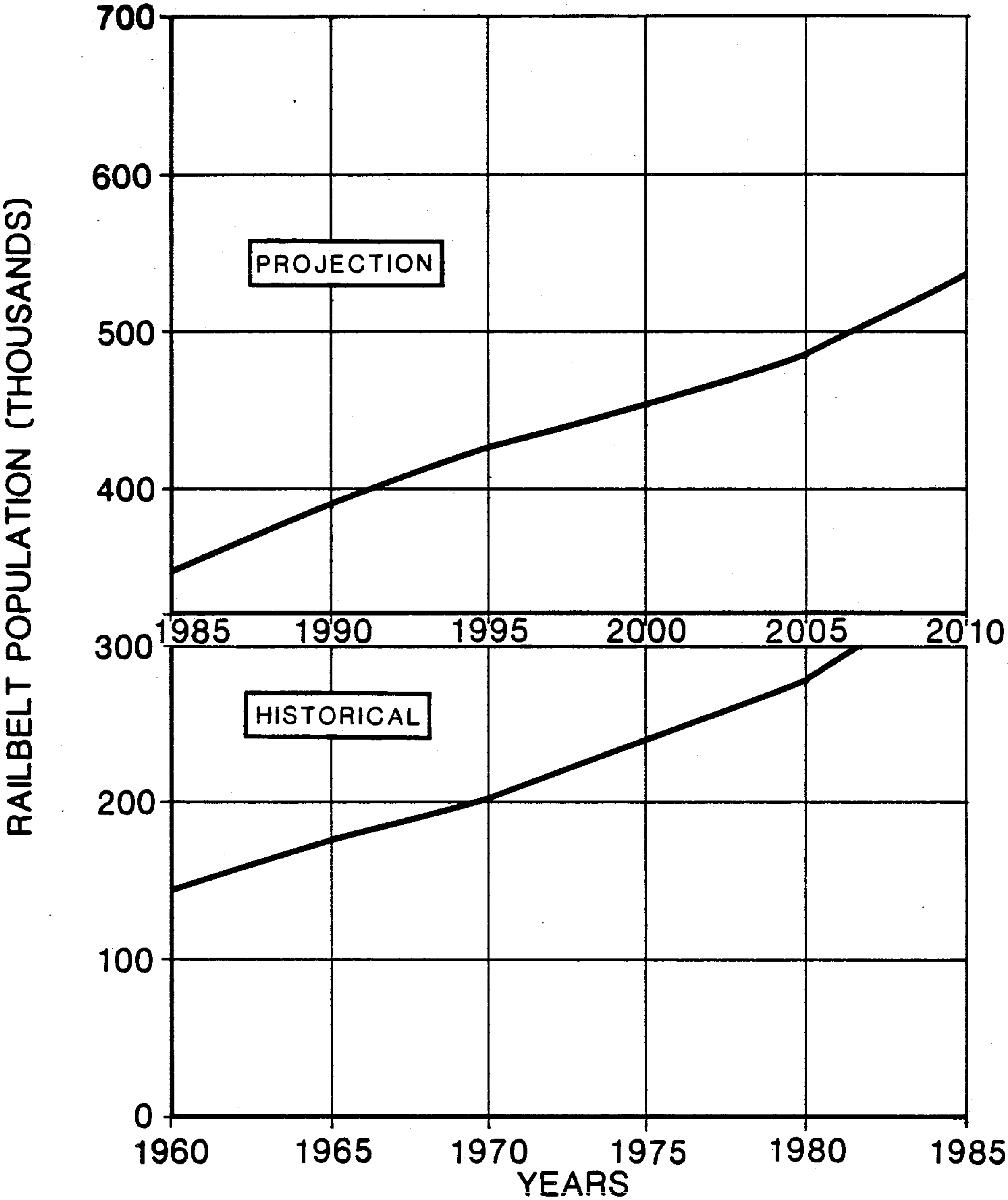
EXHIBIT 2.7

EXHIBIT 2.8



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

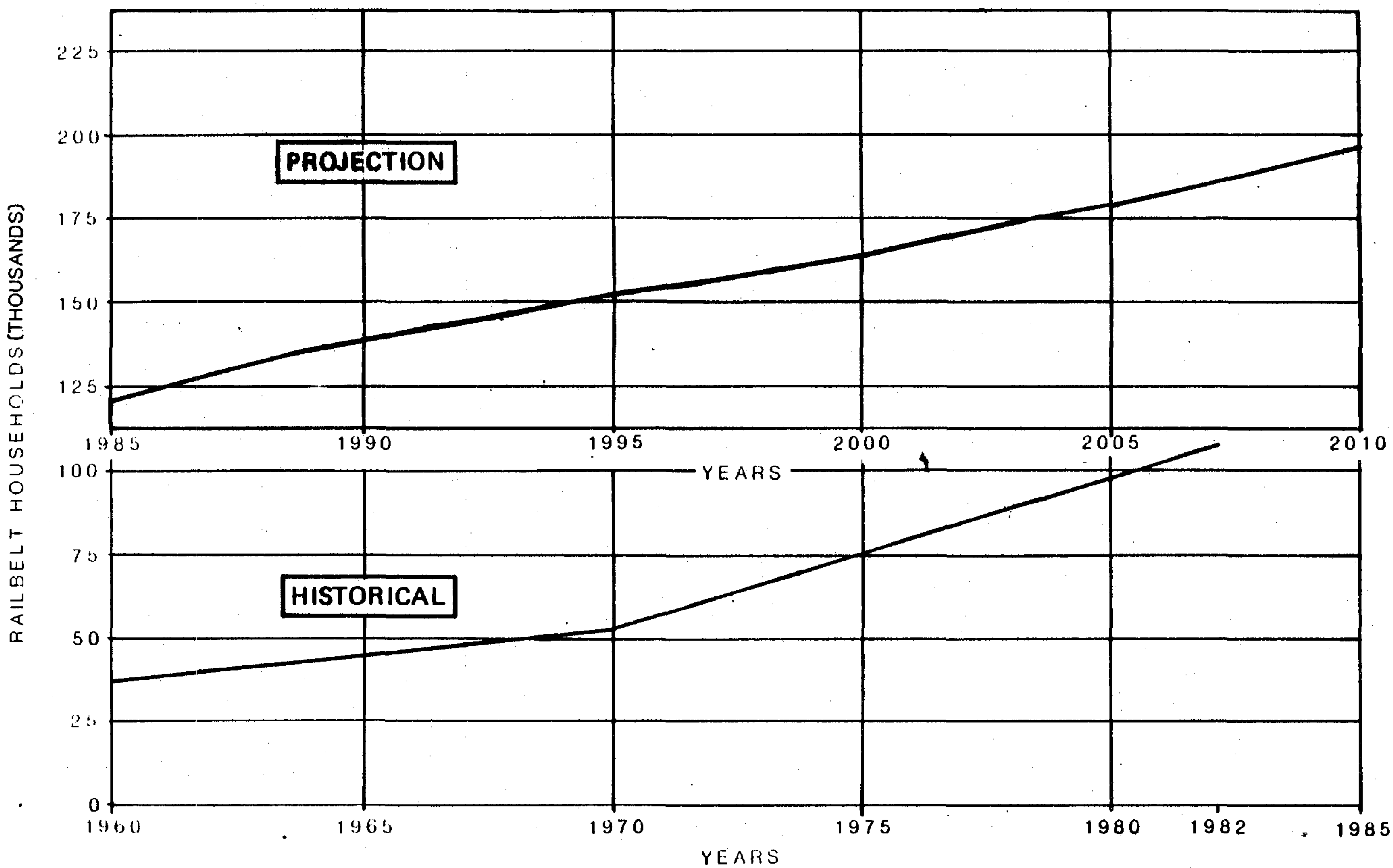
STATE GENERAL FUND EXPENDITURE FORECAST



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

RAILBELT POPULATION FORECAST

FEBRUARY 1984

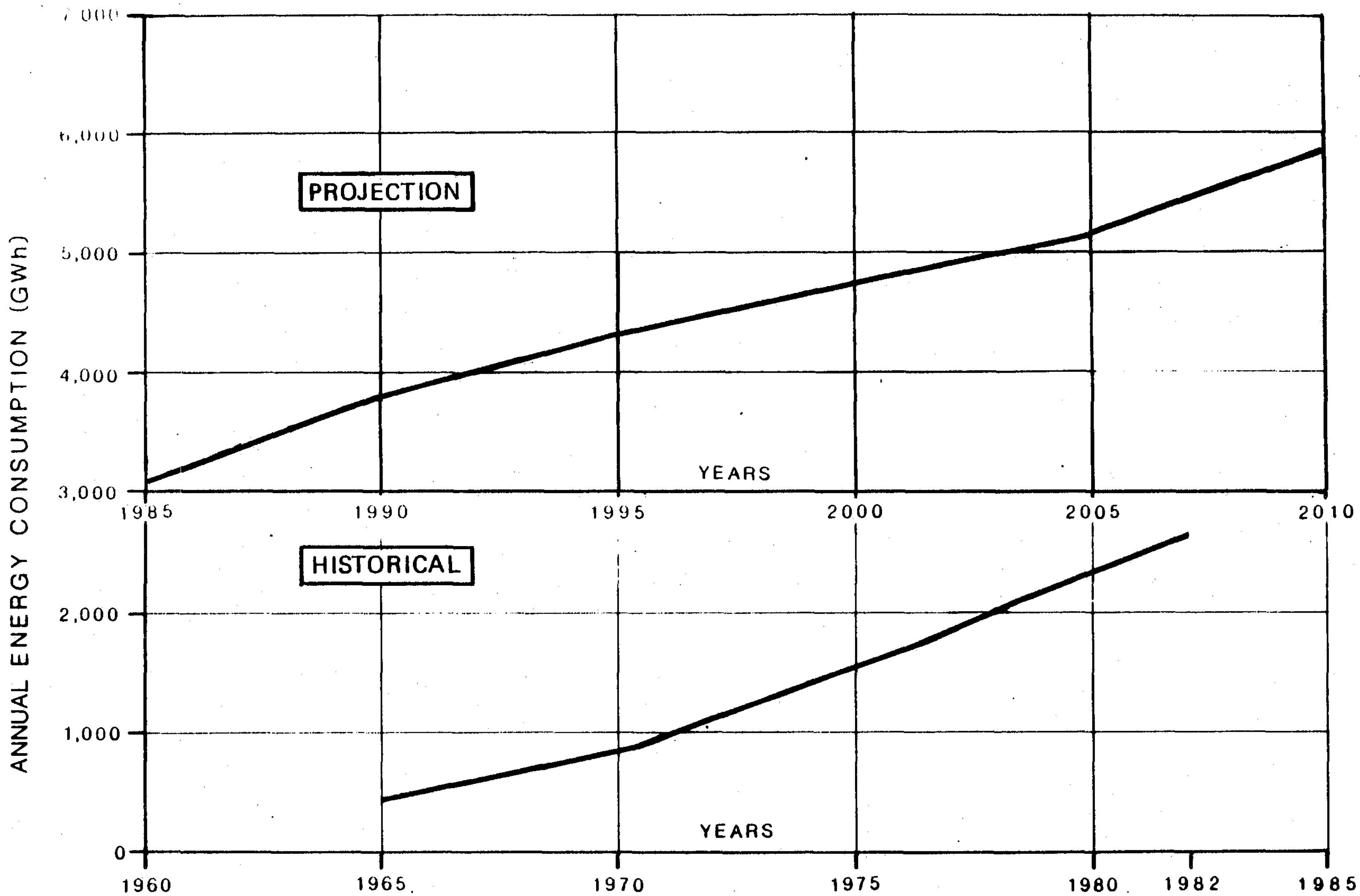


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

RAILBELT HOUSEHOLDS FORECAST

FEBRUARY 1984

EXHIBIT 2.10

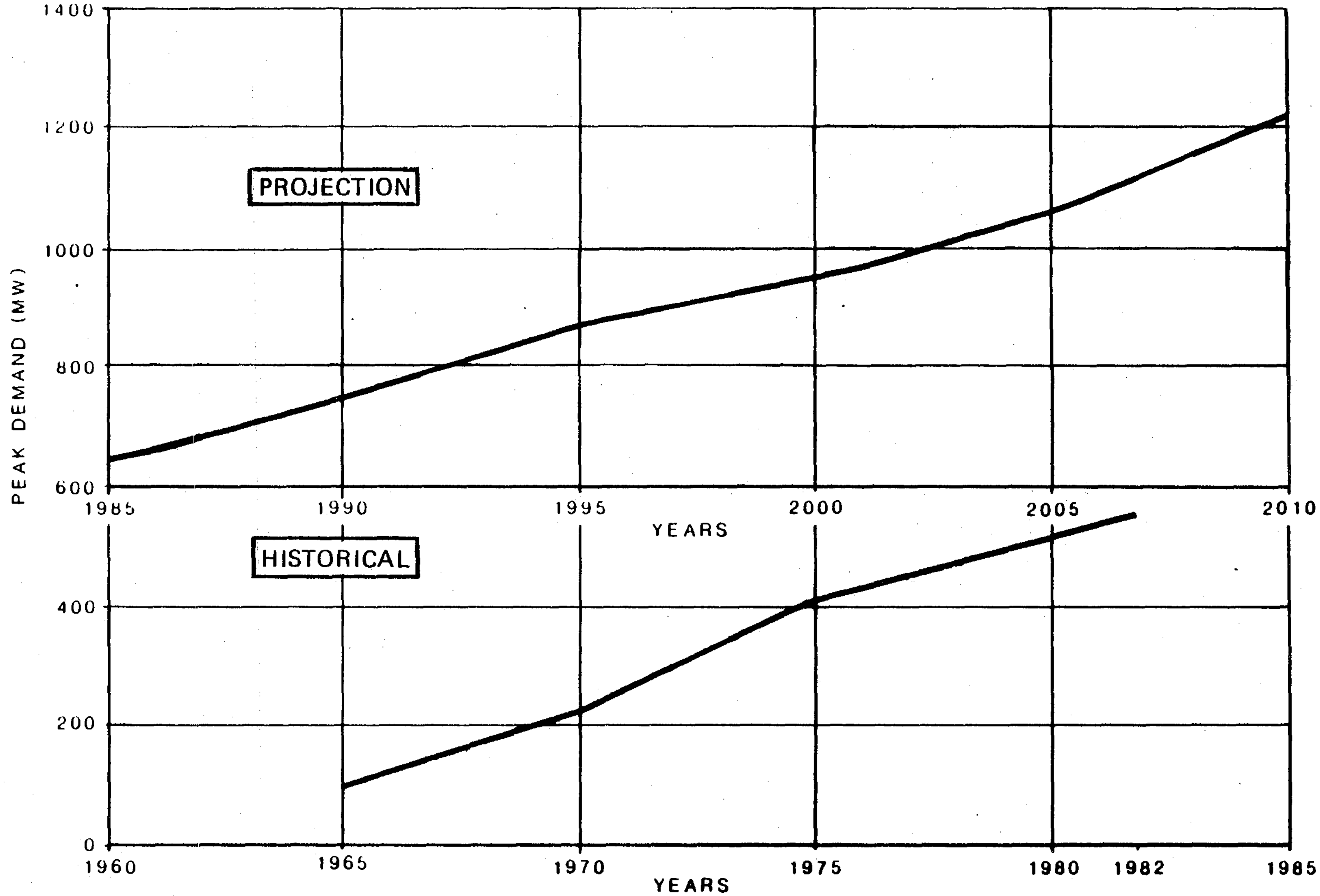


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ELECTRIC ENERGY DEMAND FORECAST

FEBRUARY 1984

EXHIBIT 2.11



ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

ELECTRIC PEAK DEMAND FORECAST

FEBRUARY 1984

EXHIBIT 2.12

EXHIBIT 2.13

STATE PETROLEUM REVENUES
(MILLION $)

Year	Royalties	Severance Taxes	Corporate Income Taxes	Property Taxes	Total Including Bonuses and Federal Shared Royalties	Total to General Fund (Net of Permanent Fund Contri-bution)
1982	1530.000	1590.000	668.899	142.700	3960.199	3570.549
1983	1456.661	1473.507	233.969	148.600	3361.836	2985.396
1984	1450.305	1474.080	328.647	153.200	3441.298	3069.956
1985	1555.117	1560.529	365.362	158.000	3668.700	3272.498
1986	1724.811	1705.298	398.724	163.456	4020.278	3582.078
1987	1896.215	1857.760	438.776	169.101	4389.691	3908.677
1988	1997.731	1647.607	396.949	174.940	4245.582	3739.060
1989	2251.456	1855.795	520.004	180.981	4837.387	4267.234
1990	2480.380	2031.695	591.983	187.231	5321.348	4693.734
1991	2352.500	1857.126	668.435	193.697	5102.781	4506.898
1992	2530.291	1929.692	794.871	200.385	5487.250	4846.672
1993	2657.006	1986.190	906.959	207.305	5790.461	5117.957
1994	2742.898	2006.949	998.581	214.464	5996.891	5302.664
1995	2651.116	1868.193	1084.124	221.870	5860.301	5188.770
1996	2599.817	1737.659	1185.670	229.532	5788.676	5129.719
1997	2755.836	1856.672	1326.406	237.458	6213.367	5515.156
1998	2865.556	1887.844	1474.798	245.658	6511.852	5785.961
1999	2950.992	1865.044	1649.613	254.141	6758.785	6011.285
2000	3077.885	1909.805	1841.891	262.917	7132.496	6353.023
2001	3210.235	1955.641	2056.580	271.996	7535.449	6722.641
2002	3348.276	2002.576	2296.294	281.389	7970.531	7122.961
2003	3492.252	2050.638	2563.949	291.106	8440.941	7557.125
2004	3642.420	2099.854	2862.802	301.158	8950.230	8028.625
2005	3799.044	2150.251	3196.489	311.558	9502.340	8541.328
2006	3962.404	2201.857	3569.072	322.317	10101.640	9099.540
2007	4132.781	2254.702	3985.082	333.447	10753.010	9708.060
2008	4310.492	2308.815	4449.578	344.962	11461.840	10372.220
2009	4495.844	2364.227	4968.219	356.874	12234.160	11097.950
2010	4689.164	2420.969	5547.316	369.198	13076.640	11891.850

SOURCE: MAP MODEL OUTPUT

STATE AND GOVERMENT EXPENDITURES
(MILLIONS $)

Year	Unre-stricted General Fund Expendi-tures	General Fund Balance	Permanent Fund Dividends	State Personal Income Tax	State Subsidy Programs	Percent of Permanent Fund Earnings Reinvested
1982	4601.891	399.200	425.000	0.000	634.000	0.000
1983	3287.977	478.004	152.608	0.000	500.000	0.500
1984	3389.729	616.992	196.738	0.000	350.000	0.500
1985	3699.507	700.539	223.721	0.000	350.000	0.500
1986	4031.094	821.113	253.168	0.000	350.000	0.500
1987	4375.941	987.922	286.008	0.000	350.000	0.500
1988	4731.574	699.973	322.441	0.000	695.501	0.500
1989	5118.008	588.465	361.817	0.000	0.000	0.500
1990	5576.836	506.125	406.085	0.000	0.000	0.500
1991	5386.480	506.141	455.185	0.000	0.000	0.500
1992	5786.504	506.152	505.111	0.000	0.000	0.500
1993	6528.020	139.531	0.000	0.000	0.000	0.500
1994	6729.594	139.543	0.000	338.049	0.000	0.500
1995	7729.250	139.563	0.000	680.847	0.000	0.000
1996	7822.879	139.586	0.000	748.723	0.000	0.000
1997	8361.188	139.609	0.000	809.145	0.000	0.000
1998	8794.711	139.633	0.000	873.359	0.000	0.000
1999	9190.000	139.652	0.000	941.928	0.000	0.000
2000	9713.740	139.668	0.000	1017.188	0.000	0.000
2001	10278.270	139.691	0.000	1098.944	0.000	0.000
2002	10886.180	139.711	0.000	1188.241	0.000	0.000
2003	11545.180	139.734	0.000	1287.516	0.000	0.000
2004	12261.640	139.766	0.000	1396.169	0.000	0.000
2005	13034.660	139.789	0.000	1513.479	0.000	0.000
2006	13871.350	139.820	0.000	1640.603	0.000	0.000
2007	14777.160	139.852	0.000	1778.121	0.000	0.000
2008	15758.890	139.891	0.000	1926.802	0.000	0.000
2009	16822.770	139.934	0.000	2085.652	0.000	0.000
2010	17975.270	139.980	0.000	2257.400	0.000	0.000

SOURCE: MAP MODEL OUTPUT

POPULATION
(THOUSANDS)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1982	437.175	307.105	239.830	67.277
1983	457.836	319.767	251.057	68.711
1984	473.752	330.202	259.679	70.523
1985	490.146	341.613	269.300	72.313
1986	505.884	352.187	278.082	74.105
1987	517.431	359.054	283.333	75.723
1988	526.823	364.583	287.969	76.615
1989	538.532	375.007	296.794	78.213
1990	554.634	389.026	308.196	80.831
1991	560.786	393.296	311.585	81.712
1992	581.846	405.991	322.865	83.127
1993	594.848	413.788	328.521	85.268
1994	602.027	420.130	332.694	87.436
1995	608.810	423.460	335.464	87.997
1996	616.422	428.574	339.629	88.945
1997	623.782	434.617	344.561	90.057
1998	630.352	440.001	348.981	91.021
1999	636.928	445.519	353.531	91.988
2000	644.111	451.561	358.441	93.120
2001	651.362	457.835	363.501	94.335
2002	658.994	464.362	368.801	95.561
2003	667.660	471.437	374.626	96.811
2004	676.878	478.925	380.769	98.156
2005	686.663	486.851	387.267	99.584
2006	697.022	495.287	394.168	101.119
2007	707.990	504.091	401.364	102.727
2008	719.644	513.431	408.995	104.436
2009	731.592	522.970	416.755	106.216
2010	744.418	533.218	425.115	108.104

SOURCE: MAP MODEL OUTPUT

EMPLOYMENT
(THOUSANDS)

Year	State Non-Ag Wage and Salary	State Total	Railbelt Total	Greater Anchorage Total	Greater Fairbanks Total
1982	192.903	231.984	154.033	120.533	33.500
1983	202.237	243.067	159.147	125.221	33.927
1984	205.903	246.984	162.259	127.853	34.406
1985	216.612	258.396	169.197	133.668	35.528
1986	225.515	267.895	174.818	138.324	36.494
1987	230.833	273.581	177.412	140.345	37.067
1988	234.657	277.669	179.422	142.065	37.357
1989	240.213	283.619	184.211	146.124	38.088
1990	249.654	293.689	190.883	151.685	39.198
1991	247.908	291.844	191.360	151.958	39.402
1992	264.012	309.031	199.404	158.995	40.409
1993	266.941	312.180	202.842	161.351	41.492
1994	267.220	312.511	203.630	161.669	41.961
1995	268.534	313.954	204.668	162.466	42.202
1996	270.783	316.404	206.258	163.772	42.486
1997	272.935	318.765	208.212	165.401	42.811
1998	274.346	320.353	210.041	166.916	43.125
1999	276.144	322.374	212.025	168.580	43.445
2000	278.729	325.186	214.541	170.645	43.897
2001	281.498	328.141	217.283	172.875	44.408
2002	284.643	331.499	220.293	175.333	44.960
2003	288.727	335.859	223.703	178.156	45.546
2004	293.137	340.569	227.487	181.265	46.222
2005	297.941	345.701	231.584	184.625	46.959
2006	303.062	351.172	235.985	188.226	47.759
2007	308.504	356.989	240.639	192.025	48.614
2008	314.317	363.203	245.561	196.044	49.517
2009	320.082	369.368	250.621	200.146	50.475
2010	326.440	376.169	255.974	204.512	51.462

SOURCE: MAP MODEL OUTPUT

HOUSEHOLDS (THOUSANDS)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1982	145.453	106.572	83.678	22.894
1983	153.141	111.549	88.038	23.511
1984	159.154	115.671	91.425	24.246
1985	165.299	120.140	95.165	24.974
1986	171.192	124.275	98.580	25.695
1987	175.620	127.053	100.709	26.344
1988	179.287	129.415	102.669	26.746
1989	183.738	133.365	105.994	27.371
1990	189.696	138.640	110.267	28.373
1991	192.234	140.401	111.662	28.739
1992	199.886	145.348	116.024	29.324
1993	204.788	148.405	118.253	30.152
1994	207.695	150.964	119.963	31.002
1995	210.461	152.463	121.197	31.267
1996	213.508	154.590	122.921	31.669
1997	216.470	157.052	124.921	32.131
1998	219.161	159.242	126.710	32.532
1999	221.854	161.483	128.549	32.934
2000	224.751	163.913	130.515	33.398
2001	227.670	166.423	132.532	33.891
2002	230.716	169.023	134.636	34.388
2003	234.112	171.820	136.928	34.892
2004	237.695	174.758	139.329	35.429
2005	241.468	177.849	141.853	35.996
2006	245.436	181.121	144.520	36.601
2007	249.609	184.516	147.285	37.231
2008	254.014	188.100	150.203	37.896
2009	258.519	191.748	153.162	38.586
2010	263.323	195.652	156.336	39.316

SOURCE: MAP MODEL OUTPUT

EXHIBIT 2.18

RESIDENTIAL ELECTRIC ENERGY USE PER HOUSEHOLD

Year	Before Conservation Adjustment and Fuel Substitution: Small Appliances (kWh)	Large Appliances (kWh)	Space Heat (kWh)	Total (kWh)	After Adjustment Total (kWh)
Anchorage-Cook Inlet Area					
1980	2110	6500	5089	13699	13699
1985	2160	6151	4812	13133	12829
1990	2210	6020	4584	12814	12561
1995	2260	5959	4516	12735	12644
2000	2310	5989	4454	12753	12736
2005	2360	6059	4420	12839	12938
2010	2410	6124	4444	12977	13198
Fairbanks-Tanana Valley Area					
1980	2466	5740	3314	11519	11519
1985	2536	6179	3606	12321	12136
1990	2606	6453	3873	12932	12736
1995	2676	6667	4050	13393	13329
2000	2746	6795	4310	13852	14009
2005	2816	6839	4536	14191	14626
2010	2886	6888	4656	14430	15180

BUSINESS ELECTRIC ENERGY USE PER EMPLOYEE

Year	Before Conservation Adjustment and Fuel Substitution: Anchorage-Cook Inlet Area (kWh)	Before Conservation Adjustment and Fuel Substitution: Fairbanks-Tanana Valley Area (kWh)	After Adjustments: Anchorage-Cook Inlet Area (kWh)	After Adjustments: Fairbanks-Tanana Valley Area (kWh)
1980	8,407	7,496	8,407	7,496
1985	9,580	7,972	9,212	7,900
1990	10,355	8,327	9,749	8,281
1995	10,918	8,662	10,078	8,665
2000	11,416	8,958	10,349	9,024
2005	12,090	9,308	10,828	9,446
2010	12,933	9,711	11,502	9,929

EXHIBIT 2.19

EXHIBIT 2.20

PROJECTION OF ELECTRICITY REQUIREMENTS

Year	RED Model Computations: Residential Requirements (GWh)	RED Model Computations: Business Requirements (GWh)	RED Model Computations: Miscellaneous Requirements (GWh)	Indust/Military* Requirements (GWh)	Total Requirements (GWh)
			Anchorage-Cook Inlet Area		
1985	1180	1231	26	124	2561
1990	1345	1479	30	192	3045
1995	1492	1637	34	208	3371
2000	1621	1766	36	238	3662
2005	1794	1999	41	273	4107
2010	2021	2352	47	315	4735
			Fairbanks-Tanana Valley Area		
1985	248	281	7	0	535
1990	310	325	7	50	691
1995	376	366	8	50	800
2000	426	396	9	50	880
2005	482	444	10	50	986
2010	551	511	11	50	1123

* Input to the RED Model

PROJECTED PEAK AND ENERGY DEMAND

	Anchorage-Cook Inlet Area		Fairbanks-Tanana Valley Area		Total System Area		
YEAR	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Load Factor (%)
1985	2561	517	535	122	3096	639	55.3
1990	3045	619	691	158	3737	777	54.9
1995	3371	686	800	183	4171	868	54.8
2000	3662	744	880	201	4542	945	54.8
2005	4107	834	986	225	5093	1059	54.9
2010	4735	961	1123	256	5858	1217	54.9

Note: Figures shown are sales at end-use. Add 10 percent losses to get generation.

EXHIBIT 2.21

RAILBELT UTILITIES FORECAST

	AML&P (1)		CEA (1) (2)		FMUS		GVEA		RAILBELT TOTAL	
YEAR	Energy (GWH)	Winter Peak (MW)	Energy (GHW)	Winter Peak (MW)	Energy (GWH)	Winter Peak (MW)	Energy (GHW)	Winter Peak (MW)	Energy (GHW)	Winter Peak (MW)
1983	717	140	1854	384	147	29	387	74	3105	627
1984	786	1152	1966	408	153	30	416	81	3321	672
1985	844	162	2079	432	161	32	447	89	3531	716
1986	915	174	2192	457	165	32	480	97	3752	761
1987	1053	197	2304	481	168	33	516	107	3974	807
1988	1126	209	2417	505	172	34	603	113	4200	850
1989	1200	221	2530	529	175	35	653	120	4443	894
1990	1270	232	2642	554	183	36	653	128	4678	940
1991	1270	232	2754	578	190	38	706	136	4920	984
1992	1322	241	2867	602	198	39	764	145	5151	1028
1993	1375	251	2979	626	206	41	826	154	5386	1073
1994	1431	261	3091	651	214	42	894	164	5630	1118
1995	1489	272	3203	675	225	45	967	174	5884	1166
1996	1549	283	3315	699	237	47	1046	185	6147	1215
1997	1621	294	3428	723	249	49	1131	197	6429	1264
1998	1697	306	3540	747	262	52	1223	209	6722	1314
1999	1775	318	3652	771	275	54	1323	222	7025	1367
2000	1858	331	3764	795	281	56	1432	236	7335	1419
2001	1944	344	3875	820	295	58	1548	251	7662	1474

NOTES:
(1) Eklutna is included in AML&P & CEA.
(2) CEA forecast includes Matanuska Electric Assoc., Homer Electric Assoc., & Seward Electric requirements.

AML&P = Anchorage Municipal Light & Power
CEA = Chugach Electric Association
FMUS = Fairbanks Municipal Utilities System
GVEA = Golden Valley Electric Association, Fairbanks Area

SOURCE: ALASKA POWER ADMINISTRATION, March 1983

EXHIBIT 2.23

CHUGACH ELECTRIC ASSOCIATION, INC.

PROJECTIONS OF TOTAL SYSTEM ENERGY GENERATION*

Year	Low		Moderate		High	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
1983	1,817	412	1,868	426	1,879	429
1984	1,942	432	2,050	463	2,081	469
1985	2,059	451	2,265	501	2,299	510
1986	2,189	470	2,473	533	2,614	575
1987	2,281	491	2,642	568	2,935	654
1988	2,365	513	2,803	606	3,283	745
1989	2,445	535	2,962	646	3,664	850
1980	2,523	559	3,121	689	4,087	974
1991	2,582	575	3,167	699	4,150	978
1992	2,651	591	3,207	706	4,164	969
1993	2,725	606	3,251	713	4,187	961
1994	2,802	623	3,299	721	4,220	954
1995	2,884	639	3,350	729	4,261	946
1996	2,982	660	3,406	738	4,315	938
1997	3,103	680	3,467	747	4,381	931

* Includes Matanuska Electric Association, Homer Electric Association, and Seward Electric System.

Source: Power Requirements Study, 1983, by Burns & McDonnell

EXHIBIT 2.24

SUMMARY OF ENERGY AND PEAK GENERATION PROJECTIONS
MADE BY POWER AUTHORITY AND UTILITIES

	1990	2000	2010
Power Authority			
Annual Energy	4,111	4,996	6,444
Peak Demand (MW)	855	1,040	1,339
Utilities			
Annual Energy	4,678	7,678	9,649
Peak Demand (MW)	940	1,419	1,854

3.0 UPDATE OF THE SUSITNA PROJECT

3.1 INTRODUCTION

Evaluating the economic feasibility of the Susitna Project and its alternatives requires that an estimate be prepared of the construction/operating costs and energy production capabilities of the Project. This Chapter provides an update of (1) the costs and power generation capacity of the Project as currently designed and set forth in the FERC License Application, and (2) the impact on the economics of the Project of certain cost-reducing design refinements.

The Power Authority Board of Directors has given conditional approval to proceeding with certain cost-saving design refinements to the Project so long as implementing those refinements will have no adverse effect on the FERC licensing schedule. On the assumption that these engineering refinements may be accommodated within the existing FERC licensing schedule, the estimated Project costs would be less, as discussed more fully in this Chapter. It should be clearly understood, however, that the Power Authority has evaluated the economic and financial feasibility of the Project in this Update based on the estimated costs as filed with the FERC. As shown below, implementation of the design refinements would improve the economics of Susitna.

The results of the assessments in this Chapter are incorporated in the studies of alternative expansion plans to meet future Railbelt electrical demand (Chapter 5), economic analyses (Chapter 6) and financial analyses (Chapter 7).

3.2 DESCRIPTION OF THE SUSITNA PROJECT AS FILED AT FERC

The Susitna Hydroelectric Project as proposed in the License Application will consist of two major developments on the Susitna River approximately 180 miles north-east of Anchorage. The Project will consist of two dams, Watana and Devil Canyon, with a combined maximum generating capacity of 1,620 MW. Watana, which will be built first, provides a major storage reservoir to control the flow of the river, and is planned to consist of an earth and rockfill dam together with associated diversion, spillway, low-level outlet and transmission facilities. Devil Canyon will consist of a concrete arch dam with associated diversion, spillway, low-level outlet and transmission facilities.

3.2.1 Watana Development

Watana Dam will create a reservoir approximately 54 miles long, with a surface area of 38,000 acres, and a gross storage capacity of 9,600,000 acre-feet at elevation (El.) 2185, the normal maximum operating level. The minimum operating level of the reservoir is proposed to be El. 2065, providing active storage volume of 3,700,000 acre-feet for normal operation.

The dam will be an embankment structure with a central impervious core. The nominal crest elevation of the dam will be El. 2205, with maximum height 885 feet above the foundation and a crest length of 4,100 feet.

The power intake will be located on the north bank at the end of an approach channel excavated in rock. From the intake structure, concrete and steel-lined penstocks will lead to an underground powerstation housing six 170-MW generating units. The maximum generating capacity of Watana, therefore, will be 1,020 MW.

Low level outlet facilities will be provided so that downstream flow requirements can be met when power releases are insufficient to meet environmental requirements and to provide flood discharge capacity.

The main spillway is a safety structure to discharge inflows to the reservoir that exceed the capacities of the other outlet works. The spillway will consist of a gated control structure with an inclined concrete chute leading to a flip bucket. The flip bucket is intended to reduce river bed erosion when the spillway is used. The spillway could discharge up to 120,000 cubic feet per second (cfs) at reservoir elevation 2193.5. The spillway will have sufficient capacity for the Probable Maximum Flood (PMF) with the reservoir level raised to El. 2201 (four feet below the nominal crest), assuming the low-level outlet facilities and powerhouse are operated concurrently.

3.2.2 Devil Canyon Development

Devil Canyon dam will form a reservoir approximately 26 miles long with a surface area of 7,800 acres and gross storage capacity of 1,100,000 acre-feet at El. 1455, the normal maximum operating level. The operating level of the Devil Canyon reservoir controls the tailwater level of the Watana Development. The minimum operating level of the reservoir will be El. 1405, providing active storage volume of 350,000 acre-feet for normal reservoir operation.

The dam will be a thin concrete arch with a crest level of El. 1463 and maximum height of 646 feet above foundation. It will be supported by mass concrete thrust blocks on each abutment. Adjacent to the southern thrust block, an earth and rockfill dam will extend across a saddle to the south bank.

The power intake will be on the north bank and will consist of an approach channel excavated in rock leading to a reinforced concrete gate structure. Concrete and steel-lined penstock tunnels will lead from the intake structure to an underground powerstation housing four 150-MW units. The maximum generating capacity of Devil Canyon is 600 MW.

Low-level outlet facilities will be located in the lower part of the main dam to assure that downstream flow requirements can be met when power releases are insufficient to meet in-stream flow requirements and to provide flood discharge capacity. The spillway is a safety facility designed to pass 123,000 cfs with the reservoir at normal maximum elevation of 1455. The reservoir will surcharge to El. 1466 during the PMF if the spillway, powerhouse, and low-level outlet works are operating concurrently.

3.3 ALTERNATIVE SUSITNA DEVELOPMENT SCHEMES

The License Application as filed found that the optimum development for Watana corresponded to maximum reservoir elevation 2185, and the Power Authority Board directed that this configuration be used in re-evaluating the economic and financial feasibility of the Project. Subsequent studies prepared in connection with this Update have verified the finding in the License Application. Table 3.1 presents the cumulative present worth of costs of alternative Susitna development plans with Watana at various elevations. As can be seen, the maximum net benefit (least cost) is obtained from a Susitna Project with Watana Development at El. 2185.

Table 3.1
CUMULATIVE PRESENT WORTH
OF ALTERNATIVE SUSITNA DEVELOPMENT PLANS
(1983 $ million)

Case	Cumulative Present Worth of Costs 1993 - 2050	Net Increase In Costs Over Elevation 2185
Watana Elevation 2185, Devil Canyon, and Thermal Generation	5730	-
Watana Elevation 2100, Devil Canyon, and Thermal Generation	5877	147
Watana Elevation 2000, Devil Canyon, and Thermal Generation	5931	201
Watana Elevation 1900, Devil Canyon, and Thermal Generation	6636	906

3.4 POTENTIAL DESIGN REFINEMENTS

Engineering review of the FERC License Application and additional geotechnical investigation at the Watana site have led to certain design refinements which could reduce Project costs without impairing safety.

The following list identifies the major design features that have been considered and proposed as refinements:

WATANA:

1. Reduction in dam foundation excavation and treatment requirements;
2. Change in dam configuration and composition to reflect available materials;
3. Resizing and relocation of cofferdam and diversion tunnels;
4. Combining of power intake and spillway approach channel;
5. Reorientation of underground caverns;
6. Shortening and reduction in number of power conduits;
7. Elimination of fuseplug spillway;
8. Reduction in transmission voltage of north line;
9. Positive cutoff treatment of relict channel;
10. Elimination of outdoor switchyard and utilization of different switchgear equipment; and
11. Increase in unit speed of generating equipment.

DEVIL CANYON:

1. Elimination of fuseplug spillway.

3.5 COST ESTIMATES

3.5.1 Construction Cost Estimate of Project as Filed at FERC

Table D.1 of the FERC License Application detailed the construction cost estimates for the Watana and Devil Canyon developments in 1982 dollars. As adjusted by an inflation factor of 1.043, the cost estimate (in 1983 dollars) is as stated in Table 3.2.

Table 3.2 shows the current estimate of the construction cost of the Watana Development as contained in the FERC License Application as $3.75 billion; the corresponding estimate for the Devil Canyon Development is $1.62 billion in 1983 dollars.

Table 3.2

SUMMARY OF COST ESTIMATE

	January 1983 Dollars ($ million)		
Category	Watana	Devil Canyon	Total
Production Plant	$ 2,391	$ 1,111	$ 3,502
Transmission Plant	476	109	585
General Plant	5	5	10
Indirect	461	215	676
Total Construction	3,333	1,440	4,773
Construction Overhead	417	180	597
TOTAL PROJECT CONSTRUCTION COST	$ 3,750	$ 1,620	$ 5,370

3.5.2 Construction Cost Estimates with Refinements

As a result of the potential design refinements listed in Section 3.4, the construction cost estimate for Watana can be reduced by about 8 percent ($300 million) to approximately $3.45 billion. The Devil Canyon costs would not be changed by the design refinement.

3.5.3 Operation and Maintenance Costs

Operation and maintenance costs (O&M) account for the personnel, equipment, materials, and facilities required to operate the generating plant and to maintain all of the structures and machinery. Under changing Project conditions the annual O&M costs would vary over time. During the first four years of Watana operation, the annual O&M costs are estimated at $8.5 million (1983 dollars). Annual O&M costs are expected to decrease to $7.3 million until Devil Canyon comes on line. During the first four years of Devil Canyon operation, the annual O&M costs for both dams would increase to a total of $9.8 million. O&M costs are then expected to decrease to approximately $7.3 million annually. Exhibit 3.1 presents the components of the first four year costs of each development and the total Project O&M costs.

3.6 RESERVOIR OPERATION STUDIES

The economic feasibility of the Project depends partially upon the amount of generating capacity and energy that will be available for sale. To evaluate this aspect of the Project, operation studies were performed to estimate the power and energy production capability of Susitna under the operating assumptions set forth in the July 1983 FERC License filing, which provides for the Watana Development to initially operate as a base load facility. Additional studies are now being conducted to determine if the economic benefits of Watana can be increased by more closely matching its operation with that of the Railbelt utilities, while still operating within environmental constraints. Regardless of the outcome of these studies, when Devil Canyon comes on line, Watana will operate to follow load while Devil Canyon will operate as a base load facility. At that time the variation in flows from Watana would be controlled by the Devil Canyon dam.

3.6.1 Simulation Model

A dual-reservoir computer simulation program was developed during the 1982 Susitna Project Feasibility Study. This program has subsequently been modified to incorporate use of a variable tailwater rating and variable turbine capacity and efficiency to study the impacts of various reservoir operation scenarios. Minor changes in data input requirements and output format were also implemented. The model is used in performing the power and energy studies presented in this Chapter.

3.6.2 Hydrology

The initial step in simulating reservoir operation is to assess the natural water flow conditions (hydrology) of the river. Thirty-three years of streamflow data from 1950 to 1982 are available and Project operation was simulated on a monthly basis for the entire historical period.

3.6.3 Reservoir Data

The relationship of area and volume of reservoirs to the elevation of the Watana and Devil Canyon dams is set forth in Exhibits 3.2 and 3.3. At the Watana Development's normal maximum pool elevation of 2185, the reservoir surface area is about 38,000 acres, and the gross storage volume is 9.6 million acre-feet. At the Devil Canyon normal maximum pool elevation of 1455, the reservoir surface area is about 7,800 acres, with a gross storage volume of 1.1 million acre-feet. The active storage volumes are 3,700,000 acre-feet for Watana, and 350,000 acre-feet for Devil Canyon.

3.6.4 Turbine and Generator Data

The installed capacity of the Watana Development is 1020 MW, provided in six units, each rated at 170 MW. The fifth and sixth units provide no additional energy production in the early years but are available for peaking use and reserve to the degree such operation would conform to stream flow requirements.

The operating characteristics for the Watana and Devil Canyon powerplants are summarized on Exhibit 3.4 based on the rated net head at each site. In all cases, generator and transformer efficiencies of 98 and 99 percent, respectively, were used to compute the overall plant efficiency. The head loss incurred in flow of water through the intake, penstocks, and discharge passages of the Watana and Devil Canyon powerplants is assumed to be 1.5 percent of the gross head.

3.6.5 Reservoir Operation Constraints

During the early years of operation, energy generation from the Susitna Project would be limited by Railbelt electrical demand. Operation simulations were made for a wide range of Railbelt system demand levels (4000-8000 GWh/year) to establish the relation of system demand to energy production from the Project.

Analysis of the Project's economics has assumed operation designed to meet certain energy requirements along with some minimum monthly instream flow requirements for the months of July, August, and September. These flows were delineated at the mouth of Gold Creek (denoted as "Case C" in the FERC License Application) are shown in Table 3.3.

A reservoir rule curve is a list of monthly target reservoir elevations which control reservoir operation to achieve a desired result with respect to use of a water resource. A preliminary Watana rule curve has been developed to maximize average energy generation, maintain a high level of dependable energy and meet environmental requirements as defined by the "Case C" minimum flows. The Devil Canyon reservoir rule curve is designed to keep the reservoir as full as possible in all cases.

Table 3.3

POTENTIAL MINIMUM FLOWS AT GOLD CREEK (cfs)*

Month	Flow	Month	Flow
October	5000	April	5000
November	5000	May	6000
December	5000	June	6000
January	5000	July	6480**
February	5000	August	12000
March	5000	September	9300**

3.6.6 Power and Energy Production

Energy production (GWh) and Project capacity (MW) have been estimated from the reservoir operation studies described above. The studies considered the energy demands for the period 1993 through 2020 for the load forecasts developed in Chapter 2. Exhibit 3.5 sets forth the annual energy production from the Watana and Devil Canyon developments, as compared with annual demand figures for the forecast demand.

Exhibit 3.6 summarizes the power and energy production for Watana and Devil Canyon under the 2020 load forecast. The power and energy esti-

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* As discussed in the FERC License Application, this flow scenario was selected as the Project operation flow regime considering both Project and in-stream flow uses.

** The flow changes by 1000 cfs per day from 6000 on July 25 to 12,000 on August 1 and from 12,000 on September 14 to 6000 on September 21.

mates are based on the modes of operation and constraints previously discussed.

3.7 ENVIRONMENTAL STATUS UPDATE

This section presents an update of the status of the principal environmental aspects of the Susitna Project, and the activities being conducted with regard thereto. As previous sections have noted, environmental restrictions (e.g., prescribed minimum downstream flows) can limit the maximum energy production which would otherwise be possible from the Susitna Project.

Environmental studies have continued since the 1982 Feasibility Report and the initial filing of the FERC License Application in February 1983. The objectives of the most recent studies have been to prepare specific information required for State, local and Federal permit applications and to assist in the licensing process by responding to FERC Staff inquiries. As of this time, responses have been prepared and provided to FERC on approximately 350 requests for clarification and supplementary information. In addition, the Power Authority has responded to over 1,000 comments on the License Application in connection with the Environmental Impact Statement process. A list of issues and questions has also been compiled from a comprehensive review of all State, local and Federal agency comments received by the Power Authority during the past four years. Most of these issues have been addressed in submissions to FERC; work on others is continuing.

In addition to answering written requests for information and responding to comments, the Power Authority has provided many recent studies to FERC, Federal and State agencies in responding to their comments on the License Application. The Power Authority also conducted a tour of the Susitna basin and related areas for FERC personnel during the week of August 21-27, 1983, so that they could better evaluate the Project using first-hand information.

Continuing environmental activities focus on the evaluation of impacts and the refinement of mitigation programs tailored to specific Project needs. These activities cover all aspects of potential Project impacts and are briefly discussed below under the major headings of aquatic, terrestrial and social sciences programs.

3.7.1 Aquatic Programs

Potential Project impacts include the possible effects of altered seasonal flow regime on the ecosystem of the Susitna River, including possibly altered water temperature regimes, turbidity and other water quality parameters (e.g., dissolved gas and suspended solids concentrations downstream from the reservoirs).

The effect of the altered flows on anadromous and resident fish habitats and their associated populations is the major focus of present studies. Five major habitats have been identified which are important to fish and will be affected by the altered flows. These are the mainstream of the Susitna River, side channels, side sloughs, upland sloughs and tributary mouths. The principal concerns of potential alterations to spawning habitats of salmon, access to the spawning habitats, and juvenile rearing habitats are addressed through a series of mathematical models relating potential changes in flow to fish habitats. Physical and biological data calibrate the predictive models and relate the physical changes in habitats to the biological impacts.

To address the potential effects of the altered temperature regime, it is necessary to estimate what changes will occur. This is accomplished through a series of mathematical models which address water temperature in the reservoirs and in the river downstream. As a part of this analysis, a mathematical model is also being used to analyze ice processes in the reservoirs and river.

Changed turbidity, sediment transport and other water quality parameters are analyzed through comparisons of predicted changes with observed changes at other comparable hydroelectric projects.

The Power Authority's environmental analysis also includes effects of changes in discharge from the Project during a single day should Watana be operated under some variation of a load-following scenario in supplying the power needs of the Railbelt system.

3.7.2 Terrestrial Programs

Project impact assessments and proposed mitigation plans regarding terrestial ecosystems continue to be evaluated as discussed in the FERC

License Application. Models have been designed to evaluate potential loss of habitat (lost moose carrying capacity and changes in moose population due to changes in carrying capacity), predator-prey ratios, hunting pressure, and other factors. Modeling components also include browse inventories, plant phenology studies, refined vegetation and wetlands mapping, moose censuses, moose movements, and predation by wolves and bears in controlling moose numbers. This information facilitates the development of mitigation programs commensurate with Project impacts.

The Power Authority continues to monitor movements and habitat use by moose in the riparian zone downstream of Devil Canyon; monitor the movements and herd size of caribou in the Project area; analyze the use of the Jay Creek mineral lick by Dall sheep; monitor bear and wolf movements and habitat use; monitor raptors, particularly golden and bald eagles; and monitor beavers in the riparian zone from Devil Canyon to Talkeetna.

3.7.3 Social Sciences Programs

Included within the social sciences programs are cultural resources, socioeconomics and recreation.

3.7.3.1 Cultural Resources

Regarding cultural resources, field work in 1983 included continued reconnaissance surveying of the proposed dam sites, impoundment areas, and borrow sites (for the purpose of identifying potential historic and archeological sites). In addition, testing of certain identified sites was conducted. A sensitivity mapping of archeological potential was completed for the proposed railroad, access road, transmission line, and Phase I Recreation Plan.

3.7.3.2 Socioeconomics

The Power Authority also continues to refine appropriate mitigation plans. Socioeconomic analyses are being refined and updated based upon survey information from adjacent communities.

3.7.3.3 Recreation

A Recreation Plan Implementation Report will outline the steps required to implement Phase I of the Recreation Plan as identified in Chapter 7, Exhibit E of the FERC License Application. This report will include a plan of action for resolving necessary policy and management issues, such as: what Project areas and facilities will be open to the public; policies regarding access and use of recreation resources; and control by landowners and landmanagers.

SUSITNA HYDROELECTRIC PROJECT
OPERATION AND MAINTENANCE COST ESTIMATES
($1000/yr)

	Watana 1/			Devil Canyon 2/			Total Project		
	Labor	Expenses	Subtotal	Labor	Expense	Subtotal	Labor	Expenses	Subtotal
Power and Transmission	3300	990	4290	625	500	1125	2740	990	3460
Contracted Services 2/		900	900		480	480		1050	1050
Townsite Operations	625	180	805	400	55	455	285	180	465
Environmental Mitigation			1000			--			1000
Contingency (15%)			1045			310			895
Total, January 1982 dollars			8040			2370			6870
Escalation to 1983 dollars (6%)			480			140			410
Total, January 1983 dollars			8520			2510			7280

1/ For first 4 years of operation of each development.

2/ Includes annual maintenance services, major maintenance overhaul, helicopter service, and road maintenance.

EXHIBIT 3.1

AREA AND VOLUME VERSUS ELEVATION
WATANA RESERVOIR

Elevation (ft, msl)	Volume (acre-feet)	Area (acres)
1460.0	0.	0.
1500.0	3000.	150.
1550.0	34000.	1100.
1600.0	127000.	2620.
1650.0	292000.	3990.
1700.0	532000.	5620.
1750.0	870000.	7860.
1800.0	1318000.	10010.
1850.0	1877000.	12270.
1900.0	2546000.	14490.
1950.0	3330000.	16880.
2000.0	4248000.	19850.
2050.0	5341000.	23870.
2100.0	6645000.	28290.
2150.0	8189000.	33940.
2200.0	10017000.	39730.
2250.0	12212000.	48030.

EXHIBIT 3.3

AREA AND VOLUME VERSUS ELEVATION
DEVIL CANYON RESERVOIR

Elevation (ft, msl)	Volume (acre-feet)	Area (acres)
900.0	0.	0.
950.0	2000.	70.
1000.0	7000.	190.
1050.0	25000.	400.
1100.0	49000.	654.
1150.0	65000.	955.
1200.0	132000.	1360.
1250.0	195000.	1860.
1300.0	292000.	2490.
1350.0	456000.	3565.
1400.0	707000.	5480.
1450.0	1048000.	7600.
1500.0	1484000.	9560.

EXHIBIT 3.4

POWERPLANT DATA

Net Head (%Rated)	Net Head (Feet)	Reservoir Elevation (Feet)	Plant Capacity (MW)	Plant Capacity (%Rated)	Efficiency Turbine	Efficiency Plant
Watana Development						
0.850	578.0	2045.1	834.4	76.9	0.894	0.867
0.900	612.0	2079.8	915.8	84.4	0.900	0.873
0.950	646.0	2114.4	999.4	92.1	0.905	0.878
1.000	680.0	2149.0	1085.1	100.0	0.910	0.883
1.030	700.4	2169.8	1131.7	104.3	0.908	0.881
1.060	720.8	2190.6	1178.4	108.6	0.906	0.879
Devil Canyon Development						
0.850	501.5	1360.5	521.1	76.9	0.894	0.867
0.900	531.0	1390.7	571.7	84.4	0.900	0.873
0.950	560.5	1420.7	623.5	92.1	0.905	0.878
1.000	590.0	1450.8	677.2	100.0	0.910	0.883
1.030	607.7	1468.8	706.3	104.3	0.908	0.881

EXHIBIT 3.5

SUSITNA ENERGY GENERATION

Year	Total Demand (GWh)	Susitna Generation Total (GWh)	Watana (GWh)	Devil Canyon (GWh)
1993	4399	2905	2905	—
1994	4492	2940	2940	—
1995	4588	2970	2970	—
1996	4670	2995	2995	—
1997	4751	3024	3024	—
1998	4833	3060	3060	—
1999	4915	3100	3100	—
2000	4996	3105	3105	—
2001	5177	3153	3153	—
2002	5238	4670	2396	2274
2003	5359	4791	2458	2333
2004	5481	4913	2520	2393
2005	5602	5034	2582	2452
2006	5771	5203	2669	2534
2007	5939	5371	2755	2616
2008	6107	5539	2842	2697
2009	6276	5708	2928	2780
2010	6444	5876	3014	2862
2011	6610	5994	3033	2961
2012	6780	6144	3109	3035
2013	6955	6285	3180	3105
2014	7135	6356	3216	3140
2015	7318	6338	3207	3131
2016	7507	6329	3202	3127
2017	7701	6496	3286	3210
2018	7899	6661	3370	3291
2019	8103	6736	3408	3328
2020	8312	6766	3423	3343

POWER AND ENERGY PRODUCTION
Year 2020 Demand Level

MONTH	WATANA ALONE			COMBINED OPERATION					
				DEVIL CANYON			WATANA AFTER DEVIL CANYON		
	Average Capacity(a) (MW)	Average Energy (GWh)	Firm Energy(b) (GWh)	Average Capacity(a) (MW)	Average Energy (GWh)	Firm Energy(b) (GWh)	Capability(c) (MW)	Average Energy (GWh)	Firm Energy(b) (GWh)
Jan	466	346	293	458	340	238	1088	369	247
Feb	426	286	226	450	302	215	999	319	219
Mar	354	263	182	368	273	213	963	281	212
Apr	338	243	153	368	264	289	928	252	106
May	307	228	139	366	272	188	922	214	94
Jun	261	188	59	366	263	200	975	188	395
Jul	292	217	81	323	240	200	1053	180	133
Aug	468	348	314	364	270	219	1114	249	199
Sep	394	283	274	366	263	263	1144	264	232
Oct	405	301	191	366	249	203	1141	350	308
Nov	554	398	290	458	329	224	1116	371	236
Dec	540	401	366	504	374	256	1080	417	269

(a) Corresponds to monthly plant capacity output that produces the total estimated monthly energy available.
(b) Based on driest historical hydrologic year.
(c) Based on monthly net head and turbine efficiency.

EXHIBIT 3.6

4.0 NON-SUSITNA GENERATION ALTERNATIVES

4.1 INTRODUCTION

Several alternative technologies exist that could be used to generate electricity for the Railbelt, either as substitutes for, or as complements to the Susitna Project. The alternatives include natural gas-fired combustion turbines, gas-fired combined cycle power plants and coal-fired steam turbines. In addition, the Chakachamna Hydroelectric Project could be a component of a Non-Susitna generating system. These alternatives are analyzed in this Update to evaluate the economic feasibility of the Susitna Project.

The ability of any alternative to meet Railbelt demand depends on electrical demand, the availability and price of fuels for thermal powerplants, and the capacity and flow regimes of hydroelectric plants. These were analyzed most recently in the July 11, 1983 FERC License Application filing. This Chapter provides a summary description of the studies contained in that document. In addition, recently completed studies by the Power Authority regarding the Chakachamna Hydroelectric Project (Bechtel 1983) and the use of North Slope gas, (Ebasco 1983) for the Railbelt are also evaluated.

The generation alternatives discussed in this Chapter are used in the formulation of system expansion plans described in Chapter 5.

4.2 NATURAL GAS-FIRED OPTIONS

Natural gas currently fuels generation which serves about 75 percent of Railbelt electric energy demand. Assessments of thermal alternatives should, therefore, logically begin with an analysis of gas-fired options.

4.2.1 Natural Gas Availability and Cost

4.2.1.1 Cook Inlet Gas Availability. The two major known gas resources in Alaska are located at Cook Inlet and the North Slope. Estimates of natural gas resources in the Cook Inlet area have been made by the Alaska Department of Natural Resources (DNR 1983), the Alaska Oil and Gas Conservation Commission (OGCC 1982) and the United States Geological Survey (USGS 1980).

Estimates of natural gas are divided into proven and undiscovered reserves. Proven gas reserves are those reserves whose location is known from wells drilled and whose quantity is estimated from flow rates and specific geologic data. Undiscovered gas reserves are reserves that are located outside of known fields, the volume of which is estimated using geological information.

OGCC estimates proven gas reserves by field on an annual basis. Gas volume is estimated using initial wellhead pressure, changes in wellhead pressure during production, analyses of drill cores, and field size obtained from seismic data. The OGCC's estimate of proven Cook Inlet gas reserves as of January 1983 is 3.5 trillion cubic feet (TCF), the figure utilized in this Update. OGCC does not estimate undiscovered reserves.

There is some uncertainty as to the amount of undiscovered gas in Cook Inlet. In 1983, DNR developed an estimate of undiscovered gas resources in the Cook Inlet area using a "Play Approach", which determines the amount of hydrocarbons in a "play", or prospect, through use of reservoir engineering equations which take probability and risk factors into account. Estimates for various reservoirs are aggregated to create an estimate of the reserves. DNR estimated undiscovered gas resources for both total gas in place and economically recoverable gas. The expected amount of total gas in place was estimated to be 3.36 TCF and the expected economically recoverable gas was estimated to be 2.04 TCF.

The USGS estimated Cook Inlet undiscovered reserves using a subjective method in which gas resources were estimated by a team of experts. Geological information and results from other methods were reviewed and weighted by the experts. The weighted average quantity of economically recoverable gas was estimated to be 5.72 TCF.

The lower DNR estimates of undiscovered reserves are used in this Update for three reasons. First, the USGS estimate was made using data available in 1980. While no exploration for non-associated gas (gas not discovered in connection with oil) occurred during the 1980-82 period, oil exploration continued and the DNR had access to additional exploration information in preparing its 1983 report that was not available to the USGS in 1980. Second, the Cook Inlet area analyzed by the USGS was larger than the Cook Inlet basin analyzed in the DNR estimate. The larger estimate consists mostly of additional on-shore areas on the Kenai Peninsula and to the west and north of Cook Inlet. Finally, the play methodology (used by DNR) is more subjective than USGS methodology. In any event, the difference between DNR and USGS estimates of undiscovered Cook Inlet gas has a relatively minor effect on the economic analysis. As shown in a sensitivity analysis presented in Chapter 6, even if the Cook Inlet reserves are unlimited, the With-Susitna expansion plan would still have a net economic benefit over the Non-Susitna plan developed with such a gas supply.

4.2.1.2 Cook Inlet Gas Consumption. Cook Inlet gas is used for household heating, commercial applications, LNG and ammonia/urea production, and electricity generation as shown in Exhibit 4.1. Of the 3.5 TCF of proven reserves, some 1.9 TCF are committed by contract to existing users, and about 1.7 TCF remain uncommitted. As previously noted, in addition to the 3.5 TCF of proven reserves, there are estimated to be 2.0 TCF of undiscovered reserves which are economically recoverable.

The pattern of future consumption of Cook Inlet gas depends on the gas needs of the major users and their ability to contract for needed supplies. Since there is a limited quantity of proven gas and the estimates of undiscovered reserves in the Cook Inlet area have yet to be proven, gas reserves may be exhausted by the late 1990's, as shown on

Exhibit 4.1. In addition, there probably is a limit to allowable gas consumption by electric utilities because other uses will be accorded higher priorities either through contract or by order of regulatory agencies. A restriction on such use of gas might be appropriate since coal could be made available for electric generation. To estimate the quantity of Cook Inlet gas available for electrical generation, therefore, it is necessary to assess the requirements of the major users. These are summarized on Exhibit 4.1 and discussed in greater detail below.

Phillips/Marathon LNG currently has 360 billion cubic feet (BCF) of gas under contract and Collier Chemical has 377 BCF. It is highly probable that both entities will obtain enough of the uncommitted gas resources to meet their needs through 2010 because both Phillips/Marathon LNG and Collier operate established facilities. They are also owned by Cook Inlet gas producers who control part of the uncommitted reserves. Phillips/Marathon LNG and Collier are therefore estimated to consume 62 BCF and 55 BCF, respectively, per year from 1983 through 2010.

At present, Enstar has enough gas under contract to serve its retail customers until after the year 2000, but since Enstar also sells gas to the military, Chugach Electric Association, and Anchorage Municipal Light and Power for electric generation, it may have to seek additional reserves to meet the needs of its larger customers. It is assumed, however, that Enstar will be able to acquire sufficient gas to meet the needs of its retail customers (including new Matanuska Valley customers). Further, it is reasonable to assume that its retail customers' needs will have priority over its wholesale sales of gas for electrical generation. Accordingly, retail use is estimated in Exhibit 4.1 to increase from about 19 BCF in 1983 to 52 BCF in 2010. Gas used in field operations and the residual, "Other Sales", vary from year to year but together are estimated, based on historical use, to average approximately 25 BCF per year over the period 1983 through 2010.

After satisfying all of the above needs, there is still a considerable amount of gas in the near term that could be used for electrical generation. Chugach Electric Association has 285 BCF committed through contract and Enstar has 759 BCF contracted, some of which will be sold to Anchorage Municipal Power and Light and Chugach Electrical Association for electrical generation. Assuming that the Anchorage-Fairbanks Intertie is completed in 1984-85, it is possible that electrical generation using Cook Inlet gas would increase to provide less costly energy to Fairbanks. This would, of course, increase the rate at which Cook Inlet reserves are depleted.

An estimate of the quantities of Cook Inlet gas required to meet all Railbelt electrical requirements was made using the estimated load and energy forecast for the Railbelt area. Forecast generation from the existing Eklutna and Cooper Lake hydroelectric units, the proposed Grant Lake and Bradley Lake projects, as well as, generation from the existing Healy coal-fired unit, was subtracted from the forecast electrical requirements. The estimated annual gas consumption for power generation under this scenario increases from 27 BCF in 1983 to 36 BCF in 2010.

The forecast annual and cumulative use of gas for each of the major users, and the total use of gas for the Railbelt, is shown in Exhibit 4.1. The remaining proven and undiscovered gas resources are also shown. As can be seen, proven reserves (3.5 TCF) will be exhausted by 1998, and proven plus economically recoverable undiscovered resources will be exhausted by about 2007. Inspection of the Total Cumulative Gas Use column in Exhibit 4.1 shows that currently committed reserves (1.9 TCF) could be exhausted in 1992 under this scenario.

The data indicates that relying on gas-fired electrical generation to provide the Railbelt's needs is problematic in that it depends on the future availability of uncommitted proven and undiscovered reserves of natural gas for electrical generation. This is especially true since uncommitted proven reserves and any undiscovered resources could also be acquired by established entities or entities not shown in Exhibit 4.1, further reducing the availability of Cook Inlet gas for electric generation. Known potential purchasers for the uncommitted recoverable and undiscovered Cook Inlet gas reserves include Pacific Alaska LNG Associates (PALNG) and the operators of the proposed Trans-Alaska Gas System (TAGS).

The proposed PALNG project could have a significant impact upon the future availability of gas. The project was initiated about ten years ago, but has been repeatedly delayed by difficulties in obtaining final regulatory approval for a terminal in California. At one time, PALNG had 980 BCF of recoverable reserves under contract. The contracts expired in 1980, but producers have not given written notice of termination, so the contracts have been held in abeyance. Recently, however, Shell Oil Company sold 220 BCF of gas formerly committed to PALNG to Enstar. This reduced reserves committed to the PALNG project to 760 BCF.

Implementation of the PALNG project would depend primarily on the availability and price of alternative sources of natural gas for the Lower 48 market, and particularly for the California market. When all factors are considered, it does not appear that the PALNG project will be implemented prior to 1995. The remaining reserves originally committed to PALNG may therefore become available to other purchasers such as Chugach Electric Association or Enstar, if the project's sponsors conclude that the potential markets for this supply are too uncertain.

The proposed TAGS project would build a natural gas transmission line from Prudhoe Bay on the North Slope to the Kenai Peninsula (near Nikishka). The gas from the North Slope would be liquefied and sold to Japan and other Asian countries. The proposed project is an alternative method of bringing North Slope gas to market.

If the project were implemented, Cook Inlet gas producers might be able to sell their gas to TAGS for liquefaction and sale to Asia, further reducing available supplies for in-State purchase and consumption. Such sale would depend on the ability of the liquefaction facilities to handle greater gas quantities and on whether the market for LNG would require such additional quantities. The price paid by TAGS to Cook Inlet producers might be high enough to outbid competing purchasers, since the Cook Inlet gas would not be burdened with the costs of the transmission line from Prudhoe Bay, although some new transmission and gathering lines would probably be required in Cook Inlet.

<u>4.2.1.3 Cook Inlet Gas Price</u>. If current and future Railbelt electrical requirements are to be met with gas generation, new purchases of uncommitted Cook Inlet gas and future purchases of undiscovered resources will be required. The price that will have to be paid for these additional gas resources is important in the evaluation of thermal alternatives to the Susitna Project.

The actual price that would be agreed upon for uncommitted gas between producers and the utilities is difficult to predict, but an indication is provided by the recent Enstar/Shell and Enstar/Marathon contracts for uncommitted gas resources. Under these agreements, the wellhead price is \$2.32/MMBtu with an additional demand charge of \$0.35/MMBtu beginning in 1986. Severance tax is estimated at \$0.15/MMBtu. An additional fixed pipeline charge of about \$0.30/MMBtu would be incurred for pipeline delivery to Anchorage.

The prices established under these contracts could be a reasonable forecast of future Cook Inlet prices if there is no additional competition for Cook Inlet gas from entities who are not current users. Although the possibility of uncommitted Cook Inlet reserves being purchased for LNG export seems to be remote at the present time, conditions may change in the future. The price that producers might be able to obtain if LNG export opportunities exist might then become important. A method that can be used to estimate wellhead prices for LNG export is to begin with the market price for delivered LNG and then subtract shipping, liquefaction, conditioning, and transmission costs to arrive at the maximum wellhead price. The wellhead price of Cook Inlet gas for LNG export calculated in this manner varies depending on the average price of oil delivered to Japan.

Based on an oil price of $29/bbl (1983 OPEC Benchmark price), the maximum price that could be paid to Cook Inlet producers for LNG is currently about $3/MCF. This price is higher than the estimated prices where no LNG export opportunities exist. Therefore, as LNG opportunities increased, the price of Cook Inlet gas for electrical generation would probably be higher than assumed above, since the utilities would have to outbid potential LNG exporters to acquire supplies.

For purposes of this Update, the Enstar contracts have been used as the basis for future Cook Inlet gas prices because they reflect recent negotiations for the purchase of that gas. It should be recognized, however, that the Enstar contracts were negotiated when oil prices were softening and there did not appear to be other markets for Cook Inlet gas. The gas price situation could change in the future for the purchase of additional gas. Uncommitted proven reserves will be exhausted by 1998 and undiscovered economically recoverable reserves will have to be brought into production through exploration and development that will involve substantially higher costs. The demand for gas could also increase, resulting in greater competition for available supplies. With time, it is possible that natural gas prices might move closer to oil prices than the approximate 40 percent relationship established under the current Enstar contracts. Therefore, the Enstar contracts are a conservative means of estimating Cook Inlet gas prices.

The method used to escalate natural gas prices over the forecast period was to correlate the increase in gas prices with the projected rate of increase in world oil prices. This method was selected in recognition of the general substitutability of the two fuels. The recent Enstar contracts are evidence of this pricing correlation, as they provide for the escalation of the gas price based upon the price of No. 2 fuel oil on the Kenai Peninsula. Projected natural gas prices were therefore based on the escalation rate for the SHCA-NSD oil price scenario shown in Exhibit 4.2.

In summary, based upon the limited remaining quantities of Cook Inlet natural gas, reliance on such electric power generation past the year 2000 would seem to entail a considerable amount of risk.

4.2.1.4 North Slope Gas. The vast reserves of natural gas on the North Slope could be moved closer to the Railbelt if either ANGTS or TAGS is built. The ANGTS project would deliver North Slope gas to the Lower 48 states by means of a large diameter pipeline traversing central Alaska and Canada. The ANGTS route is such that it would be possible to construct a lateral line to Fairbanks. The proposed TAGS project would deliver gas to the Kenai Peninsula for liquefaction and export as LNG, principally to Japan. The development of either ANGTS or TAGS depends on the future prices of world oil and natural gas prices and availability in the Lower 48 states.

Even with development of ANGTS or TAGS, it should be recognized that natural gas from the North Slope would be expensive if sold in either Fairbanks or on the Kenai Peninsula because the purchase price of such natural gas would include the costs of conditioning and transporting it to the point of end use. As estimated by Battelle, the cost of ANGTS gas in the Fairbanks area would be between \$4.03 - \$6.32/MMBtu in 1983 dollars in the first year of pipeline operation, assuming the wellhead price of gas was between \$0.00 per MMBtu and \$2.30 per MMBtu, respectively. The General Accounting Office (GAO) recently estimated the delivered price to Fairbanks to be between \$2.80 and \$5.10/MMBtu in 1983 dollars assuming wellhead prices of between \$0.00 per MMBtu and \$2.30 per MMBtu, respectively.

If the TAGS line were constructed, prices would range from \$3.03 - \$4.19/MMBtu in 1983 dollars for delivery to the Kenai Peninsula.* At \$3.03/MMBtu the TAGS net-back calculated wellhead price would be a <u>negative</u> \$1.34/MMBtu. Obviously, at a negative price, the Project would not be undertaken.

The various estimates of North Slope gas projects converge to a price of about \$4.00/MMBtu for North Slope gas delivered to the Railbelt and this value would be realistic if either TAGS or ANGTS were to be constructed.

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* <u>Use of North Slope Gas for Heat and Electricity in the Railbelt</u>, prepared by Ebasco Services, Inc. for the Power Authority, September, 1983. (Hereafter, Ebasco, 1983).

In the absence of ANGTS and TAGS, two energy development proposals utilizing North Slope gas have been analyzed in a report recently completed for the Power Authority (Ebasco, 1983). The first development involves power generation at the North Slope via simple cycle combustion turbines with attendant electrical transmission from the North Slope to Fairbanks and Anchorage. The second involves electric power generation at Fairbanks using combined cycle plants with transmission lines from Fairbanks to Anchorage. The first alternative would require the construction of two 450-mile 500-kV transmission lines from the North Slope to Fairbanks. The second alternative would require transportation of gas to Fairbanks from the North Slope by means of a 22-inch diameter, high pressure pipeline and a gas conditioning facility on the North Slope.

The North Slope power generation scenario is not economically attractive and its reliability would be questionable. The study determined that approximately $4.4 billion (1983 dollars) would be required to construct the 1400 MW of new generating capacity and transmission lines necessary to satisfy the Railbelt's electrical demand in the year 2010. Total operation and maintenance costs for the system would amount to a total of $1.1 billion for the years 1993 through 2010. In addition, the proposal is subject to some serious technical uncertainties which would require much more detailed study to determine the project's feasibility.

North Slope gas could also be made available at Fairbanks via a 22-inch diameter gas pipeline from the gas field. The pipeline design flow of 383 million cubic feet per day would transport sufficient gas to produce approximately 1400 MW of electrical power and satisfy the projected residential and commercial natural gas demand in the Fairbanks area to the year 2010.

It is estimated that the capital investment for the Fairbanks pipeline and its associated gas conditioning facilities would be about $5.8 billion, and that if capital and O&M costs increase at the rate of inflation, a levelized price for the gas would be about $9.90/MMBtu. Other assumptions in this analysis include: 1) private ownership; 2) a wellhead price of $1.00/MMBtu, subject to a 12.5 percent royalty; 3) a real discount rate of 10.0 percent and capital cost escalation rate of 3.5 percent; and 4) a pipeline and conditioning plant life of 30 years. If ownership and financing of the pipeline by the State of Alaska is assumed, the real discount rate would be 3.5 percent and the levelized delivered price of the gas would be about $7.20/MMBtu. Neither delivered price of gas would be competitive, however, making the scenario of the pipeline to Fairbanks uneconomical.

In summary, for North Slope gas to enter the marketplace by ANGTS, natural gas prices in the Lower 48 will have to rise considerably. Implementation of the TAGS project would require a demand for LNG in Asian markets at a price in excess of the current $4.80 to $5.20 per MMBtu. The alternative plans for bringing North Slope gas to the marketplace involve substantial capital investments in pipeline and gas conditioning facilities and potential technical risks which would make electricity generated under such plans substantially more expensive and uncertain than Susitna-generated power.

4.2.2 Natural Gas-Fired Powerplants

Natural gas can be used in the following types of thermal powerplants: simple cycle combustion turbines (SCCT), combined cycle combustion turbines (CCCT), and steam turbines. The SCCT and CCCT alternatives are preferred because natural gas-fired steam turbine plants are economical only at very large unit sizes (i.e., substantially larger than 200 MW). In the sizes appropriate for the Railbelt needs, SCCTs and steam turbine are more costly and less efficient than the CCCT.

4.2.2.1 Simple Cycle Combustion Turbines. The SCCT is a well proven system for electricity generation that can be used to meet both baseload and peak demand requirements. Natural gas and air under pressure are burned in the turbine, and the resulting products of combustion are expanded across the turbine. The unit is characterized by rapid start-up capability with no need for a cooling system.

The combustion turbine is factory manufactured and supplied in major components that are assembled at the site. These characteristics result in economies of mass production and quick installation. The 75 MW unit size, with a full load heat rate of 11,755 Btu/kWh, was chosen for analysis because it can be utilized effectively in the interconnected Railbelt system and is less costly on a per kilowatt basis than smaller units.

The data demonstrate that the large combustion turbine is a reasonably efficient machine when operating at or near full load. Its efficiency suffers substantially, however, when it is operated at less than 80 percent of capacity, and when load varies over a large percentage range. Capital and operation and maintenance costs of combustion turbines are summarized on Exhibit 4.3.

4.2.2.2 Combined Cycle Combustion Turbines. The CCCT makes use of the high-temperature (1000°F) combustion turbine exhaust. In the CCCT system, the exhaust is ducted to a waste heat boiler or heat recovery steam generator. The steam pressure is then raised and the steam is expanded in a conventional steam turbine to produce additional power. Because of both technical and economic gains from scale available at the 237 MW size and because of size of the Railbelt system load, this unit (with a heat rate of 8,280 BTU/kWh) was chosen for analysis.*

The CCCT has a thermal efficiency of 41 percent when operating at full load, compared to the SCCT efficiency of 29 percent (11,650 BTU/Kwh) under the same conditions. Efficiency of both types of units drops rapidly at partial loads. Capital and O&M cost estimates for a 237 MW unit are summarized on Exhibit 4.3.

4.3 COAL-FIRED OPTIONS

Coal-fired generation is another viable alternative for the Railbelt Region. Coal currently supports 8.3 percent of utility capacity, and is used to generate 13.5 of the electrical energy supplied to consumers in the Railbelt.

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* The 237 MW figure represents a 220 MW standard unit rated for Cook Inlet conditions.

4.3.1 Coal Availability and Cost in Alaska

There are three major deposits of coal in Alaska: the Nenana Field, the Beluga Field and the Kuparuk Field. There are additional smaller deposits in the vicinity of Nome, in the Matanuska Valley, and on the Kenai Peninsula. These fields contain 130 billion tons of coal resources and 6 billion tons of coal reserves. The Nenana and Beluga fields are the most important deposits, as the others have problems that preclude effective large scale exploitation in the near future.

The Nenana Field, located near Healy, has a total resource of 7 billion tons and a mineable base of 457 million tons. The Beluga Field, about 75 miles west of Anchorage across Cook Inlet, has identified resources of 1.8 to 2.4 billion tons of coal. Both fields are characterized by thick seams (i.e., thicker than 10 ft.), quantities close to the surface, and modest quality coal of 7500 - 7800 Btu/lb.

Coal production in the Nenana field is at the Usibelli Coal Company mine at Healy and current production is 830,000 tons/yr. Currently the coal produced at this mine is sold to the Fairbanks Municipal Utility System, the Golden Valley Electric Association, the University of Alaska at Fairbanks, and the U.S. Department of Defense. This production will increase to 1.7 million tons annually when the Suneel exports to Korea begin in 1984. The mine could be expanded further to about 4.0 million tons annually to support electric power generation. The current Usibelli mine uses a dragline and front-end loader-based production system. Present production capacity is about 1.7-2.0 million tons annually. The existing system would have to be duplicated to achieve doubled capacity.

The Beluga Field has not been developed. However, Beluga deposits are in reasonable proximity to tidewater and could therefore have access to Pacific Rim markets. The Beluga Field represents an export opportunity, and both Diamond Alaska Coal Company and Placer Amex are studying the potential for such development. The Diamond Alaska design would produce 10 million tons of coal annually while the Placer Amex project is sized at 5 million tons annually. These facilities are designed to serve the growing market of Japan, Korea, Taiwan, and other Asian nations. Production from the Beluga Field could begin as early as 1988, and could also serve domestic markets.

Beluga Field production costs, for 5 to 10 million tons per year export-based project, are estimated to be \$1.70/MMBtu, and the market value of the coal (FOB 1983\$ at Granite Point) is estimated to be \$1.86/MMBtu. Both costs include the cost of developing an infrastructure to serve an export market.

While the Pacific Rim market is growing, the lack of infrastructure creates major risks in predicting the development of a large Beluga mine. If export mines do not develop, a small scale coal mine could be developed for the domestic market alone. Such a development would involve altering production technologies to meet the reduced capacity requirements. If the Beluga Field were developed to serve domestic needs, the estimated initial cost of Beluga coal would be as shown in Table 4.1.

Table 4.1

ESTIMATED BELUGA FIELD COAL
COSTS WITHOUT EXPORTS

Mine Production Rate (tons/yr)	Power Plant Capacity Served (MW)	Initial Coal Cost (1983 $/MMBtu)
1,000,000	200	3.20
3,000,000	600	2.23

These costs include the expenditures required for development of infrastructure at the Beluga Field. The cost of coal is substantially higher than the $1.70 to $1.86/MMBtu cost associated with export market production of 10 million tons per year because of the smaller size mine development.

For the purposes of the planning analysis, it is assumed that up to 400 MW of coal-fired steam units would be located near the community of Nenana. The plant would not be located at the Healy coal field because of potential environmental impacts on the Denali National Park. A mine-mouth price of $1.40/MMBtu in 1983 dollars is estimated for Nenana coal based on current contracts with Golden Valley Electric Association and Fairbanks Municipal Utility System, adjusted for changes in production levels and new land reclamation regulations. Transportation costs to Nenana are estimated to be $0.32/MMBtu ($5.00 per ton) in 1983 dollars. Therefore, the total cost of the coal delivered in Nenana would be

$1.72/MMBtu. The coal has an average heat content of about 7800 Btu/lb. Other than this 400 MW unit installed at Nenana, it is assumed that all other coal-fired units would be minemouth units installed at Beluga.

Agreements between coal suppliers and electric utilities for the sale/purchase of coal are usually under long-term contracts which include a base price for the coal with an escalation clause. Several real escalation rates have been estimated for the base price of utility coal in Alaska and in the Lower 48, and they range from 2.0-2.7 percent per year. The coal escalation rates used in this Update are identical to those utilized in the July 11, 1983, FERC License Application. Those rates include a 2.3 percent real increase in the minemouth price of Nenana coal used for domestic purposes through 1993. A 1.6 percent per year real escalation rate was assumed for Beluga coal through 1993 on the assumption that coal from this field would follow the price of coal in the Pacific Rim Market.

As in the July 1983 License Application filing, both Nenana and Beluga coal prices are assumed in this Update to escalate until the date a given generating unit enters operation. At that time, the coal price for the unit is assumed to remain constant in real terms until the unit is replaced. In the expansion plan studies, Beluga and Nenana coal prices were escalated at their stated rates until 1993, the first year of coal plant operation. In 1993 the cost from either source is estimated to be $2.17/MMBtu (1983 $). For the remainder of the study horizon (1993-2050), a coal price escalation rate of one percent per year is used. This escalation rate is the result on the total coal price forecast of the assumption that coal plants "lock-up" a supply of coal at the time they enter operation. An examination of timing and size of projected coal plant additions as produced by the GOP model indicates that a straightline escalation rate of one percent from 1993 to 2020 would approximate this "lock-up" effect of the individual plants.

While these escalation rates are an adequate basis upon which to estimate future coal prices for purposes of determining the economic feasibility of the Project, for the reason noted below, the Power Authority intends to engage in further studies to refine these escalation rates before commencement of the Susitna licensing hearings. To place these further studies in perspective, it should be noted that a sensitivity analysis of coal escalation rates indicates that coal escalation is not a critical variable in the Project's economic feasibility. As addressed in greater detail in Chapter 6, the Susitna Project is economically viable even if a zero percent real coal escalation is assumed.

4.3.2 Coal-Fired Powerplants

There are several technologies potentially available for converting coal into electricity. The most favorable of these alternatives is the steam turbine system, which involves burning coal under a boiler to raise high pressure steam. This steam is expanded in a high pressure turbine and, in larger systems, exhausted from the turbine at an intermediate pressure and temperature to be reheated in the boiler to 1005°F.

Technical and capital cost studies indicate that a 200 MW coal-fired steam turbine is an appropriate size for an interconnected Railbelt system. Further, the 200 MW size is about the minimum size for using the most energy efficient technologies. The coal steam turbine system is reasonably efficient, with a fully loaded heat rate of 9,750 Btu/kWh, representing a station thermal efficiency of 35 percent. Partial load efficiencies are somewhat lower.

Capital, operational, and maintenance cost estimates for a coal plant are summarized in Exhibit 4.3. The capital costs are from the July 1983 FERC License Application filing, updated to January 1983 price levels.

4.4 CHAKACHAMNA HYDROELECTRIC PROJECT DEVELOPMENT

Chakachamna Lake is located on the west side of Cook Inlet, about 85 miles west of Anchorage. The project as currently conceived would involve diversion of water from Chakachamna Lake via a tunnel to a powerplant on the McArthur River. A Power Authority report titled, "Chakachamna Hydroelectric Project - Interim Feasibility Assessment Report" dated March 1983, assesses the merits of developing the site's power potential by diversion of water southeasterly to the McArthur River via a tunnel about 10 miles long, or easterly down the Chakachatna Valley either by a tunnel about 12 miles long or by a dam and tunnel development.

The recommended scheme, designated Alternative E, includes a dam and provisions for fish passage at the Chakachamna Lake outlet, an intake on the lake and 10 miles of power tunnel to provide water to a powerplant on the McArthur River. The project would have an installed capacity of 330 MW, average annual energy generation of 1,590 GW and is estimated to cost $1,438 billion in 1983 dollars. The project costs and power and energy capabilities are shown on Exhibit 4.4.

4.5 ENVIRONMENTAL CONSIDERATIONS OF ALTERNATIVES

The environmental and socioeconomic effects of the alternatives to Susitna are substantial and extremely varied. Exhibit 4.5 presents a summary of some of the environment-related characteristics of these alternatives, as compared with the Susitna Project. Although most of the environmental impacts associated with the alternatives can be mitigated, the cost of such mitigation could affect the economic viability of some plants at specific sites.

The purpose of this review is to ensure that the Susitna Project with its attendant environmental impacts is compared with alternative projects on equal bases, that is, that the environmental consequences of Susitna alternatives are taken into account in any comparative economic analysis.

This section reviews environmental concerns related to the following Non-Susitna alternatives:

- Natural gas-fired facilities
- Coal-fired facilities
- Chakachamna Hydroelectric Project

4.5.1 Natural Gas-Fired Facilities

Cook Inlet fields are already developed. Proven and economically recoverable reserves are expected to be depleted by the mid-1990's. North Slope gas is not yet utilized and would likely require a major pipeline to transport gas to areas of use.

In broad terms, environmental and socioeconomic concerns with gas alternatives are related to four factors:

1. Development of gas fields and required infrastructure;
2. Gas pipeline from the gas field to the power plant;
3. Construction and operation of the power plant; and
4. Transmission lines from the power plant to load centers.

If Cook Inlet gas is utilized, a power plant would be located in the Beluga Region. If North Slope gas is developed, a power plant could be located in the North Slope, Fairbanks, or the Kenai region. Environmental and socioeconomic concerns are discussed below for the four possible plant locations: Beluga, Kenai, the North Slope, and Fairbanks.

4.5.1.1 Beluga Region. Development of natural gas-fired facilities in the Beluga Region would involve two 237 MW combined cycle power plants and a 75-mile transmission line from Beluga to the Railbelt grid at Willow. Depending upon plant location, additional support facilities would include access roads, construction water supply, construction plant, airstrip, marine landing facility, and a construction camp. The natural gas would be supplied from the Beluga River, Lewis River and Ivan River fields. Potential concerns include impacts on air resources, water resources, aquatic communities, terrestrial communities, adjacent Native communities, and aesthetics.

The power plant would emit significant quantities of carbon monoxide, nitrogen oxides and water vapor and could degrade local air quality.

A supply of cooling water (200-400 gallons per minute) would be required for plant operation. The source would likely be groundwater, since surface supplies are minimal. The plant itself would likely discharge minimal wastewater to the environment, and consequently have insignificant impacts to water quality and aquatic ecology. However, if water injection were necessary to control nitrogen oxides emissions, the required supply of water would double, creating the potential for adverse impact on groundwater reserves.

Construction of the transmission line might impact water quality and aquatic communities. Clearing of the right-of-way for the transmission corridor and movement of construction equipment across watercourses could increase sediment in these streams. The additional sediment in the streams could delay hatching, reduce hatching success, preventing swim-up, and resulting in weaker fry.

The major terrestrial impact would be loss and disturbance of natural habitat in the vicinity of the power plant and along the 75-mile transmission corridor. Habitat for moose, bear, small game, and trumpeter swan would be affected.

The peak construction work force would be several hundred, while permanent operations personnel would number about 150. The largest village in the area has a population of approximately 250. Consequently, an impact on the local population and its lifestyle would be expected.

The power plant and transmission facilities would have adverse visual impacts. Moderate noise would also result from facility operations.

<u>4.5.1.2 Kenai Region</u>. Development of natural gas-fired facilities in the Kenai Region would likely include one or several combined cycle power plants, a 94-mile transmission line from Kenai to Anchorage, and associated facilities such as access roads, construction water and power supply, and a marine landing facility. The facility would use natural gas from the North Slope and would require development of the proposed TAGS pipeline.

Environmental and socioeconomic impacts would be slightly less than those discussed above for the Beluga Region. Air quality impacts would be substantially the same. Water would be derived from ample groundwater supplies. Water pollutants would not be discharged from the plant, thereby preserving water quality and the aquatic ecosystem.

Salmon are present in many streams in the area. Clearing of the transmission corridor and construction of the transmission line could increase sediment in these streams and affect fisheries.

The transmission line crossing of Turnagain Arm would be by buried submarine cables. Installation of the buried cables would temporarily disrupt the sea floor and increase local turbidity.

Impacts of the power plant on terrestrial communities would not be as significant as the Beluga location. The power plant would be located in an area already experiencing development, thus the wildlife populations are less, due to avoidance, therefore, little habitat degradation would occur.

The transmission corridor would pass through various vegetation types but mainly spruce woodlands. The corridor includes habitat for caribou and moose but clearing of the vegetative cover should not affect these animals. The power plant and transmission line would have some adverse visual impacts.

Socioeconomic impacts in the Kenai would be less severe than those at the Beluga location. There already is a relatively large population in the area, which is not likely to be adversely affected by a large construction work force. The creation of over 100 permanent jobs for operations may be considered a positive impact; however, the demand for housing in the vicinity could possibly exceed supply.

4.5.1.3 North Slope. Development of natural gas-fired facilities on the North Slope probably would include a large simple cycle plant, a 360-mile electric transmission line from the North Slope to Fairbanks, and an upgrading of the Fairbanks-Anchorage Intertie. Associated facilities would include access roads, construction water supply, construction transmission lines, and a construction camp.

The power plant would be located within the existing Prudhoe Bay industrial complex and have moderate environmental and socioeconomic impacts. The new transmission line from the North Slope to Fairbanks, on the other hand, could entail significant impacts to water quality, aquatic and terrestial communities and aesthetics.

Air quality in the vicinity of the power plant would be a concern, inasmuch as there are several gas-fired units already in operation on the North Slope to support petroleum production. The plant would emit nitrogen oxides, which are normally controlled by water injection systems. However, water injection systems cause undesirable levels of ice fog in cold climates and are very costly in the Prudhoe Bay area because fresh water is in short supply.

Water supply for other power plant uses (approximately 50 gallons per minute) would be supplied from a freshwater lake through the existing water treatment system in the Prudhoe Bay industrial complex.

Fishery resources could be affected by, construction and operation of a water supply intake, pipeline development (water or gas), access road construction, and gravel mining (for construction materials) in rivers.

Construction of the power plant, switchyard, and camp would directly disturb about 65 acres of land. Since the powerplant would be located within the Prudhoe Bay industrial complex, the impact would be less than if the area was undeveloped. Some caribou rangeland would be directly affected.

The transmission line from the North Slope to Fairbanks and an upgrade of the Intertie to Anchorage crosses hundreds of lakes and streams that are used for fish migration, rearing, spawning and wintering. Clearing of the right-of-way and movement of construction equipment could increase sediment in these streams and lakes and adversely affect fisheries.

The transmission line corridor would also pass through a wide variety of terrestrial ecosystems and would be adjacent to several major federal land areas which are protected, in part, for their wildlife values. The transmission line would have to be routed to avoid peregrine falcon nest sites. The routing would also have to avoid important Dall sheep habitat, caribou migration areas and bird migration routes.

Socioeconomic impacts of the power plant would not be significant. The additional labor requirements for construction of the power plant would not appreciably affect the existing large, transient work force.

Socioeconomic impacts related to the construction and operation of transmission facilities between Prudhoe Bay and Fairbanks would have to be strictly controlled as the peak work force would exceed 2,300. The line would be constructed within a designated utility corridor. Construction workers would be housed at pump stations or permanent camp facilities constructed for the Trans-Alaska oil pipeline. Existing facilities would be used where possible. Permanent facilities for transmission line operation and maintenance would be consolidated at several carefully selected locations.

The aesthetic impacts of the Prudhoe Bay to Fairbanks transmission line would be significant. The lines would significantly degrade the pristine nature of the wilderness landscapes.

4.5.1.4 Fairbanks. Development of natural gas fired facilities in the Fairbanks area, using natural gas from the North Slope, would probably include several combined cycle plants and an upgrading of the Anchorage-Fairbanks Intertie. Since the Fairbanks area is already developed, only minimal associated facilities such as access roads and construction facilities would be required. The 360-mile gas supply line would, however, constitute a significant impact on aquatic and terrestial communities.

A major environmental concern would be impact on air quality in the Fairbanks area. The power plant would emit nitrogen oxides. The use of a water injection system to control emission of nitrogen oxides would worsen the ice fog problem and increase carbon monoxide emissions. The area is presently subjected to extended periods of wintertime ice fogs.

The power plant would require about 200 gallons per minute for boiler makeup water, potable supplies and other uses. Ample groundwater supplies are available in the Fairbanks area.

The potential impact on aquatic ecosystems is significant. The pipeline from Prudhoe Bay to Fairbanks would cross numerous streams that are used for fish migration, rearing, spawning, and wintering. Clearing of a 50-foot wide right-of-way, burying the pipeline, and other construction activities could introduce additional sediment into the streams. The additional sediment could delay hatching, reduce hatching success, prevent upstream migration, and produce weaker fry. The construction of additional electric transmission lines may have similar impacts on watercourses along the Fairbanks to Anchorage corridor.

A power plant in the Fairbanks area would not have significant terrestrial impacts as the area is already developed. However, there are potential impacts associated with transmission and pipeline construction. Long term terrestrial impacts would result primarily from habitat elimination. Pipeline construction would require clearing of a

50-foot wide right-of-way. The pipeline compressor and metering stations would require 100 to 150 acres of land. Assuming that two additional transmission lines would be built and the Intertie extended, about 8,700 acres would be cleared, of which 80 percent is forested. Habitat for moose, caribou, grizzly and black bears, Dall sheep, and migratory waterfowl could be significantly affected.

Socioeconomic impacts in the Fairbanks area would be insignificant because of the existing large population base. There would be potential socioeconomic impacts in the area between Fairbanks and the North Slope associated with construction and operation of the gas pipeline and transmission line. Temporary camps would be required along the corridors. To minimize impacts to local villages, existing facilities would be utilized and temporary camps would be located far from the communities.

The power plant would not have significant visual impacts in the Fairbanks area, as the area is already developed. However, the transmission and pipeline corridors would have significant aesthetic impacts on the pristine wilderness landscapes.

4.5.2 Coal-Fired Facilities

As discussed earlier in this Chapter, there are two potential locations for development of a coal-fired facility, the Beluga Region or the Nenana Region. In broad terms, environmental and socioeconomic concerns would be related to five factors:

1. Development of the coal mine;
2. Transportation and storage of coal;
3. Construction and operation of the power plant;
4. Construction and operation of the transmission line from the power plant to the load center; and
5. Restoration of mined areas.

Development of coal would have significant environmental effects. For instance, an open pit mine operation would occupy about 6,000 acres and would consume habitat at a rate of 250 acres/year. Water quality could be affected by runoff from the mine, coal pile and other construction areas. Underground water supply and quality would be affected. Pit blasting and dragline operations create significant noise, dust, and aesthetic impacts.

The environmental and socioeconomic concerns of constructing and operating a coal-fired facility also depend on plant location. The two potential plant locations are near the Beluga coal field and near the Nenana coal field. The Nenana plant is assumed to be located near the town of Nenana, rather than Healy, due to Healy's proximity to Denali National Park.

4.5.2.1 Beluga. Development of a coal-fired power plant in the Beluga Region would probably involve the construction of several power plants and a 75-mile transmission line from Beluga to the Railbelt grid. Associated facilities would include access roads, construction water supply, construction transmissions lines, airstrip, marine landing facility, and construction camp. Surface coal mining would be a major activity. Potential concerns include impacts to air quality, water resources, noise, earth vibration, geologic stability, aquatic communities, terrestrial communities, socioeconomics, and aesthetics.

Coal, in contrast to natural gas, is not a high quality fuel and can generate unacceptable levels of air pollution in the absence of sophisticated control equipment. The determination of air pollution control requirements must be made on a case-by-case basis taking into account environmental, economic, and energy factors; however, it is quite certain that air pollution controls will significantly impact design, construction, operation, and maintenance costs of a coal-fired power plant. In areas of high terrain, such as found in most of Alaska, controlling sulfur dioxide to the level necessary to meet the short-term Prevention of Significant Deterioration (PDS) standards may preclude construction of economically viable facilities. Other pollutants which require analysis and control techniques include particulate matter, hydrocarbons, nitrogen oxides, and a host of pollutants defined as hazardous under the federal Clean Air Act.

The plant would require up to 4,000 gallons per minute of fresh water for cooling, boiler makeup, and other uses. Potential sources include the Beluga River or groundwater. Water withdrawals could impact local water resources.

The plant would be designed to have a zero pollutant discharge configuration and would not significantly affect water quality or aquatic ecosystems. Construction of the transmission corridor and clearing of the right-of-way could affect water quality and aquatic communities as described previously.

A major terrestrial impact would be loss and disturbance of natural habitat in the vicinity of the power plant and along the 75-mile transmission corridor. Habitat for moose, caribou, bear, small game, and trumpeter swan would be affected.

Socioeconomic impacts would be significant. The only village in the area is Tyonek, with a population of about 250. Construction activities could bring a peak work force of over 500 into the area. Operation of the mine and power plant would require 100 to 200 permanent employees, most of whom would probably live near the site in either a private housing development or permanent camp facilities. The large work force and improved access to the area would have a significant impact on the local population and its lifestyle.

The area is presently undeveloped. Development of the power plant and attendant transmission facilities would have adverse aesthetic impacts.

4.5.2.2 Nenana. Development of a coal-fired facility in the Nenana area would probably involve a 400 MW power plant and a 160-mile transmission line from the plant to Willow. Associated facilities would include access roads, construction water supply, construction transmission line, airstrip, railroad spur, and construction camp. The power plant would be located near the town of Nenana and receive coal via railroad from the existing Usibelli Coal Mine at Healy. The Usibelli Coal Mine currently produces coal from the Nenana field at a rate of 830,000 tons per year. The field furnishes coal to existing plants at Healy, Fairbanks, University of Alaska, and several military installations. The mine would have to be expanded to supply coal to a new plant at Nenana.

The concerns for the Nenana plant would be similar to those discussed previously for the Beluga area (Section 4.5.2.1). However, water withdrawal considerations are not a significant issue at Nenana, since adequate surface sources exist in the area. The air pollution concerns for this siting area are substantially the same as at Beluga with the additional concern that Denali National Park's status as a federal Class I PSD area requires that this area be protected. Such protection could involve additional control refinements for sulfur dioxide and particulate matter. Since the coal mine is already operating, impacts of Nenana mine expansion could be less than those in an undeveloped field. The Nenana site would be near Fairbanks and much of the labor force would live in Fairbanks. Therefore, the socioeconomic effects would be minimal. Aesthetic impacts would not be as severe as those in the Beluga area but have the potential to affect more people.

4.5.3 Chakachamna Hydroelectric Development

The Chakachamna Hydroelectric Development would include dam and fish passage facilities at the Chakachamna Lake outlet, a lake tap, a 10-mile long power tunnel, and a 330 MW power plant discharging to the McArthur River. Associated facilities include a 115-mile transmission line from the site to Anchorage and 40 miles of access road. Potential concerns include impacts to water resources, aquatic communities, terrestrial communities and socioeconomic impacts on the Village of Tyonek.

4.5.3.1 Water Resources. The water resources of Chakachamna Lake, Chakachatna River and McArthur River would be impacted. Construction activities, such as clearing, excavating, spoiling, stockpiling of materials, and movement of equipment, may increase erosion and sediment in the streams and lakes. Streams along the 115-mile transmission corridor could also be affected, as described previously in this Section. Water supply for construction would be pumped from the local streams.

During project operation, Chakachamna Lake would be affected by an annual 72-ft water level fluctuation. The maximum reservoir level would be at El. 1155, which is near the historical high lake level. The minimum reservoir level would be at El. 1083, about 45 feet below the historical low lake level. This drawdown would expose lake shoreline and stream deltas that are normally inundated. Additionally, at low lake levels, the tributary mouths would be altered resulting in erosion and sediment deposition in the lake.

The development would maintain some flow into the Chakachatna River. The releases, however, would be significantly less than occur under natural conditions. Under natural conditions, the mean annual flow is 3,645 cubic feet per second (cfs). With the development, the mean annual flow would be 685 cfs.

The McArthur River would receive power plant discharges ranging from a minimum of 4,600 cfs in July to a maximum of 7,500 cfs in December. Current flows in the upper reaches of the McArthur River average about 600 cfs in July and 30 cfs in December. The increased flows on the upper reaches of the McArthur River could cause significant overbank flooding. The higher flows would initially erode the stream bed and banks, and carry large quantities of sediment downstream. Release of lake water into the McArthur River would also alter the chemical composition (water quality) of the river.

The ice-formation process on McArthur River would be affected by project operations. Ice formation would be reduced or possibly eliminated by the increased quantity of flow and the higher temperature of the water originating in the lake.

4.5.3.2 Aquatic Communities. Construction and operation of the development would greatly affect the aquatic habitat and associated fishery resources in the McArthur and Chakachatna Rivers, Lake Chakachamna and lake tributaries, and the system of sloughs that connect the lower reaches of the Chakachatna River and the McArthur River. Construction activities probably would result in increased sedimentation in the lake and the streams, which could adversely affect eggs and larval fish.

The operation of the reservoir would affect the fish rearing habitat within the lake. During open water, juvenile sockeye, lake trout, round whitefish, and Dolly Varden are found throughout the lake, with many fish found offshore along steep drop-offs and just under the ice in winter.

At high reservoir levels (during October and November) lakeshore areas may be used as spawning habitat by lake trout and sockeye. After reservoir levels drop, incubating eggs and fry would be exposed to freezing or dessication. Relatively immobile invertebrates which reproduce in shoreline areas may also be affected.

The development would include a fish passage facility which is designed to permit upstream migrants to ascend from the Chakachatna River to the lake and allow downstream migrants to pass from the lake to the Chakachatna River. Sockeye salmon and Dolly Varden are expected to use this facility, as both have been observed to spawn above the lake. Based on 1982 data, it is estimated that over 41,000 sockeye would need to successfully pass through the facility to migrate upstream. Ten to more than 100 times as many sockeye smolt and a smaller number of Dolly Varden can be expected to migrate downstream.

The effectiveness of the fish passage facility, however, cannot be assured. If the facility did not successfully allow the migration of sockeye both upstream as adults and downstream as juveniles, some part of the estimated adult spawning population would be lost, as well as a portion of their contribution to the Cook Inlet fishery.

The fisheries of the McArthur and Chakachatna Rivers would also be affected, mainly from the changes in flow regimes. The water quality in the McArthur River would be changed, possibly altering fish production.

Juvenile salmon imprint on the waters of their origin. As smolt they out migrate to the ocean for the marine stage of their life cycle. Returning adults seek out their natal waters on which to spawn. The diversion of Lake Chakachamna water into the McArthur River may disrupt the homing patterns of salmon, principally sockeye, returning to tributary streams above Lake Chakachamna. If sockeye salmon were attracted by Chakachamna waters into the McArthur River they would not find adequate spawning habitat, and there would be no rearing habitat. It is necessary to maintain the 41,000 fish escapement of sockeye into Lake Chakachamna in order to assure the viability of this run.

4.5.3.3 Terrestrial Communities. Construction of the Chakachamna Project would involve removal of vegetation over a relatively small area. The fluctuation in lake levels and increased flow areas in the McArthur River would affect terrestrial habitat that is used by moose in winter and by waterfowl in spring, summer and fall. Development of disposal areas in both the McArthur and Chakachatna flood plains would result in the largest habitat loss, and greatest disturbance to birds and mammals. Moose, ptarmigan, small mammals, and passerine birds could be affected.

Clearing of the 115-mile transmission corridor and construction of a 40-mile access road would eliminate a large area of wildlife habitat. Habitat for moose, bear, and small mammals could be affected.

4.5.3.4 Socioeconomic Factors. Socioeconomic impacts would likely be significant. The development would be located in an undeveloped area, near the Village of Tyonek. A construction work force of over 250 would be required. This influx of construction personnel could impact the social and economic structure of these communities. Additionally, the improved access to the area could impact the communities. The Native community of Tyonek may seek to maintain its remote condition in order to maintain its Native cultural identity, and it may not welcome persistent high levels of construction and operation work forces.

4.5.3.5 Aesthetic Factors. The potential aesthetic impacts of the proposed Chakachamna Project are significant, particularly from a visual standpoint. Potential fluctuations in Lake Chakachamna levels would leave exposed lakeshore at certain periods. Significant reduction in outflows would result in the loss of much of the white water reach of the Chakachatna River canyon, as well as noticeable alterations to the floodplain. Disposal areas in McArthur valley would be noticeable, and together with support facilities (roads, transmission line, etc.) will result in degradation of the aesthetic character of wilderness landscapes.

ESTIMATED CUMULATIVE CONSUMPTION OF COOK INLET NATURAL GAS RESERVES (a)
(billion cubic feet)

					Electric Generation				Remaining Reserves	
Year	Phillips/ Marathon LNG/Plant	Collier Ammonia/Urea	Retail Sales	Field Operations & Other Sales	Military	Expansion Planning Studies(b)	Total Gas Use	Total Cumulative Gas Use	Proven	Proven Plus Undiscovered
1983	62	55	19.2	25	5	27.1	193.3	193.3	3157.6	5197.6
1984	62	55	19.8	25	5	28.8	195.6	388.9	2962.0	5002.0
1985	62	55	20.5	25	5	30.4	197.9	586.8	2764.1	4804.1
1986	62	55	22.8	25	5	29.1	198.9	785.7	2565.2	4605.2
1987	62	55	23.6	25	5	30.3	200.9	986.6	2364.3	4404.3
1988	62	55	24.4	25	5	27.5	198.9	1185.5	2165.4	4205.4
1989	62	55	25.3	25	5	28.7	201.0	1386.5	1964.4	4004.4
1990	62	55	26.1	25	5	29.8	202.9	1589.4	1761.5	3801.5
1991	62	55	27.1	25	5	30.4	204.5	1793.9	1557.0	3597.0
1992	62	55	28.0	25	5	31.2	206.2	2000.1	1350.8	3390.8
1993	62	55	29.0	25	5	33.0	209.0	2209.1	1141.8	3181.8
1994	62	55	30.1	25	5	33.8	210.9	2420.0	930.9	2970.9
1995	62	55	31.1	25	5	34.8	212.8	2632.9	718.0	2758.0
1996	62	55	32.2	25	5	35.5	214.7	2847.6	503.3	2543.3
1997	62	55	34.4	25	5	36.3	217.7	3065.3	285.6	2325.6
1998	62	55	34.6	25	5	37.1	218.7	3284.0	66.9	2106.9
1999	62	55	35.8	25	5	37.7	220.5	3504.5	(153.6)	1886.4
2000	62	55	37.0	25	5	38.5	222.5	3727.0		1663.9
2001	62	55	38.3	25	5	39.4	224.7	3951.7		1439.2
2002	62	55	39.7	25	5	29.5	216.2	4167.9		1223.0
2003	62	55	40.1	25	5	30.6	217.7	4385.6		1005.3
2004	62	55	42.6	25	5	31.8	221.4	4607.3		783.9
2005	62	55	44.1	25	5	32.8	223.9	4831.2		560.0
2006	62	55	45.6	25	5	24.3	226.9	5058.1		333.1
2007	62	55	47.2	25	5	25.0	219.2	5277.3		113.9
2008	62	55	48.9	25	5	26.3	222.2	5499.5		(108.3)
2009	62	55	50.6	25	5	27.7	225.3	5724.8		
2010	62	55	52.4	25	5	28.3	227.7	5952.5		

(a) Estimates of Natural gas consumption, with the exception of electric generation from expansion planning studies, proven and proven plus economically recoverable undiscovered reserves taken from FERC License Application, Table D.1.3, Appendix D-1, Exhibit D, July 1983.

(b) OGP fuel use summary for SHCA-NSD Coal/Gas expansion plan.

EXHIBIT 4.1

SHCA - NSD SCENARIO
FUEL COSTS
(January 1983 price level)

	Crude Oil		Cook Inlet Gas		North Slope Gas		Coal	
Year	Cost ($/bbl)	Average Rate of Change Per Year %	Cost ($/MMBtu)	Average Rate of Change Per Year %	Cost ($/MMBtu)	Average Rate of Change Per Year %	Cost ($/MMBtu)	Average Rate of Change Per Year %
1983	28.95		2.47		4.00		1.72/1.86	
		0.5		2.0		0.5		2.3/1.6
1993(a)	30.49		3.02		4.22		2.17	
		3.0		3.0		3.0		1.0
2000	37.50		3.71		5.19		2.33	
		3.0		3.0		3.0		1.0
2010	50.39		5.00(b)		6.97		2.57	
		2.5		2.5		2.5		1.0
2020	64.48		6.39(b)		8.92		2.84	
		1.5		1.5		1.5		1.0
2030	74.84		7.41(b)		10.35		3.13	
		1.0		1.0		1.0		1.0
2050	91.32		9.05(b)		12.63		3.82	

(a) First year of economic analysis.

(b) Economically recoverable Cook Inlet reserves assumed to be depleted in 2007. Analysis assumes further Cook Inlet gas will be priced equivalent to North Slope gas. Numbers are shown for the sensitivity analysis of unlimited Cook Inlet gas.

EXHIBIT 4.3

THERMAL PLANT OPERATING PARAMETERS AND COSTS (a)

Characteristics	Coal-fired	Combined Cycle	Combustion Turbine
Nameplate Capacity - MW	200	237	84
Heat Rate - Btu/kWh	9,750	8,280	11,650
Outage Rates, Percent of Time			
Scheduled (Immature)	12.0	8.8	3.2
Scheduled (Mature)	8.0	7.0	3.2
Forced (Immature)	8.6	10.0	8.0
Forced (Mature)	5.7	8.0	8.0
Immature Period - yrs	3	2	1
Construction Period, yrs	5	2	1
Unit Construction Costs - $/kW	2,175	604	500
Unit Investment Cost (b) - $/kW	2,370	625	510
Operation and Maintenance Costs			
Variable O&M costs - mills/kWh	0.6	1.69	4.90
Fixed O&M Costs - $/kW/yr	17.00	7.25	2.70
Economic Life - Years	30	30	20

(a) January 1983 price level

(b) Includes interest during construction at 3.5 percent interest, escalation not included.

CHAKACHAMNA HYDROELECTRIC PROJECT DATA[a]

Installed Capacity - MW	330
Total Capital Cost Including Transmission (a) - \$ million	1,307
IDC - \$ million	131
Total Capital Cost - \$ million	1,438
Total Capital Cost - \$/kW	4,358
Annual Operation and Maintenance Cost - \$ million	2.0

Monthly Power and Energy Production:

Month	Average Energy GWh	Firm Energy GWh	Minimum Plant Rating MW	Maximum Plant Rating MW
January	133	133	177	179
February	114	114	168	170
March	113	113	150	153
April	98	98	135	137
May	94	92	124	231
June	96	86	120	330
July	138	88	118	330
August	228	92	124	330
September	179	98	136	330
October	126	115	155	275
November	128	128	177	179
December	144	144	193	195
Total	1,591	1,301		

(a) Chakachamna Hydroelectric Project Interim Feasibility Assessment Report, Bechtel Civil & Minerals, Inc., Alternative E, March 1983.

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

Parameter	Susitna Hydroelectric Project, 1620 MW[a]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
Hydrology and Water Quality	Impoundment of the Susitna River would inundate approximately 86 miles of river (plus associated tributaries). The reservoirs may alter downstream temperature and flow regimes. Between Devil Canyon and Talkeetna, peak summer water temperatures are expected to be decreased and minimum winter temperatures are expected to increase. To avoid or minimize temperature changes, multi-level	Strip mining could interfere with groundwater flows and degrade water quality. Surface water could be affected by runoff from the mine, coal pile, and other constructed areas. Groundwater could be affected by acid mine drainage and ash disposal pond leachate. Long-term changes in pH, turbidity, and trace metals concentrations are expected. Discharges would be minimized by compliance with SMCRA and NPDES guidelines. The power plant would require	Because the Nenana mine is already in operation, the incremental impacts of mine expansion may be less than those for the new Beluga mine. Long-term impacts of the power plant would be similar to those caused by the Beluga option.	The gas fired power plant would require roughly 2,200 gpm of fresh water for boiler makeup and miscellaneous uses. The gas pipeline would cross 15 major streams and and numerous small streams. The buried, chilled pipe could disrupt both groundwater and surface water flows. Road cuts for pipeline access could cause disruption of groundwater flows, and also cause changes in surface runoff and soil erosion.

(a) Watana plus Devil Canyon Developments.

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

ırameter	Susitna Hydro-electric Project, 1620 MW[a]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	intakes will be provided in the dams which allow for control of downstream temperatures. A more stable flow regime is expected downstream of the Project with low winter flows increased and high summer flows (particularly flood events) decreased. Ice formation is expected to decrease, particularly between Talkeetna and Devil Canyon. Suspended sediment levels between Talkeetna and Devil Canyon will be significantly reduced. Turbidity levels will be significantly reduced in the summer and slightly increased during winter. Downstream of Talkeetna,	roughly 4,000 gpm of fresh water for boiler makeup and miscellaneous uses.		

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

Parameter	Susitna Hydroelectric Project, 1620 MW[(a)]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	project impacts are expected to be less significant due to the influence of flows from the Chulitna and Talkeenta rivers.			
Terrestrial	Construction of the Susitna Hydroelectric projects (Watana and Devil Canyon dams and reservoirs) will result in the direct removal of vegetation from an area of approximately 42,000 acres covering a range of elevations from 900 to 2400 feet. An additional 7300 acres of unvegetated areas (mostly existing river area) will be inundated or developed. 84% of the vegetated area to be cleared is forest land. This	Surface mining and power plant operation would create long-term impacts on wildlife habitats. For one mining scenario, the ultimate pit boundaries cover roughly 8 sq. miles and the support facilities would cover roughly 500 acres. Mining operations would consume roughly 250 acres/yr. of habitat. New roads into the mine area would cause substantial losses in carrying capacity and productivity in the affected areas.	The incremental impacts of the Nenana mine expansion would probably be less than operation of the new Beluga mine. Impacts of the Nenana power plant would be similar to those of the Beluga plant.	Pipeline construction would require clearing of a 50-ft. right-of-way. Construction-related impacts could intermittently disrupt wildlife habitats during the 3-year construction period. The pipeline compressor stations and metering facilities would require roughly 100-150 acres of land. The Fairbanks generating station would have a minimal impact on wildlife.

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

'arameter	Susitna Hydro-electric Project, 1620 MW[(a)]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	represents 10% of the forest land within 10 miles of the Susitna River from Gold Creek to the north of the MacLaren River. Removal of vegetation and filling of the reservoir will reduce the carrying capacity of the area for wildlife. The presence of the reservoirs and the access roads will potentially impact movements of moose, caribou and other big game in the area. New roads would add access to this presently remote area. The Project, including access and transmission routes, will disturb			

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

Parameter	Susitna Hydroelectric Project, 1620 MW[(a)]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	18 recently active raptor and raven nests and 16 or 17 inactive nests.			
Air Quality	Short-term emissions during dam construction: particles, 1,300 tons/yr.; SO_2, 300 tpy; NO_x, 2,300 tpy. Long-term emissions after dam completion should be minimal. Ambient pollutant concentrations should be well below all applicable standards.	Short-term emissions would occur during power plant construction. Long-term power plant emissions: particles, 1,800 tpy; SO_2, 1,700 tpy. These emissions would occur for the entire power plant life. Ambient SO_2 concentrations would be higher than the short-term concentrations for the Susitna project, and could violate state air quality standards.	Emissions from the Nenana power plant should be similar to those from the Beluga plant. However, the Nenana site is located in a Class I PSD area. The air quality impacts of power plant emissions on the protected area would be very significant, and siting of any major power plant to meet very stringent PSD regulations would be extremely difficult.	Short-term emissions would occur during pipeline and power plant construction. Long-term power plant emissions: negligible particulates and SO_2; approx. 5,300 tpy of NO_x. Negligible emissions from pipeline compressor stations. Ambient pollutant concentrations would exceed those for the Susitna project.
Geology and Soils	Dam construction, reservoirs, borrow sites and construction camps would affect roughly 50,000 acres. Roughly 80-90	The Beluga mine and facilities would cover roughly 9 sq. miles. Mining operations would impact roughly 250 acres/yr. Topography in the mine area would be	The Nenana coal mine is already operating, so initial expansion would probably cause less impact than would startup operations of the new Beluga	The buried pipeline would cause localized soil impacts along the entire right-of-way. Pipeline compressor stations, gas conditioning plants and

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY
ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

rameter	Susitna Hydro-electric Project, 1620 MW[a]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	miles of new access roads would be needed.	permanently affected. The power plant, coal storage, and ash disposal facilities would occupy roughly 75-150 acres.	mine. Long-term incremental mining operations would create impacts similar to those for the Beluga project. The Nenana power plant would create impacts similar to those for the Beluga plant.	the power plant would require roughly 150-200 total acres.
uatic osystem	In the reservoir area, existing Susitna River and affected tributary aquatic habitat will change from free flowing to a reservoir. Aquatic resources characteristic of a large glacially-fed lake or reservoir would develop. Small lakes within the inundation zone would be similarly changed. Between Talkeetna and Devil Canyon, flow alteration is expected to provide a more stable regime and aquatic habitat with	Some aquatic habitat would be lost due to mining operations. In addition, increased siltation, streamflow reductions, reduced stream pH and increased trace metal concentrations could result from mine drainage and power plant effluent discharges. The adverse water quality impacts could reduce fish populations in local streams and interfere with anadromous fish runs, potentially reducing marine resources in the Cook Inlet region.	Impacts of the Nenana mining activities and power plant operation could adversely affect fish populations and anadromous fish runs in local streams. These impacts would be similar to those caused by the Beluga operation.	The gas pipeline would cross numerous small streams, as well as 15 major rivers and streams. Considerable mitigative measures would be required to prevent stream blockage due to pipeline freezing, increased stream velocity due to stream diversion, changes in stream temperature caused by presence of the chilled pipeline, and prolonged stream freeze-ups that could hinder fish migrations. The Fairbanks power plant would have minimal impacts on the aquatic ecosystem.

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

Parameter	Susitna Hydroelectric Project, 1620 MW[(a)]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	increased winter flows and decreased high summer flows (particularly floods). Access for adult salmon to sloughs is expected to be hindered. However, access is to be maintained by mitigation measures. Temperature regime changes resulting from reservoir releases may alter timing of specific life stages of fish such as time of spawning, incubation time and rearing. Multilevel intakes in the dams are expected to provide control of downstream temperatures so as to avoid or minimize this effect. Decrease in			

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

rameter	Susitna Hydro-electric Project, 1620 MW[a]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	downstream sediment loads would be expected to increase benthic habitat; however, turbidity may minimize light penetration and productivity. Downstream of Talkeetna, project impacts are expected to be less significant due to the influence of flows from the Chulitna and Talkeetna Rivers.			
cioeconomic	Impacts on the Mat-Su Borough should be minor, because most construction workers will be housed at the dam site. The total expected population increase during the Watana construction is 4,700 persons, 3,600 of which will live at the full service townsites at Watana.	Construction and operation of the Beluga mine and power plant could have major socioeconomic impacts. Construction activities would create an influx of over 500 workers into an area with low population and minimal infrastructure. Even if a construction camp were established, the presence of the	The Nenana site is situated near Fairbanks. Most of the 500 person labor force would probably originate from and live in the Fairbanks region. A severe boom due to Nenana plant construction and operation would therefore be unlikely. The overall socioeconomic impacts of the facility would probably be minimal.	Generator construction should have a minimal effect on the Fairbanks region. The estimated workforce for generator construction is 200-400 persons. Most construction workers would come from the Fairbanks labor pool. Minimal additional housing and services would be needed. Facility construction would create

SUMMARY OF ENVIRONMENTAL IMPACTS CAUSED BY ALASKA RAILBELT ELECTRIC POWER ALTERNATIVES

Parameter	Susitna Hydro-electric Project, 1620 MW[a]	Beluga Coal Field and 400 MW Coal Fired Generator	Nenana Coal Field Expansion with 400 MW Coal Fired Generator	North Slope to Fairbanks Gas Line with 400 MW Combined Cycle Generator
	Virtually all social services for the 3,600 persons will be provided by the contractor. The remaining 1,100 persons are expected to inmigrate to the local towns of Cantwell, Trapper Creek and Talkeetna. This relatively low population influx would increase the utilities and services costs for those towns by only a few percent. The total traffic flow on the existing Parks and Denali Highways will increase by only 30-35 trucks per day plus commuter vehicles. Additional snow removal and maintenance will be required for the Denali Highway.	required access roads and other facilities would probably create significant impacts. Operation of the mine and power plant would require between 100-200 permanent employees, most of which would probably live near the site. Considering that the largest local town, Tyonek, has a population of less than 250, the influx of permanent workers would create major socioeconomic impacts.		slight short-term increases in Fairbanks' traffic flow. Operation of the power plant would provide additional tax revenues for the region. For pipeline construction, workers could be housed in existing campsites used for the Trans-Alaska oil pipeline.

5.0 SYSTEM EXPANSION PROGRAMS

5.1 INTRODUCTION

The objective of the system expansion studies is to develop long-term power supply plans to meet the forecast Railbelt electrical demand, using system configurations with and without the Susitna Hydroelectric Project.

The system expansion studies are performed using the OGP computer program and utilize a great deal of information relating to alternative means of electric generation, including fuel prices for thermal alternatives, developed in Chapter 4. The forecast of electrical demand is generated from the MJSENSO/MAP/RED models sequence discussed in Chapter 2, using the NSD world oil price forecast developed by SHCA.

The OGP program uses economic planning criteria that are described in detail in Chapter 6. The resultant analyses also provide annual and present worth costs of alternative expansion plans. These results are used in Chapter 6 to draw conclusions as to the economic benefit of the Project using a life cycle cost approach.

In this Chapter, the existing Railbelt system is first described. Next, system expansion from 1983 to 1992 is addressed. Since 1993 was presented in the FERC License Application as the earliest date that the Susitna Project would be available for operation, the criteria for system expansion after 1992 are discussed. The OGP computer model is described briefly, followed by a discussion of alternative expansion plans produced by the study.

5.2 THE EXISTING RAILBELT SYSTEMS

The two major load centers of the Railbelt region are the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area, which at present operate independently. These two load centers will become the interconnected Railbelt market when the Intertie, currently under construction by the Power Authority, is completed. The Glennallen-Valdez load center is not planned to be interconnected with the Railbelt nor to be served by the Susitna Project.

The existing transmission system of the Anchorage-Cook Inlet area extends north to Willow and consists of a network of 115-kV and 138-kV lines with interconnection to Palmer. The Fairbanks-Tanana Valley system extends south to Healy over a 138-kV line. The Intertie which is being built by the Power Authority to connect Willow and Healy will operate initially at 138-kV. The transmission system is illustrated in Exhibit 5.1.

5.2.1 Anchorage-Cook Inlet Area

The Anchorage-Cook Inlet area has the following major electric utilities and power producers:

- Municipal Utilities
  - Municipality of Anchorage-Municipal Light & Power Department (AMLP)
  - Seward Electric System (SES)
- Rural Electrification Cooperatives (REAs)
  - Chugach Electric Association, Inc. (CEA)
  - Homer Electric Association, Inc. (HEA)
  - Matanuska Electric Association, Inc. (MEA)
- Federal Power Marketing Agency
  - Alaska Power Administration (APAd)
- Military Installations
  - Elmendorf Air Force Base
  - Fort Richardson

AMLP and CEA are the two principal utilities serving the Anchorage-Cook Inlet area. All of these organizations, with the exception of MEA, have electrical generating facilities. MEA buys its power from CEA. HEA and SES have relatively small generating facilities that are used for standby operation. They also purchase power from CEA.

The Anchorage-Cook Inlet area is almost entirely dependent on natural gas to generate electricity. About 92 percent of the total capacity is provided by gas-fired units. The remainder is provided by hydroelectric units and oil-fired diesel units.

In 1982, the electricity generated by the Anchorage-Cook Inlet utilities was 2,446 GWh, with a peak demand of about 472 MW. Between 1976 and 1982, the demand increased at an average annual growth rate of 7.1 percent, according to figures supplied by the utilities.

5.2.2 Fairbanks-Tanana Valley Area

The Fairbanks-Tanana Valley area is currently served by the following utilities and power producers:

- Municipal Utility
  - Fairbanks Municipal Utilities System (FMUS)
- Rural Electrification Cooperatives (REAs)
  - Golden Valley Electric Association, Inc. (GVEA)
- Military Installations
  - Eielson Air Force Base
  - Fort Greeley
  - Fort Wainwright
- University of Alaska, Fairbanks

GVEA & FMUS own and operate generation, transmission, and distribution facilities. The University and military bases maintain their own generation and distribution facilities. Fort Wainwright is interconnected with GVEA and FMUS and provides both utilities with secondary energy. A large portion of the total installed capacity consists of oil-fired combustion turbines (57 percent) and coal-fired steam turbines (30 percent). The remaining capacity is provided by diesel units.

In 1982, the total energy generation, including purchases, of the Fairbanks utilities was 491 GWh, with a peak demand of 94 MW. The growth in peak demand in the past six years has averaged less than one percent.

5.2.3 Total Present System

Exhibit 5.2 summarizes the total generating capacity within the Railbelt system in 1983. The total Railbelt installed capacity amounts to 1123 MW, excluding installations not available for public service at military bases. The 1123 MW consists of 1077 MW of thermal generation fired by oil, gas, or coal, plus 46 MW from the Eklutna and Cooper Lake hydroelectric plants. Average and firm monthly energy estimates for the Eklutna and Cooper Lake hydroelectric projects are shown on Exhibit 5.3.

5.3 GENERATION EXPANSION BEFORE 1993

The Power Authority has begun the construction of an Intertie connecting the Anchorage and Fairbanks load centers with a single circuit transmission line between Willow and Healy. The line, scheduled for completion in 1984, will initially be energized at 138 kV, but can be operated at 345 kV as loads grow in Anchorage and Fairbanks. The completion of the Intertie will improve the reliability of service for both load centers and provide opportunities for economy exchanges of energy.

Because of their advanced planning status, two proposed hydroelectric plants are assumed to be added to the Railbelt system prior to 1993. These are the Bradley Lake Hydroelectric Project, with 90 MW of generating capacity and 347 GWh of average annual energy, and the Grant Lake Project, with 7 MW of generating capacity and 25 GWh of average annual energy. The average and firm monthly energy estimates for the Bradley Lake and Grant Lake projects are shown on Exhibit 5.3.

FMUS is considering the addition of a 25-30 MW cogeneration unit to replace Chena Units 1, 2 and 3, and Chugach Electric Association is studying the feasibility of a 34 MW combustion turbine at Bernice Lake and an 80 MW combustion turbine at Beluga. Although plans for these units appear to be moving forward, they have not been finalized and the units are therefore not included in the Railbelt system for purposes of the Update analysis.

5.4 FORMULATION OF EXPANSION PLANS AFTER 1993

Capacity expansion studies, such as those undertaken for the Susitna Project, serve three major functions: (1) reliability (or reserve) evaluation; (2) electricity production simulation; and, (3) capacity expansion optimization. Expansion optimization analyses provide a systematic means of evaluating the timing, type, and system costs of new power facilities, thus permitting analysis of the relative costs of different means of meeting an estimated electrical demand.

This Update uses the Optimized Generation Plan (OGP) model to develop expansion plans for the Railbelt. The OGP model was also used in the earlier feasibility studies and in the FERC License Application. Exhibit 5.4 outlines the procedure used by OGP to determine an optimum generation expansion plan. The OGP analysis conducted for this Update assumes that the Railbelt utilities are fully interconnected, share reserves, and optimize plant operation.

In developing an optimal capacity expansion plan, the program considers the existing and committed units (planned and under construction) available to the system and the operating characteristics of these units. The program then factors in given load forecast and system operation criteria in determining the need for additional future capacity to attain the specified degree of reliability. The program quantifies the amount and installation date of needed additional capacity as load increases over time.

If additional capacity is needed, the program considers additions from available alternatives and selects the available unit best fitting the system's needs. Unit selection is made by computing production costs for the system with each alternative unit included and comparing the results. The unit providing the lowest system production costs is selected and added to the system. The OGP modeling procedure contains several key elements which are discussed below.

5.4.1 Reliability Evaluation

The Loss of Load Probability (LOLP) method is used in the OGP program to determine when additional capacity is needed. The LOLP approach recognizes that forced outages of generating units would cause a deficiency in the capacity available to meet the system load unless adequate capacity had been installed. In developing an adequate reserve margin for the Railbelt three LOLPs were studied, one day in ten years, one day in five years and one day in three years. With LOLP of one day in five years, the reserve margin would normally be in the range of 30 to 50 percent, which is considered appropriate for a system such as the Railbelt, and is the reliability criteria used in the Update.

Exhibit 5.1 illustrates the reserve margin for the Non-Susitna and With-Susitna expansion plans. A spinning reserve of 150 MW is included within the reserve margin for all alternative expansion plans. Spinning reserve is available thermal capacity which can quickly be brought into full production to off-set any forced shut-down of operating units. The costs associated with this spinning reserve are included in all plans.

5.4.2 Hydro Scheduling

In the OGP simulation, the size and timing of hydroelectric units are provided as input around which thermal units are added. For purposes of the OGP runs done for this Update, the Watana Development initially operates on base load in order to maintain nearly uniform discharge from the powerplant. When Devil Canyon begins operation, Watana operates as load-following while Devil Canyon operates on base load. The operating mode of the Watana Development will be subject to more detailed analysis by the utilities, environmental agencies, and the Power Authority as planning proceeds.

5.4.3 Thermal Unit Commitment

After deducting hydroelectric plant output and thermal unit maintenance, the remaining loads are served by the thermal units available to the system. The units are added to the system to minimize operating costs, which consist of fuel costs and variable Operating and Maintenance (O&M) costs for each unit. Fixed O&M costs do not affect the order in which units are committed.

The unit operation logic determines how many units will be on-line each hour and which units are selected, with the least expensive increment being added first.

5.4.4 OGP Optimization Procedure

For each year under study, OGP evaluates system reliability to determine the need for installing additional generating capacity. If the capacity is sufficient to maintain the desired LOLP of one day in five years, the program calculates the annual production and investment costs and proceeds to the next year.

If additional capacity is needed, OGP adds units from the list of suitable additions until the given reliability level is met. Among the issues considered in determining suitability is the size of a potential unit relative to the size of system load and cost. For a combination of units the program calculates annual costs for a 10-year "look-ahead" period and selects the most economical installation.

The OGP logic utilizes an "overbuild" feature that develops annual costs over a 10-year period for combinations of units to determine if additions of new units larger than those needed to meet reliability requirements would reduce system costs. If a generating unit is found to reduce system costs, it is selected and the cost calculations for that unit become part of the present worth of the expansion plan.

5.5 1993-2020 SYSTEM EXPANSION

5.5.1 Transmission System Expansion

Transmission system expansion for the With-Susitna expansion plan has been studied in detail, and the costs have been estimated and included as part of the Project.

Transmission system expansion costs associated with Non-Susitna expansion plans are added as a separate item to those alternatives. To simplify the transmission system analysis, $220 million in transmission costs is assumed to be necessary for coal-fired and/or combined cycle plants at Beluga, while $117 million is assumed to be required for a coal-fired plant at Healy. These costs provide for new lines to the existing transmission system and for increased capacity within the present transmission system.

A preliminary review of the year-by-year transmission requirements for several specific Non-Susitna alternative expansion programs indicates that the cost estimates for the Non-Susitna transmission system are reasonably in line with, but slightly lower than, detailed year-by-year estimates.

5.5.2 Generation Expansion

Using OGP, alternative expansion programs were developed for the period from January 1993 to December 2020 to establish the least-cost system for that period with and without the Susitna Project. In the With-Susitna case, it was assumed that Watana would start operation in 1993 and Devil Canyon in 2002. This assumption was placed as input into the OGP model. All of the Susitna Project's energy would be absorbed in the system by about the year 2020.

In the Non-Susitna alternative plans, coal-fired and gas-fired thermal generation and the Chakachamna Hydroelectric Project are added to the existing units. Four basic Non-Susitna alternatives were developed to meet the forecast electrical demand. The plans are as follows:

- Plan A includes natural gas-fired combined cycle plants, coal-fired steam plants, and combustion turbines.

- Plan B includes only natural gas-fired combined cycle plants and combustion turbines.

- Plan C includes coal-fired steam plants and natural gas-fired combustion turbines.

- Plan D includes the Chakachamna Hydroelectric Project, coal-fired steam plants, natural gas-fired combined cycle and combustion turbines.

For the four plans, proven and economically-recoverable, undiscovered reserves of natural gas from Cook Inlet are assumed to be depleted by about 2007. At that time higher-priced natural gas for generation of electricity is considered to be available from undiscovered Cook Inlet reserves or from the North Slope via ANGTS or TAGS, for reasons more fully discussed in Chapter 4.

The total costs for the Non-Susitna alternatives include all costs of fuel and the O&M costs of the generating units. In addition, the production cost includes the annualized investment costs of any plants and transmission facilities added during the period. Costs common to all the alternatives, such as investment costs of facilities in service prior to 1993, and administrative and customer services costs of the utilities, are excluded.

The annual costs from 1993 through 2020 are developed by the OGP model and are converted to a 1983 present worth. The long-term system costs (2021-2050) are estimated from the 2020 annual costs, with adjustments for fuel escalation, for the 30-year period. The With-Susitna and Non-Susitna expansion plans are then compared on the basis of the sum of present worths from 1993 to 2050.

As discussed more fully in Chapter 6, present worth analysis is a means of comparing the value of benefits realized and costs incurred over different timeframes, discounted to the same base year. Such analyses recognize the fact that, at any given point in time, money that must be spent immediately has a "cost" greater than the same amount of money that must be spent later, since the funds to meet the future commitment can be invested and earn interest until the time they must be spent.

5.6 REVIEW OF EXPANSION PLANS

5.6.1 With-Susitna Expansion Plan

Exhibit 5.6 shows the yearly additions for the With-Susitna expansion plan. When Watana begins operation in 1993, it is assumed that all Railbelt utilities will be interconnected and will share reserves. It is further assumed that the Bradley Lake and Grant Lake hydroelectric projects will be in operation by 1990, and scheduled retirements of existing plants will be delayed so that sufficient reserve will be available to meet the system demand prior to 1993. After 1993, a LOLP of one day in five years is used. As shown in Exhibit 5.6, before Devil Canyon starts operation, three combustion turbines will be required to meet the reserve criteria. Ten years after Devil Canyon starts operation, additional combustion turbines and one combined cycle plant will be required to replace retired units and to meet the load demand and reserve criteria.

Based upon recent analyses, indicating that 1996 might be a more realistic date for commencement of full operation, an OGP analysis was done of the expansion plan which would be necessary under those circumstances. In that case, it is estimated that the reserve capacity prior to 1996 would become inadequate without additions of new capacity. To meet a LOLP of one day in five years, five combustion turbines would need to be added prior to 1996. The OGP program adds four combustion turbines in 1993, although in practical terms, these units would be added during the period 1984-1993. Eleven years after Devil Canyon starts operation, additional combustion turbines and one combined cycle plant would be required to replace retired units and to meet the load demand and reserve criteria.

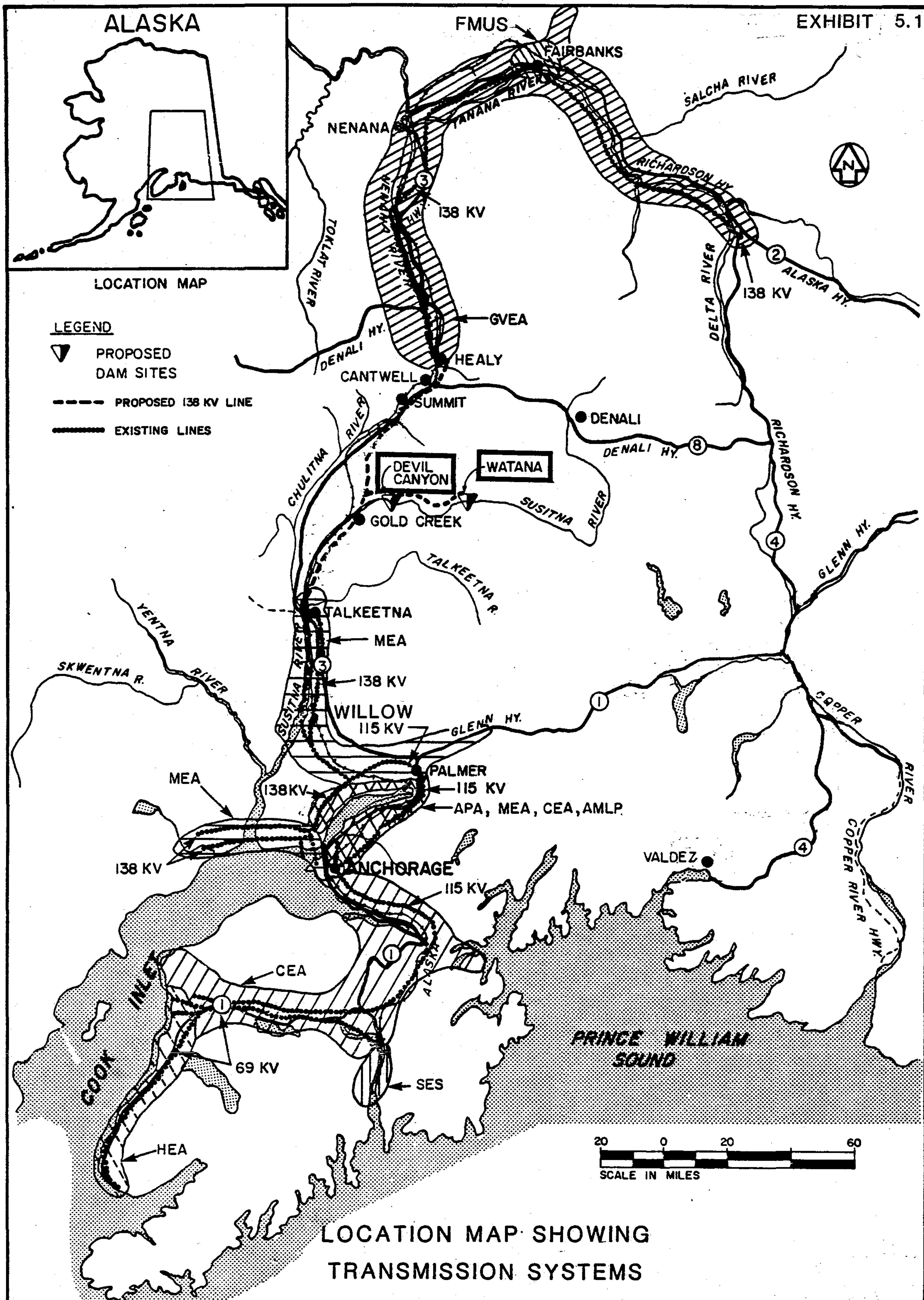
5.6.2 Non-Susitna Expansion Plans

Exhibit 5.7 shows the four Non-Susitna alternative plans. As the OGP program begins in 1993 with only the existing Railbelt capacity (plus Bradley and Grant Lakes), its first action, in order to meet the projected load growth and maintain reliability criteria, is to add a large amount of capacity in 1993. Exhibit 5.7 shows Plan A beginning with a two-unit combined cycle plant in 1993. In a "real world" situation it could be expected that these two combined cycle units or a combination of three combustion turbines and one combined cycle would be added by utilities over the 1984-1993 time period. After 2000, coal-fired plants are added and additional combustion turbines are brought on-line in Plan A to replace those added in earlier years. This Plan was developed by the OGP process of comparing the economic advantages of various mixes including combined cycle, combustion turbine and coal-fired alternatives. The OGP program was also run with the forced addition of a coal-fired plant in 1993 and no combined cycle plants (Plan C), and with the use of only gas-fired generation (Plan B). Those expansion plans were found to be less economical since they resulted in higher cumulative present worths than Plan A for the period 1993-2050.

As can be seen in Exhibit 5.8, which presents a summary of the alternative expansion plans, Plans A and D are very close in having the lowest

1983 present worth costs, with Plan D being slightly less costly than Plan A. However, the environmental impacts associated with the Chakachamna Project suggest that Plan D is less likely of being implemented as an alternative to Susitna than Plan A. The latter plan, which relies upon both gas and coal units for future Railbelt generation is, therefore, selected as the least cost, practical Non-Susitna alternative for comparison with the With-Susitna expansion plan.

Exhibits 5.9 and 5.10 compare the contribution of energy production between the With-Susitna plan and Non-Susitna plan. As shown by these two exhibits, the Railbelt system will continue to be dominated by oil and gas-fired generation over the next 10 years. By 1993 a very large share of the gas and oil-fired generation can be replaced, if Susitna is in operation. Otherwise, natural gas will continue to be the principal source of fuel for the Railbelt through the end of this century. Beyond year 2000, coal-fired generation becomes more significant in the Non-Susitna plan. The economic conclusions which can be drawn from these expansion plans are presented in the following chapter.



LOCATION MAP SHOWING TRANSMISSION SYSTEMS

EXHIBIT 5.2

TOTAL GENERATING CAPACITY WITHIN THE RAILBELT SYSTEM
in Megawatts

Abbreviations	Railbelt Utility	Installed Capacity (a)
AMLP	Anchorage Municipal Light & Power Department	311.6
CEA	Chugach Electric Association	463.5
GVEA	Golden Valley Electric Association	221.6
FMUS	Fairbanks Municipal Utility System	68.5
MEA	Matanuska Electric Association	0.9
SES	Seward Electric System	5.5
APA	Alaska Power Administration	30.0
U of A	University of Alaska	18.6
TOTAL		1122.8 (b)

(a) Installed capacity as of 1982 at 0°F
(b) Excludes National Defense installed capacity of 101.3 MW

EXISTING AND PLANNED RAILBELT HYDROELECTRIC GENERATION

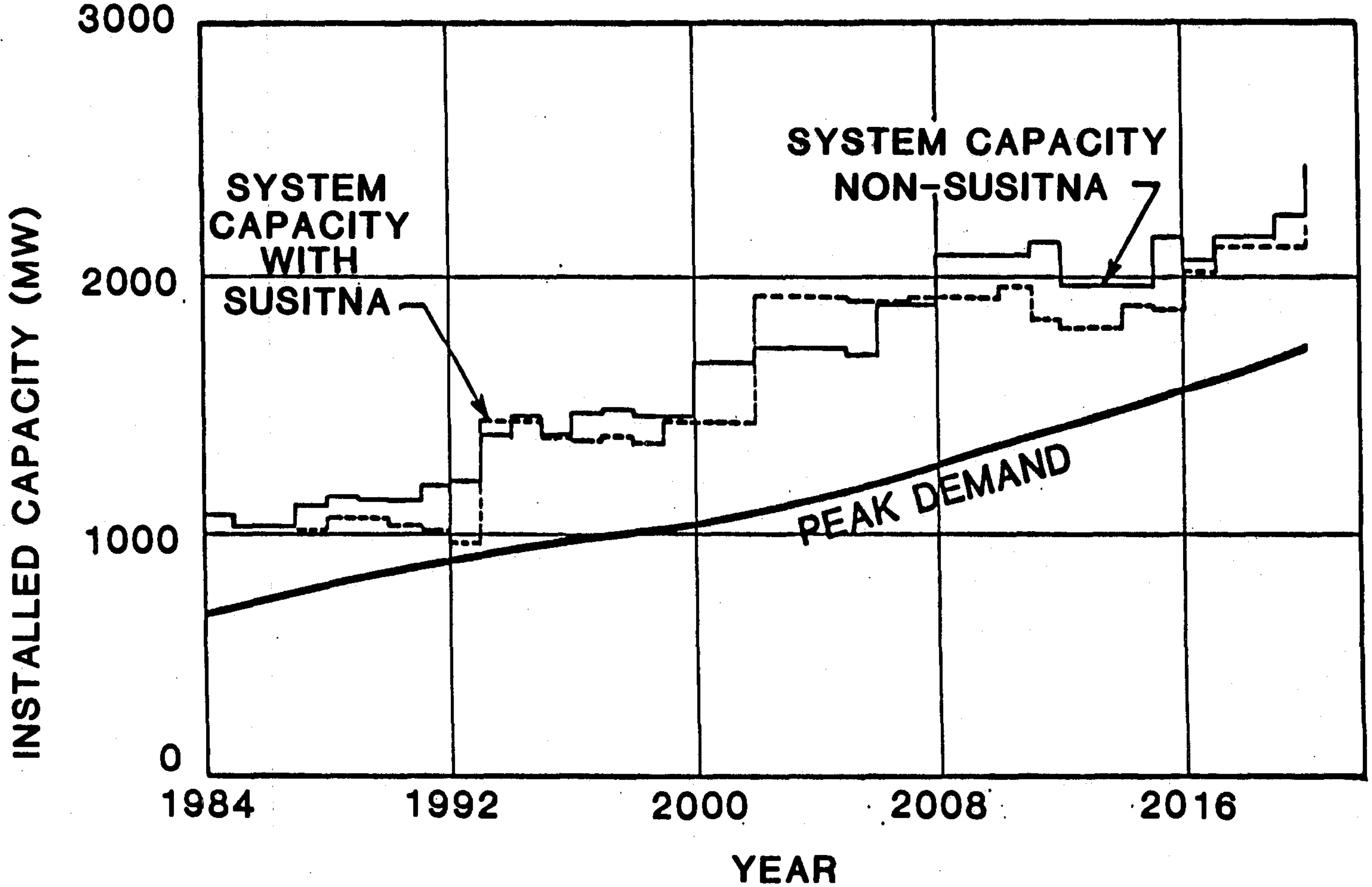
	Average Energy-GWh					Firm Energy-GWh				
	Existing Plants		Proposed Plants			Existing Plants		Proposed Plants		
Month	Eklutna (a)	Cooper Lake (a)	Bradley Lake (a)(b)	Grant Lake (b)	Total	Eklutna (a)	Cooper Lake (a)	Bradley Lake (a)(b)	Grant Lake (b)	Total
	(30 MW)	(16MW)	(90 MW)	(7 MW)	(143 MW)					
Jan	14	4	31	2	51	13	4	35	2	54
Feb	12	3	28	2	45	12	3	32	2	49
Mar	12	3	28	1	44	9	3	24	1	37
Apr	10	3	23	2	38	10	3	26	1	40
May	12	3	26	2	43	11	3	31	1	46
June	12	3	27	2	44	8	2	21	2	33
July	13	4	30	2	49	9	3	22	2	36
Aug	14	4	32	3	53	8	2	23	1	34
Sept	13	3	28	3	47	9	3	23	2	37
Oct	14	4	31	2	51	9	3	25	1	38
Nov	14	4	31	2	51	8	2	22	2	34
Dec	14	4	32	2	52	12	3	31	2	48
Total	154	42	347	25	568	118	34	315	19	486

(a) Source: 1982 Feasibility Study.

(b) Assumed to be scheduled on line in 1988.

EXHIBIT 5.3

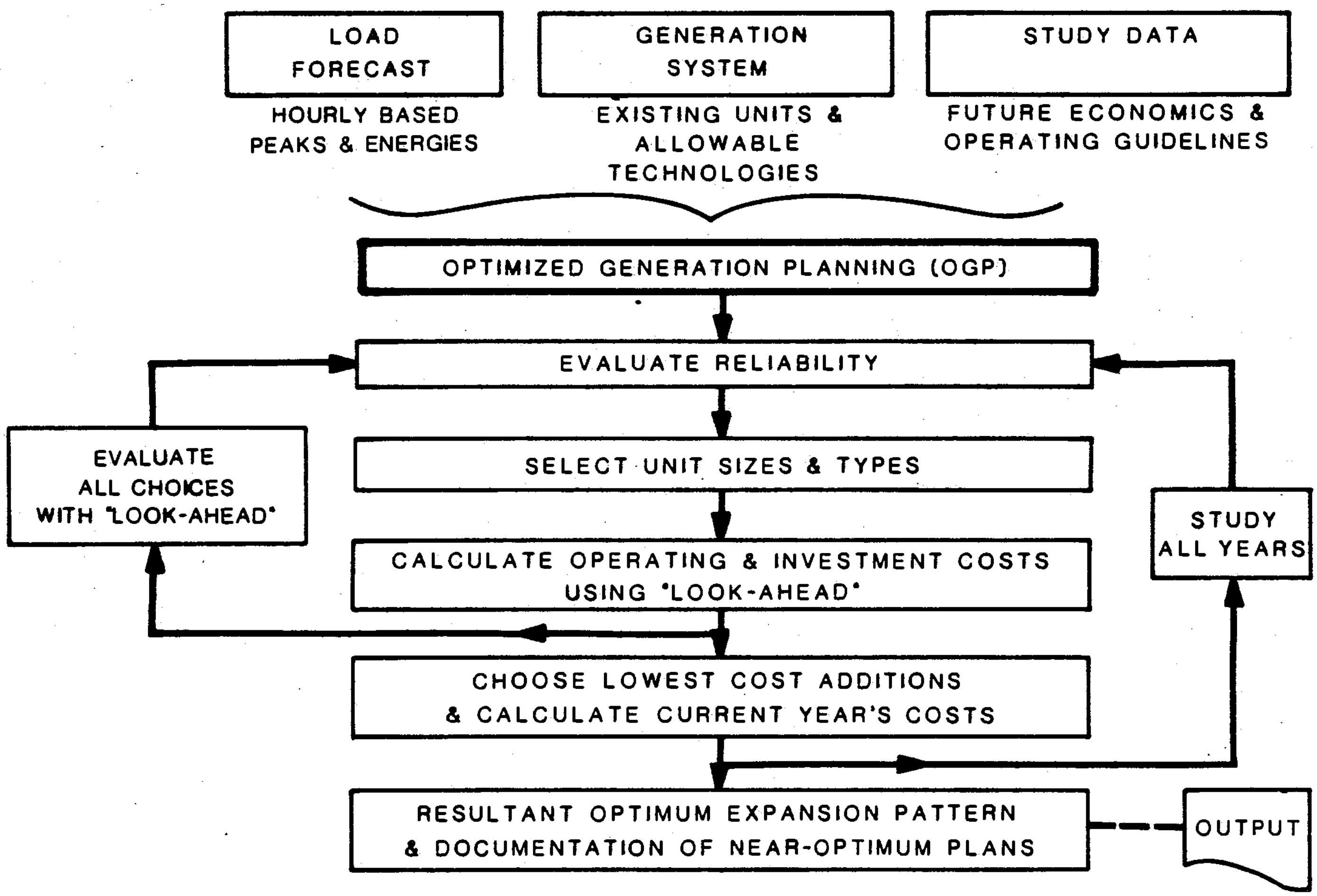
EXHIBIT 5.4



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

RAILBELT INSTALLED CAPACITY

FEBRUARY 1984



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

OPTIMIZED GENERATION PLANNING (OGP) PROGRAM INFORMATION FLOWS

FEBRUARY 1984

EXPANSION PLAN YEARLY MW ADDITIONS
WITH-SUSITNA ALTERNATIVES

Year	Pool Peak (MW)	Total Energy (GWh)	Watana (1993) + Devil Canyon (2002) Combustion Turbine (MW)	Combined Cycle (MW)	Susitna (MW)	Total(a) Capability (MW)	Watana (1996) + Devil Canyon (2002) Combustion Turbine (MW)	Combined Cycle (MW)	Susitna (MW)	Total (a) Capability (MW)
1993	915	4399			539	1433	336			1230
1994	935	4492				1432				1230
1995	955	4588				1362	84			1243
1996	972	4670	84			1358			539	1694
1997	989	4751	84			1376				1628
1998	1005	4833				1350				1602
1999	1023	4915	84			1434				1602
2000	1040	4996				1433				1601
2001	1065	5117				1433				1601
2002	1090	5238			635	1926			635	2094
2003	1114	5359				1926				2094
2004	1140	5481				1926				2094
2005	1165	5602				1905				2073
2006	1200	5771				1905				2073
2007	1234	5939				1905				2073
2008	1269	6107				1905				2073
2009	1305	6276				1905				2073
2010	1339	6444			49	1954			49	2122
2011	1373	6610				1809				1977
2012	1408	6780	168			1799				1799
2013	1444	6955				1799	420			1883
2014	1481	7135	84			1883	84			1967
2015	1519	7318				1870		237		2107
2016	1558	7507		237		2023				2107
2017	1598	7701	168			2107				2107
2018	1639	7899				2107	84			2191
2019	1681	8103	84			2107				2191
2020	1724	8312	84			2191	84			2275

(a) Includes existing generation plants less retirements.

EXHIBIT 5.6

EXHIBIT 5.7

EXPANSION PLAN YEARLY MW ADDITIONS

NON-SUSITNA ALTERNATIVES

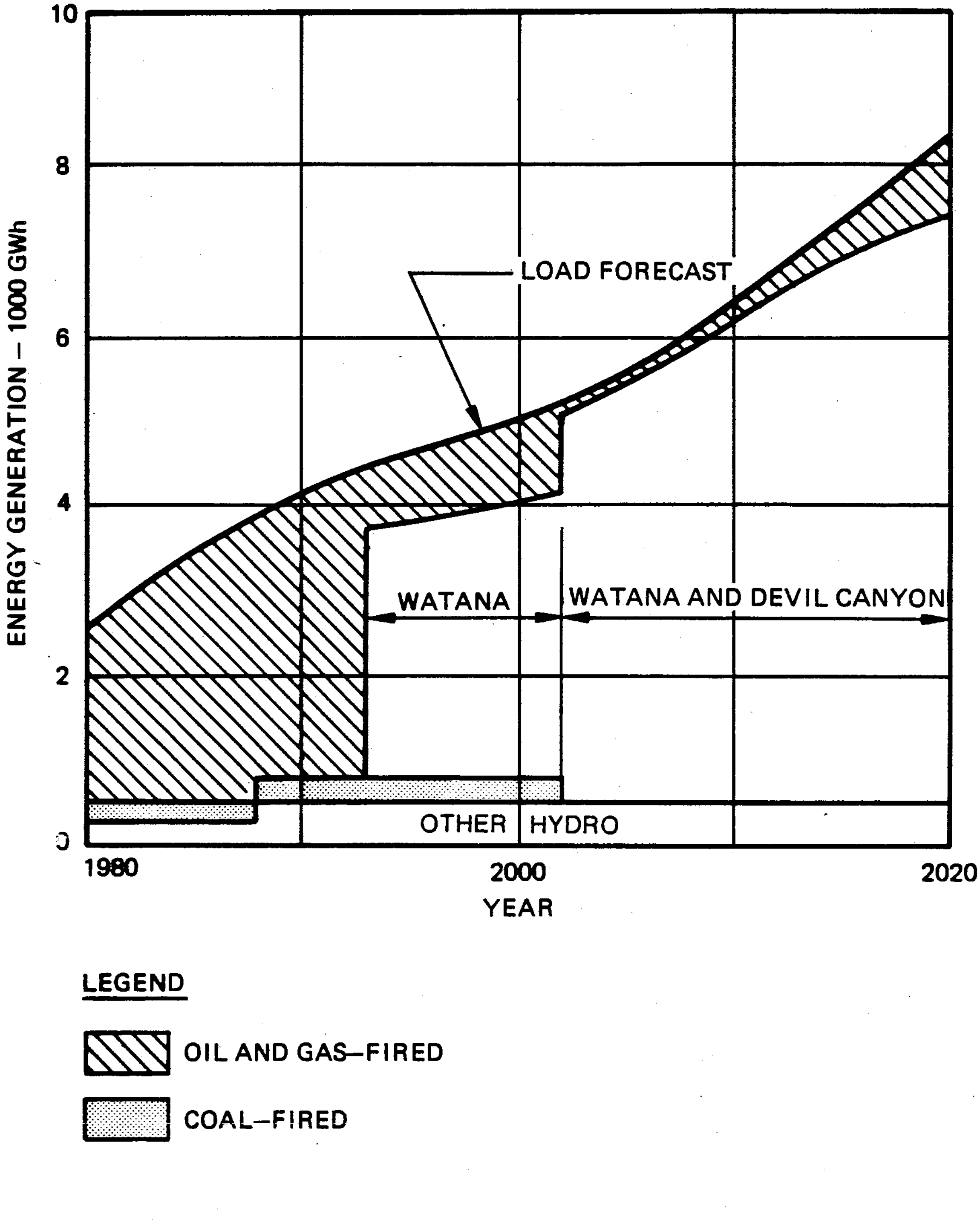
			Plan A				Plan B			Plan C			Plan D				
Year	Pool Peak (MW)	Total Energy (GWh)	Coal (MW)	Combustible Turbine (MW)	Combined Cycle (MW)	Total (a) Capability (MW)	Combustion Turbine (MW)	Combined Cycle (MW)	Total (a) Capability (MW)	Coal (MW)	Combustion Turbine (MW)	Total (a) Capability (MW)	Coal (MW)	Combustion Turbine (MW)	Combined Cycle (MW)	Hydro (MW)	Total (a) Capability (MW)
1993	915	4399			474	1369		474	1369	200	168	1263			237	195	1327
1994	935	4492		84		1453	84		1453		84	1347		84			1327
1995	955	4588				1382			1382		84	1360		84			1340
1996	972	4670		168		1462	168		1462		84	1356		84			1336
1997	989	4751		84		1480	84		1480	200		1490		84			1354
1998	1005	4833				1454			1454			1454					1412
1999	1023	4915				1454			1454			1464					1412
2000	1040	4996	200			1653	84		1537			1463					1411
2001	1065	5117				1653			1537			1463	200				1611
2002	1090	5238	200			1711		237	1632	200		1522		84			1553
2003	1114	5359				1711			1632			1522					1553
2004	1140	5481				1711			1632		84	1606	200				1753
2005	1165	5602				1691	84		1696			1585					1732
2006	1200	5771	200			1891			1696			1585					1732
2007	1234	5939				1891	84		1780	200		1785	200				1932
2008	1269	6107	200			2091			1780			1785					1932
2009	1305	6276				2091			1780			1785					1932
2010	1339	6444				2091		237	2017			1785					1932
2011	1373	6610	200			2146	84		1956	200		1840					1788
2012	1408	6780				1958		237	2015		168	1830			474		2084
2013	1444	6955				1968			2015	400		2062	200				2284
2014	1481	7135		84		1968	84		2015			1978					2284
2015	1519	7318	200			2155		237	2239		84	1965					2187
2016	1558	7507		84		2071	84		2155		168	2049					2103
2017	1598	7701		168		2155	168		2239			2049	200				2219
2018	1639	7899				2155			2239			2049	200				2335
2019	1681	8103		84		2239			2239		84	2133					2335
2020	1724	8312	200			2439	168		2323		84	2217					2335

(a) Includes existing generation plant less retirement.

SUMMARY OF RAILBELT SYSTEM GENERATION MIX IN YEAR 2020, ECONOMIC COST OF ENERGY, AND CUMULATIVE PRESENT WORTH

	NON-SUSITNA ALTERNATIVES				WITH-SUSITNA ALTERNATIVES	
	PLAN A	PLAN B	PLAN C	PLAN D	Watana (1993) Devil Canyon (2002)	Watana (1996) Devil Canyon (2002)
OPG ID	LXE1	LRA9	LTK1	LOG9	LCM3	LMG5
2020 Capacity - MW						
Coal	1400	0	1400	1200	0	0
CT	420	756	672	84	588	672
CCCT	474	1422	0	711	237	237
Hydro	143	143	143	143	143	143
Susitna	0	0	0	0	1223	1223
Chakachamna	0	0	0	195	0	0
Total	2437	2321	2215	2333	2191	2275
2020 Reliability						
Peak Demand	1724	1724	1724	1724	1724	1724
% Reserve	41.5	34.7	28.6	35.4	27.1	32.0
LOLP - D/Y	0.025	0.124	0.077	0.082	0.085	0.085
Economic Cost of Energy (mills (kWh)						
1993	35.48	35.48	40.20	38.64	53.10	39.87
2010	60.12	72.90	58.02	53.13	44.32	45.45
2020	63.65	91.01	62.37	59.05	46.64	47.12
Annual Cost ($ x 10^6)						
2020	529.2	756.5	518.4	516.6	387.7	391.7
Cumulative Present Worth ($ x 10^6)						
2020	3873	4448	3962	3854	3658	3633
2050	6791	8945	6823	6676	5730	5725

EXHIBIT 5.8

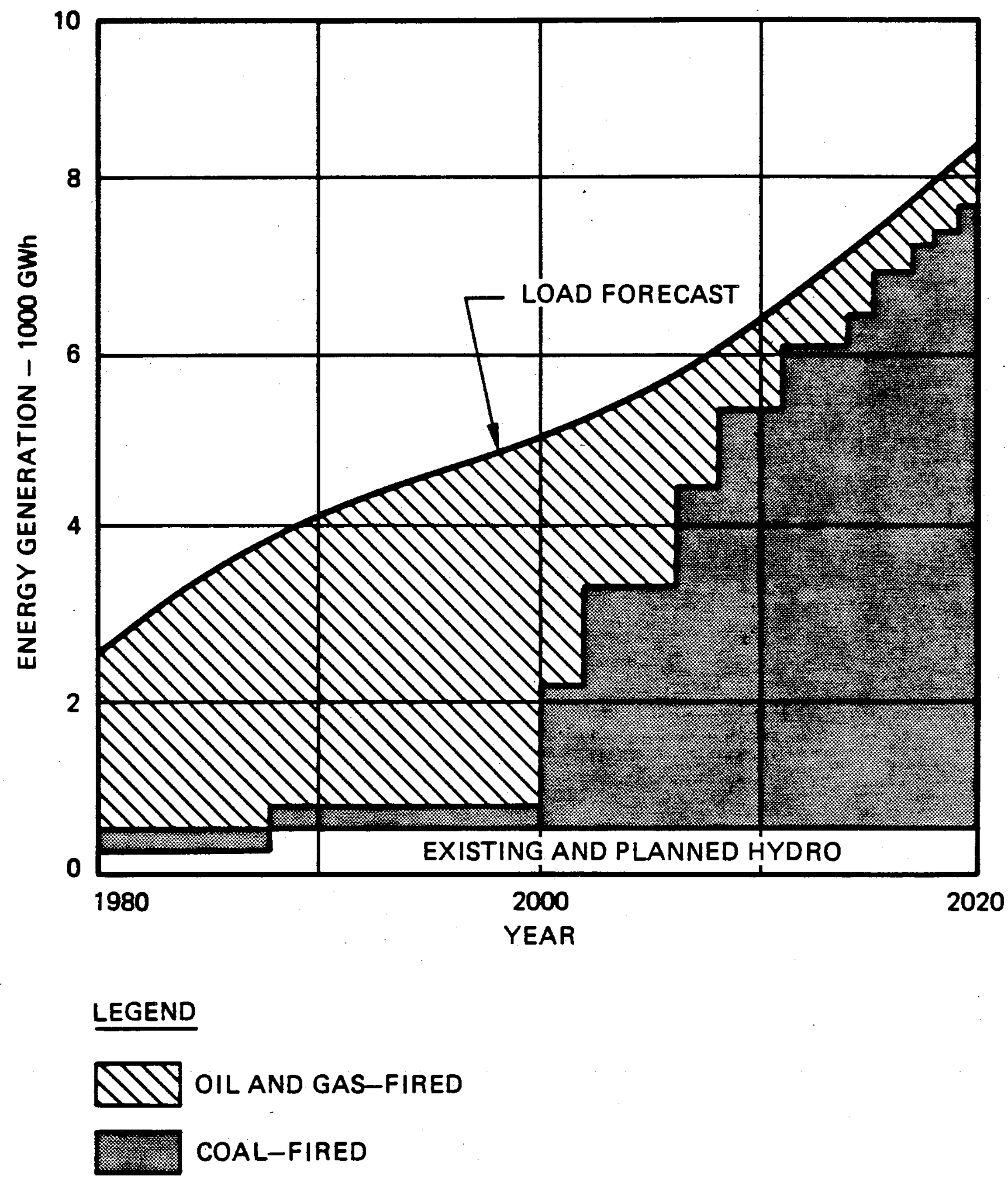


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

WITH - SUSITNA ALTERNATIVE - ENERGY DEMAND & DELIVERIES

FEBRUARY 1984

EXHIBIT 5.10



ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

NON - SUSITNA ALTERNATIVE - ENERGY DEMAND & DELIVERIES

FEBRUARY 1984

6.0 ECONOMIC FEASIBILITY

6.1 INTRODUCTION

Based upon the preceding five chapters, this Chapter summarizes the methodology and key variables used to analyze the economic feasibility of the Susitna Project. The conclusions as to the economic feasibility of the Project are then presented. Specifically, Section 6.2 contains a discussion of the methodology used in the economic analysis. Section 6.3 contains the results of the economic analysis expressed in terms of benefit-cost ratios and net benefits. The remaining two sections contain information on the threshold and sensitivity analyses performed to measure the impact on economic feasibility of changing key variables.

6.2 METHODOLOGY

The economic analysis compares the costs of alternatives during the planning period 1993-2050. The year 1993 was presented in the FERC License Application as the earliest date of Watana operation. Recent analyses of the licensing and construction schedule, however indicate that a 1996 date for Watana might be more appropriate for planning purposes. The results of the analyses indicate that the difference in the cumulative present cost worth of the Project between a 1993 and 1996 Watana on-line date is approximately $5 million. This difference is within the range of error of the modeling process and, therefore, no distinction is drawn in the economic section of this Update between a Watana on-line date of 1993 and 1996. As noted in Chapter 7, a 1996 date has been assumed for purposes of developing finance plans.

Exhibit 6.1 summarizes the principal economic parameters that were used in the economic analysis. The economic life of each generating plant type used in the economic analysis is based on 20 years for combustion turbines, 30 years for combined cycle and steam turbines, and 50 years for hydroelectric plants. Transmission lines have an economic life of 40 years.

The With-Susitna and Non-Susitna alternative expansion plans discussed in detail in Chapter 5 are utilized here to assess the economic benefits of the Susitna Project. Benefits are based on the difference between the costs of the least-cost Non-Susitna alternative and the With-Susitna alternative ("net benefits"). For the Susitna Project to be considered economically feasible, the benefit/cost ratio of the With-Susitna alternative over the Non-Susitna alternative must be greater than one. The Benefit/Cost (B/C) ratio is determined using the following formula:

$$B / C = \frac{\text{Total Present Worth of System Expansion Plan Without Susitna (benefits)}}{\text{Total Present Worth of System Expansion Plan With Susitna (costs)}}$$

Costs for each expansion alternative include three main items: investment, fuel, and O&M costs. Investment costs include construction costs (described in Chapter 3), and interest on funds used during construction. A real interest rate (adjusted for inflation) of 3.5 percent was used in estimating interest during construction. Fuel costs are for the coal or gas used yearly in the thermal plants (as described in Chapter 4). O&M costs also are expended each year.

To determine the benefit/cost ratio and net benefits, all costs (or benefits) must be adjusted to a comparable present worth. Costs are adjusted to their present worth by discounting, which gives costs in earlier years more weight than costs in later years. This concept is based on the theory that money, until it is needed to pay costs, can be invested profitably.

The 3.5 percent discount rate used in this economic analysis was provided by a survey of financial experts and economists. The total present worth of each expansion plan was obtained by calculating the present worths of each future annual cost. It is important to note that <u>costs</u> are being evaluated; hence, the alternative having the lowest present worth is the most economically attractive.

6.3 RESULTS OF THE ECONOMIC ANALYSIS

The results of the economic analysis of alternate system expansions are presented in Exhibit 6.1 and summarized in Table 6.1. As reflected in Table 6.1, the total present worth of the With-Susitna expansion plan is \$5.73 billion for the period 1993 to 2050. The total present worth of the Non-Susitna system expansion plan is \$6.79 billion for the same period. Thus, the With-Susitna expansion plan has a net benefit of \$1.06 billion and a benefit/cost ratio of 1.19.

Table 6.1

RESULTS OF ECONOMIC ANALYSIS
(1983 $ billion)

	With-Susitna Expansion Plan	Non-Susitna Expansion Plan
Total Present Worth	5.73	6.79
Net Benefits	1.06	N/A
Benefit/Cost Ratio	1.19	N/A

(N/A indicates not applicable)

As shown on Exhibit 6.2, the annual costs of the With-Susitna plan are less than the annual costs of the Non-Susitna plan after year 2003. That year represents the "cross-over" point from which time the With-Susitna plan's annual costs drop below those of the Non-Susitna plan. Thus, in year 2020, the With-Susitna annual costs are about \$162 million (1983 \$) less than the Non-Susitna costs. The total cumulative present worth of the With-Susitna plan is less than the Non-Susitna plan after year 2010.

With the potential design refinements described in Chapter 3, the construction costs of the Susitna Project could be reduced by about 8 percent. These construction cost savings would reduce the total present worth costs of the With-Susitna alternative by about six percent, and the net benefits would increase from $1.06 billion to about $1.36 billion if such design refinements are ultimately implemented.

6.4 THRESHOLD VALUES OF SUSITNA JUSTIFICATION

A threshold value is that value of a parameter at which the total present worth of the With-Susitna expansion plan is equal to that of a Non-Susitna plan. That is, the benefit/cost ratio is equal to one and there are zero net benefits. Under such circumstances the Susitna Project could not be deemed to be more economically feasible than a Non-Susitna alternative, although there might be other reasons justifying its construction. A threshold value was computed for the following four key parameters:

- Oil Price Forecasts
- Discount Rate
- Construction Cost Estimate for Watana Development
- Real Interest During Construction

6.4.1 World Oil Price Forecast

World oil price forecasts greatly influence the economics of the With-Susitna alternative; therefore it is necessary to identify the threshold value of forecast oil prices. The threshold forecast oil price is very near the mean oil price forecast by DOR in June, 1983. As noted previously, DOR has substantially raised its oil price forecasts since that time and use of this approximation of a threshold case is not intended to tie DOR to outdated forecasts; it is used because it approximates a threshold oil price only.

It is important to recognize that the threshold oil price forecast is a price line rather than a single value, and the line does not have a constant rate of change. The critical oil price is, however, $27.45 per barrel (in 1983 $) in 1999. This price was assumed to escalate at 1.5 percent for the years beyond 1999. Should all reliable oil price forecasts drop to this level, serious questions might be raised as to the economic viability of the Project.

6.4.2 Discount Rate

The discount rate at which the present worth of the With-Susitna expansion plan becomes equal to that of the least-cost Non-Susitna expansion plan is 5.3 percent. That is, should the non-inflationary value of money be greater than 5.3 percent, there might be no economic advantage to the With-Susitna expansion plan.

6.4.3 Construction Cost Estimate for Watana Development

The estimated construction cost of the Watana Development is $3.75 billion (January 1983 prices). The threshold value for Watana construction cost, using a 3.5 percent discount rate, is $5.0 billion. Hence, if the construction cost of the Watana Development were to increase by 33 percent, the cumulative present worths of the With-Susitna and Non-Susitna expansion plans would be equal.

6.4.4 Real Interest During Construction

A real (adjusted for inflation) interest rate of 3.5 percent was used to calculate interest during construction in the economic analysis. The threshold value for real interest was estimated to be 7.4 percent. That is, the real interest rate for Watana construction funds would have to increase to 7.4 percent in order for the With-Susitna present worth to be equal to the Non-Susitna alternative's present worth costs.

6.5 SENSITIVITY ANALYSIS

Economic analyses require numerous assumptions. Typically, a single value (i.e., a best estimate) for a key parameter is used in the computations, yet that single value lies within a range of possibilities. To evaluate the effects on Project economics of such a selection, economic analyses are often performed using a range of possible values for each of several key parameters. This analysis is termed "sensitivity analysis," as its objective is to determine the sensitivity of the results of economic analyses to assumed changes in one or more key variables. Sensitivity analyses were performed in preparing this Update for Cook

Inlet gas supplies, real escalation rates of fuel costs and utilities' demand forecasts.

6.5.1 Cook Inlet Gas Supply

As explained in Chapter 4, the DNR forecast of Cook Inlet gas supply was used in the economic analysis, However, if an unlimited supply of Cook Inlet gas is assumed and it is further assumed that its price will follow world oil prices, the cumulative present worth of Non-Susitna Plan A would decrease from $6791 to $6510 million. The resulting benefit/cost ratio of the With-Susitna plan would decrease from 1.19 to 1.14. Hence, the exact estimate of undiscovered Cook Inlet reserves does not materially effect the economic analysis.

6.5.2 Real Escalation of Fuel Costs

The sensitivity of the Non-Susitna expansion plan to coal price escalation was analyzed using the January 1983 coal prices of $1.86 per MMBtu for Beluga and $1.72 per MMBtu for Nenana. A scenario of zero escalation on the price of coal for the entire planning period of 1983 through 2050 was analyzed, and the results are presented in Table 6.2. As indicated there, the With-Susitna plan still has a positive benefit/cost ratio.

Table 6.2

SENSITIVITY ANALYSIS USING
ZERO PERCENT COAL ESCALATION
(1983 $ x billion)

	With-Susitna Expansion Plan	Non-Susitna Expansion Plan
Total Present Worth	5.73	5.84
Net Benefits	0.11	--
Benefit-Cost Ratio	1.02	--

The Susitna Project would supply about 80 percent of the Railbelt areas electricity requirements by the year 2020. Therefore, long-term forecasts of fuel prices and escalation rates critically influence Project economics. A special analysis of long-term oil prices was prepared by SHCA during the preparation of the License Application to support the estimation of long-term system costs (2021 - 2050). A real annual escalation rate of 1.5 percent was estimated for the period 2021 through 2030 and 1.0 percent for the period 2030 - 2050. Escalation of the natural gas price was assumed to follow that of oil.

A sensitivity analysis was conducted to compare the net benefits of the With-Susitna expansion plan against the least-cost Non-Susitna expansion plan with no allowance for real escalation of fuel costs after 2020. The results of that analysis are summarized in Table 6.3.

Table 6.3

SENSITIVITY ANALYSIS OF
REAL ESCALATION OF FUEL COSTS BEYOND 2020

System Expansion	1993-2020	With Fuel Escalation 2021-2050	With Fuel Escalation 1993-2050	With Fuel Escalation Net Benefit	Without Fuel Escalation 2021-2050	Without Fuel Escalation 1993-2050	Without Fuel Escalation Net Benefit
	Present Worth of System Costs (1983 - $ billion)						
Non-Susitna	3.87	2.91	6.79	-	2.72	6.59	-
With-Susitna	3.65	2.07	5.73	1.06	1.99	5.65	.94

As indicated, without fuel escalation, the net benefits of the With-Susitna plan would decrease from $1.06 billion to $940 million.

6.5.3 Utilities' Forecast

The Railbelt utilities annually produce 20 year forecasts for their respective markets. As shown on Exhibit 2.22, the forecasts indicate that energy generation is expected to increase from 3105 GWh in 1983 to 7662 GWh in 2001. For purposes of a sensitivity analysis, the utilities' forecasts were extended to 2020 using the same annual rate of electrical demand increase after 2001 as obtained from the Power Authority forecast. All other parameters were kept constant to those used in the Power Authority analysis. Table 6.4 presents the results of the economic analysis using the utilities' forecasts.

The OGP analysis of the systems necessary to meet the utilities' forecast demand shows that construction of Susitna would replace a significant amount of thermal generation capacity. Under the Non-Susitna expansion plan, two combined cycle plants (237 MW each) are constructed in 1993. Gas turbines are then added until 1998. After year 2000 a total of 10 coal-fired plants are constructed. With Susitna, the combined cycle plants are delayed (until 1995 and 2000) with only three coal-fired plants installed between 2012 and 2017. Calculating the cumulative present worth costs of the expansion plans indicates that the With-Susitna expansion plan would have a net benefit of $2.96 billion assuming load growth as predicted by the utilities. That figure is $1.90 billion greater than that for the With-Susitna expansion plan using the Power Authority estimate of electrical demand. The Susitna benefit-cost ratio using the utilities forecast would increase to 1.45.

Table 6.4

ECONOMIC ANALYSIS USING UTILITIES' FORECAST

(1983 $ x billion)

	With-Susitna Expansion Plan	Non-Susitna Expansion Plan
Present Worth of Annual Costs	6.57	9.54
Net Benefits	2.96	-
Benefit/Cost Ratio	1.45	-

The conclusion which can be drawn from this analysis is that if electrical demand is greater than the forecast produced by the models used in this Update, the economic benefits of the Susitna Project increase accordingly. Conversely, if electrical demand is lower than the Update forecast, a reevaluation would be necessary as to the appropriate timing of the Watana Development.

6.6 CONCLUSIONS

Although stated in various terms throughout this Chapter, the conclusion of the OGP analysis of Railbelt expansion plans, comparing the With-Susitna plan (which includes some thermal generation) against Non-Susitna alternative plans (which includes minor amounts of hydroelectric power), is that the Susitna Project would have a positive benefit/cost ratio (a ratio greater than 1.0) over the planning period of 1993-2050. Stated simply, using the most current data, it is the conclusion of this Update that the Project remains economically viable.

EXHIBIT 6.1

PRINCIPAL ECONOMIC PARAMETERS

1. All Costs in January 1983 Dollars
2. Base Year for Present Worth Analysis: 1983
3. Electrical Load Forecast: 1983 to 2020
4. Discount Rate: 3.5 percent
5. Inflation Rate: 0 percent
6. Economic Life of Projects:

Combustion Turbines:	20 years
Combined Cycle Turbines:	30 years
Steam Turbines	30 years
Hydroelectric Projects	50 years
Transmission Lines	40 years

7. Annual Fixed Carrying Charges

	20-year Life	30-year Life	40-year Life	50-year Life
Cost of Money	3.50	3.50	3.50	3.50
Amortization	3.54	1.94	1.18	0.70
Insurance	0.25	0.25	0.25	0.10
Total	7.29	5.69	4.93	4.36

EXHIBIT 6.2

RESULTS OF THE ECONOMIC ANALYSIS
OF SYSTEM EXPANSION PLANS
(1983 $ million)

YEAR	Annual Cost		Cumulative Present Worth	
	Non-Susitna	With-Susitna	Non-Susitna	With-Susitna
1993	156.0	215.0	110.6	152.4
1994	165.3	216.9	223.8	300.9
1995	172.1	221.7	337.7	447.6
1996	184.7	228.7	455.8	593.9
1997	194.6	233.5	576.0	738.1
1998	201.5	237.3	696.3	879.8
1999	208.7	243.6	816.7	1020.2
2000	229.3	248.1	944.4	1158.5
2001	237.3	252.9	1072.2	1294.6
2002	261.5	267.7	1208.2	1433.8
2003	267.1	267.7	1342.4	1568.4
2004	275.5	267.7	1476.2	1698.3
2005	282.8	267.3	1608.9	1823.7
2006	314.2	265.3	1751.3	1944.0
2007	351.9	265.3	1905.4	2060.2
2008	368.8	265.3	2061.4	2172.4
2009	377.1	268.1	2215.6	2382.1
2010	387.7	265.3	2368.7	2386.9
2011	406.3	267.4	2523.8	2488.9
2012	415.7	277.7	2677.0	2591.3
2013	425.8	281.9	2828.7	2691.8
2014	437.4	298.9	2979.3	2794.6
2015	455.9	304.0	3130.9	2895.8
2016	464.7	322.4	3280.2	2999.3
2017	479.0	328.8	3429.0	3101.4
2018	492.0	332.2	3576.5	3201.1
2019	512.1	346.1	3725.0	3301.4
2020	529.2	367.3	3873.1	3404.3
2050	619.4	420.0	6790.7	5730.1

7.0 FINANCING OPTIONS

7.1 INTRODUCTION

The purpose of this Chapter is to explore the relative merits of various funding sources and develop financing options for the Susitna Project. Implementing financing options for the Project will require certain policy decisions and commitments by Alaska decision-makers, including the Legislature. One purpose of this assessment, therefore, is to bring these necessary decisions to the attention of the Legislative and Executive branches of the State of Alaska.

Based upon continuing review and analysis conducted by the Power Authority since the filing of the July 11, 1983 FERC License Application, several potential funding sources have been identified. In this Chapter, these funding sources are reviewed on the basis of legal, practical and cost of energy considerations. The legal review examines the existing requirements, apparent constraints and legislative action that should be taken into account to utilize each of these sources. The practical considerations address the marketability and similar factors associated with each source. The cost of energy analysis is utilized to determine the size and mix of the proposed funding sources in order to give assurance that the projected wholesale cost of Susitna energy under the selected financing options is competitive with the cost of energy from the least-cost thermal alternative in the first years of operation.

After a review of the above considerations, two financing options are selected for detailed analysis as the most feasible approaches to the financing of the Project. These options are:

Option A: Tax-Exempt Revenue Bonds combined with State Equity and Rate Stabilization Fund.

Option B: REA Guaranteed Loan and Tax-Exempt Bonds (50/50) combined with State Equity and Rate Stabilization Fund.

During the past several months the Power Authority has been conducting extensive negotiations with the intended purchasers of power to be generated by the "Four Dam Pool" which is comprised of the following hydroelectric projects in various stages of completion: (1) Lake Tyee near Petersburg and Wrangell, (2) Solomon Gulch near Valdez, (3) Swan Lake near Ketchikan, and (4) Terror Lake near Kodiak. These negotiations and related hearings on necessary legislative changes are in process as the first maturity date of interim construction notes becomes imminent. It should be noted that the State's ability to deal with the Four Dam Pool situation will largely determine investor willingness to participate in the Susitna bond financing program. Future investors will respond favorably to a coordinated response by the Power Authority, the utilities and the Legislature to the need to refund the short-term indebtedness for the Four Dam Pool. By the same token, potential Susitna bond purchasers will long remember any failure by these Alaskan entities to solve the problem and avoid delays in retiring the short-term notes.

7.2 GENERAL APPROACH AND PROCEDURES

A fundamental assumption in the analysis of Susitna financing options is that the wholesale cost of energy from the Project must be competitive with the wholesale cost of energy from the least-cost Non-Susitna Alternative in the first years of operation. Generally, the Railbelt utilities are not expected to enter into contracts to purchase Susitna generated power if the rates are significantly higher than the rate that would be available from alternative generation sources. Therefore, each of the options examined below is constrained to give assurance that the wholesale cost of Susitna energy is competitive with the least-cost thermal alternative during its first years of operation.

Because of the projected long-term benefits of the Susitna Project, it has been suggested that the Railbelt utilities might be willing to pay a premium price for Susitna energy over a short period of time. While no definitive analysis has been made, the hypothesis of the "willingness to pay" of the Railbelt utilities suggests that Susitna energy might conceivably be priced at a wholesale rate as much as 20 percent greater than the least-cost thermal alternative during the early years of operation and still be marketable in the Railbelt. It is estimated that the resulting retail cost of energy would be approximately 10 percent greater, after considering costs of distribution, administration, transmission and other costs. Therefore, a sensitivity analysis was run for both of the financing options examined herein to allow wholesale Susitna costs to be 20 percent greater than the thermal alternative cost during the first years of Susitna operation. Should such premium rates be agreed upon with the utilities, it would allow a significant reduction in the necessary amount of State assistance (see Table 7.5).

Before the allowable wholesale cost of Susitna energy can be determined, it is first necessary to develop the cost of energy for the least-cost thermal alternative. The cost of energy of various thermal alternatives was computed from Optimum Generation Planning ("OGP") output summaries.

The least-cost thermal generation scenario described in Chapter 5 results in an average cost of energy in the Railbelt of 11.2¢ per kWh in the first year of operation of Watana (1996). This figure assumes that the thermal alternatives would be financed by the individual utilities using 75 percent REA loans and 25 percent tax-exempt revenue bonds on the assumption that the State will not provide equity funding or loan subsidies for thermal generation alternatives.

7.3 POTENTIAL FUNDING SOURCES

There are several different sources of funds potentially available to finance the Susitna Project. Because of the large size of the financing requirements of Susitna, however, one source may not be able to provide all necessary funding. The financing options presented in Section 7.5, therefore, draw on several funding sources. This Section discusses in general terms the types of funding sources potentially available to Susitna.

7.3.1 State Equity Contributions

The State Legislature could appropriate money from the State's General Fund to be utilized in the construction of the Susitna Project. The appropriation could take the form of a direct grant or a loan to the Power Authority or some combination of the foregoing. All financing options which have seemed feasible or possibly feasible over the course of the on-going review of Susitna have involved large levels of State assistance. It is clear that Susitna will have to be one of the State's highest capital funding priorities in order to achieve the required equity contribution.

Precise estimates of the required amount of State funds vary among the financing options analyzed. A continuing commitment to provide State funds in the form of grants or loans over a period of several years to the Susitna Project would be required. A legal constraint in making this commitment is Section 7, Article IX, of the Alaska Constitution, which prohibits one Legislature from making binding commitments on future Legislatures through a prohibition against dedicating funds. Thus, although State monies might be provided by one Legislature, there is no assurance that continued funding would be approved by subsequent Legislatures. This lack of legislative authority to make long-term commitment of grants or loans would impose considerable financial risk on the Project, a risk which would probably be perceived by other potential investors as too great, thus rendering necessary non-State funding more expensive, if not impossible.

A means of reducing the investor's risk and establishing long-term State funding for the Susitna Project would be the proposed Major Projects Fund. As proposed, this fund would operate in a manner similar to the current Permanent Fund. An amendment to the Alaska Constitution would provide for setting aside 10 percent of the State's mineral revenues into a special account which would be available for energy development projects in the State. In broad philosophical terms, it would be the goal of this fund to utilize a portion of the State's wealth derived from non-renewable energy sources to fund energy projects (either through equity contributions, rate stabilization funds or both) which utilize renewable energy, such as hydroelectric, geothermal, and solar projects. Grants or loans from the Major Projects Fund to construct the Susitna Project would be consistent with this stated philosophical goal. One advantage of this approach is that it would provide non-State investors in the Susitna Project with assurance that, to the extent of available pledged resources ("a dedicated revenue source"), the State would fulfill its funding obligations to the Project, thus eliminating the fear that future Legislatures would not authorize sufficient funds. Exhibit 7.6 indicates the portion of this special account which would be required for Susitna under both financing options analyzed.

7.3.2 Alaska Permanent Fund

Another possible financing option is the utilization of the investment capacity of the Alaska Permanent Fund, which was created by a 1976 amendment to the State Constitution. It is a separate fund composed of the revenues from at least 25 percent of all annual mineral lease rentals, royalties, royalty sale proceeds and federal mineral payments received by the State, plus earnings on these payments. An Alaska Permanent Fund Corporation was established in 1980 to provide a means of conserving this portion of the State's revenues, derived from mineral resources, to benefit future generations of Alaskans. The Corporation is a public corporation organized within the Department of Revenue whose primary purpose is to manage and invest the Permanent Fund assets. A Board of Trustees appointed by the Governor has the responsibility of ensuring that judgment and care are applied in investment of these assets, considering the "probable safety of capital as well as probable income." The statutory obligations for management and investment of the Fund's assets are specific, as are the types of investments and the designated percentage of the Permanent Fund which may be invested in each type of investment.

The Permanent Fund has been suggested by some as a potential source of financing for the construction of the Susitna Project, either as a source of loans through purchase of bonds or as a means of guaranteeing other forms of financing with the view that the construction of the Susitna Project is a means of preserving the State's mineral resource base. If Susitna is not constructed, natural gas, diesel fuel and other fossil fuels will probably be used for generation which otherwise would have been provided by Susitna to meet electric power demand within the State. In this context, use of the Permanent Fund as a financing source for Susitna could be viewed as consistent with the purpose of the Fund, i.e., "conservation of the State's revenues from mineral resources to benefit generations of Alaskans."

Pursuant to Articles IX and XV of Alaska's Constitution, the Permanent Fund's principal may be used only for "income-providing investments specifically designated by law. . ." The assets may thus presently be invested only in specific types of government securities, corporate stocks and bonds and real estate, all at market rates. Investment in below-market yield or no-income investments with Fund assets (even though long-term benefits could be argued) would probably require a Constitutional amendment in light of the conservative view typically given to the types of permissible investments in such a Fund. Further consideration of this funding source has not been given because: (1) for this source to be competitive with Option A for the financing of Watana, an interest rate of approximately 10 percent per annum would be required assuming the same approximate level of State equity; current yields available to the Permanent Fund are approximately 3 percent per annum greater for similar maturities and credit risks inasmuch as the Permanent Fund has no incentive to acquire tax-exempt debt instruments, and (2) in order to fully fund the financing of Watana by loans from the Permanent Fund (without any State equity), an interest rate of approximately 3 percent per annum would be required, which is approximately 10 percent per annum below yields otherwise available to the Permanent Fund.

7.3.3 Rate Stabilization Fund

Although not a form of financing in and of itself, a Rate Stabilization Fund (RSF) is a means of allowing other sources of financing for Susitna to be used more effectively by holding down energy costs during

Susitna's early years of operation when it is most difficult for hydro costs to be competitive with thermal alternatives. A RSF could be funded by either the issuance of additional bonds, by State appropriations, or from a dedicated revenue source such as the proposed Major Projects Fund. Bond proceeds are commonly used for this purpose, often in the form of capitalized interest. The RSF concept was developed by the Power Authority for the Four Dam Pool financing plan.

The RSF is a rate subsidy during the early years of operation. The cost of energy from the Susitna Project, based on a given financing plan, would be offset by transfers made to the accounts of the Railbelt utilities by the bond Trustee. This would result in a projected net cost of Susitna energy equivalent to the projected Non-Susitna Alternative in the early years. The cost of Susitna energy after the RSF period would be expected to be less than the least-cost thermal energy alternative during Susitna's latter years of operation, because of the high level of fixed costs associated with hydro.

Because the RSF provides State assistance in the time period most needed, it reduces the level of permanent commitment of State funds required in the form of equity. The RSF concept is included in the base case of each financing option.

As in the equity contribution approach, the RSF could present problems of continuity. Although one Legislature may agree to an RSF program, there is no assurance that subsequent Legislatures would provide further appropriations to an RSF which would be necessary over a period of years if the initial appropriation was not adequate. For purposes of analysis of the financing options, it is assumed that RSF funds would be provided as needed by a dedicated revenue source not subject to Legislative approval. A sensitivity analysis was made assuming that the underwriting standards of any debt market would require that the full amount of rate stabilization funds needed over a period of years be provided "up front" before the bonds could be sold.

7.3.4 Tax-Exempt Debt

Public power projects are commonly financed with tax-exempt debt. This type of debt can be an obligation of a state, or political subdivision of a state, the interest on which is generally exempt from Federal income taxes. This tax exemption enables states and their political subdivisions to issue debt at lower interest rates than would otherwise be the case. For example, long-term municipal bonds for public power projects were marketed in January 1984 at interest rates of 10 percent to 10.5 percent, whereas taxable corporate bonds of the same maturity and credit rating were being sold at interest rates of approximately 13 percent to 13.5 percent.

Public power projects are generally financed on a tax-exempt basis with revenue bonds, as distinguished from general obligation ("G.O.") bonds. In the case of the Susitna Project, revenue bond financing would mean that the first and primary source of payment for the principal and interest on those bonds would be the revenues derived from the Susitna Project itself. G.O. bonds, on the other hand, are backed by the full faith and credit, including the taxing power, of the issuing governmental entity. Revenue bonds have two principal advantages over G.O. bonds; one being fewer procedural steps prior to bond issuance, and the other that revenue bonds do not directly affect the G.O. rating of a state.

However, under the Internal Revenue Code (the "Code"), not all obligations of states and their political subdivisions are exempt from Federal income taxes. If the proceeds of otherwise tax-exempt bonds are made available to "non-exempt persons" (entities other than states, their political subdivisions and charitable organizations described in Section 501(c)(3) of the Code), those bonds could be classified as Industrial Development Bonds ("IDBs"). The Internal Revenue Service considers bonds to be IDBs if the bond proceeds are expected to be used in the trade or business of a non-exempt person and to be secured by payments made by such non-exempt person. Interest on IDBs is not exempt from Federal income taxes unless the size of the bond issue is below a certain level (far smaller than the needs of the Susitna Project) or unless the bond proceeds are used to fund certain types of exempt facilities (which in the case of hydroelectric projects include only projects for which the output is used in no more than two counties or their political equivalent). In other words, since Susitna does not meet the two-county rule test, if a portion of the bonds issued to finance the Susitna Project met the definitional test and were classified as IDBs, under current Federal laws, the interest on that portion of the bonds deemed to be IDBs would not be exempt from Federal income taxes and the cost of financing the Project would be correspondingly higher.

It is expected that roughly 75 percent of the energy from the Susitna Project will be sold to REA cooperatives. These cooperatives, while generally exempt from Federal income taxes, are not included in the definition of "exempt persons" under Section 501(c)(3) of the Code. The REA cooperatives would accordingly be classified as "non-exempt persons."

The Treasury Regulations and IRS rulings dealing with power generating facilities contain detailed rules for determining whether the sale of energy to "non-exempt persons" will cause bonds issued to finance those facilities to be classified as IDBs. In very general terms, such bonds would be IDBs if "non-exempt persons" entered into power sales agreements covering more than 25 percent of the capacity of the power generating facilities, and those contracts required the "non-exempt persons" to make payments covering a pro rata portion of debt service regardless of whether any power was in fact delivered. This type of power sales contract (known as a "take-or-pay" contract) is the standard in the utility finance industry, whether in the tax-exempt or corporate market and will probably be necessary for the financing of Susitna.

Because of the desirability of take-or-pay power sales contracts with the REA cooperatives as well as the exempt users, tax-exempt financing for the Susitna Project in its entirety might not be available under existing law. For several years, this issue of the availability of tax-exempt financing has been the subject of on-going research and analysis by the Power Authority and its advisors, as well as by the Governor's Office in Washington, D.C. and the Congressional delegation. The problem has become even more significant with the introduction in October 1983 of H.R. 4170, the Tax Reform Act of 1983, which is discussed below. Three possible solutions to this problem which would enable the Susitna Project to be financed on a tax-exempt basis would be to either change existing State law, modify existing Federal law or modify the planned sales to REA cooperatives.

The concept of amending State law was first introduced to the Board of the Power Authority on April 18, 1983 as a possible financing option for the Anchorage-Fairbanks Intertie Project, which also involves a heavy concentration of non-exempt users. The concept, known as "direct billing", is that a Legislative amendment would allow the Power Authority to pass-through its debt service for various projects directly to utility consumers. The utilities could contractually serve as collection agents utilizing a separate line item category in their monthly billing statements to their customers. With such a broad rate base, no power sales contracts would be necessary to market the bonds. Since the ultimate power consumers would not constitute "trades or businesses" under the Internal Revenue Code, bonds issued for projects utilizing this concept should not be deemed to be IDBs. While legal advisors to the Power Authority have expressed some level of comfort with this methodology of achieving tax-exemption, no decision has been made as to the necessity of obtaining a Revenue Ruling from the Internal Revenue Service. The Power Authority plans to introduce a bill to the current Alaska Legislature to provide for the "direct billing" concept. The bill is entitled "An Act relating to the direct sale of power by the Alaska Power Authority to retail customers".

Existing Federal law could be amended in any number of ways; either narrowly, to limit tax-exempt status solely to Susitna, or more broadly, allowing other power generation facilities to qualify for tax-exempt status. Three examples of narrow changes to existing law would be: (1) to amend current Federal law to provide that bonds issued for the construction and operation of the Susitna Hydroelectric Project would be tax-exempt; (2) to amend current Federal law to exclude bonds issued for purposes of constructing Susitna from the definition of IDBs by expanding the Section 103 definition of "exempt persons" to include REA cooperatives or specifically the purchasers of power from Susitna and (3) to amend Section 103 to broaden the definition of "qualified hydroelectric projects" which are tax-exempt to include Susitna.

A less-narrow approach involves broadening an existing list of bonds that, although IDBs, are tax-exempt. Tax-exempt IDBs include bonds issued for purposes relating to "the local furnishing of electric energy or gas." (26 U.S.C. Section 103(b)(4)(E)). As currently defined by the IRS, "local furnishing" exists only where two or fewer contiguous counties are involved (hence the term "two-county rule" evolved as a synonym of "local furnishing exemption"). Since the Susitna Project would serve several Alaska boroughs, it appears that it would not fall within the current definition of "local furnishing." This could be altered by amending Section 103 of the Code to define "local furnishing" for purposes of Alaska as involving the entire State.

It is important to note that although it may be simple to identify the sections of Federal law to be amended and to draft the necessary language, it is never easy to pass amendments benefiting a single project. A further possible constraint on tax-exempt status for Susitna bonds is the aforementioned Tax Reform Act of 1983, which would place a state-by-state limit on the amount of IDBs each state could issue. The limit currently proposed would be a $150 per person per year "cap" on tax-exempt IDBs (and student loans) allowed to be issued by each state. The pendency of this legislation, with its January 1, 1984 effective date, has created a practical moratorium on issuance of IDBs which would otherwise be classified as tax-exempt.

Because of its small population, the State of Alaska would be authorized to issue a relatively small amount of tax-exempt IDBs if the Tax Reform Act of 1983 passes as currently written. There would not be sufficient IDB capacity under the cap to fund the Susitna Project along with other projects seeking similar tax-exempt funding in the State. At the time of this writing, it is expected that a compromise will be reached between those forces in Congress seeking to "cap" tax-exempt IDBs and local government forces attempting to maintain this method of financing projects beneficial to the public; however, public power projects have not yet been included in the list of exclusions from the cap.

The approach of modifying the contemplated sales to REA cooperatives so as to obtain tax-exempt status for the revenue bonds might require restructuring the Railbelt electric system. One approach would be for the municipal electric systems in the Railbelt to purchase the non-exempt utilities in the Railbelt. There are a number of legal, political and practical difficulties with this re-organizational approach.

Inasmuch as the Power Authority does not currently control the assets or activities of any Railbelt utility and has no statutory authority to become a public utility, it is unlikely that changes could be made in the Railbelt electric system in the necessary timeframe to allow Susitna bonds to be classified as tax-exempt under current law.

A practical consideration of tax-exempt financing is that debt service coverage is often required to market bonds. For example, the Power Authority might be required to maintain revenues from the Susitna Project equal to some percentage (possibly 10 to 25 percent) in excess of the current year's debt service. However, mitigating any coverage requirement is the probability that the coverage will be retained in the flow of funds on the Project and thereby be made available for funding of reserves, improvements to the system or early retirement of debt. For purposes of analysis, it is assumed the excess coverage, after required reserves are established, is held and invested along with required reserves at a rate of 11 percent. This treatment produces a result essentially the same as retiring debt. Another treatment of coverage would be to assume the market will accept a "rolling-coverage" concept whereby certain reserve fund balances, exclusive of debt service reserves and other special purpose funds, may be included as available revenues in the setting of power rates and thus the net effect is to eliminate the coverage factor from the cost of power. Because of the use of coverage within the system or the possible elimination of coverage as described above, coverage in and of itself does not appear to be a major detriment to tax-exempt financing.

Of more concern in the tax-exempt area is the likelihood that a market saturation scenario could develop with regard to the sale of bonds for a project the size of Susitna. In such a case, bonds of succeeding series might command increasingly higher yields by comparison to similarly rated competing issues of the same type and maturity range but which do not have an overexposure to the market. For this reason, it is important to develop several financing options and to explore combinations of options to help prevent the risk of market saturation.

Another concern relative to the marketing of revenue bonds (whether tax-exempt or not) is the considerable magnitude of the obligations assumed under the power sales agreements by the Railbelt utilities as compared to their financial strength. Also their ability to perform might be jeopardized in the event of a prolonged Project outage or if the financial disability of one of the participating utilities shifts the burden to other participants. This problem has been dealt with in the Four Dam Pool negotiations, mentioned in the introduction to this Chapter, by modifications to standard take-or-pay language. The modifications shift certain risks, not covered by insurance proceeds or other available funds, from the utilities to the State's "moral obligation". The term "moral obligation" refers to the procedure of at least annually notifying the Legislature and Administration if a deficiency exists in the required Capital Reserve Fund (generally one year's debt service) associated with a bond issue. After such notification the Legislature may, at its option, restore such deficiency.

While the literal wording of this moral obligation language does not give any assurance of assistance from the State, a view generally held by investors is that a state could not in good conscience, or by using prudent business judgement acting in its own best interest, allow one of its agencies to default on a debt obligation. There are, of course, investors who do not share this view, or at least not to the extent that they would purchase bonds secured to any significant degree in this fashion. There are many investors, however, who would place reliance on the moral obligation to cover the risk of extraordinary and highly remote "doomsday scenarios". In summary, the State's willingness to assume a contingent responsibility for certain catastrophic events could be a meaningful credit enhancement for the debt portion of the financing for the Project because the State's resources appear to be commensurate with the financial obligations. The moral obligation availability would also be helpful in power sales agreement negotiations with utilities. However, it must be emphasized that the resolution of the Four Dam Pool situation is essential to any investor reliance in the future on the moral obligation of the State of Alaska.

Because of the uncertainty regarding the tax-exempt status of a portion of Susitna revenue bonds, the financing options involving tax-exempt bonds will include sensitivity analysis assessing the impact of financing a portion of the Project with taxable bonds.

7.3.5 REA Guaranteed Loan Program

A potential source of federally guaranteed financing has recently received a great deal of attention within the State. The Rural Electrification Administration (REA) is an agency within the U.S. Department of Agriculture which, under the Rural Electrification Act (7 U.S.C. Section 901), has the authority to loan monies to state agencies and non-profit cooperatives, for the purpose of providing electric service to rural areas. The REA has a guaranteed loan program which has been in existence for 10 years that could be a source of funding for a portion of Susitna. REA can guarantee loans made by any established lending institutions for generation and transmission projects to service rural areas not receiving central station service.

Under the Federal Financing Bank Act of 1973, REA borrowers are entitled to receive their loan through the Federal Financing Bank (FFB), if they choose. FFB is an arm of the U.S. Treasury. Its loans are provided at interest rates of 0.125 percent (1/8th of one percent) above prevailing Treasury bond rates. Because these terms are so favorable, most guaranteed loans are made through the FFB.* In fiscal year 1984, FFB has available $3.3 billion for REA's guaranteed loan program. Short-term construction loans, available for a term of three to seven years, can be negotiated based on interest rates for short-term Treasury bills. The

* REA has guaranteed approximately $30 billion in loans since 1973. Of this amount, only about $800,000 has been lent by institutions other than FFB.

short-term loan may be rolled over to a long-term arrangement with a maximum term of 35 years. These rates would be based on long-term Treasury bond yields.

The REA will only finance projects which are designed to serve rural needs and, therefore, Susitna's total financial needs cannot be met by REA financing. Where a proposed project is intended to serve both rural and urban areas, as is the case with Susitna, REA will serve only "Act beneficiaries", i.e., customers in areas which the Act defines as rural. The present REA cooperatives of Chugach, Matanuska, Homer and Golden Valley are deemed "Act beneficiaries", since they qualified when first formed. Having once qualified, they may continue to qualify despite population changes.

The Power Authority may be an applicant under the REA loan guarantee program. However, it should be noted that the REA guarantee program cannot be utilized in combination with tax-exempt bonds for the REA guaranteed portion of the project financing. Although REA loans are typically made to generating and transmission cooperatives (G&Ts) or REA distribution cooperatives,* the Alaska Railbelt does not have an established G&T cooperative. Generally, G&T cooperatives are formed by the initiation and concerted effort of rural cooperatives for the purposes

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* In the past 10 years of the Guaranteed Loan Program, there have been approximately 923 loans to cooperatives either in their own right, or through a G&T cooperative, 40 to public utility districts, and 4 to investor-owned or municipal utilities for service outside city boundaries.

of financing the construction of needed generation and transmission systems in the REA's service territories. Lacking such a G&T cooperative, the preferable entity in the Railbelt for receiving an REA loan for Susitna would be the Power Authority.

One key reason for this approach to REA financing is the FERC licensing procedure. If the Power Authority were to assist the rural cooperatives in establishing a G&T to act as Applicant for the loan guarantee program, it would need to transfer ownership of Susitna to the cooperative. This would necessitate a change in the Power Authority's FERC License Application, with a possible regulatory delay.

Financing a portion of the Susitna Project through the REA loan guarantee program could provide real benefits to the State as developed in greater detail in the finance plan discussed below. These benefits flow from the relatively low interest rates associated with such financing as compared to other taxable financing options. The interest rate for REA loans in January 1984 was approximately 11.75 percent, as compared to approximately 13.0 percent for taxable bonds and approximately 10.0 percent for tax-exempt bonds. Furthermore, the possible alleviation of the market saturation scenario described above could be very beneficial.

A very real drawback to the use of REA guaranteed loans is the likelihood that the REA program will continue to receive decreasing amounts of U.S. Congressional approval. The REA's guarantee program ceiling of $3.3 billion for fiscal year 1984 represents a reduction of $1.3 billion in nominal dollars from fiscal year 1983. The currently proposed

Administration budget for fiscal year 1985 is approximately $1.3 billion, again in nominal dollars. The Susitna Project would be the REA's largest single commitment if guaranteed to the maximum possible extent.

In the current political environment in Washington, the probability of gaining sufficient support for financing all of the participation of cooperatives in Susitna appears to be low. However, participation of the REA to the extent legally and practically feasible is a financing option which deserves considerable attention. This option has never been ruled out by the Power Authority but has not been pursued actively in recent years because of the size of the Project and the more attractive interest rates available if tax-exemption is achieved. Also, while the REA staff has indicated a willingness to explore more "risk-taking" on their part than would be the case in the tax-exempt bond market (such as possibly accepting yearly appropriations of the RSF rather than having dedicated stream of revenue), this would indeed be a departure from their usual policy of having binding commitments on all the elements of a financing package. The likelihood of a variance of basic policy on their largest single project exposure seems somewhat remote. It would seem more probable that the risk of non-appropriation would have to be borne by the utilities, and ultimately the consumer, as is the case on present REA loans to cooperatives within the State who now receive power rate assistance funds.

7.3.6 Other Sources of Funding

In addition to the possible funding sources reviewed above, taxable bonds or private equity financing could also provide financing for the Susitna Project. Generally, however, these sources are not attractive to the State because investors in those markets demand a higher rate of return than can be accommodated and still achieve a marketable power rate. Although a Rate Stabilization Fund or State equity could be used in conjunction with some of these markets to reduce the ultimate cost of power in the early years of operation, even that mechanism has limitations. In anticipation that other forms of financing may be considered before a final finance plan is decided upon, this section examines taxable bonds and private equity financing as sources of financing for the Project. In addition, G.O. bonds are considered.

Taxable bonds may be issued as either fixed-rate or floating interest rate obligations, as may tax-exempt bonds. Fixed-rate taxable bonds which are rated "A" by Moody's or Standard & Poor's are currently carrying an interest rate of approximately 13.0 percent or more. At this level, the wholesale cost of energy from Susitna would be quite high. Floating rate bonds carry interest rates generally tied to the movement of the prime rate or some other index rate. Because the interest rate varies over time, the cost of energy from the Susitna Project would also vary without the establishment of a variable amount RSF. Such fluctuation in the cost of energy without any ceiling would probably be unacceptable to the Railbelt utilities and their customers. A variable amount RSF would probably be unacceptable to the State as well.

Private equity, if it could be found, would enable parties other than the State of Alaska and its political subdivisions to acquire an ownership interest in Susitna. There are two major drawbacks to private equity financing for Susitna. First, the rate of return demanded by providers of private equity is quite high, with the probable result of making this the most expensive means of financing the Project. Second, allowing private equity financing of the Susitna Project would cause the State of Alaska, acting through the Power Authority, to lose considerable control over the Project, including control over its method of operation, rates and management. This would be inconsistent with the current statutory purposes of the Power Authority.

Another alternative source of financing is the use of G.O. bonds. These bonds are issued by a state relying on its general credit rating and do not depend on a dedicated stream of revenue from a project for repayment. Payments on the bonds are usually made from the general fund of a state and the bonds can be used for any legal purpose. Because these bonds are the obligations of states they are tax-exempt. The use of G.O. bonds was not considered an attractive source of financing for several reasons. First, through the credit rating process, debt markets limit the amount of G.O. bonds available to a state. The amount of G.O. bonds needed for Susitna would greatly exceed Alaska's G.O. bond capacity assuming an investment rating downgrade is unacceptable. Second, the State of Alaska has traditionally followed a prudent policy of repaying its G.O. bonds over a relatively short term while projected oil revenues are reliable, providing excellent coverage. Such financing, repayable over a short-term, would be unacceptable for purposes of

Susitna. Accordingly, although G.O. bonds are a possible but limited source of financing, it appears the State would prefer to make other uses of this financing tool; therefore, this option has not been considered in any detail in connection with the Project financing.

Another extremely important element of utilizing G.O. debt for Susitna is the probable effect of a potential downgrade in the State's G.O. debt rating resulting from issuing excessive G.O. debt. In the opinion of the financial advisor and investment bankers to the Power Authority, a bond rating of "A" or better on the Susitna revenue bonds is essential to its financing due to the sheer size of the total debt required. A downgrade in the State's G.O. rating could impact the Power Authority's ability to achieve an "A" rating on its bonds.

7.4 IMPACT OF WPPSS DEFAULT ON SUSITNA FINANCING

The effects of the recent default by the Washington Public Power Supply System ("WPPSS") on its debt relating to Units 4 and 5 and the resulting possible impact on the Power Authority, particularly the Susitna Project, must be reviewed in connection with the Susitna Update. This $2.25 billion WPPSS default is the largest municipal bond failure of record.

The implications of the WPPSS experience in the public power finance markets are broad, especially for projects in the Pacific Northwest. Hopefully, the Alaska Railbelt will not automatically be considered part of the Pacific Northwest Region by investors. In addition, Susitna is not a nuclear project as were WPPSS Units 4 and 5, nor is the Power Authority authorized to pursue nuclear projects. The financing of Susitna will be enhanced by the following facts; that it is a hydroelectric project, it has and will continue to benefit from substantial State investment and it is a project of a State agency.

The principal concerns of investors, financial analysts and the rating agencies with large power projects are illustrated perfectly by the WPPSS case. They are as follows:

(1) Economic and financial viability of the project,
   (a) Need for power (accurate load forecasts),
   (b) Acceptable power rates (competitive with alternatives),
   (c) Public support for project (environmental concerns and willingness to pay),
   (d) Executive and Legislative commitment,
   (e) Consistency in dealing with energy policy;

(2) Risks associated with the project,
   (a) Risk of completion,
   (b) Risk of cost overruns,
   (c) Risk of construction delays;

(3) Market access for subsequent series of bond issues (market saturation);

(4) Validity of power sales contracts relating to the provision of necessary revenues to service the debt.

As a case in point, Standard & Poor's, one of the two principal bond rating agencies, has written many, if not all, public power entities with rated debt outstanding and requested them to obtain new legal opinions from bond counsel to the effect that, even in light of the WPPSS decisions by the Supreme Courts of Washington and Idaho, the existing power sales agreements applicable to their project are legal, binding and enforceable in accordance with their terms. Presumably, the inability to produce such opinions could result in the reduction, if not withdrawal, of the bond rating.

Another case in point is that some large institutional investors have now established policies of not buying electric revenue bonds where power sales agreements have not been validated by litigation (test case or otherwise). And, to the extreme, some investors are shying away from all power bonds, at least for the present. It seems that load forecasts are the subject of far more review than ever before and that the investment community is striving to be certain, to the degree possible, that a given project makes economic sense, regardless of the existence of power sales agreements or the validity thereof. Nevertheless, the existence of legally binding power sales agreements will be essential and a test case may be necessary or advisable before marketing any long-term Power Authority bonds for Susitna.

The financial advisor and investment bankers of the Power Authority have in the past and continue to advise that State contributions of equity to the Project should be made in the early years and in substantial amounts with bonds issued at a later date. The WPPSS lessons learned from the default make it clear that this earlier recommendation is appropriate. It is important not only to reduce the risk of completion but also to make the cost of energy economically feasible. It also demonstrates the State's commitment to the Project, which was missing in the WPPSS situation. Despite the favorable differences between the Power Authority and WPPSS, the sheer size of the Susitna financing, even with large State equity contributions, will cause Susitna financing to be carefully scrutinized by the investment community.

7.5 FINANCING OPTIONS SELECTED FOR ANALYSIS

Based upon a review of the relative advantages and disadvantages of the various funding sources discussed in Section 7.3, two specific financing options have been identified for further analysis and discussion herein:

Option A: Tax-Exempt Revenue Bonds combined with State Equity and Rate Stabilization Fund

Option B: REA Guaranteed Loan and Tax-Exempt Revenue Bonds (50/50) combined with State Equity and Rate Stabilization Fund

In Section 7.6, Options A and B will be analyzed assuming that the Devil Canyon Phase in each instance will be financed from proceeds of revenue bonds or other debt instruments bearing the same interest rate as was assumed for Watana tax-exempt revenue bonds. Relatively small amounts of RSF funds will also be required in the first few years of operation of Devil Canyon. The exact means of financing Devil Canyon is not critical to the financing of the Watana Phase which must stand on its own in the financial market.

In Option B, a 50/50 split of the debt portion between REA guaranteed loans and tax-exempt revenue bonds is assumed because: (1) the availability of a share larger than 50 percent from the REA program is highly improbable; (2) the interest rate benefit of tax-exempt financing of approximately 1.75 percent per annum is clearly the least expensive form of long-term debt presently available, regardless of debt service coverage considerations; and (3) the 50/50 split may have a beneficial effect on the potential market saturation problem relating to the tax-exempt bond market; however, it should be noted that the Federal government could also experience market saturation problems if present levels of budget deficits continue. The actual split of the debt portion of the financing between REA guaranteed loans and tax-exempt revenue bonds would be determined based upon market conditions and availability of REA guaranteed loans at the time debt is marketed.

Both financing options employ a combination of funding sources and both utilize the Rate Stabilization Fund concept for reasons stated in Section 7.3.3, principally to lower State equity requirements (on a present worth basis) and to spread the State assistance payments over a longer period of years. The base case (or recommended approach) for each option assumes the State equity and RSF will be paid in as needed by means of a revenue source such as the proposed Major Project Fund which further assists in spreading the State's assistance over a greater period of time. In Option B, to the extent tax-exempt financing is assumed for more than the presently available 25 percent (estimated) of the Project to be utilized by "exempt persons", the base case assumes the tax-exempt question will be resolved in favor of the State.

Sensitivity analyses have been performed on: (1) the effect of the RSF being required "up-front" at the time of debt financings in the event a dedicated revenue stream has not been approved by the electorate; (2) the effect of no tax-exemption for Project financing in excess of the 25 percent estimated to be utilized by "exempt persons"; and (3) the effect on the financing and equity requirements if a 120 percent "willingness to pay" exists during the first years of operation.

7.6 ANALYSIS OF FINANCING OPTIONS

The two financing options presented in Section 7.5 were analyzed using a financial model. The model computes the annual disbursements required during the construction and operation periods of the Susitna Project. The basic assumptions used in the analysis are presented in Exhibit 7.1.

7.6.1 Comparison of Options

The amounts required from each funding source under the base case of each option are shown on Exhibit 7.2. Amounts are given on Exhibit 7.2 for both Watana and Devil Canyon; however as stated earlier, Devil Canyon is financed by revenue bonds and RSF, if necessary, under each option. For that reason the discussion that follows applies only to the Watana Development.

The annual disbursements required during the construction and operation periods for Options A and B are shown on Exhibits 7.3 and 7.4, respectively. These Exhibits also present the wholesale cost of energy for each option. Exhibit 7.5 shows the wholesale cost of energy of the two options compared to that of the least-cost thermal alternative.

A comparison of the State funds required for equity contributions and RSF under each option is shown on Table 7.1. The total equity plus RSF required in each of the options, expressed in 1983 dollars, is $1,915 million in Option A and $2,054 million in Option B, a difference of about 7 percent.

Table 7.1

COMPARISON OF STATE EQUITY

AND RSF CONTRIBUTIONS *

(In Million Dollars)

	Option A (Bonds, Equity, RSF)	Option B (Bonds, REA, Equity, RSF)
In Nominal Dollars		
Equity	2,400	2,700
RSF	1,013	888
TOTAL	3,413	3,588
In 1983 Dollars		
Equity	1,519	1,707
RSF	396	347
TOTAL	1,915	2,054

* Assumes reinvestment earnings on all State equity including rate stabilization accumulated for the benefit of the Project.

Table 7.2 shows the annual disbursement of equity and RSF contributions required for each option. Exhibit 7.6 shows the nominal disbursements in each year compared to 10 percent of forecast oil and gas revenues in each year. As can be seen from Exhibit 7.6, Watana's requirements are well below the 10 percent limit under both options, allowing funds to be used for other capital projects.

Table 7.2

DISBURSEMENT OF STATE EQUITY

AND RSF CONTRIBUTIONS

(In Million Dollars)

Year	Option A (Bonds, Equity, RSF) Nominal Dollars	Option A (Bonds, Equity, RSF) 1983 Dollars	Option B (Bonds, REA, Equity, RSF) Nominal Dollars	Option B (Bonds, REA, Equity, RSF) 1983 Dollars
1985	177	151	199	170
1986	196	157	220	176
1987	210	159	236	178
1988	227	161	254	180
1989	247	164	276	183
1990	246	153	276	172
1991	238	140	266	156
1992	237	130	265	146
1993	239	123	268	138
1994	233	113	261	126
1995	150	68	179	82
1996	256	109	200	86
1997	277	111	253	102
1998	247	93	228	86
1999	214	76	198	70
2000	19	7	9	3
TOTALS	3,413	1,915	3,588	2,054

7.6.2 Sensitivity Analyses

7.6.2.1 Revenue Bonds Two key assumptions regarding the revenue bonds used in the options are: (1) that the bonds are tax-exempt status and (2) the passage of a constitutional amendment establishing a fairly uniform dedicated stream of revenues for Watana before and during its construction and during its initial years of operation. It is assumed that taxable revenue bonds bearing an interest rate of 13 percent could be used to finance the Project if exemption is not obtained. If a dedicated stream of revenues is not allocated to Watana, bond underwriters and prospective investors will probably require that all equity and RSF funds are allocated "up front" before the revenue bonds are issued. Sensitivity analyses for these two assumptions were performed. The amounts required from each financing source are given on Table 7.3 for each option.

Table 7.3
SENSITIVITY OF ANALYSIS TO
EXEMPTION AND DEDICATED REVENUES
(In Million Nominal Dollars)

Option A

Tax-Exemption	Base Case Exempt	Sensitivity Non-Exempt
Revenue Bonds	6,075	3,324
Equity	2,400	3,800
RSF	1,013	145
TOTAL	9,488	7,269

Dedicated Revenues	Base Case Dedicated	Sensitivity Up Front
Revenue Bonds	6,075	11,181
Equity	2,400	--
RSF	1,013	1,910*
TOTAL	9,488	13,091

Option B

Tax-Exemption	Base Case Exempt	Sensitivity Non-Exempt
Revenue Bonds	2,736	2,337
REA Loan	2,332	1,884
Equity	2,700	3,200
RSF	888	607
TOTAL	8,656	8,028

Dedicated Revenues	Base Case Dedicated	Sensitivity Up Front
Revenue Bonds	2,736	5,606
REA Loan	2,332	4,964
Equity	2,700	--
RSF	888	2,280**
TOTAL	8,656	12,850

* Amount set aside during 1985-88 equals $4,314 million in 1996 with interest accruals.

** Amount set aside during 1985-88 equals $5,152 million in 1996 with interest accruals.

The annual disbursements required for the "up front" equity and RSF contributions are given on Table 7.4.

Table 7.4
SENSITIVITY ANALYSIS DISBURSEMENT
OF EQUITY AND RSF CONTRIBUTIONS
(In Million Dollars)

	Option A (Bonds, Equity, RSF)		Option B (Bonds, REA, Equity, RSF)	
Year	Nominal Dollars	1983 Dollars	Nominal Dollars	1983 Dollars
1985	419	357	501	428
1986	463	371	555	445
1987	497	374	595	448
1988	531	375	629	445
TOTALS	1,910	1,477	2,280	1,766

7.6.2.2 Willingness to Pay The concept of "willingness to pay" was discussed in Section 7.2. If a 120 percent willingness to pay is assumed for the options, the amount of financing required from each source for each option would be as indicated on Table 7.5.

The annual disbursements of State funds to the sensitivity cases are shown on Exhibits 7.7 and 7.8, respectively, for Options A and B.

Table 7.5
SENSITIVITY OF ANALYSIS TO
120 PERCENT WILLINGNESS TO PAY
(In Million Nominal Dollars)

	Base Case	Sensitivity
Option A	100%	120%
Tax-Exempt Bonds	6,075	8,090
Equity	2,400	1,500
RSF	1,013	1,373
TOTAL	9,488	10,963
Option B		
Tax-Exempt Bonds	2,736	3,608
REA Loans	2,332	3,088
Equity	2,700	1,900
RSF	888	1,177
TOTAL	8,656	9,773

7.7 CONCLUSIONS

The conclusions which can be drawn from the analysis are:

- There is a relatively minor difference (about 7 percent) in the amount of State contributions required under either financing option base case, as shown on Table 7.1. Approximately \$2 billion in 1983 dollars is required in each instance;

- The cost of energy is approximately the same under each financing option base case as reflected on Exhibit 7.5; and

- Both proposed financing options have potential for financing the Project and should be pursued in tandem.

The sensitivity analyses demonstrate that the assumptions regarding tax-exemption, the constitutional amendment establishing the dedicated stream of revenues for the Susitna Project, and willingness to pay each have a significant effect on the financing options. If tax-exemption is not obtained, the State's contribution will have to be substantially increased. Requiring State equity and RSF funds up-front will increase the debt associated with the Project and the required annual State contribution, although the State's total contribution will decrease. The State's contribution will be substantially decreased if a portion of the financial burden of the Project is passed on to consumers in the form of a willingness to pay premium.

Five issues need to be resolved before any plan of finance for the Susitna Project can be finalized. The Power Authority will pursue each of these issues with appropriate entities, keeping the Legislature and Administration apprised of progress. The five issues are:

- Tax-exempt status of the Susitna revenue bonds;
- Ability and willingness of the REA to guarantee debt in meaningful amounts;
- Establishment of a dedicated stream of revenues;

- Willingness of utilities to contract for the purchase of Susitna power; and
- Willingness of the State to allow the use of its "moral obligation" to support Project funding.

EXHIBIT 7.1
ASSUMPTIONS USED IN FINANCIAL ANALYSIS

Financing Terms:

Source	Interest Rate, Percent	Repayment Period, Years
Revenue Bonds, Tax Exempt	10.00	35
Revenue Bonds, Taxable	13.00	35
REA Loans	11.75	35

Interest Rates on Invested Funds: Equity and Short Term *: 9%/yr
Long Term: 11%/yr
Rate Stabilization Fund: 5%/yr

Inflation and Deflation Rate: 6.5%/yr

Willingness to Pay: 20% above thermal cost of energy when applicable.

Project Construction Cost (1983): (License Application)

	1983 Dollars	Nominal Dollars
Watana	$3,750 million	$7,200 million
Devil Canyon	1,620 million	4,638 million
TOTAL	$5,370 million	$11,838 million

First Year of Construction:

Watana	1989
Devil Canyon	1995

First Year of Operation:

Watana	1996
Devil Canyon	2002

Equity Contribution Limit:
10% of Oil and Gas Revenues

Oil and Gas Revenue Forecast (DOR Mean-Dec. 1983):

Calendar Year	Revenues in Million (Nominal Dollars)
1985	3,053.5
1986	3,381.5
1987	3,629.5
1988	3,910.5
1989	4,252.5
1990	4,242.0
1991	4,097.5
1992	4,083.5
1993	4,124.5
1994	4,015.5
1995	3,798.5
1996	3,818.5

* Less than one year.

EXHIBIT 7.1
ASSUMPTIONS USED IN FINANCIAL ANALYSIS

Power Market Forecast (SHCA-NSD):

Year	Railbelt Net Energy Generation Requirements, GWh
1995	4,450
2000	4,846
2020	8,063

Thermal System Energy Costs in Nominal Dollars:
1996 Target Cost: 11.2¢/kWh

Capital Renewals (as percent of escalated investment cost):
Thermal: 3.0%
Hydro: 0.3%

Revenue Bond Characteristics:

Maximum Bond Size:
No limit, determined by annual requirements.

Interest During Construction:
Each succeeding bond funds prior year(s) bond(s) interest

Debt Service:
Debt service begins in first year of operation

Debt Service Coverage: 10%

Financing Expense:
Equal to 3 percent of principal amount

Debt Service Reserve:
One year's levelized debt service based on 35-year repayment period

Reserve and Contingency Fund (hydro):
One year's capital renewals plus one year's operation and maintenance cost (established at start of bond issue)

Working Capital Fund:
Fifteen percent of first year's operation and maintenance cost plus 10 percent of first year's total annual system cost

EXHIBIT 7.2
FUNDING REQUIREMENTS - BASE CASE
(In Million Nominal Dollars)

	Watana	Devil Canyon	Total
Option A			
Tax-exempt Bonds	6,075	7,049	13,124
Equity	2,400	--	2,400
RSF	1,013	463	1,476
TOTAL	9,488	7,512	17,000
Option B			
Tax-exempt Bonds	2,736	7,049	9,785
REA Loans	2,332	--	2,332
Equity	2,700	--	2,700
RSF	888	463	1,351
TOTAL	8,656	7,512	16,168

FINANCING OPTION A - ANNUAL DISBURSEMENTS
(REVENUE BONDS PLUS EQUITY PLUS RSF)
(in million nominal dollars)

Disbursements during Construction

Year	Watana Construction Cost	Equity Contribution	Interest on Equity	Revenue Bond Funding	Debt Service Reserve	Reserve & Contingency & W. Capital Fund	Net Interest Dur. Const	Bond Fees	Bond Issues
1985	0	177	16	0	0	0	0	0	0
1986	0	196	35	0	0	0	0	0	0
1987	0	211	57	0	0	0	0	0	0
1988	0	227	83	0	0	0	0	0	0
1989	566	246	87	0	0	0	0	0	0
1990	529	246	68	0	0	0	0	0	0
1991	634	238	43	0	0	0	0	0	0
1992	734	237	19	287	40	32	17	11	387
1993	1,373	239	10	1,123	147	0	106	43	1,419
1994	1,485	233	10	1,243	180	0	263	52	1,738
1995	1,343	150	6	1,186	196	3	444	57	1,886
1996	527	0	0	527	67	0	32	19	645
	7,200	2,400	434	4,366	630	35	862	182	6,075

Disbursements during Operation

Year	Bond Debt Service	Debt Service Plus Cover	Less Interest Earnings	Thermal Investment Cost	Capital Renewals	Fuel Costs	Oper. & Maint. Cost	Total System Costs	Energy Genera-tion GWh	Energy Cost ¢/kWh	Thermal Least-Cost ¢/kWh	RSF Fund
1996	563	619	72	50	36	94	39	766	4,530	16.9	11.2	256
1997	630	693	86	50	38	107	41	843	4,608	18.3	12.3	277
1998	630	693	93	50	40	122	44	856	4,688	18.3	13.0	247
1999	630	693	100	50	43	137	47	870	4,767	18.2	13.8	214
2000	630	693	107	50	46	159	54	895	4,846	18.5	18.0	20
2001	630	693	114	50	49	183	58	919	4,963	18.5	18.8	0

EXHIBIT 7.4

FINANCING OPTION B - ANNUAL DISBURSEMENTS
(REVENUE BONDS PLUS REA LOAN PLUS EQUITY PLUS RSF)
(in million nominal dollars)

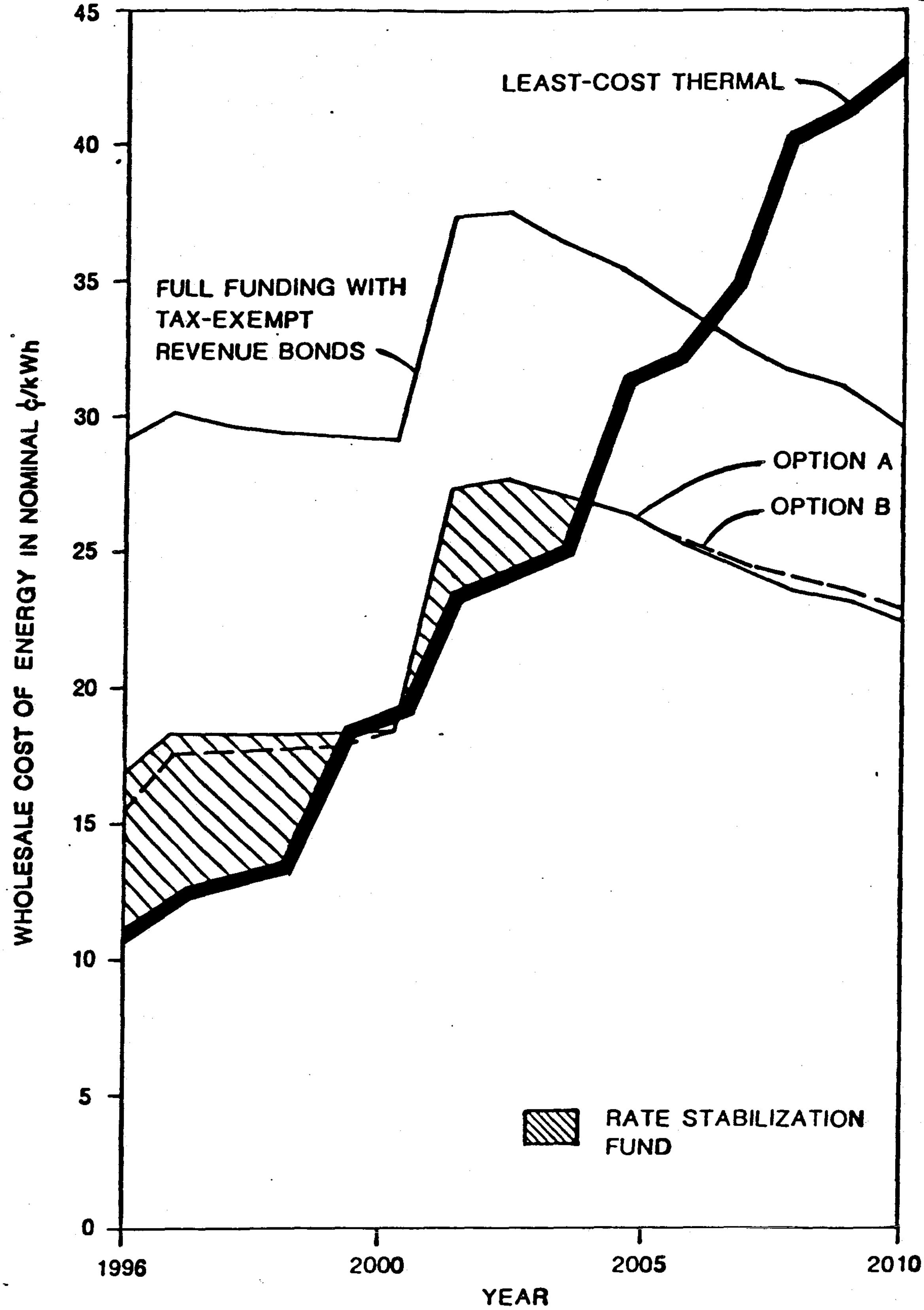
Disbursements during Construction

Year	Watana Construction Cost	Equity Contribution	Interest on Equity	Revenue Bond Funding	Debt Service Reserve	Reserve & Contingency & W. Capital Fund	Net Interest Dur. Const	Bond Fees	Bond Issue	REA Loan Funding	Net Interest Dur.Const	REA Loan
1985	0	198	18	0	0	0	0	0	0	0	0	0
1986	0	220	39	0	0	0	0	0	0	0	0	0
1987	0	236	64	0	0	0	0	0	0	0	0	0
1988	0	254	93	0	0	0	0	0	0	0	0	0
1989	566	276	101	0	0	0	0	0	0	0	0	0
1990	529	276	85	0	0	0	0	0	0	0	0	0
1991	634	266	65	0	0	0	0	0	0	0	0	0
1992	743	266	32	0	0	0	0	0	0	0	0	0
1993	1,373	268	12	538	72	34	32	21	697	538	39	577
1994	1,485	261	11	607	85	0	107	25	824	607	112	719
1995	1,343	179	8	578	93	3	193	26	893	578	194	772
1996	527	0	0	263	33	0	16	10	322	264	0	264
	7,200	2,700	528	1,986	283	37	348	82	2,736	1,987	345	2,332

Disbursements during Operation

Year	Bond Debt Service	REA Debt Service	Total Debt Service Plus Cover	Less Interest Earnings	Thermal Investment Cost	Capital Renewals	Fuel Costs	Oper. & Maint. Cost	Total System Costs	Energy Genera-tion GWh	Energy Cost ¢/kWh	Thermal Least-Cost ¢/kWh	RSF Fund
1996	250	251	527	34	50	36	94	39	712	4,530	15.7	11.2	201
1997	284	312	625	41	50	38	107	41	820	4,608	17.8	12.3	254
1998	284	312	625	44	50	40	122	44	837	4,688	17.8	13.0	228
1999	284	312	625	47	50	43	137	47	855	4,746	17.9	13.8	198
2000	284	312	625	50	50	46	159	54	884	4,846	18.2	18.0	9
2001	284	312	625	54	50	49	183	58	911	4,963	18.4	18.8	0

EXHIBIT 7.5

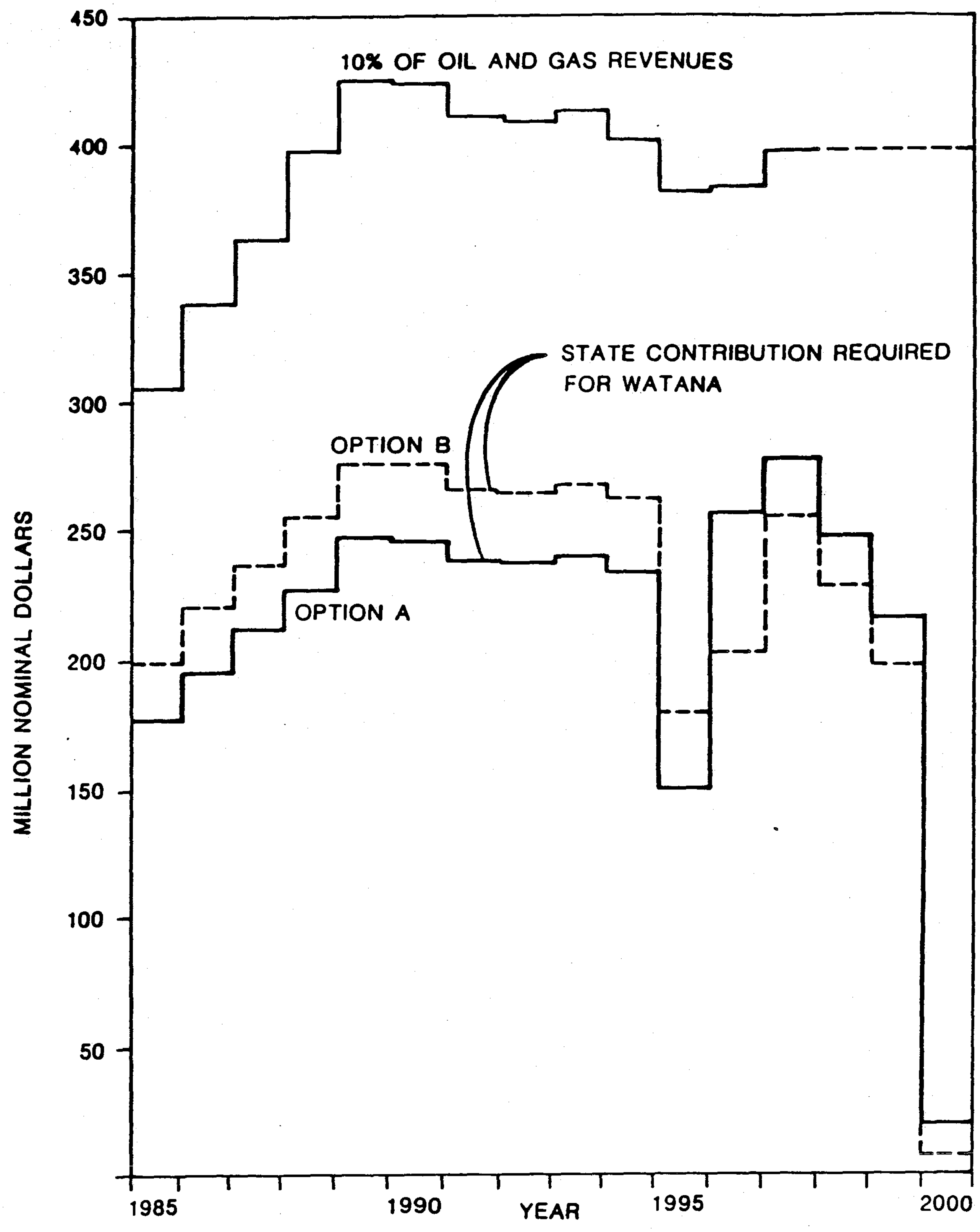


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ENERGY COST COMPARISON

FEBRUARY 1984

EXHIBIT 7.6

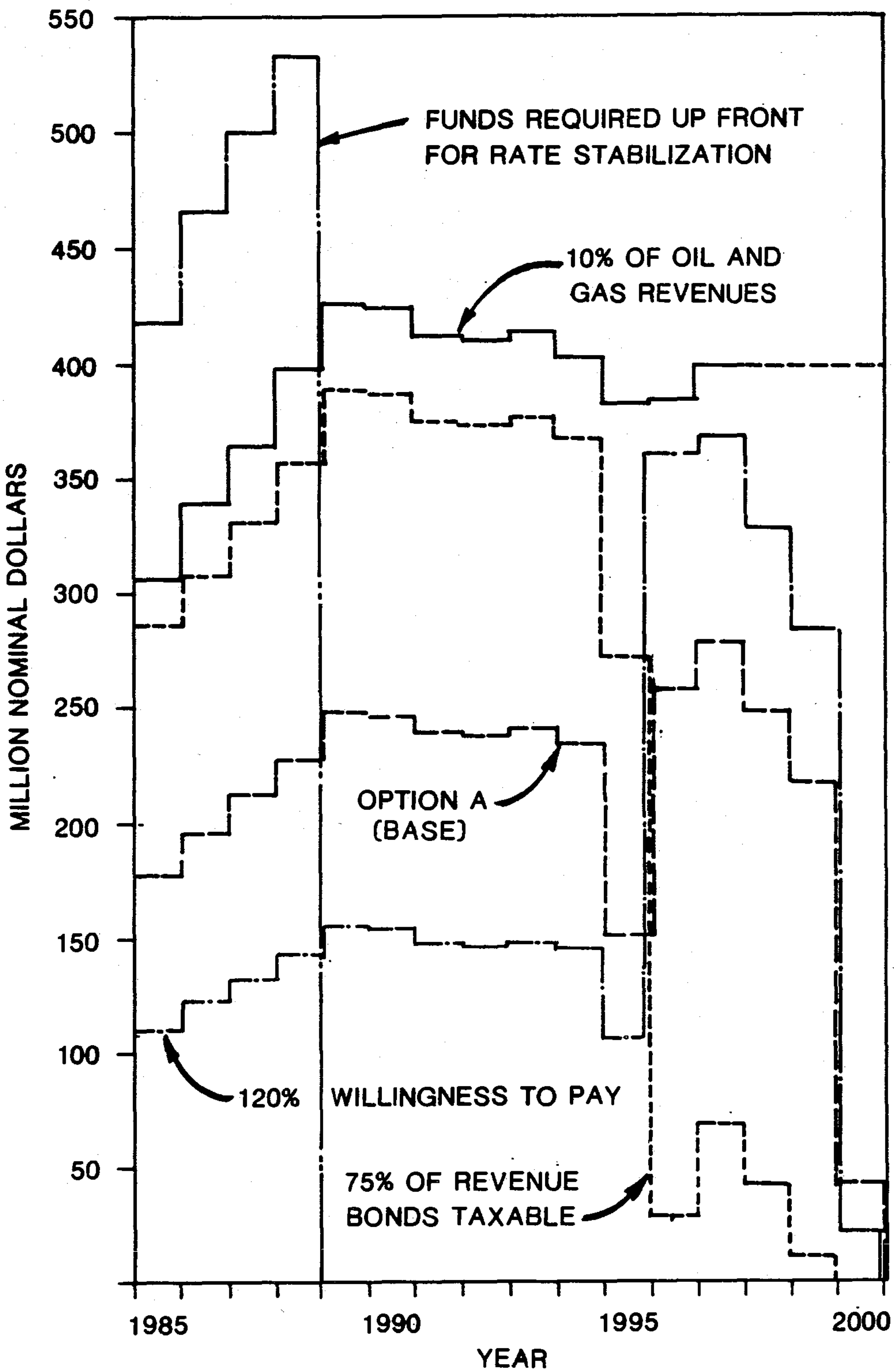


ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT UPDATE

ANNUAL STATE CONTRIBUTIONS FOR FINANCING OPTIONS A AND B

FEBRUARY 1984

EXHIBIT 7.7



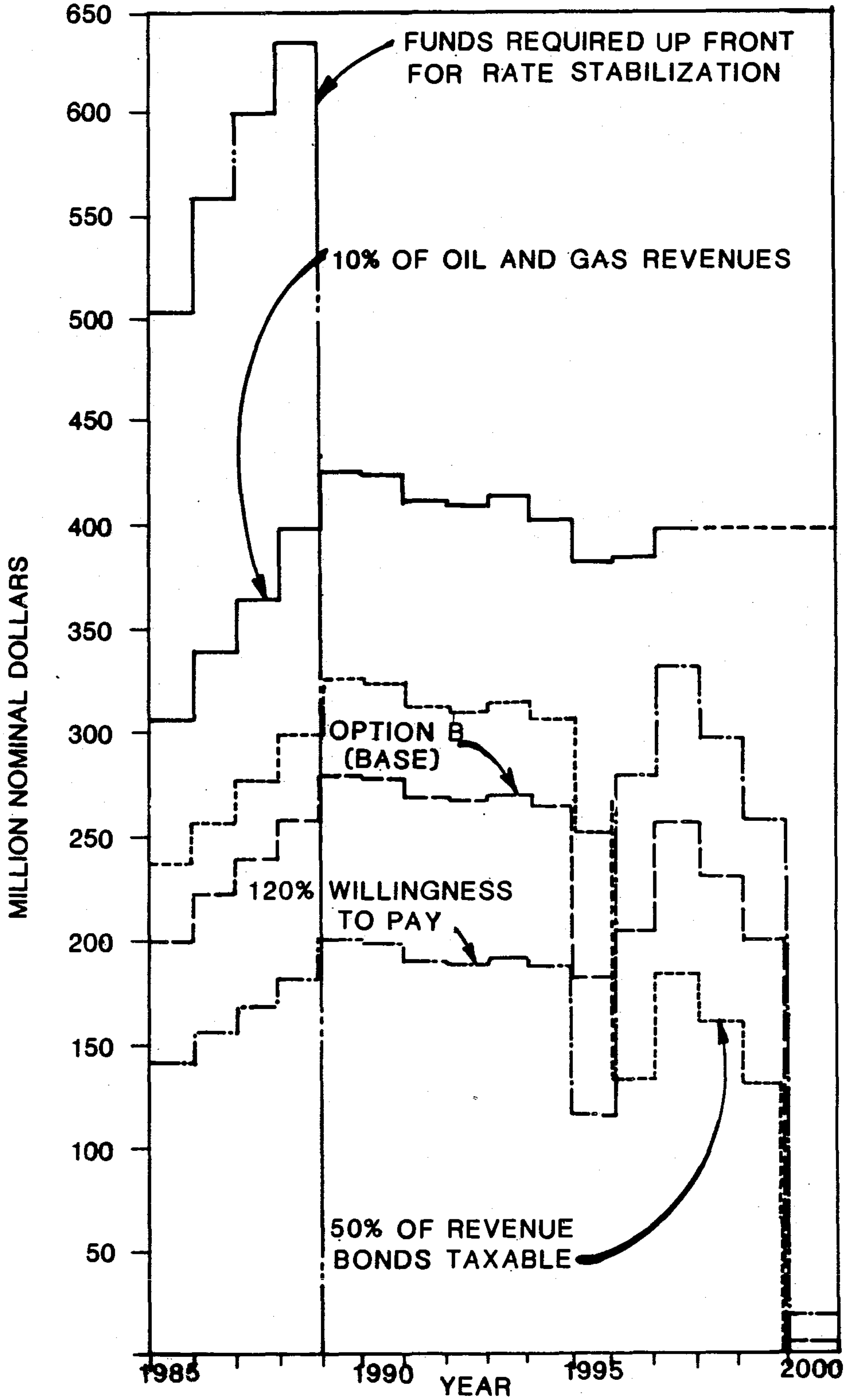
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

ANNUAL STATE CONTRIBUTIONS FOR OPTION A SENSITIVITY CASES

FEBRUARY 1984

EXHIBIT 7.8



ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT UPDATE

ANNUAL STATE CONTRIBUTIONS FOR OPTION B SENSITIVITY CASES

FEBRUARY 1984

8.0 FUTURE ACTIONS

8.1 INTRODUCTION

Chapters 1 through 7 of this Report have provided an Update of the economic and financial feasibility of the Susitna Hydroelectric Project. The purpose of this Chapter is to outline the major future actions to be accomplished prior to construction of the Project. The Power Authority has identified 9 such major actions and these are reviewed below.

8.2 POWER SALES AGREEMENTS

Power sales agreements need to be signed and in place before the start of engineering design for the Project. The Railbelt utilities have been contacted to provide letters of support for the Project. To date, three utilities have provided such letters and others are expected. Although these letters do not obligate the utilities to enter into power sales agreements, they will be used in support of the FERC License Application.

The preparation of utility profiles has been initiated. These profiles, to be developed in cooperation with the utilities, will serve as a basis for cost of energy and Project feasibility analyses. These analyses will provide the analytical tool for the Railbelt utilities and the Power Authority to evaluate the merits of the Project as a basis for signing Letters of Intent. Continued update of these profiles and economic and financial assumptions based on the current estimated cost of the Project will enable the utilities and the Power Authority to enter into power sales agreements.

8.3 FINAL FINANCE PLAN

Before a final finance plan for Susitna can be devised, a number of issues need to be resolved. First, the tax-exempt status of Susitna revenue bonds must be determined. As noted in Chapter 7, if Susitna is financed using revenue bonds on which interest is taxable, the higher interest rate of those bonds will require the State's equity and RSF contribution in the Project to increase. Determining the tax-exempt status will depend upon possible changes to existing law (either Federal or State) or possible restructuring of the Railbelt electric system. As discussed in Chapter 7, all possible changes contain considerable uncertainty. It is also possible that only a request for a Revenue Ruling from the Internal Revenue Service will resolve the question; however, such a request can only be made when the final form of the power sales contracts has been determined and the relative participation of Railbelt utilities is known.

A second issue to be resolved is the ability and willingness of REA to guarantee debt in meaningful amounts. Specific matters to be pursued with REA include the availability of REA funds for Susitna, the quantities expected to be available in the key financing years, and the decision of REA to make necessary commitments. If REA is unwilling to make commitments for funds or if tax-exempt interest rates continue to be more favorable than REA interest rates, Option B would have to be revised.

The third finance issue which needs to be resolved is the willingness of the State to establish a dedicated revenue source to support the Project's financing. As noted in Chapter 7, one means of providing the necessary equity contributions and RSF payments would be the proposed Major Projects Fund. A measure now pending before the Alaska Legislature would place a proposed constitutional amendment creating such a fund on the ballot in November 1984. Careful attention to the funding mechanism provided for in such legislation is necessary to assure that such mechanism is consistent with assumptions made herein.

Fourth, the willingness of Railbelt utilities (and ultimately Railbelt consumers) to pay a premium price for Susitna energy needs to be explored and validated. As noted in Chapter 7, if there was a willingness to pay 20 percent more for wholesale Susitna energy, it would reduce the State's necessary equity and RSF contribution in the Project. However, there is no assurance that such willingness to pay exists.

Finally, the willingness of the State to allow the use of its "moral obligation" to support Project funding needs to be assessed. The completion of Four Dam Pool power sales agreement negotiations embodying moral obligation features will be an indication of the State's willingness to consider such an arrangement for its projects.

8.4 LEGISLATIVE AUTHORIZATION

As with all new projects of the Power Authority, the Legislature must approve the Susitna Project by enacting law that authorizes the Project at an approved construction cost. Prior to such Legislative approval, ALASKA STAT. § 44.83.183 requires that the Power Authority submit a feasibility study and plan of finance to the Office of Management and Budget (OMB) for review. OMB must then submit a report of their findings along with a recommendation of approval or disapproval to the Governor and Legislature within 60 days. Existing law ALASKA STAT. § 44.83.185 further requires that the feasibility study, plan of finance, an independent cost estimate, and the report from OMB be submitted to the Legislature for consideration.

8.5 FERC LICENSE AND OTHER MAJOR PERMITS

A number of regulatory approvals must be obtained before construction of the Susitna Project can commence. Although the most important of these is issuance of a license to construct and operate the Project by the FERC, a number of permits from other Federal and State agencies must also be obtained.

8.5.1 FERC License

The FERC licensing process is currently underway and proceeding toward the target license issuance date of March 18, 1987. The Susitna License Application was accepted for processing by the FERC on July 29, 1983.

Since that time the Power Authority has responded to numerous FERC Staff requests for additional information and has begun preparation for the two-phase hearings tentatively planned for the case. The current schedule calls for "Need for Power" hearings to be held in the Summer of 1984 and for hearings on environmental and dam safety issues to begin in the Spring of 1985. The second phase hearings may be shortened through settlements; if so, it is possible that a FERC License could be issued earlier than the March 1987 target date. As with most regulatory actions, however, there is the possibility of future legal challenges which could delay the effective date of the FERC License.

8.5.2 Other Major Permits

In addition to the FERC License, several Federal, State and local permits will be required to construct the Project. A listing of the major permits, and the agencies involved, follows:

Federal Permits

1. U.S. Army Corps of Engineers, Obstructions of Navigable Waterway Permit
2. U.S. Army Corps of Engineers, Wetlands Fill Permit
3. Bureau of Land Management, Right-of-Way Grant, Land and Gravel Permits
4. Environmental Protection Agency, National Pollution Discharge Elimination System Permit
5. Environmental Protection Agency, New Source Performance Statements

State Permits

1. Department of Environmental Conservation, Water Quality Certificate of Reasonable Assurance, Air Quality Permits to Operate
2. Office of Management and Budget, Coastal Zone Consistency Determination
3. Department of Fish and Game, Fisheries Protection Permits
4. Department of Natural Resources, Water Right, Permit to Construct a Dam, Material Sales, Right-of-Way

Local

1. Matanuska-Susitna Borough, Talkeetna Mountains Special Use District Variance

The Power Authority has been coordinating with permitting agencies for the past two years to insure that timely acquisition of permits will be achieved. Applications have already been submitted for several permits. It is anticipated that, in most instances, the information and analyses being prepared to support the FERC licensing process will also support the processing of necessary Federal, State and local permits.

8.6 DESIGN COMPLETION FOR INITIAL CONTRACTS

Before award of initial construction contracts the Power Authority will require completion of detailed design. This policy will reduce the tendency for construction cost over-runs that has been experienced as a result of the common industry practice of inviting bids on preliminary design documents and then completing design during construction.

8.7 EXTERNAL REVIEW BOARD CONCURRENCE

As will be required by the FERC, the Power Authority has retained a board of qualified, independent engineering consultants to review the design, specifications and construction of the Susitna Project for safety and adequacy. The consultants on this External Review Board have been involved in reviewing the Project's design for the past several years, and will be required to submit a final statement to the FERC indicating their satisfaction with the construction, safety and adequacy of the Project's structures when built. In addition, the Power Authority will require the External Review Board's concurrence on final Project design before proceeding with construction. These measures provide an extra layer of review which ensures that the Project will be built to the highest engineering standards.

8.8 ACCEPTABLE LABOR AGREEMENT

A Project Labor Agreement will be necessary to provide uniformity, stability and continuity during construction and to avoid potentially costly labor disputes. The labor agreement will include standardized working hours, strong work stoppage - no strike clauses, progressive grievance and arbitration procedures, jurisdictional delineation of crafts, and training programs and employment opportunities for Native Alaskans and other minorities.

Since it would not be practical to negotiate wage rates for the length of the job, provisions will be negotiated providing that in the event of a strike by a local bargaining unit, work would continue on the Susitna Project and the wage scale eventually agreed upon would be paid retroactively to those Susitna craftsmen represented by the local unit.

8.9 ACQUISITION OF PROJECT LANDS

Approximately 71,000 acres of land are required for the Susitna Project. The current ownerships of that acreage is distributed as follows:

1. 6,944 acres, State of Alaska
2. 33,350 acres, Native (CIRI and CIRI Villages)
3. 31,105 acres Federal (29,600 of these are State and Native Selected)
4. 270 acres Municipal Lands (Mat-Su Borough and Municipality of Anchorage)

The following methods will be used to obtain the use or title to each land ownership category:

1. State of Alaska lands, easements, classifications
2. Native Land, purchase or land trade, use provisions of Section 24 of Federal Power Act
3. Federal Land, State selection under Statehood Entitlement, Land Use Permits, and Grants of Right-of-Way
4. Municipal, purchase or grant of Right-of-Way

Although land acquisition planning is underway, no land will be acquired until the construction of the Project has been legislatively approved.

8.10 POWER AUTHORITY DECISION TO CONSTRUCT

Before construction of the Susitna Project commences a final decision will be required by the Board of Directors of the Power Authority. The Board will not authorize construction unless it has been shown that the Project is economically and financially feasible and all actions discussed in this Chapter have been completed to the extent necessary.